NUREG-1875, Vol. 2

Safety Evaluation Report
Related to the License Renewal of Oyster Creek Generating Station

Docket No. 50-219

AmerGen Energy Company, LLC

Manuscript Completed: March 2007
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Division of License Renewal
Office of Nuclear Reactor Regulation
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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Oyster Creek Generating Station (OCGS) license renewal application (LRA) by the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff). By letter dated July 22, 2005, AmerGen Energy Company, LLC submitted the LRA for OCGS in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54). AmerGen Energy Company, LLC requests renewal of the operating license for OCGS (Facility Operating License Number DPR-16), for a period of 20 years beyond the current expiration date of midnight April 9, 2009.

OCGS is located in Lacey Township, Ocean County, New Jersey, approximately two miles south of the community of Forked River, two miles inland from the shore of Barnegat Bay, and nine miles south of Toms River, New Jersey. The NRC issued the OCGS construction permit on December 15, 1964, the OCGS provisional operating license on April 9, 1969, and the OCGS operating license on July 2, 1991. OCGS is a single unit facility with a single-cycle, forced-circulation boiling water reactor (BWR)-2 and a Mark 1 containment. The nuclear steam supply system was furnished by General Electric and the balance of the plant was originally designed and constructed by Burns & Roe. OCGS licensed power output is 1930 megawatt thermal with a gross electrical output of approximately 619 megawatt electric.

This SER presents the status of the staff's review of information submitted through February 15, 2007, the cutoff date for consideration in the SER. The staff identified open items that were resolved before the staff made a final determination on the application. SER Section 1.5 summarizes these items and their resolution. Section 6.0 provides the staff's final conclusion on the review of the OCGS LRA.

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ABBREVIATIONS

AAC	alternate AC
ACAD	atmospheric containment air dilution system
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductor steel reinforced
ADAMS	Agency Document Access Management System
ADS	automatic depressurization system
AERM	aging effect requiring management
AFU	air filtration unit
AmerGen	AmerGen Energy Company, LLC
AMP	aging management program
AMR	aging management review
APCSB	Auxiliary and Power Conversion Systems Branch
API	American Petroleum Institute
ART	adjusted reference temperature
ASA	American Standards Association
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
BOP	balance of plant
BTP	Branch Technical Position
BWROG	BWR Owner's Group
BWR	boiling water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAP	corrective action program
CASS	cast austenitic stainless steel
CDF	core damage frequency
CFR	*Code of Federal Regulations*
CI	confirmatory item
CIS	containment inerting system
CIV	containment isolation valve
CLB	current licensing basis
CMAA	Crane Manufactures Association of America
CRD	control rod drive
CRL	component record list
CS	core spray
CST	condensate storage tank
CUF	cumulative usage factor
CVB	containment vacuum breaker
CWS	circulating water system
DBA	design basis accident
DBD	design basis document

DBE	design basis event
DC	direct current
DFED	drywell floor and equipment drains
DG	diesel generator
DWST	demineralized water storage tank
ECCS	emergency core cooling systems
ECP	electrochemical corrosion potential or electrochemical potential
ECT	eddy current testing
EDG	emergency diesel generator
EDGCW	emergency diesel generator cooling water
EFPY	effective full-power years
EMA	equivalent margin analysis
EMRV	electromatic relief valve
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESW	emergency service water
F	Fahrenheit
FAC	flow-accelerated corrosion
F_{en}	environmental fatigue factor
FFW	final feedwater facility
FHAR	Fire Hazards Analysis Report
FP	fire protection
FRCT	Forked River Combustion Turbines
FS	feedwater system
FSSD	fire safe shutdown
FWH	feedwater heater
GALL	Generic Aging Lessons Learned
GDC	general design criteria or general design criterion
GE	General Electric
GEIS	Generic Environmental Impact Statement
GL	generic letter
GPUN	General Public Utilities Nuclear Corporation
GSI	generic safety issue
HELB	high-energy line break
HEPA	high efficiency particulate air
HP	high pressure
HPCI	high pressure coolant injection (system)
HVAC	heating, ventilation, and air conditioning
HVS	hardened vent system
HWC	hydrogen water chemistry
HX	heat exchanger
I&C	instrumentation and controls

IASCC	irradiation assisted stress corrosion cracking
ICS	isolation condenser system
ID	inside diameter or identification
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IPE	individual plant examination
IRM	intermediate range monitoring
ISG	interim staff guidance
ISI	inservice inspection
ISP	integrated surveillance program
ITS	important to safety
KIP	1000 lb; or 1 kilo-pound
ksi	one KIP per square inch, 1000 psi
kV	kilovolt
LBB	leak-before-break
LER	licensee event report
LLRT	local leak rate test
LOCA	loss of coolant accident
LOOP	loss of offsite power
LPRM	local power range monitor
LR	license renewal
LRA	license renewal application
MCC	motor control center
MEL	master equipment list
Met Tower	Meteorological Tower
MFED	miscellaneous floor and equipment drain
MFL	magnetic flux leakage
MG	motor generator
MGAS	main generator and auxiliary system
MIC	microbiologically influenced corrosion
MSIV	main steam isolation valve
MSS	main steam system
MTAS	main turbine and auxiliary systems
MUD	makeup demineralizer
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NESC	Nuclear Electrical Safety Code
NFPA	National Fire Protection Association
NITS	not important to safety
NMMS	noble metals monitoring system
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission

NSR	nonsafety-related
NUREG	U.S. Nuclear Regulatory Commission Regulatory Guide
OCCW	open-cycle cooling water
OCGS	Oyster Creek Generating Station
ODSCC	outside-diameter stress-corrosion cracking
OI	open item
P&ID	piping and instrumentation diagram
PASS	post accident sampling system
PBD	program basis document
PCIS	primary containment isolation system
PDI	performance demonstration initiative
PM	preventive maintenance
PORC	Plant Operations Review Committee
PP	position paper
PT	penetrant testing
P-T	pressure-temperature limit curves
PTFE	polytetrafluoroethylene
PTS	pressurized thermal shock
PUAR	plant-unique analyses report
PWR	pressurized water reactor
PWSCC	primary water stress-corrosion cracking
RAI	request for additional information
RBCCW	reactor building closed cooling water
RBVS	reactor building ventilation system
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RDODS	roof drains and overboard discharge system
RFED	reactor building floor and equipment drains
RFP	reactor feed pump
RG	regulatory guide
RHCS	reactor head cooling system
RHR	residual heat removal (system)
ROPS	reactor overfill protection system
RPS	reactor protection system
RPT	recirculation pump trip
RPV	reactor pressure vessel
RT_{NDT}	reference temperature nil ductility transition
RVI	reactor vessel internals
RWCU	reactor water cleanup system
RWSS	reactor water sample system
SBLC	standby liquid control
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SCS	shutdown cooling system

SE	safety evaluation
SEN	significant event notification
SEP	Systemic Evaluation Program
SER	safety evaluation report
SFPCS	spent fuel pool cooling system
SGTS	standby gas treatment system
SHE	standard hydrogen electrode
SI	Structural Integrity Associates, Inc.
SLCS	standby liquid control system
S_{mc}	stress intensity
SOC	statement of consideration
SR	safety-related
SP	specification
SR	safety-related
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SS	stainless steel
SSC	system, structure, and component
SV	solenoid valve
SWS	service water system
t	thickness
TBCCW	turbine building closed cooling water
TDR	time domain reflectometry
TIP	traveling in-core probe
TLAA	time-limited aging analysis
TOC	total organic carbon
TR	topical report
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
USAS	United States of America Standard
USE	upper-shelf energy
UT	ultrasonic testing
VFLD	vessel flange leak detection
VT	visual examination

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) contains the evaluation of aging management programs (AMPs) and aging management reviews (AMRs) for Oyster Creek Generating Station (OCGS) by the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff). In Appendix B of its license renewal application (LRA), AmerGen Energy Company, LLC, (AmerGen or the applicant) described the 56 AMPs that it relies on to manage or monitor the aging of long-lived, passive structures and components (SCs).

In LRA Section 3, the applicant provided the results of the AMRs for those SCs identified in LRA Section 2 as within the scope of license renewal and subject to an AMR.

3.0 Applicant's Use of the Generic Aging Lessons Learned Report

In preparing its LRA, the applicant credited draft NUREG-1801, "Generic Aging Lessons Learned (GALL) Report, " dated January 2005. The use of the draft January 2005 GALL Report (draft GALL Report) is in accordance with the January 13, 2005, meeting between the NRC and Nuclear Energy Institute (NEI) on updating license renewal guidance documents, as summarized and documented in a meeting summary dated February 17, 2005 (ADAMS Accession Number ML050490142). The GALL Report contains the staff's generic evaluation of the existing plant programs, and documents the technical basis for determining where existing programs are adequate without modification, and where they should be augmented for the period of extended 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 license renewal SCs without change. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that the programs at its facility correspond to those reviewed and approved in the Report.

In AmerGen letter dated March 30, 2006, (ML060950408), the applicant summarized the results of its reconciliation of the LRA with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Revision 1, and GALL Report, Revision 1, both dated September 2005. The applicant provided details of this reconciliation in its document, "Reconciliation of Program and Line Item Differences Between January 2005 Draft NUREG-1801 and September 2005 Revision 1 NUREG-1801, Revision 1," dated March 24, 2006. In its reconciliation document, the applicant identified differences between the draft GALL Report AMPs and AMR line items used in the LRA with those in the GALL Report Revision 1. This reconciliation document was reviewed by the staff and treated as a supplement to the LRA.

The purpose of the GALL Report is to provide the staff with a summary of staff-approved AMPs to manage or monitor the aging of SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs the time, effort, and resources used to review the LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a reference for applicants and staff reviewers to quickly identify AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies: (1) systems, structures, and components (SSCs), (2) SC materials, (3) environments to which the SCs are exposed, (4) the aging effects associated with the materials and environments, (5) the AMPs credited with managing or monitoring the aging effects, and (6) recommendations for further applicant evaluations of aging management for certain component types.

To determine whether using the GALL Report would improve the efficiency of the license renewal review, the staff conducted a demonstration project to test the GALL Report process and to determine the format and content of a safety evaluation based on it. The results of the demonstration project confirmed that the GALL Report process will improve the efficiency and effectiveness of the LRA review and maintain the staff's focus on public health and safety. SRP-LR Revision 1 dated September 2005 was prepared based on both the GALL Report model and lessons learned from the demonstration project.

The staff performed its review in accordance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants, " the guidance of the SRP-LR, and the guidance of the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMRs and associated AMPs during the weeks of October 3-7, 2005, January 23-27, 2006, February 13-17, 2006, and April 19-20, 2006. The staff documented the results of its audit and review in "Audit and Review Report for Plant Aging Management Reviews and Programs, Oyster Creek Generating Station (OCGS)" (Audit and Review Report) dated August 18, 2006 (ADAMS Accession Number ML062280051). The onsite audits and reviews are designed to maximize the efficiency of the staff's review of the LRA. The applicant can respond to questions and the staff can readily evaluate the applicant's responses. As a result, the need for formal correspondence between the staff and the applicant is reduced, and the result is an improvement in the review's efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format, as agreed to between the staff and the NEI, by letter dated April 7, 2003 (ML030990052). This revised LRA format incorporates lessons learned from the staff's reviews of the previous LRAs.

The organization of LRA Section 3 parallels SRP-LR Chapter 3. The AMR results in LRA Section 3 are presented in the following two table types:

- Table 1s: Table 3.x.1 – where "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, and "1" indicates the first table type in LRA Section 3.
- Table 2s: Table 3.x.2.1.y – where "3" indicates the LRA section number; "x" indicates the subsection number from the GALL Report; "2" indicates the second table type in LRA Section 3; "1" indicates the summary subsection for materials, environments, aging effects, and AMPs; and "y" indicates the system table number.

In its Table 1s the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In its Table 2s the applicant identified the linkage between the scoping and screening results in LRA Section 2 and the AMRs in LRA Section 3.

3.0.1.1 Overview of Table 1

Each Table 3.x.1 (Table 1) provides a summary comparison of how the facility aligns with the corresponding tables in the GALL Report. The tables are essentially the same as Tables 1 through 6 in the GALL Report, except that the "ID" column has been deleted, the "Type" column has been replaced by an "Item Number" column, and the "Related Generic Item" and "Unique Item" columns have been replaced by a "Discussion" column. The "Item Number" column provides the staff reviewer with a means to cross-reference Table 2s with Table 1s. The "Discussion" column is used by the applicant to provide clarifying information. The following are examples of information that might be in this column:

- further evaluation recommended - information or reference to where that information is located
- the name of a plant-specific program used
- exceptions to GALL Report assumptions
- a discussion of how the line is consistent with the corresponding line item in the GALL Report when it may not be intuitively obvious
- a discussion of how the item is different from the corresponding line item in the GALL Report (e.g., when there is exception taken to a GALL AMP)

The format of each Table 1 allows the staff to align a specific row in the table with the corresponding GALL Report table row so that the consistency can be easily checked. It should be noted that, since the LRA was prepared based on the draft January 2005 version of the GALL Report, there is not always a one-to-one correspondence between the LRA Table 1 line items and the line items in the September 2005 Revision 1 of the GALL Report, which was used as the basis for this safety evaluation.

3.0.1.2 Overview of Table 2

Each Table 3.x.2.1.y (Table 2) provides the detailed results of the AMRs for those components identified in LRA Section 2 as subject to an AMR. The LRA contains a Table 2 for each of the systems or structures within a specific system grouping (e.g., reactor coolant systems, engineered safety features, auxiliary systems, etc.). For example, the engineered safety features group contains tables specific to the core spray system, containment spray system, and standby gas treatment system. Each Table 2 consists of the following nine columns:

(1) Component Type – The first column identifies the component types from LRA Section 2 that are subject to an AMR. The component types are listed in alphabetical order.

(2) Intended Function – The second column identifies the license renewal intended functions for the listed component types. Definitions of intended functions are contained within LRA Table 2.1-1.

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

(4) Environment – The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated and a list of these environments is provided in LRA Tables 3.0-1 and 3.0-2, respectively.

(5) Aging Effect Requiring Management – The fifth column lists aging effects requiring management (AERMs). As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.

(6) Aging Management Programs – The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.

(7) NUREG-1801 Volume 2 Item – The seventh column lists the GALL Report item(s) that the applicant identified as similar to the AMR results in the LRA. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the items in the GALL Report. If there were no corresponding items in the GALL Report, the applicant left the column blank. In this way, the applicant identified in the LRA tables AMR results that correspond to the items in the GALL Report tables.

(8) Table 1 Item – The eighth column lists the corresponding summary item number from LRA Table 1. If the applicant identified in each LRA Table 2 AMR results consistent with the GALL Report, then the associated Table 1 line item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, column eight is left blank. In this manner, the information from the two tables can be correlated.

(9) Notes – The ninth column lists the corresponding notes that the applicant used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes identified by letters were developed by an NEI work group. These notes will be used in future LRAs. Any plant-specific notes are identified by a number and provide additional information concerning the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

The staff conducted the following three types of evaluations of the AMRs and associated AMPs:

(1) For items that the applicant stated were consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency with the GALL Report.

(2) For items that the applicant stated were consistent with the GALL Report with exception(s) and/or enhancement(s), the staff conducted either an audit or a technical review of the item to determine consistency with the GALL Report. In addition, the staff conducted either an audit or a technical review of the applicant's technical justifications for the exceptions and of the adequacy of the enhancements.

The SRP-LR states that an applicant may take one or more exceptions to specific GALL AMPs program elements. However, any deviation or exception to the GALL AMP should be described and justified. Therefore, the staff considers exceptions as portions of the GALL AMP that the applicant does not intend to implement.

In some cases, an applicant may choose an existing plant program that does not meet all the program elements defined in the GALL AMP. However, the applicant may make a commitment to augment the existing program to satisfy the GALL AMP prior to the period of extended operation. Therefore, the staff considers these revisions or additions to be enhancements. Enhancements include, but are not limited to, those activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

(3) For other items, the staff conducted a technical review to determine whether the applicant conforms with the requirements in 10 CFR 54.21(a)(3).

The staff performed audits and technical reviews of the applicant's AMPs and AMRs. These audits and technical reviews determined whether the aging effects on SCs can be adequately managed so that their intended function(s) can be maintained consistent with the plant's current licensing basis (CLB) for the period of extended operation as required by 10 CFR Part 54. Detailed results of the staff's onsite audit and review are documented in the Audit and Review Report.

3.0.2.1 Review of AMPs

For those AMPs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify consistency of the applicant's AMPs with the GALL AMPs. For each AMP with one or more deviations, the staff evaluated each deviation to determine whether it was acceptable and whether the AMP, as modified, would adequately manage the aging effect(s) for which it was credited. For AMPs not evaluated in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR, Appendix A.

1. Scope of the Program – Scope of the program should include the specific SCs subject to an AMR for license renewal.
2. Preventive Actions – Preventive actions should prevent or mitigate aging degradation.
3. Parameters Monitored or Inspected – Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended function(s).
4. Detection of Aging Effects – Detection of aging effects should occur before there is a loss of structure or component intended function(s). Such detection includes 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 predictability of the extent of degradation as well as timely corrective or mitigative actions.
6. Acceptance Criteria – Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all CLB 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 – Confirmation process should ensure that preventive actions are adequate and that 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 of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide

objective evidence for the conclusion that the effects of aging will be adequately managed so that the SC intended function will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) are documented in the Audit and Review Report and summarized in SER Section 3.0.3.

The staff reviewed the applicant's Quality Assurance Program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the Quality Assurance Program included assessment of the following program elements: (7) corrective actions, (8) confirmation process, and (9) administrative controls.

The staff reviewed the information concerning the operating experience program element (10) and documented its evaluation in the Audit and Review Report. The staff also included a summary of the program in SER Section 3.0.3.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information on whether the AMRs correlate with the AMRs of the GALL Report. For AMRs in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular component type within a system. The AMRs that correlate between a combination in a Table 2 and a combination in the GALL Report were identified by a referenced item number in column seven, "NUREG-1801 Vol. 2 Item." The staff also conducted onsite audits to verify the correlations. A blank column seven indicates that the applicant was unable to locate an appropriate correlating combination in the GALL Report. The staff conducted a technical review of these combinations inconsistent with the GALL Report. The next column, "Table 1 Item," provides a reference number indicating the correlating row in Table 1.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and associated AMPs that it reviewed, the staff also reviewed the UFSAR supplement, which summarizes the applicant's programs and activities for managing aging effects for the period of extended operation as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In its review the staff used the LRA, LRA supplements, OCGS reconciliation document, SRP-LR, and the GALL Report.

During the onsite audit, the staff examined the applicant's justifications, as documented in the Audit and Review Report, to verify that the applicant's activities and programs will adequately manage aging effects on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

SER Table 3.0.3-1, provided below, presents the AMPs that the applicant takes credit for to manage aging in the listed SCs and whether they are consistent with the GALL Report. The table also indicates the SER section in which the staff's evaluation is documented.

Table 3.0.3-1 OCGS Aging Management Programs

OCGS AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Existing AMPs				
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)	Consistent with exceptions and enhancements	XI.M1	reactor vessel, internals, and reactor coolant systems; ESFs; auxiliary systems; steam and power conversion system	3.0.3.2.1
Water Chemistry (B.1.2)	Consistent with exceptions	XI.M2	reactor vessel, internals, and reactor coolant systems; ESFs; auxiliary systems; steam and power conversion system; containment, structures, component supports, and piping and component insulation	3.0.3.2.2
Reactor Head Closure Studs (B.1.3)	Consistent with exception	XI.M3	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	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	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	reactor vessel, internals, and reactor coolant systems	3.0.3.2.6
BWR Stress Corrosion Cracking (B.1.7)	Consistent with exception	XI.M7	reactor vessel, internals, and reactor coolant systems; ESFs; auxiliary systems	3.0.3.2.7
BWR Penetrations (B.1.8)	Consistent with exceptions	XI.M8	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	reactor vessel, internals, and reactor coolant systems	3.0.3.2.9
Flow-Accelerated Corrosion (B.1.11)	Consistent	XI.M17	steam and power conversion system	3.0.3.1.2

OCGS AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Bolting Integrity (B.1.12)	Consistent with exception	XI.M18	reactor vessel, internals, and reactor coolant systems; ESFs; 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	auxiliary systems	3.0.3.2.11
Closed-Cycle Cooling Water System (B.1.14)	Consistent with exception	XI.M21	auxiliary systems, steam and power conversion system	3.0.3.2.12
Boraflex Rack Management Program (B.1.15)	Consistent with exception	XI.M22	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 exception and enhancements	XI.M23	auxiliary systems	3.0.3.2.14
Compressed Air Monitoring (B.1.17)	Consistent	XI.M24	auxiliary systems	3.0.3.1.3
BWR Reactor Water Cleanup System (B.1.18)	Consistent with exception	XI.M25	auxiliary systems	3.0.3.2.15
Fire Protection (B.1.19)	Consistent with exception and enhancements	XI.M26	auxiliary systems	3.0.3.2.16
Fire Water System (B.1.20)	Consistent with enhancements	XI.M27	auxiliary systems	3.0.3.2.17
Fuel Oil Chemistry (B.1.22)	Consistent with exceptions and enhancements	XI.M30	auxiliary systems	3.0.3.2.19
Reactor Vessel Surveillance (B.1.23)	Consistent with enhancement	XI.M31	reactor vessel, internals, and reactor coolant systems	3.0.3.2.20
Buried Piping Inspection (B.1.26)	Consistent with exception and enhancement	XI.M34	ESFs; auxiliary systems; steam and power conversion system	3.0.3.2.22
ASME Section XI, Subsection IWE (B.1.27)	Consistent with exception	XI.S1	auxiliary systems; containment, structures, component supports, and piping and component insulation	3.0.3.2.23

OCGS AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
ASME Section XI, Subsection IWF (B.1.28)	Consistent with exception and enhancements	XI.S3	containment, structures, component supports, and piping and component insulation	3.0.3.2.24
10 CFR Part 50, Appendix J (B.1.29)	Consistent	XI.S4	auxiliary systems; containment, structures, component supports, and piping and component insulation	3.0.3.1.5
Masonry Wall Program (B.1.30)	Consistent	XI.S5	containment, structures, component supports, and piping and component insulation	3.0.3.1.6
Structures Monitoring Program (B.1.31)	Consistent with enhancements	XI.S6	reactor vessel, internals, and reactor coolant systems; ESFs; auxiliary systems; steam and power conversion system; containment, structures, component supports, and piping and component insulation FRCT Mechanical Systems FRCT Electrical Systems FRCT Structural Systems Met Tower Structural Systems Radio Com. System	3.0.3.2.25
RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with enhancements	XI.S7	containment, structures, component supports, and piping and component insulation	3.0.3.2.26
Protective Coating Monitoring and Maintenance Program (B.1.33)	Consistent with enhancements	XI.S8	containment, structures, component supports, and piping and component insulation	3.0.3.2.27
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits (B.1.35)	Consistent with enhancements	XI.E2	electrical components	3.0.3.2.28
Periodic Testing of Containment Spray Nozzles (B.2.1)	Plant-specific	NA	ESFs	3.0.3.3.1

OCGS AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Lubricating Oil Monitoring Activities (B.2.2)	Plant-specific	NA	reactor vessel, internals, and reactor coolant systems; auxiliary systems; steam and power conversion system	3.0.3.3.2
Generator Stator Water Chemistry Activities (B.2.3)	Plant-specific	NA	steam and power conversion system	3.0.3.3.3
Periodic Inspection of Ventilation Systems (B.2.4)	Plant-specific	NA	ESFs; auxiliary systems	3.0.3.3.4
Periodic Monitoring of Combustion Turbine Power Plant (B.2.7)	Plant-specific	NA	This AMP was deleted.	3.0.3.3.7
Metal Fatigue of Reactor Coolant Pressure Boundary (B.3.1)	Consistent with enhancement	X.M1	reactor vessel, internals, and reactor coolant systems	3.0.3.2.29
Environmental Qualification (EQ) Program (B.3.2)	Consistent	X.E1	electrical components	3.0.3.1.9
New AMPs				
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.1.10)	Consistent	XI.M13	reactor vessel, internals, and reactor coolant systems	3.0.3.1.1
Aboveground Outdoor Tanks (B.1.21)	Consistent with exception	XI.M29	auxiliary systems; steam and power conversion system	3.0.3.2.18
One-Time Inspection (B.1.24)	Consistent with exceptions	XI.M32	reactor vessel, internals, and reactor coolant systems; ESFs; auxiliary systems; steam and power conversion system; containment, structures, component supports, and piping and component insulation	3.0.3.2.21
Selective Leaching of Materials (B.1.25)	Consistent	XI.M33	ESFs; auxiliary systems; steam and power conversion system	3.0.3.1.4

OCGS AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.34)	Consistent	XI.E1	electrical components	3.0.3.1.7
Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36)	Consistent	XI.E3	electrical components FRCT Electrical Systems	3.0.3.1.8
Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.40)	Consistent	XI.E6	electrical components, metallic parts	3.0.3.1.10
Periodic Inspection Program (B.2.5)	Plant-specific	NA	auxiliary systems; steam and power conversion system	3.0.3.3.5
Wooden Utility Pole Program (B.2.6)	Plant-specific	NA	electrical components	3.0.3.3.6
New AMPs for Forked River Combustion Turbines (FRCT), Radio Communications System, and Meteorological Tower				
Bolting Integrity - FRCT (B.1.12A)	Consistent with exceptions	XI.M18	FRCT Mechanical Systems	3.0.3.2.30
Closed-Cycle Cooling Water System - FRCT (B.1.14A)	Consistent with exception	XI.M21	FRCT Mechanical Systems	3.0.3.2.31
Aboveground Outdoor Tanks - FRCT (B.1.21A)	Consistent with exception	XI.M29	FRCT Mechanical Systems	3.0.3.2.32
Fuel Oil Chemistry - FRCT (B.1.22A)	Consistent with exceptions	XI.M30	FRCT Mechanical Systems	3.0.3.2.33
One-Time Inspection - FRCT (B.1.24A)	Consistent with exceptions	XI.M32	FRCT Mechanical Systems	3.0.3.2.34
Selective Leaching of Materials - FRCT(B.1.25A)	Consistent with exception	XI.M33	FRCT Mechanical Systems	3.0.3.2.35

OCGS AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Buried Piping Inspection - FRCT (B.1.26A)	Consistent with exception	XI.M34	FRCT Mechanical Systems Radio Com. System	3.0.3.2.36
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT (B.1.38)	Consistent with exception	XI.M38	FRCT Mechanical Systems	3.0.3.2.37
Lubricating Oil Analysis - FRCT (B.1.39)	Consistent with exceptions	XI.M39	FRCT Mechanical Systems	3.0.3.2.38
Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	Consistent with three GALL AMP elements	XI.E1 XI.E3 XI.E4 (plant-specific program)	FRCT Electrical Systems	3.0.3.3.8
Periodic Inspection Program - FRCT (B.2.5A)	N/A	OCGS plant-specific program	FRCT Mechanical Systems	3.0.3.3.9
Buried Piping Inspection-Met Tower (B.1.26B)	Consistent with exceptions	XI.M34	Met Tower Mechanical Systems	3.0.3.2.39

3.0.3.1 AMPs That Are Consistent with the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as consistent with the GALL Report:

1. Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.1.10)
2. Flow-Accelerated Corrosion (B.1.11)
3. Compressed Air Monitoring (B.1.17)
4. Selective Leaching of Materials (B.1.25)
5. 10 CFR Part 50, Appendix J (B.1.29)
6. Masonry Wall Program (B.1.30)
7. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.34)
8. Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36)
9. Environmental Qualification (EQ) Program (B.3.2)
10. Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.40)

3.0.3.1.1 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

Summary of Technical Information in the Application. In LRA Section B.1.10, the applicant described the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program as a new program consistent with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)."

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program provides 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 program will include a component-specific evaluation of the loss of fracture toughness. A supplemental inspection of components where loss of fracture toughness may affect function of the component will use 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. In SER Section 3.0.2.1, the staff reviewed the program elements of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program and basis documents for consistency with GALL AMP XI.M13. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.1. The staff found the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program consistent with GALL AMP XI.M13, including the associated operating experience attribute.

Operating Experience. In LRA Section B.1.10, the applicant explained that the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is a new program, and therefore, no operating experience exists for the program.

In Program Basis Document (PBD)-AMP-B.1.10, the applicant stated that research data on both laboratory-aged and service-aged materials have confirmed that loss of fracture toughness could occur in some reactor vessel CASS internal components. Internal reactor vessel CASS components are periodically examined, but no degradation has been identified to date. Because the thermal aging and neutron irradiation embrittlement of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is new, a review of plant operating experience cannot confirm at this time that loss of fracture toughness of CASS is a factor.

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program will include a component-specific evaluation to assess susceptibility to 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 using the criteria provided in GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel." This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.

The staff also reviewed the operating experience provided in the basis document, and interviewed the applicant's technical personnel 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.

UFSAR Supplement. In LRA Section A.1.10, the applicant provided the UFSAR supplement for the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. In LRA Section B.1.11, the applicant described the existing Flow-Accelerated Corrosion (FAC) Program as consistent with GALL AMP XI.M17, Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion Program is based on Electric Power Research Institute (EPRI) guidelines in NSAC-202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program." 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 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 followup inspections to confirm the predictions. Inspections use ultrasonic, radiographic, visual, or other approved testing techniques capable of detecting wall thinning. Repairs and replacements are performed as necessary.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with GALL AMP XI.M17. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.2. The staff determined that this AMP is consistent with GALL AMP XI.M17, including the associated operating experience attribute.

Operating Experience. In the LRA Section B.1.11, the applicant states that the operating experience of the Flow-Accelerated Corrosion Program activities shows that the program can determine susceptible locations for FAC, predict the component degradation, and detect the wall thinning in piping, valves, and feedwater heater shells due to FAC. 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" feed pump 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-inch pipe, one 90-degree elbow, and three 45-degree elbows were replaced with chrome-moly material.

During cycle 17, ultrasonic (UT) inspections were performed on the high pressure (HP) feedwater heater (FWH) shells. These inspections were driven by the Point Beach Nuclear Power Plant FWH shell rupture event and other industry experience, as described in Significant Event Notification (SEN) 199 and information notice (IN) 99-19. 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 determined to be acceptable through the remainder of the operating cycle, at which time further inspections and repairs were performed.

A number of steam leaks has been associated with flash tank and drain tank piping and attached piping. A condition report was initiated to determine why the FAC scope and inspection frequency did not prevent these failures from occurring. As documented in the condition report response, the Corporate FAC Program Manager performed an oversight self-assessment of the Flow-Accelerated Corrosion Program at OCGS in February 2003. Two deficiencies in the program were identified: (1) the system susceptibility evaluation did not meet EPRI or procedural requirements and (2) plant model input to the Flow-Accelerated Corrosion Program software tool, CHECWORKS, contained a number of errors and omissions. These deficiencies were identified as the primary reasons the Flow-Accelerated Corrosion Program has missed identifying components that developed leaks due to FAC. A Flow-Accelerated Corrosion Program improvement project was implemented to correct the deficiencies. The project was completed in August 2003. As a result of the improvement project, the risk of a FAC failure in unidentified susceptible lines has been reduced, and FAC inspections and outage inspection costs and time have been optimized since the tools are now available to assist in selecting the right outage inspection scope.

The staff 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 staff also reviewed the operating experience provided in the 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, the staff determined that the applicant's Flow-Accelerated Corrosion program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

<u>UFSAR Supplement</u>. In LRA Section A.1.11, the applicant provided the UFSAR supplement for the Flow-Accelerated Corrosion Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Compressed Air Monitoring

Summary of Technical Information in the Application. In LRA Section B.1.17, the applicant described the existing Compressed Air Monitoring Program as consistent with GALL AMP XI.M24, Compressed Air Monitoring.

The Compressed Air Monitoring Program ensures dewpoint, particulates, and suspended hydrocarbons are kept 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 5 years and visual inspections. The activities are consistent with the OCGS response to Generic Letter (GL) 88-14, "Instrument Air Supply Problems," and utilize guidance and standards provided by the Institute of Nuclear Power Operations (INPO) Significant Operating Experience Report (SOER) 88-01, EPRI TR-108147, and American Society of Mechanical Engineers (ASME) OM-S/G-1998, Part 17. Testing and monitoring activities are implemented through station procedures.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.3. The staff found the Compressed Air Monitoring Program consistent with GALL AMP XI.M24, including the associated operating experience attribute.

Operating Experience. In LRA Section B.1.17, the applicant stated that the reliability of the 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 the GALL Report, and replacement dryers have increased air quality as indicated by air quality test results and dewpoint monitoring.

The staff also reviewed the operating experience provided in the 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, the staff determined that the applicant's Compressed Air Monitoring program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.17, the applicant provided the UFSAR supplement for the Compressed Air Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Compressed Air Monitoring Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 Selective Leaching of Materials

Summary of Technical Information in the Application. In LRA Section B.1.25, the applicant described the new Selective Leaching of Materials Program as consistent with GALL AMP XI.M33, "Selective Leaching of Materials."

The Selective Leaching of Materials Program will consist of one-time inspections to determine whether loss of material due to selective leaching occurs. The scope of the program includes such susceptible components as piping, pumps, and valves within the scope of license renewal 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 percent zinc, and aluminum bronze with greater than 8 percent aluminum. The One-Time Inspection Program includes visual inspections consistent with ASME Code Section XI visual examination (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 potentially aggressive environments. The purpose of the program is to determine whether loss of material due to selective leaching occurs. If selective leaching is found, the program evaluates the effect on the ability of the affected components to perform intended function(s) for the period of extended operation and the need to expand the sample of components to be tested. The program will be implemented prior to the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.5. The staff found the Selective Leaching of Materials Program consistent with GALL AMP XI.M33, including the associated operating experience attribute.

Operating Experience. In LRA Section B.1.25, the applicant explained that the Selective Leaching of Materials Program is new and, therefore, no programmatic operating experience is available. Industry operating experience identifies graphitization of pump components from long-term submersion in saltwater environments. Any degradation of components due to selective leaching at OCGS may have been classified with different aging mechanisms and the component deficiency corrected by repair or replacement, including the cast iron circulating water and service water (SW) pump subcomponents that have been replaced with stainless steel. Sample inspections at OCGS will include cast iron components in a saltwater environment.

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 operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Selective Leaching of Materials

Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.25, the applicant provided the UFSAR supplement for the Selective Leaching of Materials Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Selective Leaching of Materials Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 10 CFR Part 50, Appendix J

Summary of Technical Information in the Application. In LRA Section B.1.29, the applicant described the existing 10 CFR Part 50, Appendix J Program as consistent with GALL AMP XI.S4, "10 CFR 50, Appendix J."

The 10 CFR Part 50, Appendix J Program provides for detection of age-related pressure boundary degradation and loss of leak tightness due to such aging effects as loss of material, cracking, or loss of preload in the primary containment and various systems penetrating the 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 program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR 50 Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, Regulatory Guide (RG) 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 assure that leakage through the primary containment and systems and components penetrating the primary containment does not exceed allowable 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) on isolation valves and containment access penetrations comply with frequency requirements of 10 CFR 50 Appendix J, Option B.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.5. The staff determined that the 10 CFR Part 50, Appendix J Program is consistent with GALL AMP XI.S4, including the associated operating experience attribute.

Operating Experience. In LRA Section B.1.29, the applicant explained that the industry has found the 10 CFR Part 50, Appendix J Program effective in maintaining the pressure integrity of the containment boundaries, including identification of leakage within the various system pressure boundaries.

The OCGS facility has demonstrated experience in effectively maintaining the integrity of the containment boundaries as evidenced by the selection of Option B of 10 CFR 50 Appendix J leakage testing requirements. The station has experienced "as found" LLRT results in excess of individual containment penetration administrative limits. Evaluations were performed and corrective actions were taken to restore the individual penetration leakage rates to within the established administrative leakage limits in accordance with the Appendix J testing program. Some site-specific examples include the following:

- In 2000, an 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 in the next refueling outage.
- In 2002, an 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.
- In 2004, an 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.

The staff reviewed the operating experience provided in the LRA and PBD, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's 10 CFR Part 50, Appendix J Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.29, the applicant provided the UFSAR supplement for the 10 CFR Part 50, Appendix J Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's 10 CFR Part 50, Appendix J Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 Masonry Wall Program

Summary of Technical Information in the Application. In LRA Section B.1.30, the applicant described the existing Masonry Wall Program as consistent with GALL AMP XI.S5, "Masonry Wall Program."

The Masonry Wall Program is part of the Structures Monitoring Program. It 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 with intended function(s) in accordance with 10 CFR 54.4. The program requires inspection of masonry walls for cracking on a frequency of four years, so that the established evaluation basis for each masonry wall remains valid during the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.6. The staff determined that the Masonry Wall Program is consistent with GALL AMP XI.S5, including the associated operating experience attribute.

Operating Experience. In LRA Section B.1.30, the applicant explained that the Masonry Wall Program identified 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. In response to Bulletin 80-11 and IN 87-67 various actions were taken, including program enhancements, followup inspections to substantiate masonry wall analyses and classifications, and 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. Operating experience review concluded that the program is effective for managing aging effects of masonry walls.

The staff reviewed the operating experience provided in the LRA and the PBD and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Masonry Wall Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.30, the applicant provided the UFSAR supplement for the Masonry Wall Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Masonry Wall Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements

Summary of Technical Information in the Application. In LRA Section B.1.34, the applicant described the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program as consistent with GALL AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will be used to manage non-EQ cables and connections within the scope of license renewal that are subject to adverse localized environments. An adverse localized environment is a condition in a limited plant area significantly more severe than the specified service environment for a subject cable or connection. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on its operation. 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 is inspected visually for signs of accelerated age-related degradation like embrittlement, discoloration, cracking, or surface contamination. Additional inspections, repair, or replacement are initiated as appropriate. Accessible cables and connections in adverse areas are inspected prior to 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 areas.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.9. The staff finds the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program consistent with GALL AMP XI.E1, including the associated operating experience attribute.

Operating Experience. In LRA Section B.1.34, the applicant explained that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is new and, therefore, no programmatic operating experience is available. Disposition of instances of potentially age-related degradation of cables identified during routine maintenance activities has been by the corrective action process. In each instance engineering evaluations determined the cause of the apparent degradation, the effect on operation, and appropriate corrective action. OCGS also has a history of age-related cable failures of inaccessible medium-voltage cables in a wetted environment. Operating experience for these cables is addressed in the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program. As noted in the GALL Report, industry operating experience shows that adverse localized environments have been found to produce visible degradation of insulating materials for electrical cables and connections.

The staff also reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.34, the applicant provided the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements

Summary of Technical Information in the Application. In LRA Section B.1.36, the applicant described the new Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages inaccessible medium-voltage cables exposed to significant moisture simultaneously with significant voltage. Significant moisture is defined as lasting more than a few days (e.g., cable in standing water). Periodic exposures to moisture lasting less than a few days (i.e., normal rain and drain) are not significant. Significant voltage is defined as subject to system voltage more than 25 percent of the time. OCGS has a total of 47 medium-voltage cable installations. Because of OCGS's history of medium voltage cable failures, all 47 cable circuits are conservatively assumed to have potential exposure to significant moisture conditions. This program will inspect manholes, conduits, and sumps of the 47 cable circuits for water collection so draining or other corrective actions can be taken. In addition, these medium-voltage cable circuits will be tested for deterioration of the insulation system due to wetting by a proven test like power factor, partial discharge, or polarization index as described in EPRI TR-103834-P1-2, or other state-of-the-art testing at the time. Cable testing will be performed at least once every10 years testing frequency will be adjusted in accordance with the results obtained. The first tests will be completed prior to the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.10. The staff determined that, with Commitment No. 36, the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is consistent with GALL AMP XI.E3, including the associated operating experience attribute.

The staff requested that the applicant clarify its use of polarization index testing. In its response, 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 sole condition monitoring test in its Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

In its letter dated April 17, 2006, the applicant stated that the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be revised to clarify that polarization index testing is not used as the sole condition monitoring test for medium-voltage cable circuits.

The staff's review of LRA Section B.1.36 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's request for additional information (RAI) as discussed below.

As stated in SER Section 2.5, in 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 responded. The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program scope has been revised to include 13.8 kV inaccessible medium-voltage cables associated with the FRCTs. The staff noted that OCGS has included 2.3 kV, 4.1 kV, and 13.8 kV system circuits in the scope of the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. In addition, as a result of the applicant's reconciliation of the September 2005 revision of the GALL Report with the January 2005 draft revision, 34.5 kV system cables will be added to this program.

In its letter dated March 30, 2006, the applicant committed (Commitment No. 36) to revise the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program in the LRA to include 34.5 kV system cables in the program.

In its letter dated June 23, 2006, the applicant committed (Commitment No. 36) to revise the Inaccessible Medium Voltage Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, including Appendix A Section A.1.36 to test cable circuits at an initial frequency of six years, after which the frequency will be evaluated and adjusted, based on test results; period between tests shall not exceed 10 years.

Operating Experience. In LRA Section B.1.36, the applicant explained that OCGS has experienced eleven in-service medium voltage circuit failures to date, five 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, OCGS implemented a medium voltage cable testing program covering all 47 of its medium voltage circuits in an attempt to identify cable degradation so that appropriate corrective action could be taken prior to failure. The results of that inspection program have successfully identified degradation in cross-linked polyethylene (XLPE) insulated cables prior to failure. The results failed to identify degradation in EPR-insulated cables.

The applicant stated that testing under the current cable testing program has successfully identified degradation in XLPE-insulated cables (e.g., General Electric (GE) Vulkene) so that replacements could be made prior to in-service failures. Eleven XLPE-insulated cable circuit replacements have been made based on test results since the testing program was implemented in 1991. No in-service failures of XLPE-insulated cable have occurred since the testing program was implemented in 1991.

The applicant also stated that the current cable testing program has not been successful at identifying degradation in EPR-insulated UniShield type cables (for example, Anaconda UniShield) so that replacements could be made prior to in-service failures. Five in-service 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 to address manufacturing defects were implemented in mid-1984. OCGS has experienced no failures in UniShield cables manufactured since that date.

The fifth and most recent in-service cable failure occurred in 2003. Corrective actions were completed 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 of any manufactured before 1985 which might be exposed to significant moisture, and (4) eliminate the future use of UniShield cables.

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. Additional medium voltage cables were tested in 2005. The current inspection program will remain in effect until replaced by the Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program before entering the period of extended operation.

The Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program is new; therefore, no programmatic operating experience is available. The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

The staff noted that the new Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program now includes the underground circuits in the 2.4 kV, 4.16 kV, 13.8 kV, and 34.5 kV systems. This program will test in-scope medium-voltage cables at OCGS for 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 like power factor, partial discharge, or polarization index as described in EPRI TR-103834-P1-2, or other state-of-the-art testing at the time. 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 preventive measures. The applicant stated that underground 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 AMP. The 13.8 kV circuits date back to the 1989 installation of alternate alternating current (AC) capabilities for station blackout (SBO) at OCGS. There have been no failures reported on these cables.

The staff asked the applicant whether it has any plans to trend the cable test data during the period of extended 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 June 23, 2006, the applicant committed (Commitment No.36) that cable test/monitoring will be trended.

The staff also noted that the recent industry concern with direct current (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 by partial discharge or power factor testing methodologies. The applicant stated that it is not implementing 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 has concerns about 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 operating experience as well as discussions with the applicant's technical personnel, the staff concludes 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 identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.36 and letters dated March 30, April 17 and June 23, 2006, the applicant provided the UFSAR supplement for the Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Environmental Qualification (EQ) Program

Summary of Technical Information in the Application. In LRA Section B.3.2, the applicant described the existing Environmental Qualification Program as consistent with GALL AMP X.E1, "Environmental Qualification (EQ) of Electric Components."

The Environmental Qualification Program is implemented through station procedures and preventive maintenance tasks. The Environmental Qualification 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 of the qualified life for 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 prior to the end of qualified life when the reanalysis will be completed. Qualified life is determined for equipment within the scope of the Environmental Qualification Program and such appropriate actions as replacement or refurbishment are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The Environmental Qualification Program addresses the low voltage instrument and control cable issues consistent with those described in the closure of generic safety issue (GSI)-168, "Environmental Qualification of Electrical Equipment."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.11.

The staff reviewed those portions of the applicant's Environmental Qualification Program for which the applicant claimed consistency with GALL AMP X.E1 and found them consistent with this GALL AMP, including the associated operating experience attribute. The staff concludes that the applicant's Environmental Qualification Program provides reasonable assurance that electrical components important to safety in harsh environments will be adequately managed. The staff found that the applicant's Environmental Qualification Program conforms to the recommended GALL AMP X.E1.

Operating Experience. In LRA Section B.3.2, the applicant explained that the Environmental Qualification 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, GLs and Part 21 notifications are evaluated for applicability. The evaluations are documented and corrective actions are identified. Operating experience is reviewed to determine whether it is applicable to EQ equipment. When problems have been identified through industry or plant-specific experience, corrective actions have been taken to prevent recurrence.

The staff's review of the applicable corrective action process database and sample EQ binders revealed no occurrence where the qualified life of a component had been exceeded. This review indicated no adverse trend in the Environmental Qualification Program.

The staff also reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Environmental Qualification Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.3.2, the applicant provided the UFSAR supplement for the Environmental Qualification Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Environmental Qualification Program, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. Originally, this AMP was not included within the scope of this LRA. However, in response to RAI 3.6.2.3.3 (documented in SER Section 3.6), by letter dated May 9, 2006, the applicant committed (Commitment No. 64) to develop and implement this AMP to manage the aging effects of electrical connections.

In the May 9, 2006, letter the applicant stated that the new Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Program is consistent with GALL AMP XI.E6, "Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Program is a new program that will be used to manage the aging effects of metallic parts of non-EQ electrical cable connections within the scope of license renewal. The program will address cable connections for cable conductors to other cables or electrical devices. The most common types of connections in nuclear power plants are splices (butt or bolted), crimp-type ring lugs, connectors, and terminal blocks. Most connections have insulating material and metallic parts. The applicant stated that this AMP will account for the aging stressors of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation of the metallic parts.

Electrical cable connections, metallic parts not subject to 10 CFR 50.49 environmental qualification requirements subject to aging stressors, will be managed by testing for an indication of the integrity of the cable connections. The type of test to be performed, (i.e., thermography), is proven for detecting loose connections. A representative sample of electrical cable connections will be tested.

This program as described can be thought of as a sampling program. The following factors are considered for sampling: application (high, medium, and low voltage), circuit loading, and location (high temperature, high humidity, vibration, etc.) with respect to connection stressors. If an unacceptable condition or situation is identified in the selected sample, a determination is made whether the same condition or situation is applicable to other connections not tested.

A sample of non-EQ electrical cable connections metallic parts will be tested prior to the period of extended operation with an inspection frequency of at least once every 10 years.

Staff Evaluation. The staff review of LRA Section 3.6.2.3.3 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI 3.6.2.3.3 dated April 20, 2006, the staff requested that the applicant provide an AMP with the 10 elements to manage the aging effects of electrical components, metallic parts, or for justification for not requiring an AMP. In its response dated May 9, 2006, the applicant committed (Commitment No. 64) to develop and implement the Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Program to manage aging effects of electrical connections.

To determine whether the applicant's AMP is adequate to manage the effect of aging so that intended function(s) will be maintained consistent with the CLB for the period of extended operation the staff evaluated seven elements. The staff reviewed those portions of the applicant's program for which the applicant claimed consistency with GALL AMP XI.E6 and found them consistent with this GALL AMP. The staff concludes that the applicant's program provided reasonable assurance that electrical components, metallic parts, will be adequately managed. The staff finds that the applicant's program conforms to the recommended GALL AMP XI.E6.

The staff reviewed the Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Program against the AMP elements in the GALL Report, SRP-LR Section A.1.2.3, and Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 program elements (i.e., "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience").

The applicant indicated that "corrective actions," "confirmation process," and "administrative controls" program elements are parts of the site-controlled QA program. The staff's evaluation of the QA program is addressed in SER Section 3.0.4. The remaining seven elements are discussed as follows.

(1) Scope of Program - In its letter, the applicant stated that the metallic parts of electrical cable connections not subject to 10 CFR 50.49 associated with cables within the scope of license renewal are part of this program regardless of their association with active or passive components

The staff confirmed that this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1 and concludes that this program attribute is acceptable.

(2) Preventive Actions - In its letter, the applicant stated that no actions are taken as part of this program to prevent or mitigate aging degradation.

No actions are taken as part of this program to prevent or mitigate aging degradation, and the staff identified no need for such actions.

The staff confirmed that this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2 and concludes that this program attribute is acceptable.

(3) Parameters Monitored and Inspected - In its letter, the applicant stated that this program will focus on the metallic parts of electrical cable connections. The monitoring includes loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. A representative sample of electrical cable connections is tested. The following factors are considered for sampling: application (high, medium and low voltage), circuit loading, and location (high temperature, high humidity, vibration, etc.) with respect to connection stressor. The technical basis for the sample selected is documented.

The staff confirmed that this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.3 and concludes that this program attribute is acceptable.

(4) Detection of Aging Effects - In its letter, the applicant stated that electrical cable connections - metallic parts - not subject to 10 CFR 50.49 environmental qualification requirements within the scope of license renewal will be tested at least once every 10 years. This period is adequate to preclude failures of the electrical connections since experience shows that aging degradation is a slow process. Testing will utilize thermography. A 10-year testing interval will provide during a 20-year period two data points which can be used to characterize the degradation rate. The first tests for license renewal are to be completed before the period of extended operation.

The staff confirmed that this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4 and concludes that this program attribute is acceptable.

(5) Monitoring and Trending - In its letter, the applicant stated that trending actions are not included as part of this program.

The staff finds this statement acceptable because the ability to trend inspection results is limited.

The staff confirmed that this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.5 and concludes that this program attribute is acceptable.

(6) Acceptance Criteria - In its letter, the applicant stated that the acceptance criteria for each test are defined by the specific type of test performed and the specific type of cable connections tested.

The staff finds this statement unacceptable because the applicant provided no acceptance criteria for the testing selected (thermography). On June 2, 2006, the applicant provided supplemental information in which the "acceptance criteria" program element was revised. In its supplemental letter, the applicant stated that, "Measured temperature by thermography should be evaluated against baseline(s), if available, or similarly configured component(s). Consideration should be given to ambient temperature, electrical load, system operating parameters and visual indications when determining if measured temperature is acceptable or requires further evaluation." The staff finds this statement acceptable.

The staff confirmed that the this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.6 and concludes that this program attribute is acceptable.

(10) Operating Experience - In its letter, the applicant stated that this AMP is new. As there is no adverse OCGS operating experience information, this new AMP will be implemented in alignment with GALL AMP XI.E6 recommendations, including assessment of stressors, implementation of a sampling approach, and a frequency of every 10 years with the first inspection prior to the period of extended operation.

The staff found the applicant's statement unacceptable because the applicant did not include industry operating experience. On June 2, 2006, the applicant provided supplemental information. In its supplemental letter, the applicant stated that operating experience, both internal and external, will be used to enhance this program, prevent repeat events, and prevent events that have occurred at other plants from occurring at OCGS. This prevention will be implemented through the OCGS operating experience process. The process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. Additionally, the process for managing programs requires the review of program-related operating experience by the program owner. The staff finds this process acceptable.

The staff confirmed that this program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.10 and concludes that this program attribute is acceptable.

UFSAR Supplement. In its letter dated May 9, 2006, the applicant provided the UFSAR supplement for the Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant committed (Commitment No. 64) to manage the aging effects of metallic parts during the period of extended operation. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cable Connections - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program and RAI response, the staff determined that all the program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that, with the inclusion of Commitment No. 64, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

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

In LRA Appendix B, the applicant identified that the following AMPs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
2. Water Chemistry (B.1.2)
3. Reactor Head Closure Studs (B.1.3)
4. BWR Vessel ID Attachment Welds (B.1.4)
5. BWR Feedwater Nozzle (B.1.5)
6. BWR Control Rod Drive Return Line Nozzle (B.1.6)
7. BWR Stress Corrosion Cracking (B.1.7)
8. BWR Penetrations (B.1.8)
9. BWR Vessel Internals (B.1.9)
10. Bolting Integrity (B.1.12)

11. Open-Cycle Cooling Water System (B.1.13)
12. Closed-Cycle Cooling Water System (B.1.14)
13. Boraflex Rack Management Program (B.1.15)
14. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.1.16)
15. BWR Reactor Water Cleanup System (B.1.18)
16. Fire Protection (B.1.19)
17. Fire Water System (B.1.20)
18. Aboveground Outdoor Tanks (B.1.21)
19. Fuel Oil Chemistry (B.1.22)
20. Reactor Vessel Surveillance (B.1.23)
21. One-Time Inspection (B.1.24)
22. Buried Piping Inspection (B.1.26)
23. ASME Section XI, Subsection IWE (B.1.27)
24. ASME Section XI, Subsection IWF (B.1.28)
25. Structures Monitoring Program (B.1.31)
26. RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)
27. Protective Coating Monitoring and Maintenance Program (B.1.33)
28. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits (B.1.35)
29. Metal Fatigue of Reactor Coolant Pressure Boundary (B.3.1)
30. Bolting Integrity - FRCT (B.1.12A)
31. Closed-cycle Cooling Water System - FRCT (B.1.14A)
32. Aboveground Steel Tanks - FRCT (B.1.21A)
33. Fuel Oil Chemistry - FRCT (B.1.22A)
34. One-Time Inspection - FRCT (B.1.24A)
35. Selective Leaching of Materials - FRCT (B.1.25A)
36. Buried Piping Inspection - FRCT (B.1.26A)
37. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT (B.1.38)
38. Lubricating Oil Analysis Program - FRCT (B.1.39)
39. Buried Piping and Tank Inspection-Met Tower Repeater Engine Fuel Supply (B.1.26B)

For AMPs that the applicant claimed are consistent with the GALL Report, with exception(s) and/or enhancement(s), the staff performed an audit and review to confirm that those attributes or features of the program, for which the applicant claimed consistency with the GALL Report, were indeed consistent. The staff also reviewed the exception(s) and/or enhancement(s) to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Summary of Technical Information in the Application. In LRA Section B.1.1, the applicant described the existing ASME Section XI Inservice Inspection (ISI), Subsections IWB, IWC, and IWD Program as consistent, with exceptions and enhancements, with GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is part of the ISI program and provides for monitoring the condition 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 of the isolation condenser. The program is implemented through procedures that require examinations consistent with ASME Code Section XI, and through specific tasks that require the ASME Section XI augmentation activities identified in the GALL Report. The program includes:

- Cracking monitoring for susceptible ISI 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 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 SCC and IGSCC or loss of material detection due to general and 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.1. The staff reviewed the exceptions and enhancements and their justifications to determine whether the AMP, with the exceptions and enhancements, remained adequate to manage the aging effects for which it was credited.

The staff reviewed those portions of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for which the applicant claimed consistency with GALL AMP XI.M1 and found them consistent. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the aging effects for which this program was credited will be adequately managed. The staff 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 exceptions and an enhancement described below.

Exception 1. In LRA Section B.1.1, the applicant stated an exception to the GALL Report program elements “scope of program,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions.” Specifically, the exception stated that:

> 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 staff reviewed the OCGS ISI program plan (OC-1) titled “OCGS ISI Program Plan Fourth Ten-Year Inspection Interval,” Revision 1, dated September 30, 2004. 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. With the information in this document, the staff 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 arrangement is part of the CLB. On this basis, the staff finds this exception acceptable.

Exception 2. In LRA Section B.1.1, the applicant stated an exception to the GALL Report program elements “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions.” Specifically, the exception stated that:

> 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 10 CFR50.55a, 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.

In reviewing this exception the staff noted that, in accordance with 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 LRA, the applicant stated that it is currently in its fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012. For this interval the 1995 ASME Section XI B&PV Code with 1996 addenda is the appropriate edition to be used; therefore, the staff determines that this exception is justified and acceptable.

Enhancement. In LRA Section B.1.1, the applicant stated the following enhancement in meeting the GALL Report program elements “scope of program,” “parameters monitored or inspected,” and “monitoring and trending.” Specifically, the enhancement stated:

> 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 staff noted that in Table IV.C1 of the GALL Report item IV.C1-4 for isolation condenser components states that GALL AMP XI.M1 is to be augmented to detect cracking due to SCC. In addition, the GALL Report stated that verification of the program's effectiveness is necessary to ensure that significant degradation does not occur and that the component's intended function will be maintained during the period of extended operation. An acceptable verification program includes 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 of the GALL Report AMP. On this basis, the staff finds this enhancement acceptable.

Operating Experience. In LRA Section B.1.1, the applicant explained that OCGS has successfully identified indications of age-related degradation prior to the loss of the intended function(s) of the components and has taken appropriate corrective actions through evaluation, repair, or replacement of the components in accordance with ASME Code Section XI and station implementing procedures. Some site-specific examples are provided. Periodic self-assessments of the ISI programs have been performed to identify areas that need improvement to maintain program quality.

An NDE examination of ESW piping for corrosion in 2002 identified an elbow with a measured wall thickness below the minimum. An evaluation provided an operability justification until the following outage when the elbow was replaced. During a Class 1 pressure test of core spray piping following a refueling outage leakage was observed at a field weld and repaired via the corrective action process. An expanded examination of similar type welds found no additional indications, supporting the conclusion that the observed defect was not a generic issue.

The staff reviewed the operating experience provided in the LRA and in the AMP basis document, interviewed the applicant's technical personnel, and confirmed that the plant-specific operating experience revealed no 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 personnel, the staff concludes 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 LRA.

UFSAR Supplement. In LRA Section A.1.1, the applicant provided the UFSAR supplement for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation, with the exception of eddy current testing of the tubes and inspection (VT or UT) of the channel head and tube sheets which will be performed during the first 10 years of the period of extended operation, will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.2, the applicant described the existing Water Chemistry Program as consistent, with exceptions, with GALL AMP XI.M2, "Water Chemistry."

The Water Chemistry 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 (CRD) water, demineralized water storage tank water (DWST), condensate storage tank water, torus water, and spent fuel pool water, all classified as treated water for aging management. The program activities monitor and control water chemistry by station procedures and processes based on Boiling Water Reactor Vessel Internals Project (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. As specified by the GALL Report, the Water Chemistry Program may not be effective in low-flow or stagnant areas. The One-Time Inspection Program includes provisions specified by the GALL Report for verification of chemistry control and confirmation of the absence of loss of material and cracking in stagnant areas in piping systems and components.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.2. The staff reviewed the exceptions and their justifications to determine whether the AMP remained adequate to manage the aging effects for which it was credited.

The staff reviewed those portions of the Water Chemistry Program for which the applicant claimed consistency with GALL AMP XI.M2 and found them consistent. Furthermore, the staff concludes that the applicant's Water Chemistry Program provides reasonable assurance of mitigation of degradation caused by corrosion and SCC in components exposed to treated water. The staff found that the applicant's Water Chemistry Program conforms to the recommended GALL AMP XI.M2 with exceptions described below.

Exception 1. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "parameters monitored or inspected." Specifically, the exception stated:

> 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 staff recognized that the SER for the Dresden/Quad Cities LRA (NUREG-1769) has accepted BWRVIP-79, which is Revision 2 of the EPRI document EPRI-TR-103515, published in 2000. Therefore, the staff reviewed the differences between the 2000 revision (BWRVIP-79) and 2004 revision (BWRVIP-130). The review demonstrated that the use of the 2004 revision of the EPRI BWR water chemistry guidelines is an acceptable method of controlling water chemistry consistent with the GALL Report recommendations. On this basis, the staff finds this exception acceptable.

Exception 2. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "parameters monitored or inspected." Specifically, the exception stated:

> 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 staff reviewed the water chemistry guidelines of 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 staff also noted that BWRVIP-130 does not change the original intent of the Revision 2 guidelines in BWRVIP-79. The applicant was asked to clarify the details of this exception as it was not clear why it was needed. Based on the applicant's response, the staff determined that not all of the good practices recommended in BWRVIP-130 are applicable to or achievable by OCGS. However, the applicant had implemented those practices applicable to the plant and 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 staff determined that the applicant had implemented those good practice recommendations applicable to the conditions of the reactor water and beneficial to the total water chemistry optimization program. On this basis, the staff finds this exception acceptable.

Exception 3. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "parameters monitored or inspected." Specifically, the exception stated:

> 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.

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

The staff recognized that the ECP quantifies the oxidizing power of a solution in contact with a specific metal surface. ECPs of reactor internals component materials are very sensitive to the concentration of oxygen, hydrogen, and hydrogen peroxide (which determine the ECP) and therefore differ at locations within the BWR reactor system. BWRVIP-79 Section 5.3 discusses locations suitable for measuring the ECP (Figure 5.5) and Section 5.4 provides alternate ECP estimation techniques. Therefore, during the audit the staff requested that the applicant 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 the ECP is directly monitored with ECP probes in the B recirculation loop via the reactor water cleanup (RWCU) system (location E in Figure 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 alternative 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 procedures, verification of mitigation can also be based on radiolysis modeling using an EPRI model as an alternative to ECP measurement.

The staff determined that the 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 staff finds this exception acceptable.

Exception 4. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "parameters monitored or inspected." Specifically, the exception stated:

> 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.

During the interview, the applicant stated that the water in the CST, DWST, spent fuel pool, and torus are exposed to atmospheric conditions (i.e., air-saturated) and hence measuring dissolved oxygen in the water at 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 exposed to the atmosphere and therefore containing 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 is thus consistent with the GALL Report. However, the tanks or reservoirs of these systems are monitored for conductivity, chlorides, sulfates, and TOC in accordance with limits set by BWRVIP-130, Appendix B, as an alternate method for ensuring component integrity.

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

Exception 5. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "parameters monitored or inspected." Specifically, the exception stated:

> 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.

In reviewing this exception, the staff noted that OCGS monitors conductivity, chlorides, sulfates, and 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 used to monitor pH in the torus water. In its response, the applicant stated that a periodic pH analysis has found torus water pH near neutral (i.e., 6.6 - 7.4) based on measurements during the last 5 years

(July 2001 - 6.7; March 2002 -7.0; July 2003 - 6.9; April 2005 - 7.4; and June 2005 - 6.6).

The staff determined that the applicant had been routinely monitoring parameters suggested in the BWRVIP-130 and had confirmed pH of the torus water to ensure its quality. On this basis, the staff finds this exception acceptable.

Exception 6. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "detection of aging effects." Specifically, the exception stated:

> 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.

As part of the audit the staff interviewed the applicant's technical personnel to discuss issues related to this exception. During the interview the applicant stated that aging of the 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 maintained in the storage tank would mask most of the chemistry parameters monitored. The applicant claimed 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 Program. The applicant was asked to confirm that the one-time inspection will consider the SBLC pump casing and 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) will be selected for thickness measurements and crack detection by a volumetric examination such as UT. Since the SBLC is a standby system, any section of pipe (with the smallest thickness compared to valve and pump bodies or other pipe fittings) containing sodium pentaborate represents a "worst-case" location.

The staff determined that the applicant will select a "worst-case" sample from the SBLC system in the One-time Inspection Program, which will reasonably assure adequate management of the aging effects for this system. On this basis, the staff finds this exception acceptable.

Operating Experience. In LRA Section B.1.2, the applicant explained that periodic self-assessments of water chemistry activities continue to identify areas that need improvement to maintain the quality performance of the activity. The Water Chemistry Program has identified parameters outside the established specifications. Increased sampling and actions to bring the parameters back into specification were initiated. The chemistry excursion was then documented in a condition report in accordance with plant administrative procedures. The corrective action process ensures that adverse conditions are promptly corrected. If the deficiency is assessed to be significantly adverse the cause of the condition is determined and a corrective action plan is developed to prevent 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. Increased sampling and corrective actions (such as placing two RWCU pumps 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 incomplete work in the under drain 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 staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel the staff concludes that the applicant's Water Chemistry Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.2, the applicant provided the UFSAR supplement for the Water Chemistry Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.3, the applicant described the existing Reactor Head Closure Studs Program as consistent, with an exception, with GALL AMP XI.M3, "Reactor Head Closure Studs."

The Reactor Head Closure Studs 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 Code Section XI,

Table IWB-2500-1, and preventive measures described in RG 1.65, "Materials and Inspection for Reactor Vessel Closure Studs."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.3. The staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remained adequate to manage the aging effects for which it was credited.

The staff reviewed those portions of the Reactor Head Closure Studs Program for which the applicant claimed consistency with GALL AMP XI.M3 and found them consistent. Furthermore, the staff concludes that the applicant's Reactor Head Closure Studs Program provides reasonable assurance that the effects of cracking due to SCC/IGSCC and loss of material due to wear will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation. The staff found that the applicant's Reactor Head Closure Studs Program conforms to the recommendations in GALL AMP XI.M3, "Reactor Head Closure Studs," with an exception described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program elements "parameters monitored/ inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the exception stated:

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

The applicant stated in the LRA that for justification of exceptions to the ISI program see the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and documented its acceptability in SER Section 3.0.3.2.1. On this basis, the staff finds this exception acceptable.

Operating Experience. In LRA Section B.1.3, the applicant explained that OCGS is in its fourth ISI inspection interval. In the history of the 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, evidence that the AMP 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 staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Reactor Head Closure Studs Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.3, the applicant provided the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Reactor Head Closure Studs Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.4, the applicant described the existing BWR Vessel ID Attachment Welds Program as consistent, with exceptions, with GALL AMP XI.M4, "BWR Vessel ID Attachment Welds."

The BWR Vessel ID Attachment Welds Program incorporates 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 mitigate cracking through water chemistry and monitor for cracking through in-vessel examinations. Reactor vessel attachment weld inspections are implemented through station procedures that are part of ISI and incorporate the requirements of ASME Code Section XI. Inspections are in accordance with ASME Code requirements consistent with BWRVIP-48.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.4. The staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remained adequate to manage the aging effects for which it is credited.

The inspection guidelines of BWRVIP-48 recommend enhanced visual VT-1 (EVT-1) examination of all safety-related attachments and those nonsafety-related attachments susceptible to IGSCC. The applicant's examination plan applies EVT-1 for all of the ID attachment welds regardless of whether the welds are known to be susceptible to IGSCC. The staff finds this plan acceptable as more conservative than the GALL Report recommendation.

The staff reviewed those portions of the BWR Vessel ID Attachment Welds Program for which the applicant claimed consistency with GALL AMP XI.M4 and found them consistent. Furthermore, the staff concludes that the applicant's BWR Vessel ID Attachment Welds

Program provides reasonable assurance that cracking will be adequately managed and that the intended function of the vessel ID attachments will be maintained consistent with the CLB for the period of extended operation. The staff found that the applicant's BWR Vessel ID Attachment Welds Program conforms to the recommended GALL AMP XI.M4 with exceptions described below.

Exception 1. In the LRA, the applicant identified an exception to the GALL Report program element "preventive actions." Specifically, the exception stated:

> 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 applicant stated in the LRA that the 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 refer to the Water Chemistry Program in SER Section 3.0.3.2.2 where the staff documents its acceptability. On this basis, the staff finds this exception acceptable.

Exception 2. In the LRA, the applicant stated an exception to the GALL Report program elements "parameters monitored/ inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the exception stated:

> 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 staff reviewed this exception as part of its review of the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program and finds it acceptable. The staff's finding is documented in SER Section 3.0.3.2.1.

Operating Experience. In LRA Section B.1.4, the applicant explained that the inspection and testing methodologies have detected no cracking in the attachment welds in the history of the plant. This history is evidence that the Water Chemistry Program has been effective in minimizing the effects of SCC in the attachments welds. The same inspection and testing methodologies are used for the attachments welds as 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.

The staff also reviewed the operating experience provided in the LRA, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's BWR Vessel ID Attachment Welds Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.4, the applicant provided the UFSAR supplement for the BWR Vessel ID Attachment Welds Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Vessel ID Attachment Welds Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.5, the applicant described the existing BWR Feedwater Nozzle Program as consistent, with an exception and an enhancement, with GALL AMP XI.M5, "BWR Feedwater Nozzle."

The BWR Feedwater Nozzle 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 UT inspections of critical regions of the feedwater nozzle. Inspections are at intervals not exceeding 10 years.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.5. The staff reviewed the exception and enhancement and their justifications to determine whether the AMP, with the exception and enhancement, remained adequate to manage the aging effects for which it is credited.

The applicant stated that the original feedwater spargers were replaced in 1977 to address industry-wide feedwater nozzle cracking issues in response to NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." Each 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, the removed stainless steel cladding was removed at the feedwater nozzle areas and all cracks found there were repaired. The feedwater flow control system was also changed to improve system performance and reduce temperature fluctuations at the nozzle bend areas during low power operation. The RWCU system was not rerouted. In accordance with NUREG-0619, the applicant performed liquid penetrant examination (PT) of the originally cladded surfaces to ensure that no cracks remained in the nozzle area.

During the audit, the staff requested that the applicant 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: 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 ground out with pencil grinders and surface-polished. Subsequent examinations have identified no new indications.

In its response, the applicant also stated that OCGS continued to inspect the feedwater sparger visually during every subsequent refueling outage and found no sign of degradation. During the 1988-89 refueling outage (12R), the applicant performed UTs from outside of all nozzle safe ends, bores, and inside blend radius 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 these 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 to which it had committed 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 performed UT examination of these nozzles in lieu of the PT examination recommended in NUREG-0619.

The staff 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 PT examination should any indications of cracking be found based on the UT examination, as recommended in NUREG-0619.

After the 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. In 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. In 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 UT requirements as the primary means of inspection. OCGS has committed (Commitment No. 5) to implementing the UT methodology recommended in the GE report to inspect the nozzle in future, including the standard performance demonstration initiative (PDI) UT methodology that meets the requirements of Appendix VIII of ASME Code 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 staff reviewed those portions of the BWR Feedwater Nozzle Program for which the applicant claimed consistency with GALL AMP XI.M5 and found them consistent. Furthermore, the staff concludes that the applicant's BWR Feedwater Nozzle Program provides reasonable assurance of timely detection of cracking in the nozzle area by enhanced inspection of the feedwater nozzles by GE-recommended periodic ultrasonic inspection of critical regions. The staff found that the applicant's BWR Feedwater Nozzle Program conforms to the recommended GALL

AMP XI.M5, with an exception and an enhancement described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions." Specifically, the exception stated:

> 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 on 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 staff reviewed this exception as part of its review of the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program and finds it acceptable. The staff's review is documented in SER Section 3.0.3.2.1. The staff determined that for the fourth ten-year inspection interval effective from October 15, 2002, through October 14, 2012, the 1995 ASME Section XI B&PV Code with 1996 addenda is the appropriate ASME Code edition to use.

Enhancement. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending." Specifically, the enhancement stated:

> 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.

In the LRA, the applicant stated that OCGS is committed to implementing the recommendations in NE-523-A71-0594, Revision 1, prior to the period of extended operation. The applicant's BWR Feedwater Nozzle Program will be enhanced to include the recommendations of the BWROG licensing topical report 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 staff reviewed the ISI program plan, OC-1, and found that it had not been updated in the section for the feedwater nozzle inspections because the commitments had been 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 ISI program plan, OC-1, will be revised at the time this AMP is enhanced prior to the period of extended operation.

The staff finds this enhancement acceptable because, when implemented, the BWR Feedwater Nozzle Program will be consistent with GALL AMP XI.M5 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.5, the applicant explained that it had inspected the feedwater nozzles in 1977 in response to industry experience. Cracks found in the nozzles were 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, evidence that the thermal sleeve modification has been effective in mitigating the effects of thermal fatigue on the feedwater nozzle.

The staff 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 performed at a frequency of at least every fourth refueling outage, as recommended in NUREG-0619, the staff finds no evidence for this claim. However, the applicant will enhance the BWR Vessel Internals Program to include and document the conditions of the feedwater nozzle as well as the CRD return line nozzle thermal sleeves (Commitment No. 9).

The staff reviewed the operating experience provided during the audit and interviewed the applicant's technical personnel to confirm that since the recommendations of NUREG-0619 were implemented, including the installation of replacement feedwater spargers, this program has detected no cracks in the feedwater nozzle regions at OCGS.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's BWR Feedwater Nozzle Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.5, the applicant provided the UFSAR supplement for the BWR Feedwater Nozzle Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Feedwater Nozzle Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.6, the applicant described the existing BWR Control Rod Drive Return Line Nozzle Program as consistent, with exceptions, with GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle."

The BWR Control Rod Drive Return Line Nozzle Program provides for monitoring the CRD return line nozzle for cracking through station ISI procedures based on the ASME Code Section XI, augmented by inspections in accordance with recommendations of NUREG-0619. OCGS requested and received relief from the NRC for the recommendation of NUREG-0619 to perform

UT testing in lieu of periodic dye PT. Inspections will be at intervals not exceeding 10 years.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.6. The staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remained adequate to manage the aging effects for which it is credited.

During the audit, the staff requested that the applicant discuss activities performed in response to NUREG-0619. In its response, the applicant stated that OCGS had removed the original CRD return line nozzle thermal sleeve and performed a dye PT on the inside diameter of the nozzle in 1977 (7R outage) to address industry-wide CRD return line 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, it had replaced the CRD return line nozzle thermal sleeve 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 1-inch schedule 40 pipe attached to the remaining portion of the removed thermal sleeve by an interference fit. The 1-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 staff noted that the applicant continued to inspect the CRD return line nozzle visually during every subsequent refueling outage and found no sign of degradation. During the 1991 refueling outage (13R), the applicant performed 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 staff reviewed those portions of the BWR Control Rod Drive Return Line Nozzle Program for which the applicant claimed consistency with GALL AMP XI.M6 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's program provides reasonable assurance of timely detection of cracking in the nozzle area by enhanced inspection of the CRD return line nozzles by NUREG-0619-recommended periodic inspection of critical regions. The staff found that the applicant's BWR Control Rod Drive Return Line Nozzle Program conforms to the recommendations in GALL AMP XI.M6 with exceptions described below.

Exception 1. In the LRA, the applicant stated an exception to the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions." Specifically, the exception stated:

> 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 staff reviewed this exception as part of its review of the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program and finds it acceptable. The staff's review is documented in SER Section 3.0.3.2.1. The staff determined that for the fourth ten-year inspection interval effective from October 15, 2002, through October 14, 2012, the 1995 ASME Section XI B&PV Code with 1996 addenda is the appropriate ASME Code edition to use.

Exception 2. In the LRA, the applicant stated an exception to the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.3.2.5, in 1992 the applicant submitted a relief request to eliminate routine PT examination of the feedwater and CRD return line nozzles to which it had committed in response to NUREG-0619 and to 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 performed UT examination of these nozzles in lieu of the PT examination recommended in NUREG-0619.

The staff recognized that relief requests typically apply only to the current inspection interval; therefore, they do not apply 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, periodic CRD return line nozzle inspections are performed using qualified UT techniques at least once every 10 years (120 months). The inspection interval is based on fatigue crack growth analyses in accordance with the methodology in ASME Code Section XI. If UT examination results indicate the presence of a flaw exceeding the ASME Code allowable crack size, OCGS is committed to 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 CRD return line nozzle thermal sleeve has played a major role in the prevention of CRD return line nozzle cracks.

The staff noted that the CRD return line nozzle is included in the 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 recommendations.

The staff reviewed the ISI program plan, OC-1, and found that it had not been updated in the section for the CRD return line nozzle inspections because the commitments had been 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 ISI program plan. In its response, the applicant stated that the ISI program plan, OC-1, will be revised to reflect the CRD return line nozzle inspections prior to the period of extended operation.

The staff determined that although the applicant takes exceptions to some aspects of the ISI, the current ISI program includes the recommendations of NUREG-0619 and follows the guidelines of the GALL Report. On this basis, the staff determined that this exception is acceptable.

Exception 3. In the LRA, the applicant stated an exception to the GALL Report program elements "acceptance criteria" and "corrective actions." Specifically, the exception stated:

> 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.

During the audit, the staff requested that the applicant clarify the OCGS position stated in this exception. In its response, the applicant stated that all indications and relevant conditions detected during past examinations at OCGS had been evaluated in accordance with ASME Section XI Subsection IWB-3100 for Class 1 components by 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 under applicable procedures. An analytical evaluation in accordance with IWB-3600 or an approved repair in accordance with plant procedure ER-AA-330-002 had been performed. In either case, staff's approval had been required prior to resumption of operation.

The applicant also stated that NUREG-0619 recommends that 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 subsequent inspections. OCGS inspections during 1977 and subsequently have found no flaw indications in the CRD return line nozzle. The applicant has followed the ISI guidelines for this nozzle inspection. According to these guidelines, repairs are made if the flaw does not meet the requirements of IWB-3600, in which case crack repairs may use the grind-out option.

The staff noted that the 1995 or later version of the ASME Code Section XI 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 accordance with IWA-4000, as discussed in the OCGS PBD for this AMP.

The staff determined that the current ISI program provides reasonable assurance that the intent of the NUREG-0619 acceptance criteria is met. On this basis, the staff determined that this exception is acceptable.

Operating Experience. In LRA Section B.1.6, the applicant explained that OCGS had 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, good evidence that the thermal sleeve modification has been effective in mitigating the effects of thermal fatigue on the CRD nozzle.

The staff 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 routinely inspected the nozzle thermal sleeve area visually and no such degradation of the replacement thermal sleeve has been noted.

The staff reviewed the operating experience provided during the audit and interviewed the applicant's technical personnel to confirm that since the recommendations of NUREG-0619 were implemented, including the installation of a replacement nozzle thermal sleeve, this program has detected no cracks in the CRD return line nozzle regions.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's BWR Control Rod Drive Return Line Nozzle Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.6, the applicant provided the UFSAR supplement for the BWR Control Rod Drive Return Line Nozzle Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Control Rod Drive Return Line Nozzle Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.7, the applicant described the existing BWR Stress Corrosion Cracking Program as consistent, with an exception, with GALL AMP XI.M7, "BWR Stress Corrosion Cracking."

The BWR Stress Corrosion Cracking Program mitigates IGSCC in stainless steel reactor coolant pressure boundary piping components and piping 4 inches and greater NPS 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 weight percent and a minimum ferrite level of 7.5 weight percent. Inspection and flaw evaluation are in accordance with the ISI program plan for the station. 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 Revision 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 Generic Letter 88-01 Inspection Schedules," BWRVIP-130, "BWR Vessel and Internals Project BWR Water Chemistry Guidelines," and ASME Section XI.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.7. The staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remained adequate to manage the aging effects for which it is credited.

The applicant was asked to provide details of all weld repairs and material replacement of components to implement the NUREG-0313 and GL 88-01 recommendations. In its response, the applicant stated that the following piping was replaced with IGSCC-resistant material (low carbon stainless steel):

- all isolation condenser large bore piping outside the drywell (from the drywell penetrations to the isolation condensers), and all new welds were stress-improved;
- all piping within the four isolation condenser drywell penetrations and the two RWCU system drywell penetrations, which contain welds that cannot be inspected;
- the isolation condenser piping at the isolation condensers at 95 feet elevation;
- the head cooling spray nozzle assembly; and
- the 4-inch tee and flange of the reactor vent line. Additionally, all welds accessible for inspection 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 had IGSCC indications. Following numerous piping replacements, 11 welds remained in service with indications of IGSCC. Nine welds were repaired with full structural overlays (four in core spray, four in recirculation and one 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. The NRC-approved PDI inspections in 2002 and 2004 using the new UT technique found no indications of IGSCC in either of the recirculation system welds.

The staff reviewed the OCGS program plan (OC-2: Program Plan - IGSCC Inspection Program, Revision 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. The applicant confirmed the use of these documents under the IGSCC program. Thus, the applicant has inspected the relevant piping in accordance with NRC-approved BWRVIP-75 since the BWR Stress Corrosion Cracking Program was first implemented.

As to the program element for "corrective actions," the GALL Report states that guidance for weld overlay repair and stress improvement or replacement is in GL 88-01; ASME Code Section XI, Subsections IWB-4000 and IWB-7000, IWC-4000 and IWC-7000, or IWD-4000 and IWD-7000, respectively, for Classes 1, 2, or 3 components and ASME Code Case N504-1. These ASME Code Section XI subsections in earlier editions (1986 edition) have been replaced by subsections IWA-4000 in later ASME Code editions. ISI program corrective action requirements are in accordance with IWA-4000 of the 1995 edition of the ASME Code. The staff finds these requirements acceptable as consistent with the version of the ASME Code Section XI applicable to OCGS.

The staff reviewed those portions of the BWR Stress Corrosion Cracking Program for which the applicant claimed consistency with GALL AMP XI.M7 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's BWR Stress Corrosion Cracking Program provides reasonable assurance that IGSCC in reactor coolant pressure boundary stainless steel and nickel-based alloy piping components (both base metal and welds) will be adequately managed. The staff found that the applicant's BWR Stress Corrosion Cracking Program conforms to the recommended GALL AMP XI.M7 with an exception and an enhancement described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program element "preventive actions." Specifically, the exception stated:

> 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.

In Attachment 1, item B.1.7 of its reconciliation document, the applicant stated that this exception 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 the BWR Stress Corrosion Cracking Program was compared, no longer makes reference to BWRVIP-29; therefore, this exception no longer applies to the BWR Stress Corrosion Cracking Program.

The staff 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 staff reviewed the Water Chemistry Program and concludes that the use of BWRVIP-130 is acceptable. The staff's evaluation of the Water Chemistry Program is discussed in SER Section 3.0.3.2.2. On this basis, the staff concludes that the exception is not required and finds acceptable the applicant's decision to withdraw it.

Enhancement. In the LRA, the applicant stated that there are no enhancements for this AMP. However, in PBD-AMP B.1.07, the applicant identified an enhancement not included in the LRA to meet the GALL Report program element "preventive actions." Specifically, the enhancement stated:

> 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.

In its letter dated April 17, 2006, the applicant committed (Commitment No. 7) to revise the BWR Stress Corrosion Cracking Program in the LRA to include the enhancement identified in PBD-AMP-B.1.07, which states that for those components within the scope of the BWR Stress Corrosion Cracking Program all new and replacement stainless steel materials will be low-carbon grades of stainless steel with carbon content limited to 0.035 weight percent maximum and ferrite content limited to 7.5 percent minimum.

In reviewing this enhancement, the staff 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 already should have been implemented at OCGS. The applicant was asked to explain the reasons for this enhancement to an existing program, which should have included this screening criterion as part of the CLB. In its response, the applicant stated that all replacements of piping components susceptible to IGSCC during refueling outage 13R were in accordance with GL 88-01. However, the current documentation does not include the GL 88-01 commitments in the BWR Stress Corrosion Cracking Program; therefore, this enhancement to the program is necessary to update the plant documentation to meet the recommendations of the September 2005 GALL Report.

The staff finds the enhancement acceptable because when implemented the BWR Stress Corrosion Cracking Program will be consistent with GALL AMP XI.M7 and will provide additional assurance that the effects of aging for which this program is credited will be adequately managed.

Operating Experience. In LRA Section B.1.7, the applicant explained that of the welds included in the scope of GL 88-01, OCGS 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 inservice without repair in the recirculation system because they were both stress-improved before the inspections found IGSCC. Both of these welds in the recirculation system have recently been re-examined by the PDI-qualified UT method and no IGSCC was identified. No new indications of IGSCC have been detected by inspection during the last 6 outages.

OCGS 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). All new welds were stress-improved.

(2) All piping within the four isolation condenser drywell penetrations and the two RWCU system drywell penetrations containing welds not accessible for inspection.

(3) The head cooling spray nozzle assembly, the 4-inch tee, and flange of the reactor vent line were replaced.

Additionally, all accessible welds inside the drywell (except RWCU system) were stress-improved.

Furthermore, as a result of the improved quality of water chemistry due to the execution of hydrogen water chemistry (HWC) and noble metal chemical addition (NMCA), inspection frequency reductions permissible per BWRVIP-75 were implemented.

BWR Stress Corrosion Cracking 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 repaired as necessary in accordance with ASME Section XI. As a result OCGS has no indications of IGSCC at this time.

The staff reviewed the operating experience information given in the PBD and found that, since GL 88-01 was issued, OCGS has performed ISI examinations on piping subject to the GL recommendations. During this period, OCGS has implemented 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. OCGS 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 6 outages.

The staff reviewed the operating experience provided in the LRA, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's BWR Stress Corrosion Cracking Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.7 and letter dated April 17, 2006, the applicant provided the UFSAR supplement for the BWR Stress Corrosion Cracking Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Stress Corrosion Cracking Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.8, the applicant described the existing BWR Penetrations Program as consistent, with exceptions, with GALL AMP XI.M8, "BWR Penetrations."

The BWR Penetrations Program 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 program is implemented through station procedures that mitigate cracking through the water chemistry and monitor for cracking through inservice inspection examinations. Penetration inspections through station procedures for reactor internals inspection incorporate the requirements of ASME Code Section XI.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.8. The staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remained adequate to manage the aging effects for which it is credited.

The staff 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 in accordance with the station ISI program (OC-1). The staff also noted that repair and replacement activities, if needed, are in accordance with the recommendations of the appropriate BWRVIP repair/replacement guidelines. These activities are specified in implementation procedure ER-AB-331-1001 (Revision 0).

The staff reviewed those portions of the BWR Penetrations Program for which the applicant claimed consistency with GALL AMP XI.M8 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's BWR Penetrations Program provides reasonable assurance of effective management of cracking due to SCC or IGSCC in both instrument and SLC/Delta-P penetrations in the vessel. The staff found that the applicant's BWR Penetrations Program conforms to the recommendations provided in GALL AMP XI.M8 with the exceptions described below.

Exception 1. In the LRA, the applicant stated an exception to the GALL Report program element "preventive actions." Specifically, the exception stated:

> 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 staff reviewed the Water Chemistry Program (AMP B.1.2) and concludes that the use of BWRVIP-130 is acceptable. The staff's evaluation of the Water Chemistry Program is discussed in SER Section 3.0.3.2.2. On this basis, the staff concludes that the exception is acceptable.

Exception 2. In the LRA, the applicant stated an exception to the GALL Report program element "parameters monitored or inspected." Specifically, the exception stated:

> 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 staff reviewed this exception as part of its review of the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program and finds it acceptable. The staff's evaluation is documented in SER Section 3.0.3.2.1.

Operating Experience. In LRA Section B.1.8, the applicant explained that OCGS is currently in its fourth ISI interval. In the history of the OCGS ISI program, no evidence of instrument penetration or standby liquid control nozzle cracking has been found, evidence that the Water Chemistry Program has been effective in minimizing SCC effects in the instrument and standby liquid control penetrations. The same inspection and testing methodologies are used for the BWR penetrations as 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.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's BWR Penetrations Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.8, the applicant provided the UFSAR supplement for the BWR Penetrations Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Penetrations Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.9, the applicant described the existing BWR Vessel Internals Program as consistent, with exceptions and enhancements, with GALL XI.M9, "BWR Vessels Internals."

In LRA Section B.1.9, the applicant stated that this program manages the effects of cracking initiation and growth of reactor vessel internals (RVI) components through condition monitoring activities consisting of examinations by station procedures consistent with the recommendations of BWRVIP guidelines as well as the requirements of ASME Code Section XI. The program also mitigates the effects of SCC, IGSCC, and irradiation-assisted stress corrosion cracking (IASCC) in RVI components through water chemistry activities implemented through station procedures which are consistent with the guidelines of BWRVIP-130: " BWR Vessel and Internals Project BWR Water Chemistry Guidelines," 2004 Revision. Inspections and evaluations of RVI components are consistent with the guidelines in the following BWRVIP reports:

- BWRVIP-18-A, BWR Core Spray Inspection and Flaw Guidelines
- BWRVIP-25, BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26, BWR Top guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-27-A, BWRVIP Standby Liquid Control System/Core Spray/ Core Plate ΔP Inspection and Flaw Evaluation Guidelines
- BWRVIP-38, BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-47, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
- BWRVIP-48, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines
- BWRVIP-49-A, Instrument Penetration Inspection and Flaw Evaluation Guidelines
- BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines
- BWRVIP-76, BWR Core Shroud Inspection and Flaw Evaluation Guidelines
- BWRVIP-104, Evaluation and Recommendations to Address Shroud Support Cracking in

BWRs

The applicant stated that BWRVIP-41, "BWR Vessel and Internals Project, Jet Pump Assembly, Inspection and Flaw Evaluation Guidelines," and BWRVIP-42, "BWR Vessel and Internals Project, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines," are not applicable because OCGS has no such components. The applicant also stated that OCGS has or will complete each of the license renewal applicant action items described in the staff's safety evaluations (SEs) for each BWRVIP report prior to the period of extended operation. In addition, OCGS will implement the guidelines of BWRVIP-139, "BWR RVI components Project, Steam Dryer Inspection and Flaw Evaluation Guidelines," for the steam dryer when issued.

Staff Evaluation. In the LRA, the applicant stated that it will implement the BWR Vessel Internals Program to manage cracking in RVI components due to SCC, IGSCC, and IASCC consistent with the GALL AMP XI.M9. To monitor the aging effects, the applicant proposed to implement the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant stated that this program is consistent with GALL AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, IWD," with one exception. In SER Section 3.0.3.2.1 the staff evaluated the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it will comply with the recommendations of GALL AMP XI.M1.

The applicant stated that the Water Chemistry Program will be used at OCGS to manage the aging effects due to SCC, IGSCC, and IASCC. The applicant further stated that the Water Chemistry Program is consistent with GALL AMP XI.M2 with one exception. In SER Section 3.0.3.2.2, the staff evaluated the Water Chemistry Program and determined that it will comply with the recommendations of GALL AMP XI.M2.

The applicant is required to comply with the license renewal action items specified in the staff's SER as to the BWRVIP reports for the period of extended operation. The following list documents the license renewal action items specified in the staff's SEs of the applicable BWRVIP reports, the applicant's responses to these license renewal action items, and the corresponding staff's evaluation.

(1) The license renewal applicant is to verify that its plant is bounded by the applicable BWRVIP report. Further, the license renewal applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. License renewal applicants will be responsible for describing any such commitments and how they will be controlled. Any deviations from the AMPs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain component functions or from other information presented in the report, like materials of construction, must be identified by the license renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

    The applicant verified that OCGS is bounded by applicable BWRVIP reports. Additionally, OCGS committed (Commitment No. 9) to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operations. If, upon review of a BWRVIP-approved guideline, the applicant determines that exceptions to full compliance are warranted the staff will be notified of the exception within 45 days of the receipt of staff final approval of the guideline.

The staff finds this commitment acceptable as it complies with the staff's license renewal action items specified in the respective SERs on the BWRVIP reports.

Similarly, LRA Section A.1.9 references the BWRVIP-94 report, "BWR Vessels and Internals Project, Program Implementation Guideline." The staff's review of LRA Section B.1.9 identified areas in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI 1.9-1(A) dated March 20, 2006, the staff requested that the applicant revise the BWR Vessel Internals Program to refer to the BWRVIP-94 report and include the following issues related to the scope of implementation of the BWRVIP-94 guidelines.

- The applicant shall inform the staff within 45 days of the report of any decision not to implement fully a BWRVIP guideline approved by the staff.
- The applicant shall notify the staff if changes are made to the AMP related to the RVI components that affect the implementation of the BWRVIP guidelines.
- The applicant shall submit any deviation from the existing flaw evaluation guidelines specified in the BWRVIP report.

In its response dated April 18, 2006, the applicant stated that it will create a new commitment to incorporate these issues. The staff reviewed the response and concludes that the applicant's commitment (Commitment No. 9) to incorporate the program implementation requirements specified in the BWRVIP-94 report in the LRA is acceptable. Based on the review, the staff determined that its concern described in RAI B.1.9-1(A) is resolved.

(2) Section 54.21(d) of 10 CFR requires a UFSAR supplement for the facility to contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. License renewal applicants shall describe summarily in the UFSAR supplement programs and activities specified as necessary in applicable BWRVIP reports. One of the license renewal application action items identified in the staff's corresponding SER on the applicable BWRVIP report addresses the applicability of TLAA for evaluating the aging degradation of a specific RVI component.

The applicant stated that UFSAR supplements included as LRA Appendix A summarize programs and activities specified as necessary for the BWRVIP program. According to the applicant there are no TLAA issues for OCGS related to the following BWRVIP reports:

- BWRVIP-18, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines."
- BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines."
- BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines."
- BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines."

In RAI B.1.9-9 dated March 20, 2006, the staff requested that the applicant make a commitment to incorporate programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation at OCGS. The staff also requested that the applicant include this commitment in the BWR Vessel Internals Program and its UFSAR supplement.

In its response dated April 18, 2006, the applicant stated that it will include the following BWRVIP guidelines in the BWR Vessel Internals Program and its UFSAR supplement.

- BWRVIP-05, "Reactor Vessel Shell Weld Inspection Guidelines."
- BWRVIP-18-A, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines."
- BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines."
- BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines."
- BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines."
- BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines."
- BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines."
- BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines."
- BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines."
- BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines."
- BWRVIP-75, "BWR Vessel and Internals Project (BWRVIP), Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule."
- BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines."
- BWRVIP-78, "BWR Integrated Surveillance Program (ISP) Plan."
- BWRVIP-86, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation."
- BWRVIP-104, "Evaluation and Recommendations to Address Shroud Support Cracking in BWRs."
- BWRVIP-116, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation for License Renewal."
- BWRVIP-130, "BWR Water Chemistry Guidelines."

The staff reviewed the response and concludes that the applicant's inclusion of these BWRVIP inspection guidelines in the UFSAR will ensure timely identification of aging degradation of the RVI components so that their intended functions will not be compromised during the period of extended operation.

By complying with the applicable BWRVIP recommendations, the applicant will identify and evaluate any potential TLAA issues addressed in the BWRVIP reports. After reviewing the SEs of the BWRVIP-18, 27-A and 47 reports, the staff determined that there are no TLAA issues associated with these reports at OCGS. As to the potential TLAA issue of the core plate hold-down bolts addressed in the BWRVIP-25 report, the applicant stated that it had installed wedges and that there is no TLAA issue for this component. The applicant's disposition of the TLAA issue with the core plate hold-down bolts is consistent with the staff's SER of the BWRVIP-25 report and the staff finds it acceptable. Based on this review, the staff's concern described in RAI B.1.9-9 is resolved.

The license renewal action items specified in the staff's SER dated October 18, 2001, on the BWRVIP-74-A report, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," address the aging effects of the RVI components and provide requirements to effectively manage the aging effects during the period of extended operation. The BWRVIP-74-A report also addresses the license renewal action items associated with TLAAs for the period of extended operation. The following paragraphs address the TLAAs specified in the BWRVIP-74-A report, the applicant's responses to these license renewal action items, and the corresponding staff's evaluation of each TLAA.

(1) License renewal applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternate actions where the estimated fatigue usage is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a license renewal applicant must address environmental fatigue for components listed in the BWRVIP-74-A report for the license renewal period.

    The applicant stated that thermal fatigue (including discussions of cycles, projected cumulative usage factors, environmental factors, etc.) is evaluated as a TLAA in LRA Section 4. Environmental fatigue for those components described in NUREG-6260 is addressed in the LRA Section 4.6.

    The staff evaluated the TLAA of thermal fatigue in SER Section 4.6 and concludes that the applicant, as recommended by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

(2) Appendix A to the BWRVIP-74-A report indicates that a set of pressure-temperature (P-T) curves should be developed for the heat-up and cool-down operating conditions in the plant at a given effective full power year (EFPY) in the license renewal period.

    The applicant stated that the development of P-T curves for OCGS for the license renewal period is described as a TLAA in SER Section 4.2.

    The staff evaluated the TLAA of P-T curves in SER Section 4.2 and concludes that the applicant, as required by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

(3) To demonstrate that the beltline materials meet the charpy upper shelf energy (USE) criteria specified in Appendix B of the BWRVIP-74-A report, the applicant shall demonstrate that the percent reduction in charpy USE for their beltline materials is less than that specified for the limiting BWR/3-6 plates or the non-Linde 80 submerged arc

welds and that the percent reduction in charpy USE for their surveillance weld and plate is less than or equal to the values projected using the methodology in RG 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2.

The applicant stated that the discussion of charpy USE for OCGS for the license renewal period is described as a TLAA in LRA Section 4.2.

The staff evaluated the TLAA of USE criteria for the reactor pressure vessel (RPV) beltline materials in SER Section 4.2. The staff concludes that the applicant, as required by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

(4) To obtain relief from the ISI of the circumferential welds during the license renewal period, the BWRVIP-05 report, "Reactor Vessel Shell Weld Inspection Guidelines," requires each licensee to demonstrate that: (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in Appendix E of the staff's July 28, 1998, SER on the BWRVIP-05 report, and (2) that they have implemented operator training and established procedures that limit the frequency of cold over-pressure events to that specified in the staff's July 28, 1998, SER on the BWRVIP-05 report.

The applicant stated that relief from the ISI of the circumferential welds for OCGS for the license renewal period is described in LRA Section 4.2.

The staff's evaluation of the TLAA of the relief from the ISI of the RPV circumferential shell welds for OCGS is addressed in SER Section 4.2. The staff concludes that the applicant, as required by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

(5) A license renewal applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine that the mean reference nil-ductility transition temperature (RT_{NDT}) of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of the staff's October 18, 2001, SER on the BWRVIP-74-A report.

The applicant stated that The RPV axial weld failure probability TLAA is addressed in LRA Section 4.2.

The staff evaluated the TLAA of the RPV axial weld failure probability for OCGS in SER Section 4.2. The staff concludes that the applicant, as required by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

(6) The Charpy USE, P-T limit, inspection relief for the RPV circumferential welds, and RPV axial weld integrity evaluations are all dependent upon the neutron fluence. The license renewal applicant may perform neutron fluence calculations using staff-approved methodology or may submit a methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.

The applicant stated that the neutron fluence calculation methodology for OCGS is consistent with RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

The staff evaluated the TLAAs associated with the neutron fluence calculations in SER Section 4.2 and concludes that the applicant, as required by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

(7) Components with indications previously analytically evaluated in accordance with subsection IWB-3600 of the ASME Code, Section XI until the end of the 40-year service period shall be re-evaluated for the 60-year service period of the license renewal term.

The applicant stated that OCGS has evaluated flaws for previously identified indications discussed in LRA Section 4.7.4.

The staff's evaluation of the TLAA of the flaw evaluations of previously identified indications in RPV and RVI components at OCGS is addressed in SER Section 4.7.4. The staff concludes that the applicant, as required by the BWRVIP-74-A report, has addressed the need to include this TLAA in the LRA.

The following paragraphs address additional license renewal action items specified in the BWRVIP-74-A report, the applicant's responses to these license renewal action items, and the corresponding staff's evaluation.

(1) Section 54.22 of 10 CFR requires each license renewal applicant to include any technical specification changes (and justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the LRA. The applicable BWRVIP reports may state that there are no generic changes or additions to technical specifications as a result of its AMR and that the applicant will justify plant-specific changes or additions. License renewal applicants referring to applicable BWRVIP reports shall ensure that the inspection strategy described in the reports does not change or conflict with their technical specifications. If technical specification changes or additions result, the applicant must include those changes in its LRA.

The applicant stated that there have been no OCGS technical specification changes based upon the BWRVIP reports.

The AMR indicated no changes in technical specifications based upon applicable BWRVIP reports and, therefore, the staff concludes that the applicant adequately addressed this issue in LRA Section B.1.9.

(2) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the vessel flange leak detection (VFLD) lines, cause an increase in the concentration of contaminants, and cause cracking in the VFLD line. The BWRVIP-74-A report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, license renewal applicants should identify an AMP for the VFLD line.

The applicant stated that its VFLD line is a Class 1 line visually inspected (VT-3) during reactor cavity flood up each refueling outage as part of the ASME Section XI programs.

The staff accepted the applicant's AMP for the VFLD systems because by implementing the inspection program during each refueling outage the applicant can effectively monitor the aging effect in the VFLD components.

(3) License renewal applicants shall describe how each plant-specific AMP addresses the following elements: (1) "scope of program," (2) "preventative actions," (3) "parameters monitored and inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience."

The applicant stated that there is no plant-unique AMP credited for managing aging of the RVI components.

The only AMP for managing aging effects in the RVI components is the BWR Vessel Internals Program. The staff concludes that this AMP is consistent with GALL AMP XI.M9 and is effective for managing the aging effects of the RVI components. Therefore, the staff finds this AMP acceptable.

(4) The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program of inspection and water chemistry. The BWRVIP-29 report describes a water chemistry program with monitoring and control guidelines for BWR water acceptable to the staff. The BWRVIP-29 report is not discussed in the BWRVIP-74-A report. Therefore, in addition to the BWRVIP reports, the LRA shall contain water chemistry programs with monitoring and control guidelines for reactor water chemistry contained in the BWRVIP-29 report.

The applicant stated that the BWR Stress Corrosion Cracking and BWR Vessel Internals Programs include water chemistry controls as preventive measures. The Water Chemistry Program meets the recommendations of the latest BWRVIP guidelines, BWRVIP-130, to help ensure the long-term integrity of the RVI components.

The staff concludes that implementation of the Water Chemistry Program in conjunction with the BWR Stress Corrosion Cracking and BWR Vessel Internals Programs is consistent with the license renewal action items specified in the staff's October 18, 2001, SER on the BWRVIP-74-A report. The staff believes that the guidelines included in BWRVIP-130 takes into account the most recent industry experience and latest information from EPRI, which has been proven effective in controlling water chemistry. Therefore, the staff finds this implementation acceptable.

(5) One license renewal action item specified in the staff's October 18, 2001, SER on the BWRVIP-74-A report requires license renewal applicants to identify their vessel surveillance program as either an integrated surveillance program (ISP) or plant-specific in-vessel surveillance program applicable to the license renewal period.

The applicant stated that the OCGS Reactor Vessel Surveillance Program will be the ISP for the license renewal term.

The staff determined that by implementing the BWR ISP the applicant complied with the license renewal action items specified in the staff's October 18, 2001, SER on the BWRVIP-74-A report. Therefore, the staff finds this implementation acceptable. Details of the staff's evaluation of the Reactor Vessel Surveillance Program are in SER Section 3.0.3.2.20.

In LRA Section B.1.9, the applicant stated that this program is consistent with GALL AMP XI.M9 with exceptions and enhancements.

The applicant stated that the BWR Vessel Internals Program will be enhanced to include inspections of the steam dryer in accordance with BWRVIP-139. The staff is currently reviewing the BWRVIP-139 report relevant to the steam dryer component. The applicant has modified its UFSAR and committed (Commitment No. 9) to inspect the steam dryer in accordance with this Topical Report (TR). Because the staff's conditions and license renewal items to be specified in the final SER of this TR will be incorporated in the BWRVIP-139, the staff concludes that this commitment is adequate.

The applicant stated that the program will be enhanced to include the GALL Report recommendations related to IASCC in the top guide grid beam. The applicant stated that during the 1991 refueling outage it had found a crack on the underside of a top guide grid beam. Additional cracked beams were discovered in 1992 and 1994. The applicant stated that crack growth in the top guide beam is monitored by visual inspection (VT-1) during every outage. The applicant claimed that under flaw evaluation guidelines the structural integrity of the top guide is not challenged during the next cycle of operation. During the staff's audit, the applicant stated that it will perform UT of the top guide grid beam during the next refueling outage. The applicant stated that it will comply with all the recommendations of the BWRVIP-26 report and will conduct additional inspections if significant crack growth is identified. The applicant has made a commitment (Commitment No. 9) to inspect the top guide as recommended in the GALL Report. Based on UT results, the applicant will develop inspection frequency and scope guidelines for the top guide. The staff finds the applicant's commitment acceptable because it provides reasonable assurance that the top guide will perform its intended functions during the period of extended operation.

Based on a review of the enhancements for the top guide, the staff determined that the applicant's proposed augmented inspections of the top guide grid beams and slots are consistent with inspection criteria specified in Table IV.B1, item IV.B1-17, of the GALL Report. Therefore, the staff concludes that the proposed inspections of the top guide grid beams will adequately manage the aging effect due to IASCC so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

The applicant stated that during the 2000 refueling outage RPV pressure test leakage was observed from two CRD housing penetrations at the reactor bottom head interface. A roll expansion repair design was completed on the two CRD housings to stop the leaks. This roll expansion method was approved by the staff on November 16, 2000, for one operating cycle only. Subsequent inspections in 2002 and 2004 found no evidence of any CRD housing penetration leakage. The applicant further stated that this repair was submitted to the ASME Code in the form of draft ASME Section XI Code Case N-730, "Roll-Expansion of Class 1 Control Rod Drive Bottom Head," for review and approval. The applicant intends to apply this repair permanently at the OCGS when ASME Code Case N-730 is approved by the ASME Code and the staff. The staff determined that the applicant's proposal to use the ASME Section XI Code Case N-730 for permanent repair of the CRD stub tubes will be acceptable provided the ASME Code Case is approved by the staff.

In RAI B.1.9-3 dated March 20, 2006, the staff requested that the applicant provide details of the CRD repair. The staff requested that, if the ASME Code Case is not approved, the applicant submit a permanent repair plan for review and approval 2 years prior to the beginning of the period of extended operation. The staff requested that the applicant commit to immediate repair of any leaking CRD stub tubes during the period of extended operation if there is a leak after the implementation of an approved permanent roll repair by implementing a permanent weld repair per the approved ASME Section XI Code Cases with staff conditions, if any. The staff also requested that the applicant revise the BWR Vessel Internals Program and its UFSAR supplement to indicate that it will implement the staff-approved permanent repair of the CRD stub tubes for no leakage during the period of extended operation.

In its response dated April 18, 2006, the applicant stated that if the ASME Section XI Code Case N-730 is not approved it will develop a permanent repair plan that complies with the ASME Code Section XI requirements. This permanent repair could be in accordance with the BWRVIP-58-A report, "BWRVIP Vessel And Internals Project, CRD Internal Access Weld Repair," which has been approved by the staff, or an alternate ASME Code repair plan which would be submitted for prior staff approval. If the repair plan needs prior staff approval, the applicant will submit the repair plan 2 years before the period of extended operation. After the implementation of an approved permanent roll repair, if there is a leak in a CRD stub tube, the applicant will use the staff-approved weld repair method prior to restarting the plant. The applicant stated that the UFSAR supplement and the commitment list will be updated to reflect such commitments (Commitment No. 9).

The staff finds the response acceptable because it committed to submit any repair plan not previously approved 2 years prior to the period of extended operation for NRC review and approval. The staff's concerns described in RAI B.1.9-3 are resolved.

In RAI B.1.9-2 dated March 20, 2006, the staff stated that the BWRVIP-76 report, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," and the BWRVIP-104 report, "Evaluation and Recommendations to Address Shroud Support Cracking in BWRs," were under staff review. The staff requested that the applicant make a commitment that it will comply with all requirements specified in the staff's final SERs on these reports and that it will complete all license renewal action items specified in the final SERs when issued.

In its response dated April 18, 2006, the applicant committed (Commitment No. 9) to comply with all applicable conditions specified in the staff's final SERs on the BWRVIP-76 and BWRVIP-104 reports and will complete all the license renewal action items specified in the final SERs on these reports when issued. The staff finds this commitment acceptable. The staff's concern described in RAI B.1.9-2 is resolved.

In RAI B.1.9-6 dated March 20, 2006, the staff requested that the applicant provide information about the type of core plate plugs used at OCGS. If spring-loaded core plate plugs are used at OCGS, the applicant was asked for the type of AMP implemented to ensure their integrity.

In its response dated April 18, 2006, the applicant stated that the core plate at OCGS does not have drilled flow holes as in some BWR-3 and BWR-4 plants and, therefore, has neither spring-loaded or welded core plate plugs. Based on this response, the staff's concern described in RAI B.1.9-6 is resolved.

In the past, one of the aging degradation mechanisms in the RVI components was attributed to IGSCC, which is dependent on the oxygen content of the reactor coolant system (RCS) water. High oxygen levels in the RCS water is one of the chief factors contributing to IGSCC in the RVI components. Addition of hydrogen is considered effective in reducing the oxygen levels in the RCS water and minimizing IGSCC. In addition, NMCA can increase the effectiveness of hydrogen addition.

In RAI B.1.9-7 dated March 20, 2006, the staff requested that the applicant provide information as to whether any NMCA is applied at the OCGS. The staff further requested that the applicant confirm the method of controlling HWC and any NMCA as a mitigative method to reduce IGSCC susceptibility in the RVI components.

The staff also requested that the applicant provide details on the methods for determining the effectiveness of HWC and/or NMCA by the following parameters:

- electro chemical potential (ECP)
- feedwater hydrogen flow
- main steam oxygen content
- hydrogen/oxygen molar ratio

In its response dated April 18, 2006, the applicant stated that HWC and NMCA had been implemented at OCGS in 1992 and 2002, respectively. HWC control is established by monitoring and maintaining the hydrogen-oxygen molar ratio and the ECP of the RCS water. ECP of the RCS water is determined and managed in accordance with requirements specified in the BWRVIP-130 report, "BWR Water Chemistry." For NMCA, noble metal concentrations are monitored and re-application of noble metals is scheduled when the platinum (Pt)-Rhodium (Rh) concentration is predicted to fall below established limits. The guidelines in the BWRVIP-130 report for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen be monitored and kept below the recommended levels to mitigate corrosion. Two impurities, chlorides and sulfates, determine the RCS water conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine the ECP. The EPRI guidelines recommend that the RCS water conductivity and ECP also be monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. OCGS monitors ECP directly with probes in the B recirculation loop via the RWCU system. OCGS uses reactor water dissolved oxygen as a secondary parameter to maintain mitigation in the recirculation loops. The hydrogen concentrations in the feedwater are monitored daily. Calculated hydrogen flow rates are established to maintain hydrogen and oxygen levels in the vessel within guidelines developed from the BWRVIP-130 report. The hydrogen-oxygen molar ratio is maintained greater than or equal to 3 to 1 to ensure proper ECP levels and NMCA effectiveness. The oxygen levels in the main steam lines are not monitored because oxygen levels are measured directly in the RCS water as a means of maintaining chemistry control.

The staff reviewed the applicant's response and finds it acceptable for the following reasons:

- HWC/NMCA addition to the RCS water protects the majority of the RVI components from IGSCC except in areas exposed to high radiation levels (near the core region).
- The applicant's methodology of monitoring the effectiveness of HWC/NMCA includes measurement of the ECP of the RCS water and monitoring the feedwater hydrogen and the RCS oxygen levels. These methods adequately protect the majority of the RVI components from IGSCC.
- The applicant's methodology in maintaining a hydrogen-oxygen molar ratio of 3 to 1 ensures sufficient hydrogen coverage for the majority of the RVI components and reduces the IGSCC crack growth rates in these components.
- Since the RCS water chemistry and conductivity are in compliance with the industry-

accepted BWRVIP-130 report guidelines the staff determined that proper mitigation of IGSCC can be achieved for the majority of the RVI components. The staff understands that some RVI components will not be fully protected from IGSCC due to exposure to neutron radiation.

Based on the review, the staff's concern described in RAI B.1.9-7 is resolved.

Nonsafety-related RVI components (e.g., steam dryer, core shroud heads and separators, internal feedwater spargers, and RPV surveillance capsule holders) can be subject to aging degradation due to pitting and crevice corrosion, SCC, and IGSCC. In RAI B.1.9-8 dated March 20, 2006, the staff requested that the applicant address how it will use the BWR Vessel Internals Program to monitor loss of material due to pitting and crevice corrosion, SCC, and IGSCC in nonsafety-related RVI components.

In its response dated April 18, 2006, the applicant stated that it will monitor the aging degradation in the nonsafety-related RVI components by implementing the BWR Vessel Internals Program. In addition, the applicant committed (Commitment No. 9) to inspect the steam dryer in accordance with the guidelines of the BWRVIP-139 report and that inspections will begin in 2008. The feedwater spargers are inspected in accordance with the recommendations of NUREG-0619. The applicant further stated that it conducts inspections of the steam separator, shroud head, and the core inlet flow baffle (diffuser) in the lower head regions. The applicant has committed to enhance the BWR Vessel Internals Program to include inspections to monitor corrosion in the feedwater sparger, steam separator, RPV surveillance capsule holders, and baffle plates. The staff finds this response acceptable because the applicant committed to monitor the aging degradation due to pitting and crevice corrosion, SCC, and IGSCC in nonsafety-related RVI components. Furthermore, conditions specified in the staff's SER on BWRVIP-139 would apply for OCGS. The staff's concerns described in RAI B.1.9-8 are resolved.

Operating Experience. In LRA Section B.1.9, the applicant provided information about its capabilities in detecting the aging degradation of the RVI components and implementation of appropriate corrective actions, including prompt repair of degraded components prior to failure, to maintain system and component intended functions. Some site-specific examples are provided.

The applicant stated that in 1978 it had identified crack indications in the core spray spargers. Mechanical clamps were installed for structural support for identified cracks and indications in the core spray sparger. Recent inspections in 1998, 2000, 2002, and 2004 have confirmed that the repair clamps are in good condition.

In RAI B.1.9-4 dated March 20, 2006, the staff requested that the applicant provide further information on its future inspection plans for core spray spargers and core spray piping welds including the type and frequency of inspections, inspection methods, sample size, for the repaired and non-repaired core spray components during the period of extended operation.

In its response dated April 18, 2006, the applicant stated that it complied with all the recommendations of the BWRVIP-18 report, specifically as to the type and frequency of inspections, re-inspection frequency, and flaw evaluation methods. The applicant also provided its previous inspection results of the core spray piping brackets and sparger nozzle welds and the repairs performed on core spray sparger tee box welds. As the AMP for the core spray system is consistent with the guidelines specified in the staff-approved BWRVIP-18A report and GALL AMP XI.M9, the staff concludes that the applicant's response was acceptable and, therefore, the staff's concern described in RAI B.1.9-4 is resolved.

The applicant stated that in 1994 it had installed shroud repair hardware (vertical tie rods) after cracks were discovered in the shroud horizontal welds. 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. Inspections of shroud vertical welds completed in 1998 and 2002 have confirmed that the Water Chemistry Program mitigation efforts have been successful as no new crack indications have been observed.

In RAI B.1.9-5 dated March 20, 2006, the staff requested that the applicant provide information on its future plans for type and frequency of inspections and percentage of the core shroud tie rods currently inspected. If the inspection sample size was not consistent with the BWRVIP-76 guidelines the applicant was asked to explain the inconsistency. The staff also asked the applicant for its inspection plans (i.e., inspection methods, sample size, and inspection frequency) of non-repaired core shroud welds during the period of extended operation.

In its response dated April 18, 2006, the applicant stated that thus far it had complied with the BWRVIP-76 guidelines for inspection of the core shroud. The program mandates 100 percent inspection of the 10 shroud repair tie rods every 10 years with visual testing (VT-3) methods. In addition, the BWRVIP-76 report specifies inspection of all of the tie rod repair anchorage points (lug-clevis assemblies) every 10 years by EVT-1. The BWRVIP-76 report does not require inspections for the shroud horizontal welds when they are repaired with the tie rods. The applicant stated that the horizontal shroud welds are not inspected. However, it will continue to inspect all accessible core shroud non-repaired (vertical) welds in accordance with the BWRVIP-76 report. The staff finds this response acceptable because the applicant had made a commitment (Commitment No. 9) to monitor the aging degradation of the core shroud welds consistent with the recommendations of the BWRVIP-76 report and GALL AMP XI.M9.

The applicant stated that it had been inspecting the steam dryer every refueling outage for many years. Cracks were first identified on a lower bank brace in 1983 followed by weld repairs in 1983 and again in 1986. A different repair method, "stop drilling," was implemented in 1996 to mitigate the cracks. Subsequent inspections indicate these measures have been successful in arresting crack growth.

The staff is currently reviewing the BWRVIP-139 report relevant to the steam dryer component. The applicant has modified its UFSAR and committed (Commitment No. 9) to inspect the steam dryer in accordance with this Topical Report (TR). Because the staff's conditions and license renewal items to be specified in the final SER of this TR will be incorporated in the BWRVIP-139, the staff concludes that this commitment is adequate.

The staff's review of OCGS operating experience concludes that by implementing the BWR Vessel Internals Program the applicant had adequately demonstrated its capability in identifying the aging effects associated with the RVI components. The applicant also demonstrated that it can adequately monitor the aging degradation of the RVI components by using proper corrective actions to restore their structural integrity.

UFSAR Supplement. In LRA Section A.1.9 and letter dated April 18, 2006, the applicant provided the UFSAR supplement for the BWR Vessel Internals Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's BWR Vessel Internals Program and RAI responses, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that implementation of the enhancements prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Bolting Integrity

Summary of Technical Information in the Application. In LRA Section B.1.12, the applicant described the existing Bolting Integrity Program as consistent, with an exception, with GALL AMP XI.M18, "Bolting Integrity."

The Bolting Integrity 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 visual inspections for pressure-retaining bolted joint leakage. Inspection of ASME Code Classes 1, 2, and 3 components is conducted in accordance with ASME Code Section XI. Non-Classes 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.10. The staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Bolting Integrity Program for which the applicant claimed consistency with GALL AMP XI.M18 and found them consistent. Furthermore, the staff concludes that the applicant's Bolting Integrity Program provides reasonable assurance that the aging effects for bolting will be adequately managed for the period of extended operation. The staff found that the applicant's Bolting Integrity Program conforms to the recommended GALL AMP XI.M18, with an exception described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "corrective actions." Specifically, the exception stated:

> 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.

In the LRA, the applicant stated that the Bolting Integrity Program does not address structural or component support bolting. For safety-related bolting, the GALL Report relies on the NRC recommendations and guidelines delineated in NUREG-1339 and industry's technical basis for the program and guidelines as to material selection and testing, bolting preload control, ISI, plant operation and maintenance, and evaluation of structural integrity of bolted joints outlined in EPRI NP-5769 with the exceptions noted in NUREG-1339.

The aging management of structural bolting is addressed by the Structures Monitoring Program and the ASME Section XI, Subsection IWE Program addresses primary containment pressure bolting. Aging management of ASME Code Section XI Classes 1, 2, and 3 and Class MC support members is addressed by the ASME Section XI, Subsection IWF Program.

The staff reviewed this exception and found that structural or component support bolting aging effects will be adequately managed by the Structures Monitoring, ASME Section XI, Subsection IWE, and the ASME Section XI, Subsection IWF Programs. The staff's review of these AMPs is discussed in SER Sections 3.0.3.2.24, 3.0.3.2.25 and 3.0.3.2.26, respectively. On this basis, the staff finds this exception acceptable.

Enhancement. In the LRA, the applicant stated that no enhancements were needed for this AMP. However, in the PBD the applicant identified an enhancement to the GALL Report program elements "scope of program," "preventive actions," and "corrective actions." Specifically, the enhancement stated:

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

The applicant stated, in the PBD, that the program addresses the guidance in EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide;" however, the report is not specifically cited as a reference in the Exelon corporate or station-specific bolted joint inspection/repair procedures. The staff noted that this enhancement is not identified in LRA Section B1.12. The applicant was asked to clarify this discrepancy.

In its letter dated April 17, 2006, the applicant committed (Commitment No. 12) to revise the Bolting Integrity Program in the LRA to include the enhancement identified in the PBD stating that the site procedure will be enhanced to include reference to EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," December 1995.

The staff reviewed the EPRI TR-104213, 1995 Edition, and finds it an acceptable revision of the original EPRI TR-104213. The staff finds this enhancement acceptable as when implemented the program will be consistent with GALL AMP XI.M18 and provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.12, the applicant explained that it had experienced isolated cases of bolting function loss attributed to loss of material. Review of operating history has identified no cracking of stainless steel bolting. RCPB leakage due to boric acid-induced degradation is not applicable because the station is a BWR. In all cases the existing inspection and testing methodologies have discovered the deficiencies and corrective actions have been implemented prior to loss of system or component intended functions.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Bolting Integrity Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.12 and letter dated April 17, 2006, the applicant provided the UFSAR supplement for the Bolting Integrity Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Bolting Integrity Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and the enhancement and their justifications and determined that the AMP, with the exception and the enhancement, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.13, the applicant described the existing Open-Cycle Cooling Water System (OCCWS) Program as consistent, with enhancements, with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

The Open-Cycle Cooling Water System Program manages aging of piping, piping components, piping elements, and heat exchangers included in the scope of license renewal for loss of material and reduction of heat transfer and exposed to raw water-salt water. Program activities include: (1) surveillance and control of biofouling (including biocide injection), (2) verification of heat transfer capabilities for components cooled by the SW and ESW systems, (3) inspection and maintenance activities, (4) walkdown inspections, and (5) review of maintenance, operating, and training practices and procedures. Inspections may include visual, UT, and eddy current testing (ECT) methods. The OCCWS Program is based on the recommendations of NRC GL 89-13.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.11. The staff reviewed the enhancements and their justifications to determine whether the AMP, with the enhancements, remained adequate to manage the aging effects for which it was credited.

The staff reviewed those portions of the Open-Cycle Cooling Water System Program for which the applicant claimed consistency with GALL AMP XI.M20 and found them consistent. Furthermore, the staff concludes that the applicant's Open-Cycle Cooling Water System Program provides reasonable assurance that aging effects attributable to open cycle cooling water will be adequately managed during the period of extended operation. The staff found that the applicant's Open-Cycle Cooling Water System Program conforms to the recommended GALL AMP XI.M20 with enhancements described below.

<u>Enhancement 1</u>. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending." Specifically, the enhancement stated:

> 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.

In reviewing this enhancement, the staff noted that volumetric inspections of above-ground ESW and SW piping original to the plant design are at a minimum of 10 locations every 2 years based on the maximum anticipated corrosion rates determined from past inspections and analyses. The enhancement will add a minimum of 4 UT inspections every 4 years on above-ground piping replaced with the same internal coatings and materials as new buried ESW and SW piping. As above-ground and buried piping are subject to the same internal environments and failure mechanisms, the volumetric inspections of above-ground 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 above-ground ESW and SW piping. The applicant also stated that the frequency of the testing and inspections is based on previous findings and, if testing and inspections need to be more frequent or the scope needs to be increased, the program allows for such adjustments.

The staff determined that the 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 samples and frequencies are adequate because, based on previous findings, the applicant's program allows for adjustment of the sample and frequency as needed. On this basis, the staff finds the enhancement acceptable because when implemented the program 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>. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending." Specifically, the enhancement stated:

> 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 microbiologically influenced corrosion in the RBCCW, TBCCW and Containment Spray preventative maintenance tasks.

In reviewing this enhancement the staff noted that the reactor building closed cooling water (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 turbine building closed cooling water (TBCCW) heat exchangers are included for a leakage boundary function only. The current GL 89-13 program includes only the ESW system and containment spray heat exchangers. Attributes of the GL 89-13 guidance will be implemented for the SW system, RBCCW system, and TBCCW system heat exchangers as parts of the Open-Cycle Cooling Water System Program. Upon implementation of this enhancement, the program will be consistent with the recommendations in AMP XI.M20 in the GALL Report.

On this basis, the staff finds this enhancement acceptable because when implemented the Open-Cycle Cooling Water System Program will be consistent with GALL AMP XI.M20 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.13, the applicant explained that OCGS had reviewed both industry and plant-specific operating experience with the Open-Cycle Cooling Water System Program. Inspections implementing the guidance of GL 89-13 have identified deterioration, degradation, and loss of material from inside the pipe.

OCGS evaluations have identified 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, 50 percent of the buried ESW and 10 percent of the buried SW piping were replaced with new pipe and an improved coating system. A plan is in place to replace the other 50 percent of the buried ESW piping prior to 2007.

After reviewing several ESW pipe leaks and wall thinning events, the applicant identified a common failure mechanism (local wall thinning due to salt-water corrosion). The results were entered into the corrective action process and an operability evaluation was performed in 2003. The operability evaluation included the effect of the failure mechanism on the SSC safety function thresholds and methods for detection of leaks for each of the safety functions. Additionally, the corrective action process problem resolution response developed 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, to modify piping segments that pose high risks and cannot reasonably be inspected, to modify piping to allow system flexibility for future repairs, and to 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 staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience, and discussions with the applicant's technical personnel, the staff concludes that the applicant's Open-Cycle Cooling Water System Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.13, the applicant provided the UFSAR supplement for the Open-Cycle Cooling Water System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Open-Cycle Cooling Water System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Closed-Cycle Cooling Water System

Summary of Technical Information in the Application. In LRA Section B.1.14, the applicant described the existing Closed-Cycle Cooling Water System (CCCWS) Program as consistent, with an exception, with GALL AMP XI.M21, "Closed-Cycle Cooling Water System"

The Closed-Cycle Cooling Water System Program manages aging of piping, piping components, piping elements, and heat exchangers included in the scope of license renewal for loss of material and reduction of heat transfer and exposed to a closed cooling water environment. The program provides for preventive, performance monitoring, and condition monitoring activities implemented through station procedures. Preventive activities include measures to maintain water purity and the addition of inhibitors to minimize corrosion based on EPRI 1007820, "Closed Cooling Water Chemistry Guidelines." Performance monitoring provides indication of degradation in CCCWSs with plant operating conditions indicating degradation in normally operating systems. In addition, station maintenance inspections and NDE monitor the condition of heat exchangers exposed to closed-cycle cooling water environments.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.12. The staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Closed-Cycle Cooling Water System Program for which the applicant claimed consistency with GALL AMP XI.M21 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's Closed-Cycle Cooling Water System Program provides reasonable assurance that aging effects attributable to closed-cycle cooling water systems will be adequately managed during the period of extended operation. The staff found that the applicant's program conforms to the recommended GALL AMP XI.M21 with an exception described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program elements "preventive actions," "parameters monitored or inspected," and "monitoring and trending." Specifically, the exception stated:

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 requirements of EPRI TR-107396 *for maintaining conditions to minimize corrosion and* microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

During the audit, 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 the GALL Report, and EPRI TR-1007820, "Closed Cooling Water Chemistry Guideline, Revision 1," which is the 2004 revision implemented by OCGS. In addition, 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, to confirm that the new guidance provided in TR-1007820 was not contrary to that in TR-107396.

The staff 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 recommendations for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects. On this basis, the staff finds this exception acceptable.

<u>Operating Experience</u>. *In LRA Section B.1.14, the applicant explained that the 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 subject to CCCWS activities. Additionally, industry operating experience demonstrates that the use of corrosion inhibitors in CCCWSs that are monitored and maintained is effective in mitigating loss of material and buildup of deposits. Buildup of deposits have degraded heat transfer in heat exchangers on the tube side of the heat exchangers. The tube side of the heat exchangers is exposed to raw water-salt water and managed by the Open-Cycle Cooling Water System Program.

In 2002 OCGS increased its desired molybdate range in all of the CCCWSs from 50-125 ppm to 200-1000 ppm, enabling OCGS 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 add returned pH back in spec 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, OCGS monitors the RBCCW, TBCCW and emergency diesel generator (EDG) cooling water (EDGCW) for microbiological growth (total bacteria colonies) in accordance with EPRI 1007820, "Closed Cooling Water Chemistry Guidelines." To date there have been no adverse trends in microbiological growth in CCCWSs.

By improving the CCCW monitoring parameters, promptly returning out of range parameters within acceptable limits, and monitoring for microbiological growth OCGS has been effective in managing loss of material and reduction of heat transfer for components in a closed cooling water environment. Additionally, the Closed-Cycle Cooling Water System Program is adjusted continually to account for industry and station experience and research. With additional operating experience lessons learned will be used to adjust this program as needed.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Closed-Cycle Cooling Water System Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.14, the applicant provided the UFSAR supplement for the Closed-Cycle Cooling Water System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Closed-Cycle Cooling Water System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.15, the applicant described the existing Boraflex Rack Management Program as consistent, with an exception, with GALL AMP XI.M22, "Boraflex Monitoring."

The Boraflex Rack Management Program is based on manufacturer recommendations, industry guidelines developed in response to 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 percent 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 the BADGER device, monitoring dissolved silica in the spent fuel storage pool, and trending the results with an 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.13. The staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Boraflex Rack Management Program for which the applicant claimed consistency with GALL AMP XI.M22 and found them consistent. Furthermore, the staff concludes that the applicant's Boraflex Rack Management Program provides reasonable assurance that the effects of aging will be managed adequately during the period of extended operation. The staff found that the applicant's Boraflex Rack Management Program conforms to the recommended GALL AMP XI.M22 with an exception described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program element "preventive actions." Specifically, the exception stated:

> 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.

In the LRA, the applicant stated 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. During the audit, the staff questioned why area density measurement is equal to or better than Blackness tests. The applicant replied that blackness testing provides only information on the presence of neutron absorber material. Blackness testing provides information on 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 in a boraflex panel whereas a BADGER test quantitatively measures the Boron-10 areal density of neutron absorber in the rack.

The staff reviewed this exception and concludes that because the areal density test is more quantitative than the blackness test this exception is acceptable.

Operating Experience. In LRA Section B.1.15, the applicant explained that the 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 with the BADGER device. To date two BADGER tests have been conducted, the first in 1997, the second in 2001. Both 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 areal density certified by the manufacturer. The in-situ areal density test by the BADGER device has proved effective in identifying unacceptable degradation prior to a loss of an intended function.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant Boraflex Rack Management Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.15, the applicant provided the UFSAR supplement for the Boraflex Rack Management Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Boraflex Rack Management Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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 Handling Systems

Summary of Technical Information in the Application. In LRA Section B.1.16, the applicant described the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program as consistent, with an exception and enhancements, with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

This Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program provides for periodic visual inspections of overhead heavy load and light load (related to refueling) handling systems through station procedures and is relied upon to manage loss of material of cranes and hoists 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 inspections 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 GALL Report Bolting Integrity Program. Inspection frequency is annual for cranes and hoists accessible during plant operation and every 2 years for cranes and hoists accessible only during refueling outages.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.14. The staff reviewed the exception and enhancements and their justifications to determine whether the AMP, with the exception and enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program for which the applicant claimed consistency with GALL AMP XI.M23 and found them consistent. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the aging effects for which this program is credited will be adequately managed. The staff 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 with the exception and enhancements described below.

Exception: In the LRA, the applicant stated an exception to the GALL Report program element "monitoring and trending." Specifically, the exception stated:

> 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.

In reviewing this exception, the staff 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 as 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 had been deleted.

On the basis that the GALL Report Revision 1 does not recommend monitoring the number of lifts made by each crane the staff determined that the applicant's program element is consistent with the GALL Report and that this exception is not required.

Enhancement 1. In the LRA, the applicant stated an enhancement to the GALL Report program element "scope of program." specifically, the enhancement stated:

> 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 staff noted that LRA Section 2.3.3.11 stated that other cranes and hoists not in scope of NUREG-0612 but traveling in the vicinity of safety-related SSCs are also within the scope of license renewal if their failure will impact a safety-related function. As a result, the reactor building 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 (elevation 95'), and the torus bay monorail are within the scope of license renewal. This enhancement makes the AMP consistent with the recommendations of the GALL Report.

On this basis, the staff finds the enhancement acceptable because when implemented the Inspection of the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be consistent with GALL AMP XI.M23 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2. In the LRA, the applicant stated an enhancement to the GALL Report program elements "parameters monitored or inspected" and "detection of aging effects." Specifically, the enhancement stated:

> The program will provide for specific inspections for rail wear.

The staff 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 staff finds the enhancement acceptable because when the enhancement is implemented the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be consistent with GALL AMP XI.M23 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3. In the LRA, the applicant stated an enhancement to the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the enhancement stated:

> 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 staff 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 staff concludes that this enhancement is adequate.

On this basis, the staff finds the enhancement acceptable because when implemented the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be consistent with GALL AMP XI.M23 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.16, the applicant explained that the plant operating and maintenance experience review identified no incidents of failure of passive cranes and hoists structural components due to age-related degradations. Minor nonage-related degradations have been identified in nonload-bearing components during the inspections. The degradations were repaired and documented in accordance with the corrective action process.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.16, the applicant provided the UFSAR supplement for the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications, and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.18, the applicant described the existing BWR Reactor Water Cleanup System Program as consistent, with an exception, with GALL AMP XI.M25, "BWR Reactor Water Cleanup System."

The BWR Reactor Water Cleanup System Program describes the requirements for augmented ISI for SCC or IGSCC on stainless steel RWCU system piping welds outboard of the second containment isolation valves. The program includes inspection guidelines delineated in NUREG-0313, Revision 2 and 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. RCS chemistry activities that support the AMP for the RWCU system consist of preventive measures used to manage cracking in license renewal components exposed to reactor water and steam.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.15. The staff reviewed the exception and its justifications to determine whether the AMP, with the exception, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the BWR Reactor Water Cleanup System Program for which the applicant claimed consistency with GALL AMP XI.M25 and found them consistent with the GALL Report AMP. The staff found that the applicant's BWR Reactor Water Cleanup System Program conforms with the recommended GAL AMP XI.M25 with an exception described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report AMP element "preventive actions." Specifically, the exception stated:

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 staff reviewed the applicant's exception as part of the Water Chemistry Program and determined that it is acceptable. The evaluation of this exception is discussed in SER Section 3.0.3.2.2.

Operating Experience. In LRA Section B.1.18, the applicant explained that no indications of IGSCC have been found in the RWCU, which is not stress-improved. The following mitigative actions also have been implemented to reduce the susceptibility to IGSCC in the RWCU system: improved water chemistry guidelines (BWR Water Chemistry Guidelines 2004 Revision (BWRVIP-130)), Hydrogen Water Chemistry (HWC), and Noble Metals Chemical Addition (NMCA).

The staff requested clarification on when the HWC and NMCA mitigative actions had been initiated. In its response, the applicant stated that the HWC had been implemented during cycle 12 (1990) and NMCA implemented in refueling outage 1R19 (2002).

The staff reviewed the operating experience provided in the LRA and PBDs, interviewed the applicant's technical personnel, and confirmed that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's BWR Reactor Water Cleanup System Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.18, the applicant provided the UFSAR supplement for the BWR Reactor Water Cleanup System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Reactor Water Cleanup System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.19, the applicant described the existing Fire Protection Program as consistent, with an exception and enhancements, with GALL AMP XI.M26, "Fire Protection."

The Fire Protection Program provides for aging management of various fire protection-related components within the scope of license renewal. The program visually inspects fire barrier penetration seals for such signs of degradation as change in material properties, cracking, and loss of material, through periodic inspection, surveillance, and maintenance activities. The program visually inspects 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 program 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 whenever fire doors and components are repaired or replaced. The program will manage loss of material aging effects for the fuel oil systems for the diesel-driven fire pumps by periodic fuel oil system surveillance tests implemented through recurring task work orders and station procedures. The program will manage aging of external surfaces of the carbon dioxide and halon fire suppression system components by corrosion and mechanical damage through periodic operability tests based on the National Fire Protection Association (NFPA) codes and visual inspections.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.16. The staff reviewed the exception and enhancements and their justifications to determine whether the AMP, with the exception and enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Fire Protection Program for which the applicant claimed consistency with GALL AMP XI.M26 and found them consistent. The staff found that the applicant's Fire Protection Program conforms to the recommended GALL AMP XI.M26 with the exception and enhancements described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program elements "parameters monitored or inspected" and "detection of aging effects." Specifically, the exception stated:

> 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.

In reviewing this exception, the staff noted that the Fire Protection Program directs halon fire suppression system surveillance that verifies halon storage tank weight, level, and pressure every six months. Actuation of the system (automatic and manual, including dampers) and flow are 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 staff noted that the CLB for periodic inspection and functional test frequency of the halon and CO_2 systems is every 18 months.

OCGS test procedures will be enhanced to include visual inspections of component external surfaces for signs of corrosion and mechanical damage. In LRA Section B.1.19, the applicant stated that plant-specific operating experience shows 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 identified no aging-related degradation adversely affecting the operation of the halon or CO_2 systems.

Although the frequency of functional testing exceeds that recommended in GALL AMP XI.M26, the staff determined that it is sufficient to ensure system availability and operability with the enhancement to include visual inspections of component external surfaces for signs of corrosion and mechanical damage. In addition, the station operating history indicates no aging-related events adversely affecting system operation. Based on its review of the applicant's program and plant-specific operating experience, the staff finds that the 18-month frequency is adequate for aging management considerations. On this basis, the staff finds this exception acceptable.

<u>Enhancement 1</u>. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

> 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.

In reviewing this enhancement, the staff noted that the applicant's Fire Protection Program 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.

The staff finds this enhancement acceptable because when implemented the Fire Protection Program will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

<u>Enhancement 2</u>. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

> 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.

In reviewing this enhancement, the staff noted that the applicant's Fire Protection Program 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 operational 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. Because the inclusion of visual inspections will provide additional assurance of adequate management of aging degradation of the fuel supply lines this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Protection Program will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

> 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.

In reviewing this enhancement, the staff noted that, as part of the applicant's Fire Protection Program, the aging effects on the intended function of fire barrier walls, ceilings, and floors that perform a fire barrier function are managed by specific inspection parameters in accordance with industry codes, standards, and guidelines that detect and correct aging degradation prior to loss of intended functions. This enhancement will add inspections of fire barrier walls, ceilings, and floors 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. As these enhanced inspections will provide additional assurance of adequate management of aging degradation of fire barrier walls, ceilings, and floors this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Protection Program will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 4. In the PBD for this AMP, the applicant stated an additional enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" not identified in the LRA. Specifically, the enhancement stated:

> 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.

In its letter dated April 17, 2006, the applicant committed (Commitment No. 19) to revise LRA Section B.1.19 to add the following enhancement to the Fire Protection Program for periodic visual inspections of fire door surface integrity and clearance checks as described in PBD-AMP-B.1.19.

In reviewing this enhancement, the staff noted that the applicant's Fire Protection Program will direct that fire doors within the scope of license renewal be visually inspected by designated qualified personnel for such signs of degradation as wear, missing parts, holes, and clearances. Functional/operational condition tests of fire doors also will be conducted. In PBD-AMP-B.1.19, 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 2 years. This inspection frequency ensures timely detection and correction of degraded door conditions prior to a loss of intended function. The staff determined that visual inspection of fire doors for such signs of degradation as wear, missing parts, holes, and clearances will provide additional assurance of adequate management of aging effects as recommended in the GALL Report; therefore, this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Protection Program will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.19, the applicant explained that the Fire Protection Program had been effective in identifying aging effects and taking appropriate corrective action. Minor degradation like minor cracks have been detected in concrete components in structures within the scope of license renewal. Evaluation and disposition of observed degradation were based on program acceptance criteria and in accordance with the corrective action process. The OCGS experience with fire barrier penetration seals is consistent with the industry experience. Silicone foam fire barrier penetration seals are used. OCGS has experienced fire door component degradation due to wear, loss of material due to corrosion, and physical damage. Mitigating actions have been taken as appropriate. OCGS operating experience shows no loss of material on the external surfaces of components in the halon and carbon dioxide systems adversely affecting system operation. The OCGS diesel-driven fire pump fuel oil systems have experienced minor system events promptly detected and corrected. These events were detected 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.

The staff reviewed the operating experience provided in the LRA and Program Basis Document PDB-AMP-B.1.19 and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience. The Fire Protection Program activities with enhancements will be effective in managing aging degradation for the period of extended operation by timely detection of aging effects and appropriate corrective actions prior to loss of system or component intended functions.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Fire Protection Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.19 and letter dated April 17, 2006, the applicant provided the UFSAR supplement for the Fire Protection Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fire Protection Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception and enhancements, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.20, the applicant described the existing Fire Water System Program as consistent, with enhancements, with GALL AMP XI.M27, "Fire Water System."

The Fire Water System Program will manage identified aging effects for the water-based fire protection system and associated components through 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 in accordance with guidance from NFPA standards. Fire system main header flow tests are conducted at least once every 3 years, hydrant flushing and inspections at least once every 12 months. The condition of the fire pumps is confirmed once every 18 months by 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 so that a loss of system pressure is immediately detected and corrective actions initiated. Periodic water samples will be tested to detect microbiologically influenced corrosion (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 to maintain system intended functions.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.17. The staff reviewed the enhancements and their justifications to determine whether the AMP, with the enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Fire Water System Program for which the applicant claimed consistency with GALL AMP XI.M27 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's Fire Water System Program provides reasonable assurance that aging effects on fire protection components within the scope of license renewal will be adequately managed during the period of extended operation. The staff found that the applicant's Fire Water System Program conforms to the recommended GALL

AMP XI.M27 with enhancements described below.

Enhancement 1. In the LRA, the applicant identified an enhancement to meet the GALL Report program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

> 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.

In reviewing this enhancement, the staff noted that the applicant's Fire Water System 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 in accordance with guidance from NFPA standards. This enhancement adds volumetric inspections by appropriate techniques on system piping to monitor pipe wall thickness and evaluate internal pipe conditions as recommended in the GALL Report. Because 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 staff determined that this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Water System Program will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2. In the LRA, the applicant identified an enhancement to meet the GALL Report program element "preventive actions." Specifically, the enhancement stated:

> 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

In reviewing this enhancement, the staff noted that the applicant's Fire Water System Program includes preventive actions to preclude buildup of significant corrosion, MIC, or biofouling by 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. Because the addition of water sampling for the presence of MIC will provide additional assurance that the effects of aging will be adequately managed, the staff determined that this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Water System Program will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3. In the LRA, the applicant identified an enhancement to meet the GALL Report program element "detection of aging effects." Specifically, the enhancement stated:

> 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.

In reviewing this enhancement, the staff noted that the applicant's Fire Water System Program will manage identified aging effects for the water-based fire protection system and associated components through 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 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 50 years in service. Thereafter, this testing will be repeated on a frequency of once every 10 years during the period of extended operation to ensure that signs of degradation like corrosion are detected promptly. Initial inspections of the sprinkler heads will be prior to 50 years in service. Because the addition of 50-year sprinkler head inspections will provide additional assurance of adequate management of aging effects, the staff determined that this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Water System Program will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 4. In the LRA, the applicant stated an enhancement in meeting the GALL Report program element "scope of program." Specifically, the enhancement stated:

> *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.*

In reviewing this enhancement, the staff noted that the applicant's Fire Water System Program will manage identified aging effects for the water-based fire protection system and associated components through 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 in accordance with guidance from NFPA standards. The redundant water storage tank is inspected every 5 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. Because visual inspection of the redundant fire water storage tank heater will provide additional assurance of adequate management of aging effects the staff determined that this enhancement is acceptable.

The staff finds this enhancement acceptable because when implemented the Fire Water System Program will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.20, the applicant explained that in 2003 a leak was discovered in a small diameter cooling water line of the #2 diesel driven fire pump. The line comes off of the 10-inch pump discharge line and provides cooling water to the diesel engine when the engine-driven pump operates. Normally in standby, the pump is operated during pump testing. The leak was discovered during a pump performance test. The leak did not render the system, pump, or engine inoperable, and the line was subsequently replaced. The cause of the leak was attributed to MIC and a combination of highly turbulent flow in the line and the stagnant lay-up conditions when the pump is not operating. The cooling water line on the #1 diesel-driven fire pump was subsequently inspected by NDE techniques and wall thinning was found. The extent of wall thinning did not render the pump inoperable, and the line is scheduled for replacement.

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 considered available for use in an emergency. It was replaced with a new hydrant.

The 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.

The staff reviewed the operating experience provided in the LRA, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience. The Fire Water System Program activities with enhancements will be effective in managing aging degradation for the period of extended operation by timely detection of aging effects and 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 personnel, the staff concludes that the applicant's Fire Water System Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.20, the applicant provided the UFSAR supplement for the Fire Water System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fire Water System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.21, the applicant described the new Aboveground Outdoor Tanks Program as consistent, with an exception, with GALL AMP XI.M29, "Aboveground Carbon Steel Tanks."

The Aboveground Outdoor Tanks Program provides 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 program will require removal of insulation to permit visual inspection of insulated tank surfaces. The program will be implemented prior to the period of extended operation. Tanks will be inspected at an initial frequency of every 5 years.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.18. The staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Aboveground Outdoor Tanks Program for which the applicant claimed consistency with GALL AMP XI.M29 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's Aboveground Outdoor Tanks Program provides reasonable assurance that the effects of aging will be managed during the period of extended operation. The staff found that the applicant's Aboveground Outdoor Tanks Program conforms to the recommended GALL AMP XI.M29 with exceptions described below.

Exception 1. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "preventive actions." Specifically, the exception stated:

> 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 applicant stated in the LRA that the program includes the outdoor aluminum storage tanks in addition to the carbon steel tanks. Due to corrosion-resistant properties of aluminum the tanks are not painted. For aluminum tanks, the AMP includes visual inspections, sealants/coating examination at the tank foundation interfaces, and periodic UT inspections on the tank bottom. The staff's review of operating experience for the Aboveground Outdoor Tanks Program found this exception acceptable because it appropriately adds aluminum tanks to the scope of the AMP.

The staff reviewed this exception and concludes 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 not to paint aluminum tanks because experience shows that aluminum does not rust when exposed to atmospheric conditions.

Exception 2. In the PBD for this AMP the applicant stated an exception to the GALL Report program element "monitoring and trending" not stated in the LRA. Specifically, the exception stated:

The specified frequency by the Oyster Creek program is every 5 years in place of system walkdowns each outage.

In its letter dated April 17, 2006, the applicant committed (Commitment No. 21) to revise the Aboveground Outdoor Tanks Program as described in the LRA to include the exception identified in the PBD, which states that the specified frequency by the program is every 5 years in place of system walkdowns each outage.

The applicant stated in the PBD that 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 consistent with industry guidelines 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 tank surfaces before an intended function is impacted.

The staff questioned the schedule for conducting the walkdowns and asked whether the schedule is consistent with the GALL Report recommendation. The applicant stated that it uses structured inspections every 5 years rather than system walkdowns every outage and that this use is an exception to the GALL Report 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 under the Maintenance Rule. The staff finds this exception to GALL Report acceptable because it meets the requirements of the Maintenance Rule and is consistent with ASME Section XI Code.

The staff's review of operating experience for the Aboveground Outdoor Tanks Program finds this exception acceptable based on industry experience and plant operating experience.

Operating Experience. In LRA Section B.1.21, the applicant explained that the Aboveground Outdoor Tanks Program is being implemented at OCGS; 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 above-ground and buried tanks. The program is based on industry guidance and the GALL Report program for above-ground carbon steel tanks. The condensate storage tank (CST) has been repaired to replace a corroded tank bottom. Periodic UT inspections will be performed on aluminum and carbon steel tank bottoms.

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 personnel, the staff concludes that the applicant's Aboveground Outdoor Tanks Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.21 and letter dated April 17, 2006, the applicant provided the UFSAR supplement for the Aboveground Outdoor Tanks Program. The staff determined that the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Aboveground Outdoor Tanks Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.22, the applicant described the existing Fuel Oil Chemistry Program as consistent, with exceptions and enhancements, with GALL AMP XI.M30, "Fuel Oil Chemistry."

The Fuel Oil Chemistry Program activities are preventive and provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of licensing 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 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 particulate 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 in accordance with approved procedures for new and stored fuel. Fuel oil tanks are drained periodically of accumulated water and sediment and 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.19. The staff reviewed the exceptions and enhancements and their justifications to determine whether the AMP, with the exceptions and enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Fuel Oil Chemistry Program for which the applicant claimed consistency with GALL AMP XI.M30 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the aging effects for which this program is credited will be adequately managed. The staff found that the applicant's Fuel Oil Chemistry Program conforms to the recommended GALL AMP XI.M30 with exceptions and enhancements described below.

Exception 1. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the exception stated:

> 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.

In reviewing the OCGS PBD for the Aboveground Outdoor Tanks Program (PBD-AMP-B.1.22), the staff noted that OCGS 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 staff 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 undetected, leading to the possibility that undetected corrosion could be present in the day tanks. The applicant was asked why the day tanks cannot be sampled, cleaned, or inspected and what evidence demonstrated that the operating experience had 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 that periodic sampling will not be done for the day tanks but that the Fuel Oil Chemistry Program will be revised to include a one-time inspection of the EDG day tanks.

In its letter dated April 17, 2006, the applicant committed (Commitment No. 22) to revise the Fuel Oil Chemistry Program in the LRA to include a one-time internal inspection of the EDG day tanks to confirm the absence of aging effects. Visual and further inspections will quantify the degradation if any evidence of corrosion or pitting was observed during the visual inspection.

The staff reviewed the applicant's response and determined that the new commitment to a one-time inspection of the EDG day tanks will provide objective evidence to determine whether undetected aging degradation is present. If degradation is detected, further actions will be taken to quantify and, if necessary, correct the degradation. On this basis, the staff concludes that the applicant's response was acceptable.

Following the staff's review of this exception and the applicant's commitment to perform a one-time inspection of the EDG day tanks the staff concludes 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>. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the exception stated:

> 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.

In reviewing this exception, the staff noted that neither the LRA nor the PBD for this AMP discusses the specific sampling process for the EDG fuel oil storage tank or the differences compared to ASTM 4057-95. The applicant was asked for 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 the bottom of the tank sump and specifically designed to collect condensation/moisture and sediment from within the tank.

As 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 ASTM D 4057-95 (2000) guidelines and, therefore, was not identified as an exception.

The staff reviewed the applicant's response as well as ASTM D 4057-95 (2000) and the applicant's oil sampling procedure 828.7. The OCGS technical personnel were also interviewed to discuss the sample station operation. The staff determined that the OCGS sampling procedure will conservatively estimate fuel oil contaminants, which tend to settle to the lower levels of the tank. On this basis, the staff concludes that this exception is acceptable.

Exception 3. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the exception stated:

> 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 requirements 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.

In reviewing this exception, the staff reviewed ASTM D 4057-95 (2000). For fuel oil storage tanks of 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). The OCGS fire pond diesel fuel oil storage tanks are 2.1 cubic meters so the spot sampling recommendations in ASTM D 4057 are applicable. The staff recognized that the actual sample location for the OCGS fire pond diesel fuel oil storage tanks in the tanks is lower than prescribed by the ASTM D 4057 standard and will result in samples 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 staff concludes that this exception is acceptable.

Exception 4. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of program" and "preventive actions." Specifically, the exception stated:

> 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 will be detected by routine analysis or by periodic draining of water and sediment from the storage tank bottoms.

In evaluating this exception, the staff reviewed the applicant's fuel oil sampling activities to determine whether they are adequate for timely detection of corrosion. The staff determined that fuel oil analyses for particulates as well as water and sediment are performed quarterly or more frequently for the fuel oil storage tanks. In particular, the applicant stated that complete off-site lab fuel oil analyses are performed for particulate contamination, bacteria, American Petroleum Institute (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 analyses are 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 staff determined that the applicant's fuel oil sampling together with the inspection activities will provide reasonable assurance that, if corrosion were occurring in the fuel oil tanks, it will be detected in a timely manner. If evidence of corrosion is detected, corrective actions will be taken to mitigate it. On this basis, the staff concludes that this exception is acceptable.

Exception 5. In Attachment 1, item B.1.22 of its reconciliation document, the applicant identified an additional exception to the GALL Report program element "scope of program" not included in the LRA. Specifically, the exception stated:

> 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 will 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).

In its letter dated March 30, 2006, the applicant stated that the Fuel Oil Chemistry Program will be revised to include the exception identified in the reconciliation document stating that OCGS has not adopted the Standard Technical Specifications; however, the fuel oil specifications and procedures invoke similar requirements for fuel oil purity and fuel oil testing.

The applicant was asked for additional information on the specific fuel oil specifications 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 operating experience at OCGS 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 quarterly. This frequency exceeds the standard technical specifications requirements of 31 days; however, it is aligned with RG 1.137, which states that a quarterly basis is sufficient unless accumulated condensation is suspected, in which case a monthly basis is appropriate. As 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, OCGS did not have in place recurring tasks to drain water and sediment periodically from the bottom of fuel oil storage tanks. Current practices include quarterly 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 tank.

The applicant further stated in its response that the standard technical specifications reference RG 1.137 as supplemented by ANSI N195 for recommended fuel oil practices. 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 obtained with the 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 RG 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 staff 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; OCGS 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 staff 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 of 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 staff concludes that this exception is acceptable.

Enhancement 1. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

> 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 staff noted that 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 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. The staff finds this enhancement acceptable because when implemented the Fuel Oil Chemistry Program will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

> 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 staff noted that 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 fuel oil system. The staff finds this enhancement acceptable because when implemented the Fuel Oil Chemistry Program will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the enhancement stated:

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 staff noted that 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 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. The staff finds this enhancement acceptable because when implemented the Fuel Oil Chemistry Program will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 4. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "preventive actions," and "detection of aging effects." Specifically, the enhancement stated:

> 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 staff noted that 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 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. The staff finds this enhancement acceptable because when implemented the Fuel Oil Chemistry Program will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 5. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "scope of program," "preventive actions," and "detection of aging effects." Specifically, the enhancement stated:

> 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 staff noted that 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 EDG fuel storage tank. Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses when there is 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. The staff finds this enhancement acceptable because when implemented the Fuel Oil Chemistry Program will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.22, the applicant explained that the Fuel Oil Chemistry Program has proven to be effective in identifying and correcting abnormal conditions promptly. In 2003, OCGS experienced high concentrations of water and sediment in main fuel oil tank samples. On previous occasions, high concentrations of water and sediment also had 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 promptly 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.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Fuel Oil Chemistry Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.22 and letters dated March 30, and April 17, 2006, the applicant provided the UFSAR supplement for the Fuel Oil Chemistry Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fuel Oil Chemistry Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes 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

Summary of Technical Information in the Application. In LRA Section B.1.23, the applicant described the existing Reactor Vessel Surveillance Program as consistent, with an enhancement, with GALL AMP XI.M.31, "Reactor Vessel Surveillance."

In LRA Section B.1.23, the applicant stated that this program monitors the effects of neutron embrittlement of the RPV beltline materials. The program is based on the BWR ISP and satisfies the requirements of 10 CFR 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." The Reactor Vessel Surveillance Program is based upon the BWRVIP-78 "BWR Integrated Surveillance Program Plan," and the BWRVIP-86-A, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation," reports. The staff in its SER dated April 27, 2004, approved use of the BWRVIP ISP at OCGS (license amendment 242).

The BWRVIP-116, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal," report identifies and schedules additional capsules to be withdrawn and tested during the license renewal period. OCGS will continue to use the ISP during the period of extended operation by implementing the requirements of the BWRVIP-116 report and by addressing any additional actions required by the staff's SER associated with the BWRVIP-116 report after it is issued.

The representative material and host plant for the limiting RPV plate and weld materials and the schedule for withdrawal of these materials are identified in the BWRVIP-116 report. Future withdrawal and testing of the remaining OCGS surveillance capsule will be permanently deferred. As described in the BWRVIP-116 report, BWR facilities that will not be required to remove additional surveillance capsules will determine vessel fluence utilizing a staff-approved neutron fluence methodology during the extended license period. The program will ensure coupon availability during the period of extended operation by saving withdrawn coupons for future reconstitution. If the BWRVIP-116 report is not approved by the staff a plant-specific surveillance plan will be provided for the license renewal period in accordance with Appendices G and H to 10 CFR Part 50.

OCGS has performed the RPV fluence analysis by a staff-approved methodology to support license renewal. This analysis also satisfies the commitment associated with amendment 242 for OCGS to perform a neutron fluence evaluation using a method in accordance with RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

Staff Evaluation. In LRA Section B.1.23, the applicant described its AMP to manage irradiation embrittlement of the RPV through testing that monitors RPV beltline materials. The LRA stated that the RPV surveillance program will be enhanced by making it consistent with the BWRVIP ISP for periods of extended operation prior to the OCGS period of extended operation.

The applicant has implemented the BWRVIP ISP based on the BWRVIP-78 report, "BWR Integrated Surveillance Program Plan," and the BWRVIP-86-A report, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation." These reports are consistent with the GALL AMP XI.M31, "Reactor Vessel Surveillance," for the period of the current OCGS license. The staff concludes that the BWRVIP ISP in BWRVIP-78 and BWRVIP-86-A reports are acceptable for BWR licensee implementation provided that all participating licensees use one or more compatible neutron fluence methodologies acceptable to the staff for determining surveillance capsule and RPV neutron fluences. The staff's acceptance of the BWRVIP ISP for the current term at OCGS is documented in SER dated April 27, 2004.

The applicant further stated that the enhanced program will be consistent with GALL AMP XI.M31. The BWRVIP-116 report, "BWR Vessel And Internals Project, Integrated Surveillance Program (ISP) Implementation For License Renewal," provides guidelines for an ISP to monitor neutron irradiation embrittlement of the RPV beltline materials for all US BWR power plants for the license renewal period. The staff also reviewed the UFSAR supplement to determine whether it provides an adequate description of the program.

The staff's review of LRA Sections B.1.23 and A.1.23 identified areas in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI B.1.23-1 dated March 20, 2006, the staff requested that the applicant provide the following commitment in the UFSAR supplement.

> OCGS will implement BWRVIP ISP as specified in the staff approved BWRVIP-116 report, or if the ISP is not approved two years prior to the commencement of the extended period of operation, a plant-specific surveillance program for the OCGS unit will be submitted.

In its response dated April 18, 2006, the applicant updated the UFSAR supplement to include the aforementioned commitment (Commitment No. 23) proposed by the staff.
By letter dated February 24, 2006, the staff issued the final SER of the BWRVIP-116 report and, therefore, the staff requested that the applicant include the following statements in LRA Sections A.1.23 and B.1.23.

> The ISP-BWRVIP-116 report which was approved by the staff will be implemented at OCGS with the conditions documented in Sections 3 and 4 of the staff's final SER of the BWRVIP-116 report."

In its supplemental letter dated July 7, 2006, the applicant modified the UFSAR and its commitment (Commitment No. 23) to specify that it will comply with BWRVIP-116, including the conditions specified by the staff in its SER dated February 24, 2006. The staff finds this acceptable, therefore, the concern described in RAI B.1.23-1 is resolved.

Part 50, Appendix H of 10 CFR requires that an ISP used as a basis for a licensee implemented RPV surveillance program be reviewed and approved by the staff. The ISP to be used by the applicant is a program developed by the BWRVIP and the applicant will apply the BWRVIP ISP as the method by which it will comply with the requirements of 10 CFR Part 50, Appendix H. The BWRVIP ISP identifies capsules that must be tested to monitor neutron radiation embrittlement for all licensees participating in the ISP and identifies capsules that need not be tested (standby capsules). Tables 2-3 and 2-4 of the BWRVIP-116 report indicate that the remaining capsule from OCGS is not to be tested. This untested capsule was originally part of the applicant's plant-specific surveillance program and has received significant amounts of neutron radiation.

In RAI B.1.23-2 dated March 20, 2006, the staff requested that the applicant include the following commitment in the UFSAR supplement.

> If the OCGS standby capsule is removed from the RPV without the intent to test it, the capsule will be stored in manner which maintains it in a condition which will permit its future use, including during the period of extended operation, if necessary.

In its response dated April 18, 2006, the applicant committed (Commitment No. 23) to store the standby capsules. The staff finds this acceptable, therefore, the concern described in RAI B.1.23-2 is resolved.

The staff finds that the applicant has demonstrated that the effects of aging due to loss of fracture toughness of the reactor pressure vessel beltline region 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).

Operating Experience. In LRA Section B.1.23, the applicant explained that Oyster Creek has successfully implemented a plant-specific reactor surveillance program in accordance with 10 CFR 50, Appendix H, ASTM Standard E-185, and RG 1.99, Revision 2. One of the original surveillance test capsules has been removed and tested.

Through participation in the BWRVIP ISP, the Oyster Creek Vessel Surveillance Program will be adjusted to account for industry experience and research. As additional operating experience is obtained, lessons learned will be used to adjust this program as needed.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Reactor Vessel Surveillance Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant described the existing Reactor Vessel Surveillance Program in LRA Section A.1.23. The program periodically tests metallurgical surveillance samples to monitor the loss of fracture toughness of the RPV beltline region materials consistent with the requirements of 10 CFR Part 50, Appendix H. The applicant further stated that it will implement the staff-approved BWRVIP-116 report for the license renewal period. The BWRVIP-116 report was approved by the staff and, as described in the staff evaluation section, the applicant should include the following statement in the UFSAR supplement:

> The ISP BWRVIP-116 which was approved by the staff, will be implemented, and will comply with the conditions documented in Sections 3 and 4 of the staff's final SER of the BWRVIP-116 report.

As to the status of the remaining standby capsule, the applicant made a commitment (Commitment No. 23) to incorporate the following statement in the UFSAR supplement:

> If the OCGS standby capsule is removed from the RPV without the intent to test it, the capsule will be stored in manner which maintains it in a condition which will permit its future use, including during the period of extended operation, if necessary.

The staff reviewed the applicant's proposed revision to the UFSAR supplement and determined that by implementing the most recent staff-approved version of the BWRVIP-116 report the applicant demonstrated its compliance with the requirements of 10 CFR Part 50, Appendix H.

The staff's review determined that the following license condition will be required to ensure that changes in the BWRVIP withdrawal schedule will be submitted for staff review and approval.

> All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC, as required by 10 CFR Part 50, Appendix H.

The staff concludes that the information provided in the UFSAR supplement for the aging management of systems and components is consistent with the recommendations of the GALL Report and, therefore, provides an adequate summary of program activities as required by 10 CFR 54.21 (d).

Conclusion. The staff's review of the applicant's Reactor Vessel Surveillance Program and RAI responses determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 One-Time Inspection

Summary of Technical Information in the Application. In LRA Section B.1.24, the applicant described the new One-Time Inspection Program as consistent, with exceptions, with GALL AMP XI.M32, "One-Time Inspection."

The applicant stated that the One-Time Inspection Program provides reasonable assurance that an aging effect does not occur or occurs so slowly as not to affect the component or structure intended function during the period of extended operation and therefore requires no 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 rule it out completely, (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than 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 that crack initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or thermal and mechanical loading does not occur in Class 1 piping less than 4-inch nominal pipe size (NPS) 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 that loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment.
- To confirm that loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment.
- To confirm that loss of material is insignificant for nonsafety-related 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. The staff noted that the LRA does not show any exceptions to the GALL AMP. However, in their reconciliation document, the applicant identified three exceptions to the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.1.4. The staff reviewed the exceptions and their justifications to determine whether the AMP, with the exceptions, remained adequate to manage the aging effects for which it is credited.

The staff noted that LRA Table 3.3.1, item 43, states 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 Program does not verify the effectiveness of the Selective Leaching of Materials Program. As described in the Selective Leaching of Materials Program, the program is itself a one-time inspection to confirm that loss of material due to the selective leaching aging mechanism does not occur.

In its letter dated April 17, 2006, the applicant stated that item 43 in LRA Table 3.3.1 will be modified to delete reference to use of the One-Time Inspection Program to verify the effectiveness of the Selective Leaching of Materials Program. The staff agreed that item 43 in LRA Table 3.3.1 should be modified as such verification is not one of the intended uses of the One-Time Inspection Program.

The staff also noted in the LRA description of the One-Time Inspection Program that this new program will include program elements to determine the sample size and location as well as inspection techniques. The applicant was asked for additional information on the rationale to be used in selecting the size and location as well as the inspection techniques.

In its response the applicant stated that an inspection sample basis document had 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 one-time inspections will be through the normal maintenance planning process.

The staff reviewed the inspection sample basis document, an OCGS report titled "Inspection Sample Basis, Oyster Creek License Renewal Project" dated August 16, 2005, and determined that it provides an adequate rationale for selecting one-time inspection samples to manage the aging effects for which it is credited.

The staff also reviewed the following exceptions to the GALL Report program elements identified by the applicant.

Exception 1. In its reconciliation document, the applicant identified an exception to the GALL Report program elements "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the exception stated that:

> 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, One Time Inspection of ASME Code Class 1 Small Bore-Piping. NUREG-1801 aging management program XI.M35, One Time Inspection of ASME Code Class 1 Small Bore-Piping 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 NPS 4.

In its letter dated March 30, 2006, the applicant committed (Commitment No. 24) to revise the One-Time Inspection Program in the LRA to include the exception identified in the reconciliation document, which states that the new One-Time Inspection Program will include the one-time inspection of Class 1 piping less than NPS 4, and that GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping," will not be used.

The staff compared the program elements for the One-Time Inspection Program to those for GALL AMP XI.M35 to determine whether they were consistent for the inspection of piping less than 4-inch NPS. Specifically, because the selection of the one-time inspection sample for the One-Time Inspection Program is described in the OCGS inspection sample basis document, an OCGS report titled "Inspection Sample Basis, Oyster Creek License Renewal Project" dated August 16, 2005, the staff reviewed this document to determine how the small bore piping inspection sample will be determined. GALL AMP XI.M35 recommends for ASME Code Class 1 small bore piping a one-time inspection with volumetric examination on selected weld locations to detect cracking. The sample size should be based on susceptibility, accessibility for inspection, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 smallbore piping locations.

The staff noted that the inspection sample basis document stated that sample size for Class 1 piping less than 4-inch NPS will include 10 percent of the total butt welds, and inspection locations will be based on physical accessibility, exposure levels, non-destructive examination (NDE) techniques, 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, including socket-welded piping, are included in the sample selection for Class 1 piping less than 4-inch NPS.

In its response to the staff'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 June 23, 2006, the applicant committed (Commitment No. 24) to such inspections of small-bore piping as part of the One-Time Inspection Program.

The staff determined that the applicant had committed to do a non-destructive or destructive examination of one socket weld prior to the period of extended operation in response to the staff's concern in this area. As this is a sampling process, the staff determined that one socket weld will represent the population for Class 1 piping less than 4-inch NPS. With this new commitment and the examination of 10 percent of the butt welds in all Class 1 small bore piping, there is reasonable assurance that the aging of small bore piping will be adequately managed during the period of extended operation.

Exception 2. In its reconciliation document the applicant identified an exception to the GALL Report program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the exception stated that:

> 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 10 CFR50.55a, 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.

In its letter dated March 30, 2006, the applicant stated that the One-Time Inspection Program will be revised to include this exception.

The staff evaluated this exception as part of its review of AMP B.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and found it acceptable as consistent with the requirements of 10 CFR 50.55a. The staff's evaluation is discussed in SER Section 3.0.3.2.1.

Exception 3. In its reconciliation document, the applicant identified an exception to the GALL Report program elements "scope of program" and " "monitoring and trending." Specifically, the exception stated that:

> NUREG-1801 states in XI.M35, One Time Inspection of ASME Code Class 1 Small Bore-Piping, 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.

In its letter dated March 30, 2006, the applicant stated that the One-Time Inspection Program will be revised to include this exception.

In reviewing this exception the staff noted that EPRI Report 1000701 focuses on PWR plant locations susceptible to thermal fatigue but also includes generic guidance that may be useful for boiling water reactor (BWR) plants. The applicant was asked to clarify whether the generic guidance in EPRI Report 1000701 had been considered in the development of the One-Time

Inspection Program.

In its response the applicant stated that the evaluation to identify piping susceptible to the effects of thermal fatigue is in 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 staff reviewed Section 3.1 of the program basis document (PBD) for the One-Time Inspection Program and confirmed that the evaluation used the generic guidance in the EPRI report. The evaluation identified no locations that would be subject to thermal fatigue. On this basis, the staff finds this exception acceptable.

Operating Experience. In LRA Section B.1.24, the applicant stated that there is no programmatic operating experience specifically applicable to the new One-Time Inspection Program but that plant and industry operating experience will be considered in the selection of the component sample set.

Because this program is new there was no plant-specific programmatic operating experience for the staff to review. However, the staff expects the One-Time Inspection Program to adequately manage the aging effects for which it is credited on the basis of its consistency with GALL AMP XI.M32, with exceptions.

The staff concludes that the corrective action process, which captures internal and external plant operating experience issues, will ensure that operating experience is reviewed and incorporated to provide objective evidence for the conclusion that the effects of aging are adequately managed.

UFSAR Supplement. In LRA Section A.1.24 and letters dated March 30, April 17, and May 1, 2006, the applicant provided the UFSAR supplement for the One-Time Inspection Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection Program, the staff determined that all the program elements are consistent with the GALL Report. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which is credited. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.22 Buried Piping Inspection

Summary of Technical Information in the Application. In LRA Section B.1.26, the applicant described the existing Buried Piping Inspection Program as consistent, with an exception and enhancement, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

The Buried Piping Inspection 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. During the period of extended operation, inspection of buried piping will be within 10 years unless an opportunistic inspection occurs within any 10-year period. The program will be enhanced for reasonable assurance that buried piping and piping components will perform their intended function during the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.21. The staff reviewed the exception and enhancement and their justifications to determine whether the AMP, with the exception and enhancement, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Buried Piping Inspection Program for which the applicant claimed consistency with GALL AMP XI.M34 and found them consistent. Furthermore, the staff concludes that the applicant's Buried Piping Inspection Program provides reasonable assurance that the aging effects for these materials will be adequately managed during the period of extended operation. The staff found that the applicant's Buried Piping Inspection Program conforms to the recommended GALL AMP XI.M34 with an exception and an enhancement described below.

Exception 1. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of the program," "preventive actions," and "acceptance criteria." Specifically, the exception stated:

> *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.*

Exception 2. In the LRA, the applicant stated an exception to the GALL Report program elements "scope of the program," "preventive actions," and "acceptance criteria." Specifically, the exception stated:

> *Oyster Creek does not have any buried tanks in the scope of license renewal.*

During the audit, the staff asked the applicant whether 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 the period of extended operation unless an opportunistic inspection occurs during that time.

The staff also asked the applicant whether each buried material will be inspected. The applicant stated that all types of materials will not be examined. Rather, the inspections will be of a system with high likelihood of corrosion problems or systems with histories of corrosion. The Buried Piping Inspection Program contains aluminum, cast iron, stainless steel, and bronze in addition to the carbon steel. All but 25 feet of 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 and process steam and roof drain and overboard discharge systems may contain coated stainless steel and bronze fittings. OCGS has never experienced any failures of these materials. To be conservative, OCGS has included these materials in the scope of the Buried Piping Inspection Program.

The staff finds the applicant's exception to the GALL Report 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 staff finds this exception acceptable.

<u>Enhancement 1</u>. In the LRA, the applicant stated that there is an enhancement to meet the GALL Report program elements "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the enhancement stated:

> 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

<u>Enhancement 2</u>. In the LRA, the applicant stated that there is an enhancement to meet the GALL Report program elements "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the enhancement stated:

> 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 recoated, if any such locations remain.

In the LRA, the applicant stated that inspections will confirm that coating and wrapping are intact. These inspections effectively ensure that corrosion of external surfaces has not occurred and that intended function has been maintained. External inspections of buried components occur opportunistically when they are excavated during maintenance. Buried piping will be opportunistically inspected whenever excavated for maintenance. The inspections will be on all of the areas made accessible to support the maintenance activity. Areas with the highest likelihood of corrosion problems with a history of corrosion problems have been identified in Topical Report (TR) "Oyster Creek Underground Piping Program Description and Status." Several yard excavation activities to date have uncovered buried piping that has been inspected. OCGS has performed focused inspections on their underground piping within the past 10 years. Several inspections have been performed on the ESW and SW systems, which have a high likelihood and a history of corrosion-related problems. In addition other inspections and testing have been performed and are documented in the Technical Data Report TDR-829, "Pipe Integrity Inspection Program," and TR-116, "Oyster Creek Underground Piping Program Description and Status."

The applicant further stated that, during the period of extended operation, inspection of buried piping will be performed within 10 years unless an opportunistic inspection occurs within the 10-year period. Areas with the highest likelihood or a history of corrosion problems have been identified in the TR. These are primarily in the ESW and SW systems. These areas have been inspected within the past 10 years. Monitoring and trending from testing can aid in the detection of system pipe leaks. Periodic leak testing and component inspections are credited as well.

ASME Code Section XI, Pressure Testing, directs testing of buried cooling water piping for the detection of leaks. This pressure testing is via pump surveillances.

The staff noted that this enhancement adds additional components into the Buried Piping Inspection Program, which is conservative. The staff finds this enhancement acceptable because when implemented the Buried Piping Inspection Program will be consistent with GALL AMP XI.M34 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.26, the applicant explained that the Buried Piping Inspection Program, as enhanced, will be effective in managing aging degradation for the period of extended operation by timely detecting aging effects and implementing appropriate corrective actions prior to loss of system or component intended functions. OCGS has performed numerous external inspections of buried pipe during excavation activities and repair of degraded coatings when necessary. In 1992, the SW 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, OCGS initiated the Underground Piping Program. To date there have been no other buried pipe leaks due to external degradation. Although failure of buried piping has occurred, the applicant has determined that the leaks were caused from the inside of the buried piping, which is evaluated with the Open-Cycle Cooling Program. OCGS conducts pressure tests of SR buried piping to identify leaks and to ensure adequate pressure integrity. This pressure testing is performed by pump surveillances.

In plant operating experience, coatings and wrappings have protected the external surfaces of buried piping adequately and loss of material due to external corrosion has not been a concern. There are some portions of buried stainless steel and bronze piping that may not be coated or wrapped. OCGS has had no failures of this piping due to external degradation. Therefore, in OCGS and industry operating experience stainless steel and copper alloy material are resistant to corrosion in a buried environment. Additionally, OCGS cast iron fire hydrants are not coated or wrapped and OCGS has had no failures of any of the buried hydrants due to external degradation. Furthermore, one of the hydrants was replaced in 2003 due to failure of the hydrant to drain and the external condition of the hydrant was good. Thus inspection of buried piping when excavated for maintenance provides reasonable assurance that the intended functions will be maintained. Inspections will be performed within 10 years after the start of the period of extended operation unless an opportunistic inspection occurs within this 10-year period.

The staff noted that the applicant has no exception to the GALL Report program element "parameters monitored or inspected" and has added enhancements of 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. OCGS has performed numerous external inspections of their buried components since 1991. These inspections have shown no significant external coating failures. Coatings have been repaired during these inspections in accordance with corporate procedures.

In 2004, 50 percent of the buried ESW and 10 percent of SW piping were replaced with new, coated piping. During the audit, the staff asked the applicant when the remaining pipe will be replaced. In its letter dated May 1, 2006, the applicant committed (Commitment No. 63) to replace the remaining safety-related ESW piping prior to the period of extended operation.

In 1993 an inspection of 20 feet of RBCCW showed that the external coating was in good condition. In 1992 the fire protection system underground piping was inspected by 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 CST 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 relocated aluminum piping above ground in tunnels or vaults. Currently 90 percent of all aluminum piping is located above ground. The remaining buried aluminum pipe was inspected in 1993 and has an expected service life of 15-20 years. An Action Request has been submitted to inspect the remaining buried, uncoated aluminum pipe prior to December 2008. The remaining buried aluminum piping does have cathodic protection.

The operating experience of the Buried Piping Inspection Program has shown objective evidence that the program has identified susceptible buried pipe locations and has created a monitoring program effective in preventing failures prior to the loss of system intended function. The operating experience of the Buried Piping Inspection Program shows no adverse trend in performance. Problems identified will 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 effects of corrosion on the pressure-retaining capacity of buried piping. Appropriate guidance for reevaluation, repair, or replacement is provided for loss of material. Periodic self-assessments of the Buried Piping Inspection Program identify areas that need improvement to maintain the quality performance of the program.

Continued implementation of the Buried Piping Inspection Program provides reasonable assurance that the effects of loss of material due to corrosion on the pressure-retaining capacity of buried carbon steel piping is adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Buried Piping Inspection Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.26 and letter dated May 1, 2006, the applicant provided the UFSAR supplement for the Buried Piping Inspection Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Buried Piping Inspection Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancement and confirmed that implementation of the enhancement prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that 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 IWE

Summary of Technical Information in the Application. In LRA Section B.1.27, the applicant described the existing ASME Section XI, Subsection IWE Program as consistent, with an exception, with GALL AMP XI.S1, "ASME Section XI, Subsection IWE."

The ASME Section XI, Subsection IWE 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 air locks, 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 manages 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 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 50.55(a).

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.23.

During the onsite audits of October 3-7, 2005, January 23-27, 2006, February 13-17, 2006, and April 19-20, 2006, the staff 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 period of extended operation.

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 staff's review of the applicant's original license renewal commitments, the development of the applicant's new commitments, and the remaining unresolved issues are documented in the Audit and Review Report. To summarize the staff's evaluation of the containment corrosion issue, the staff focused on the following four specific areas:

(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

(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 requested, as necessary, to facilitate a thorough assessment and evaluation of the applicant's aging management plans for the license renewal period. The results of this detailed audit are documented in the following paragraphs. In addition, the staff's evaluation of the information in each of these four areas is presented under the drywell degradation issue at the end of this section.

Water Leakage from the Refueling Cavity. During the audit, the applicant stated that a special coating is applied to the refueling cavity liner prior to flooding the reactor for refueling to prevent leakage into the annular space between the drywell shell and the concrete shield wall. As a result, the applicant believes that water intrusion into the refueling cavity has been eliminated as a source of 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; the staff requested that the applicant identify whether it is committed to continue the use of this special coating as part of its refueling procedure through the period of extended operation. If not, the applicant was asked to identify what enhanced inspections will be conducted during the period of extended operation 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 strippable coating has been effective in mitigating water intrusion into the annular space and in reducing the rate of corrosion. The applicant committed to applying the strippable coating to the reactor cavity liner prior to flooding for refueling during the period of extended operation. In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) 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.

In reviewing PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE Program, the staff noted that, page 7 of this document states 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, the applicant committed (Commitment No. 27) to the following: The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for water leakage periodically.

The staff requested that the applicant describe this commitment in more detail. In its response, the applicant stated that the commitment for monitoring the sand bed drains is in a staff SER transmitted by letter November 1, 1995. This SER requested a commitment to perform inspections "3 months after the discovery of any water leakage." Subsequent correspondence from General Public Utilities Nuclear Corporation (GPUN) clarified the commitment after discussions with the staff. The commitment made and accepted by the staff in a February 15, 1996, letter 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 from normal refueling activities. This commitment is consistent with the present commitment in PBD-AMP-B.1.27.

The applicant further stated in its response that, although there is no formal leakage monitoring in place, there has been no reported evidence of leakage from the former sand bed drains. Issue Report #348545 was submitted into the corrective action process when this lack of formal leakage monitoring was discovered. Corrective actions have been initiated to create recurring activities controlled by work management process and procedures for all future required inspections to meet the present commitment. Because there has been no reported leakage, there has been no need to investigate the source of leakage, take corrective actions, evaluate the impact of leakage, or perform additional drywell inspections.

The applicant further stated that numerous actions have been taken to alleviate the previous water leakage problem since discovery of the consequent 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 its drain. Clearing of the trough drain and repair of the trough route any leakage away from the drywell shell. In addition, a strippable coating is applied to the reactor cavity walls before the reactor cavity is filled with water to minimize the likelihood of leakage into the trough area. These preventive actions have resulted in no evidence of leakage over the years at the former sand bed drains.

During the ACRS meeting on February 1, 2007, the applicant agreed to perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage. By letter dated February 15, 2007, the applicant, in Commitment Number 27, "ASME Section XI, Subsection IWE," item 19, committed to complete the engineering study prior to the period of extended operations.

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 staff 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 ASME Section XI, Subsection IWE Program is credited to address the drywell corrosion TLAA. In LRA Section 4.7.2, under Analysis, the applicant stated that the ASME Section XI, Subsection IWE Program 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 Program performs periodic UT inspections at critical locations, performs calculations to track corrosion rates, projects vessel thickness based on conservative corrosion rates, and demonstrates maintenance of the minimum required vessel thickness.

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, arrested. The drywell surfaces that were coated show no signs of deterioration. Drywell vessel wall thickness measurements indicate substantial margin to the minimum wall thickness, even when projected to the year 2029 with conservative estimates of 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 staff reviewed the applicant's discussion of aging management activities for the upper region of the drywell shell and determined that additional information was needed on the augmented scope of IWE. In its response, the applicant stated that OCGS had been 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, calculations to track corrosion rates, vessel thickness projections based on conservative corrosion rates, and demonstrations of maintenance of minimum required vessel thickness, 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 Code Section XI IWE inspections. The inspection of the exterior surfaces of the drywell in the sand bed region is included in the Protective Coating Monitoring and Maintenance Program.

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 period of extended 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, the applicant committed (Commitment No. 27) to conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations currently measured prior to and during the period of extended operation.

In reviewing PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE Program, the staff noted that, in the discussion on pages 25 through 31 of 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.

During the audit, the staff requested that the applicant describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete to allow the upper portion of the drywell to meet ASME Code requirements. 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 period of extended 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 to allow the upper portion of the drywell to maintain the ASME Code requirements are the following:

- Cleared the former sand bed region drains to improve the drainage path.
- Replaced reactor cavity steel trough drain gasket, which was found to be leaking.
- Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.
- Confirmed that the reactor cavity concrete trough drains are not clogged.
- 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 OCGS 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 staff noted that, in the ASME Section XI, Subsection IWE Program discussion of operating experience, the applicant had stated that sand was removed and a protective coating was applied to the shell to mitigate further corrosion. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program, which is discussed in SER Section 3.0.3.2.27. The staff reviewed the Protective Coating Monitoring and Maintenance Program and determined that the coating is included within its scope. The staff noted that the discussion of operating experience in the Protective Coating Monitoring and Maintenance Program is similar to the discussion of operating experience in ASME Section XI, Subsection IWE Program.

The staff reviewed the applicant's aging management activities for the former sand bed region of the drywell shell and determined that additional information was needed on aging management of this region. In its response, the applicant stated that monitoring and maintenance of the coating in the former sand bed region are included in the scope of the Protective Coating Monitoring and Maintenance Program. These activities are in accordance with specifications SP-1302-32-035 and SP-9000-06-003, which are included in the program.

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 Code Section XI, Subsection IWE. As stated in ASME Code Section XI, Subsection IWE 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 commitments for the current term.

As a result of discussions between the staff and the applicant on January 26, 2006, and April 20, 2006, the applicant supplemented its initial response to include the following:

- OCGS will also perform periodic UT inspections of the drywell shell thickness in the sand bed region, as discussed previously in this section.
- OCGS will also enhance the Protective Coating Monitoring and Maintenance Program 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 Program. Details are provided later in this section.

- On April 20, 2006, OCGS provided supplemental information on torus coating.

Details of the enhancement to the Protective Coating Monitoring and Maintenance Program and the staff's evaluation of this AMP are discussed in SER Section 3.0.3.2.27.

After the applicant's initial response, the applicant was asked for its technical basis for not also crediting its ASME Section XI, Subsection IWE Program for managing loss of material due to corrosion in the former sand bed region of the drywell.

The applicant stated that visual inspection of the containment drywell shell, conducted in accordance with ASME Code 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 are considered inaccessible by ASME Code Section XI, Subsection IWE; thus, visual inspection was not possible for a typical Mark I containment 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, OCGS periodically visually inspected the coating under a CLB commitment implemented prior to the ASME Section XI, Subsection IWE Program. As a result, inspection of the coating was in accordance with the Protective Coating Monitoring and Maintenance Program. The applicant's evaluation of this AMP 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 CLB commitment and that inclusion of the coating inspection under the ASME IWE inspection is not required. However, the applicant will amend this position to 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 Code Section XI, Subsection IWE during the period of extended operation.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following: Prior to the period of extended operation, the applicant will perform additional visual inspections of the epoxy coating applied to the exterior surface of the drywell shell in the sand bed region so the coated surfaces in all 10 drywell bays will have been inspected at least once. In addition, the ISI program will be enhanced to require inspection of 100 percent of the epoxy coating every 10 years during the period of extended operation. These inspections will be in accordance with ASME Code Section XI, Subsection IWE. The inspections will be staggered so that at least three bays will be examined every other refueling outage.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following: UT thickness measurements of the drywell shell in the sand bed region will be 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 of UT measurements in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT measurements will result in corrective actions: (1) additional UT measurements to confirm the readings, (2) notice to the staff within 48 hours of confirmation of the condition, (3) visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected, (4) an engineering evaluation of the extent of condition to determine whether additional inspections are required to assure drywell integrity, and (5) an operability determination and justification for operation until the next inspection. These actions will be completed prior to restart from the outage.

In its letter dated May 1, 2006, the applicant committed (Commitment No. 27) to the following: *During the next UT inspections of the drywell sand bed region (reference AmerGen April 4, 2006, 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 use 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 or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable.*

The staff requested that the applicant provide a discussion of the scope of the current coating inspection program and the license renewal commitment. In its response 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. The current program requires visual inspection of the coating in accordance with Engineering Specification IS-328227-004. Inspection criteria are not provided by the specification. However, inspections are by individuals qualified for coating inspections. Acceptance criteria in the specification are that any coating defects be submitted for engineering evaluation. The inspection frequency is every other refueling outage.

The applicant further stated in its response that, as discussed with the staff, the existing Protective Coating Monitoring and Maintenance Program does not invoke all of the requirements of ASME Code Section XI, Subsection IWE. The applicant has committed (Commitment No. 27) to enhance the program to incorporate coated surfaces inspection requirements specified in ASME Code Section XI, Subsection IWE and has provided specific enhancements that will be made to the program as follow:

> *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.

During the audit, the staff asked the applicant for information related to inspections of the drywell sand bed region. In response, the applicant stated that the minimum recorded thickness in the sand bed region from approximately 120 UT measurements taken on the outside of the drywell shell is 0.618". The minimum recorded thickness in the sand bed region from the 6" by 6" UT measurement grids inside the drywell shell is 0.603". These minimum recorded thicknesses are isolated local measurements and represent single point UT measurements.

On April 19, 2006, the applicant supplemented its response, 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 through 1992 and two subsequent readings taken in September 1994 and in 1996 shows that 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 approximately 6 inches x 6 inches. Thus, the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806 inches. The 0.806 inches 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 inches) and in 1992 (0.800 inches). However, the three values are within the tolerance of +/- 0.010 inches 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. For license renewal the use of corrosion rate trends after 1992 is appropriate because of such corrosion mitigating measures 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 inches), 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 conducted prior to the period of extended operation and after UT inspections every 10 years thereafter.

The applicant further stated in its response that the engineering analysis that demonstrated compliance with ASME Code requirements had 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 transmitted to the staff in December 1990 and in 1991, respectively. Index Nos. 9-3 and 9-4 were revised later to correct errors identified during an internal audit and resubmitted to the staff in January 1992.

The staff requested that the applicant provide information related to the evaluation of the results of the next UT inspection of the sand bed region. In its response, the applicant stated that the new set of UT measurements for the former sand bed region will be analyzed by 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 shows that UT measurements can vary significantly unless the UT instrument is positioned on the exact point as for 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 requiring corrective actions described previously.

The staff's review of this information is in its evaluation of the drywell degradation issue presented at the end of this section.

Pitting Corrosion of the Suppression Chamber (Torus). In reviewing information in the ASME Section XI, Subsection IWE Program discussion of operating experience for the suppression chamber (torus) and vent system, the staff noted that the applicant had stated that the coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion. The staff referred to the Protective Coating Monitoring and Maintenance Program for additional details. The staff reviewed the Protective Coating Monitoring and Maintenance

Program and noted that, under operating experience, the applicant stated that torus and vent header vapor space Service Level I coating inspections in 2002 found the coating in these areas in good condition. Inspection of the immersed coating in the torus found blistering that primarily in the shell invert but also on the upper shell near the water line. The majority of the blisters remained intact and continued to protect the base metal. However, several areas included pitting damage where the blisters were fractured. A qualitative assessment of the pits concluded that the pit depths were significantly less than the established acceptance criteria. The fractured blisters were repaired to reestablish the protective coating barrier.

To clarify, the staff asked the applicant for information pertaining to operating experience and license renewal aging management for the suppression chamber (torus) and vent system. In its response, the applicant stated that inspection of the suppression chamber (torus) and vent system coating is by divers every other outage in accordance with Engineering Specification SP-1302-52-120, which provides inspection and acceptance criteria for the coating and for pitting as a contingency 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.

The applicant further stated that the specification requires inspection of the torus and vent system surfaces for coating integrity. If pitting is observed isolated pits of 0.125 inches in diameter have an allowed maximum depth of 0.261 inches 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 than 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 than 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.

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. The program was evaluated against the 10 elements of GALL AMP 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 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 ASME Code Case N-597 as guidance for calculation of pit depths that will not violate the local stress requirements of either ASME Code Section III, 1977 Edition or Section VIII, 1962 Edition.

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 ASME Section XI, Subsection IWE and the Protective Coating Monitoring and Maintenance Programs are credited to manage loss of material due to corrosion for the suppression chamber (torus) and the vent system for the period of extended 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 Code Subsection IWE. This specific commitment (Commitment No. 33) is associated with the Protective Coating Monitoring and Maintenance Program.

In its letter dated May 1, 2006, the applicant committed (Commitment No. 27) to the following: As noted in the applicant's April 4, 2006 letter to NRC, OCGS will perform torus coating inspections in accordance with ASME Code 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 Code Section XI, Subsection IWE.

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. These improvements will be described in a letter to the NRC.

In its letter dated May 1, 2006, the applicant stated that it 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.

The staff finds this 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 previously 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. 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 inches. Based on the results of the inspections performed through 1993 (14R), it was concluded that the torus shell thickness had remained virtually unchanged following the repair and recoating efforts performed in 1984. 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 electromatic relief valve (EMRV) technical specification 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 inches. 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 inches 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 inches. The following areas have been mapped for trending and analysis during future inspections: 1 pit of 0.042 inches in bay 1; 1 pit of 0.0685 inches in bay 2; 2 pits of 0.050 inches in bay 6; 1 pit of 0.058 inches 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.

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 staff reviewed the applicant's response and determined that it was responsive to the questions asked.

In reviewing PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE Program, the staff noted that, in the discussion of torus degradation pages 25 to 31 of this document state 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 ASME Section XI, Subsection IWE 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 maximum) 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).

The staff asked the applicant to confirm or clarify that (1) 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, and (5) the minimum pit depth of concern is 141 mils (0.141 inches) and pits as deep as 261 mils (0.261 inches) 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 to which the inspection report referred included fractured blisters as well as any mechanically damaged areas which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters will be candidates for repair, not 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. Most blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001 inches. 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 inches) of the substrate.

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 inches 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 inches and were judged to be representative of typical conditions found on the shell. Prior to the 2002 inspection, 4 pits greater than 0.040 inches were identified. The pit depths were 0.058 inches (1 pit in 1988), 0.05 inches (2 pits in 1991), and 0.0685 inches (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found acceptable.

The applicant also stated that the acceptance criteria for pit depth are as follow: Isolated pits of 0.125 inches in diameter have an allowed maximum depth of 0.261 inches 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 criterion includes old pits or old areas of pitting corrosion that have been filled or re-coated. Multiple pits that can be encompassed by a 2-1/2 inches diameter circle shall be limited to a maximum pit 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 than 20.0 inches. This criterion includes old pits or old areas of pitting corrosion that have been filled or re-coated.

Drywell Degradation Issue. The staff evaluated the applicant's revised aging management commitments to address four distinct issues: (1) monitoring/eliminating water leakage, (2) corrosion in the upper drywell region, (3) corrosion in the former sand bed region, and (4) pitting corrosion in the suppression chamber (torus). The staff's evaluation of 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 commitment (Commitment No. 27), 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 committed (Commitment No. 27) 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, OCGS is committed to monitor the former sand bed region drains for water leakage. This commitment was not previously identified in the LRA.

The staff noted that while these new commitments address both mitigation of and monitoring for water leakage; they are an essential element of the applicant's overall program to manage aging of the degraded drywell during the license renewal period, the applicant has not established a leakage monitoring program.

However, 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 process 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 staff 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. Subsequent to the audit, in response to RAI 4.7.2-1, by letter dated June 20, 2006, the applicant provided additional information regarding the AMP and activities associated with drywell leakage monitoring program. The staff's evaluation of the applicant's additional information and commitments is documented in SER Section 4.7.2.

(2) Upper Drywell Region. The applicant made a new license renewal commitment (Commitment No. 27), to continue UT measurements of the upper drywell region for the period of extended operation.

The applicant manages loss of material due to corrosion in the upper drywell region (spherical and cylindrical sections) by augmented examinations in accordance with IWE-1240. An UT 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 per 10 CFR 54.21(c). The applicant's TLAA is documented in LRA Section 4.7.2. The applicant implements 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 evaluation of this TLAA is addressed in SER Section 4.

(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 years) to confirm its soundness. The last UT readings were 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. In its letters dated April 4, 2006, and May 1, 2006, the applicant revised the commitments:

- Monitor the protective coating on the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Code Section XI, Subsection IWE during the period of extended operation (Commitment No. 27),
- Conduct periodic UT inspection of the former sand bed region before the license renewal period and every 10 years thereafter (Commitment No. 27),
- Attempt during the UT inspections of the sand bed region prior to the period of extended operation a UT inspection from the exterior of the drywell of some of the locally thinned areas identified in the 1992 inspection (Commitment No. 27),
- Inspect the remaining 50 percent of the external coating in the former sand bed region before the license renewal period (to date, only 50 percent of this coating has been inspected since it was applied in the early 1990s) and conduct a 100 percent re-inspection of the coating every 10 years during the license renewal period (Commitment No. 27),
- 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:

    - Perform additional UT measurements to confirm the readings.
    - Notify the staff within 48 hours of confirmation of the identified condition.
    - Inspect the coatings in the sand bed region in areas where the additional corrosion was detected.
    - Perform an engineering evaluation to assess the extent of the condition and to determine whether additional inspections are required to assure drywell integrity.
    - Perform an operability determination and justification for continued operation until next scheduled inspection.

  These actions will be completed before restarting from an outage (Commitment No. 27).

The staff 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 inches vs. 0.736 inches). This apparent lack of margin led the staff to request 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 for localized areas where the measured thickness is less than the minimum required uniform thickness. The applicant provided additional information on these subjects. During a followup onsite audit conducted April 19-20, 2006, the staff discussed these responses with the applicant in detail to ensure a complete understanding.

The staff 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 staff pointed out a definite bias in the 1996 readings because the average thickness (based on 49 readings/location) increased at almost all locations. The staff and the applicant's personnel discussed possible causes for this bias, but no conclusions could be drawn.

The staff'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 inches at most monitored locations. Several locations are close to the original design thickness of 1.154 inches. However, in a few very localized areas, primarily in Bays 1 and 13, remaining thicknesses less than 0.736 inches have been measured.

The staff also reviewed the technical basis documents that established compliance with ASME Code requirements. In response to a question, the applicant stated that the engineering analysis demonstrating compliance with ASME Code requirements was performed in two parts, stress and stability analysis with and without sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4 transmitted to the NRC in December 1990 and in 1991, respectively. Index Nos. 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 conservatively assumed that the shell thickness in the entire sand bed region had 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 assuming a uniform reduction in thickness of 27 percent to 0.536 inches over a 1 ft^2 area will create only a 9.5 percent reduction in the load factor and theoretical buckling stress for the whole drywell. A second buckling analysis assuming a wall thickness reduction of 13.5 percent to 0.636 inches over a 1 ft^2 area reduced the load factor and theoretical buckling stress by only 3.5 percent for the whole drywell.

The applicant further stated that to bring these results into perspective, a review of the NDE reports indicates there are 20 UT measured areas in the whole sand bed region with thicknesses less than 0.736 inches covering a conservative total area of 0.68 ft^2 of the drywell surface with an average thickness of 0.703 inches or 4.5 percent reduction in wall thickness. Furthermore, all of these very local wall areas are centered about the vents, significantly stiffening the shell. This stiffening effect limits the shell buckling in the shell sand bed region to the midpoint between two vents.

The staff reviewed the detailed UT thickness readings, the GE stability analyses, and the conservative assumptions used in the GE Letter Report, "Sand Bed Local Thinning and Raising the Fixity Height Analysis." The staff concludes that the degraded condition of the former sand bed region of the drywell shell measured in 1996 was adequate for 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 inches at several locations, the staff initiated further evaluation of the applicant's aging management commitment for UT inspection of the former sand bed region.

The applicant credited its Protective Coating Monitoring and Maintenance Program to monitor/maintain the protective coating on the exterior surface of the drywell in the former sand bed region. The staff evaluated this program in SER Section 3.0.3.2.27. The staff finds the enhancement to the protective coating monitoring and maintenance program acceptable because it ensures that the requirements of ASME Code IWE related to coating inspection will be implemented during the period of extended operation. The applicant's revised aging management commitment (Commitment No. 27) is to complete a 100 percent inspection of the coating (initiated in 1994 and currently 50 percent complete) prior to the license renewal period and to conduct subsequent 100 percent reinspections 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 staff 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.

Subsequent to the audit, in response to RAI 4.7.2-1, by letter dated June 20, 2006, the applicant provided additional information regarding the AMP and activities associated with drywell shell corrosion. The staff's evaluation of the applicant's additional information and its commitments is documented in SER Section 4.7.2.

(4) Suppression Chamber (Torus). The applicant credited its Protective Coating Monitoring and Maintenance Program to monitor/maintain the protective coatings inside the suppression chamber (torus) to mitigate corrosion. The staff's detailed evaluation of the applicant's Protective Coating Monitoring and Maintenance Program is addressed in SER Section 3.0.3.2.27.

The staff questioned the applicability and implementation of ASME 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 inches diameter on the inner surface is considered acceptable if its depth does not exceed 0.261 inches. According to the applicant, the torus as-built wall thickness is 0.385 inches. Therefore, a pit depth equal to 67 percent of the as-built thickness is considered acceptable if isolated. For a cluster of pits within a 2.5 inches diameter circle the acceptable pit depth is 0.141 inches or 37 percent of the as-built thickness. The acceptable pit depth includes allowance for an assumed 0.0009 inches per year corrosion rate over the 4-year period between inspections. 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."

The applicant stated that the maximum pit depth measured in the torus is 0.0685 inches (measured in 1992 in Bay 2). It was evaluated as acceptable by the design calculations at that time and was not based on calculation C-1302-187-E310-038. This bounding wall thickness in the torus remains. 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 Code Section III and VIII requirements for the torus. The torus inspection program will be enhanced per IR 373695 to improve the detail of the acceptance criteria and margin management requirements by the ASME Code Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If ASME Code Case N-597-1 is required to develop these criteria for future inspections, staff review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to monitor periodically to verify that they remain bounded.

The applicant's response clarified for the staff that pit depth acceptance criteria based on ASME Code Case N-597-1 had not been implemented and that if implementation should be contemplated the applicant will seek staff review and approval. The staff finds this clarification acceptable to resolve its concern about the use of ASME Code Case N-597-1.

From the applicant's response, the staff determined that there was minimal margin remaining between the current thickness and the minimum required thickness for the torus. During a followup onsite audit April 19-20, 2006, the staff 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 inches). Five isolated pits, ranging from 0.042 to 0.068 inches in depth, are monitored and trended during each inspection. The applicant supplemented its earlier response to document this explanation.

The applicant further explained that pit depth acceptance criteria based on ASME Code Case N-597-1 had never been used to for 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 indicate that, "Pits greater than 0.040 inches in depth shall be documented and submitted to engineering for evaluation."

In its letter dated May 1, 2006, the applicant supplemented its earlier response, committing (Commitment No. 27) 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. If the coating system is replaced, the inspection frequency and scope will be re-evaluated. The inspection scope will meet, as a minimum, the requirements of ASME Code Subsection IWE.

The applicant also committed (Commitment No. 27) 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 inspections and prior to the period of extended operation.

NRC inspectors conducted an inspection during the Oyster Creek October 2006 refueling outage. The team documented its findings in inspection report 05000219/20006013, dated January 17, 2007, (ML070170396). The inspection team reviewed supporting documentation and interviewed applicant personnel to confirm the adequacy of the license renewal conclusions from the visual inspections conducted in the torus. The inspection team noted that commitments for the torus were met. The visual test inspection procedures contained appropriate criteria for reporting nonconforming conditions and for dispositioning non-conforming conditions. On the basis of the inspection report findings, the staff determined that commitment 2 for the torus identified in the applicant's letter dated May 1, 2006, has been completed.

Based on the staff'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 staff concludes that the applicant's AMP for the suppression chamber (torus) provides reasonable assurance that the effects of aging will be adequately managed during the period of extended operation.

The staff reviewed those portions of the ASME Section XI, Subsection IWE Program for which the applicant claimed consistency with GALL AMP XI.S1 with the exception described below. Based on its review, the staff identified five open items (OIs) 4.7.2-1.1, 4.7.2-1.2, 4.7.2-1.3, 4.7.2-1.4, and 4.7.2-3, pertaining to aging management of primary containment (drywell shell). The staff resolution of these open items is discussed in Section 4.7.2.

Exception. In the LRA, the applicant stated an exception to the GALL Report recommendations in the "Program Description." Specifically, the exception stated:

> 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 10 CFR50.55a, 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 staff 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 ASME Code version incorporated into 10 CFR 50.55a 12 months before the start of the next 120-month inspection interval. As this incorporation is consistent with the recommendations in the GALL Report, the staff did not consider it an actual exception and finds it acceptable.

In its letters dated December 3, 2006 and December 15, 2006, the applicant revised the commitments for the IWE program based on the results of the October 2006 refueling outage NDE inspection activities associated with the primary containment drywell shell.

Specifically, during the 2006 drywell license renewal inspections, standing water was identified in contact with the drywell shell inside the trench in bay #5 as described below. Inspection and evaluation of the drywell shell concludes that because the water environment is alkaline and oxygen is limited during plant operation, the expected corrosion is insignificant. However, AmerGen will further enhance this aging management program to ensure potential drywell corrosion is detected and corrective actions are taken before a loss of the drywell intended function. The specific commitments which the applicant added are:

14. UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are Identified.

16. Perform visual inspections of the drywell shell inside the trenches in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

17. Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor curb, installed Inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.

After each inspection, UT thickness measurements results will be evaluated and compared with previous UT thickness measurements. If unsatisfactory results are identified, then additional corrective actions will be initiated, as necessary, to ensure the drywell shell integrity is maintained throughout the period of extended operation.

During the Advisory Committee on Reactor Safeguards (ACRS) meeting on February 1, 2007, the applicant committed to perform an engineering study prior to the period of extended operation in order to identify options to eliminate or reduce the leakage in the refueling cavity liner. The applicant also committed to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

In its letter dated February 15, 2007, the applicant documented the commitments it made to the ACRS and revised Commitment 27 ASME Section XI, Subsection IWE. The applicant also added commitments to inspect the drywell trenches and the 10 drywell bays. The specific commitments and item numbers which the applicant added are:

18. AmerGen will perform a 3-D finite element structural analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements.

19. AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage.

20. AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17 during the Oyster Creek 2008 refueling outage (see item number 16 of AmerGen's IWE Program (Commitment 27), in its letter 2130-06-20426). AmerGen will extend this commitment and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.

21. Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as:
    - UT measurements from inside the drywell (item number 1)
    - Visual inspections of the drywell external shell epoxy coating in all 10 bays (item number 4)
    - Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (item number 12)
    - UT measurements at the external locally thinned areas inspected in 2006 (item numbers 9 and 14)

Associated with these new commitments, the staff identified licensing conditions that require the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed license; perform full scope inspections of the drywell sand bed region every other refueling outage; and monitor drywell trenches every refueling outage to identify and eliminate the sources of water and receive NRC approval prior to restoring the trenches to their original design configuration. The staff finds the applicant's additional commitments for enhancing the ASME Section XI, Subsection IWE aging management program acceptable; therefore, the concern described in RAI 4.7.2-5 is resolved.

Operating Experience. The applicant stated, in the LRA, that ASME Section XI, Subsection IWE as described in the 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 two recordable conditions, a loose locknut on a spare drywell penetration and a weld rod stuck to the underside of the drywell head. Engineering evaluation concluded that the stuck weld rod had no adverse impact on drywell head structural integrity and that 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 from water leakage into the gap between the containment and the reactor building in the 1980s. As a result the area is subject to augmented examinations by UT thickness measurements as required by ASME Code Section XI, Subsection IWE. UT measurements taken in 2004 showed that the drywell shell thickness meets ASME Code criteria and that the rate of corrosion is declining. 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.

The applicant stated that the sand bed region also experienced loss of material due to corrosion 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. Subsequent inspections confirmed that corrosion of the shell had been arrested. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program. The staff evaluation of this program is addressed in SER Section 3.0.3.2.27.

The applicant 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.

The applicant stated that from operating experience it had concluded that ASME Section XI, Subsection IWE is effective for managing aging effects of primary containment surfaces.

In 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 industry operating experience had confirmed that corrosion had occurred in containment shells. INs 86-99, 88-82, and 89-79 described occurrences of corrosion in steel containment shells. GL 87-05 addressed the potential for corrosion of BWR Mark I steel drywells in the "sand pocket region." More recently, IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. Plant operating experience shows that corrosion has occurred in several containment locations including 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 the ASME Section XI, Subsection IWE Program has identified and corrected the degradation. Experience with the ASME Section XI, Subsection IWE Program shows that it is effective in managing aging effects for the primary containment and its components.

The applicant included the following discussion and three examples of operating experience as evidence that the ASME Section XI, Subsection IWE Program effectively assures that intended functions will be maintained consistent with the CLB for the period of extended operation:

> The Oyster Creek ASME Section XI, Subsection IWE 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 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 Information Notice 86-99 and Generic Letter 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.

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 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. Evaluation of UT measurements taken from inside the drywell, in the 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.

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 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 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 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 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 PBD-AMP-B.1.27, the applicant concluded that the operating experience of the ASME Section XI, Subsection IWE Program shows no adverse trend in performance. Problems identified will not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. The implementation of the ASME Section XI, Subsection IWE 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 program identify areas that need improvement to maintain performance of the program.

In its letter dated December 3, 2006, the applicant revised the operating experience section of the AMP B.1.2.7 to include experience from the October 2006 refueling outage. The additional operating experience included the following:

During the October 2006 refueling outage UT thickness measurements in the sand bed region were made inside the drywell at the same locations examined in 1996. The results of the statistical analysis of the 2006 UT data were compared to the 1992, 1994 and 1996 data statistical analysis results. Some of the 1996 data contained anomalies that are not readily justifiable but the anomalies did not significantly change the results. The comparison confirmed that corrosion on the exterior surfaces of the drywell shell in the sand bed region has been arrested.

In addition 106 UT thickness measurements were made in locally thinned areas, identified in 1992, from outside the drywell in the sand bed region. The 2006 UT thickness readings in the locally thinned areas are lower when compared to 1992 readings. This is largely due to using a more accurate UT instrument and the procedure used to take the measurements, which involved moving the instrument within the locally thinned area in order to locate the minimum thickness in that area. In addition the inner drywell shell surface could be subject to some insignificant corrosion due to water intrusion onto the embedded shell (see discussion below). Additional measurements of the locally thinned areas will be taken in 2008 using the same type of UT instrument to better correlate the measurements and confirm significant corrosion is not ongoing in the inner drywell shell surface.

During the 2006 refueling outage (1R21), UT thickness measurements were taken at the 4 elevations discussed above in accordance with the Oyster Creek ASME Section XI, Subsection IWE aging management program. The results of the UT thickness measurements indicated that no observable corrosion is occurring at elevations 51' 10" and 60' 10". A single location (Bay 15 -23L) of the 3rd elevation (50 '2") continues to experience minor corrosion at a rate of 0.66 mils/yr. The corrosion rate for the 4th elevation (87' 5") is now statistically insignificant and this elevation can be considered as no longer undergoing observable corrosion.

In addition UT measurements were taken on 2 locations (bay #15 and bay #17) at elevation 23' 6" where the circumferential weld joins the bottom spherical plates and the middle spherical plates. This weld joins plates that are 1.154" thick to the plates that are 0.770" thick. These two bays were selected because they are among those that have historically experienced the most corrosion in the sand bed region. At each location 49 UTs were taken above the weld on the 0.770" thick plate and 49 UTs were taken below the weld on the 1.154" thick plate. The minimum average thickness measured on the 0.770" thick plate is 0.766" and 1.160" on the 1.154" thick plate. The minimum measured local thickness on the 0.770" thick plate is 0.628" and on the 1.154" thick plate is 0.867". The minimum measured general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin.

UT measurements were also taken on 2 locations (bay #15 and bay #19) at elevation 71' 6" where the circumferential weld joins the transition plates (referred to as the knuckle plates) between the cylinder and the sphere. This weld joins the knuckle plates, which are 2.625" thick to the cylinder plates, which are 0.640" thick. These two bays were selected because they also have historically experienced the most corrosion in the sand bed region. At each location 49 UTs were taken above the weld on the 0.640" thick plate and 49 UTs were taken below the weld on the 2.625" thick plate. The minimum measured average thickness on the 0.640" thick plate is 0.624" and 2.530" on the 2.625" thick plate. The minimum measured local thickness on the 0.640" thick plate is 0.449" and 2.428" on the 2.625" thick plate. The minimum measured general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin.

<u>Inner Drywell Shell in the Embedded Region</u>

In 1986, as part of an ongoing effort at the Oyster Creek Generating Station to investigate the impact of water on the outer drywell shell, concrete was excavated at two locations inside the drywell (referred to as trenches) to expose the drywell shell below the Elevation 10'-3" concrete floor level to allow ultrasonic (UT) measurements to be taken to characterize the vertical profile of corrosion in the sand bed region outside the shell. The trenches (approximately 18" wide) were located in bays #5 and #17 with the bottom of the trenches at approximate elevations 8'-9" and 9-3" respectively (The elevation of the sand bed region floor outside the drywell is approximately 8'-11").

Following UT examinations in 1986 and 1988, the exposed shell in the trenches was prepped and coated and the trenches were filled with Dow Corning 3-6548 silicone RTV foam covered with a protective layer of Promatic low density silicone elastomer to the height of the concrete floor (Elevation 10'-3"). The assumption was that these materials would prevent water that might be present on the concrete floor from entering the trenches. Before the 2006 outage these materials had not been removed from the trenches since 1988.

During the October 2006 refueling outage, the filler material from the two trenches was removed to allow inspection of the shell in accordance with commitment number 27, item number 5. Upon removal of the filler material, approximately 5" of standing water was discovered in the trench located in bay #5. The trench area in bay #17 was damp; but no standing water was observed. Investigations concluded that the likely source of water was a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough, or condensation within the drywell that either fell to the floor or washed down the inside of the drywell shell to the concrete floor. Water samples taken from the trench in bay #5 were tested and determined to be non-aggressive with pH (8.40 - 10.21), chlorides (13.6 - 14.6 ppm), and sulfates (228 - 230 ppm). The joint between the concrete floor and the drywell shell had not been sealed to prevent water from coming in contact with the inner drywell shell. The degraded trough drainage system and the unsealed gap between the concrete slab/curb and the interior surface of the drywell shell was first discovered during this October 2006 refueling outage. This condition was entered into the Corrective Action Process (IR 546049). The following corrective actions were taken during the October 2006 refueling outage.

- Walkdowns, drawing reviews, tracer testing and chemistry samples were performed to identify the potential sources of water in the trenches.
- Standing water was removed from trench in bay #5 to allow visual inspection and UT examination of the drywell shell.
- An engineering evaluation was performed by a structural engineer, reviewed by an industry corrosion expert, and an independent third party expert to determine the impact of the as-found water on the continued integrity of the drywell.
- Field repairs/modifications were implemented to mitigate/minimize future

water intrusion into the area between the shell and the concrete floor. These repairs/modifications consisted of:

- Repair of the trough concrete in the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell rather than reaching the drywell sump,
- Caulking the interface between the drywell shell and the drywell concrete floor/curb to prevent water from reaching the embedded shell, and
- Grouting/caulking the concrete/drywell shell interfaces in the trench areas.

- The trench in bay #5 was excavated to uncover an additional 6" of the internal drywell shell surface for inspection and allow UT thickness measurements to be taken in an area of the shell that was embedded by concrete.

- Visual inspection of the drywell shell within the trenches was performed.

- A total of 584 UT thickness measurements were taken using a 6"x6" template (49 points) within the two trenches. Forty-two (42) additional UT measurements were taken in the newly exposed area in bay #5.

Visual examination of the drywell shell within the two trenches initially identified minor surface rust; with water in bay #5 and moisture in bay #17. After the surfaces were cleaned with a flapper wheel (lightly to avoid removing the metal) a visual examination of the shell was conducted in accordance with ASME Section XI, Subsection IWE. The visual examination identified no recordable (significant) corrosion on the inner surface of shell.

A total of 294 UT thickness measurements were taken in the bay #5 trench and 290 measurements were taken in the bay #17 trench during 2006 refueling outage. The results of the measurements indicated that the drywell shell in the trench areas experienced a reduction in the average thickness of 0.038"since 1986. AmerGen's evaluation concluded that the wall thinning was a result of corrosion on the exterior surface of the drywell shell in the sand bed region between 1986 and 1992 when the sand was still in place and corrosion was known to exist.

An engineering evaluation of the Oyster Creek inner drywell shell condition was prepared by a structural engineer and reviewed by an industry corrosion expert and independent third-party expert to determine the impact of the as-found water on the continued integrity of the drywell shell. The evaluation utilized water chemical analysis, visual inspections and UT examinations. It concluded that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel concrete interface is still intact and significant corrosion of the drywell shell would not be expected as long as this benign environment is maintained. Therefore, since the concrete environment complies with the EPRI concrete structure guidelines, corrosion would not be considered significant within the Oyster Creek drywell and the water could remain in contact with the interior drywell shell indefinitely without having long term adverse effects.

More specifically, the results of this engineering evaluation indicate that no significant corrosion of the inner surface of the embedded drywell shell would be anticipated for the following reasons:

- The existing water in contact with the drywell shell has been in contact with the adjacent concrete. The concrete is alkaline which increases the pH of the water and, in turn, inhibits corrosion. This high pH water contains levels of impurities that are significantly below the EPRI embedded steel guidelines action level recommendations.

- Any new water (such as reactor coolant) entering the concrete-to-shell interface (now minimized by repairs/modifications implemented during this outage) will also increase in pH due to its migration through and contact with the concrete creating a nonaggressive, alkaline environment.

- Minimal corrosion of the wetted inner drywell steel surface in contact with the concrete Is only expected to occur during outages since the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant since the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also, repairs modifications implemented during the 2006 outage will further minimize exposure of the drywell shell to oxygen.

Based on the UT measurements taken during the 2006 outage of the newly exposed shell area in Bay 5 that has not been examined since it was encased in concrete during Initial construction (pre-1969), it was determined that the total metal lost based on a current average thickness measurement of 1.113" versus a nominal plate thickness of 1.154" is only 0.041" (total wall loss for both inside and outside of the drywell shell). Although no continuing corrosion is expected, but conservatively assuming that a similar wall loss could occur between now and the end of the period of extended operation, a margin of 336 mils to the 0.736" required wall thickness would exist.

As for the 0.676" thick embedded plate, conservatively assuming the plate has undergone corrosion of 0.041" to date, and will undergo similar wall loss between now and the end of the period of extended operation a margin of 115 mils against the required minimum general thickness of 0.479" required for pressure is provided.

The engineering evaluations summarized above confirmed that the condition identified during the 2006 outage would not impact safe operation during the next operating cycle. Also, a conservative projection (noted above) of wall loss for the 1.154" and 0.676" thick embedded shell sections indicates that significant margin is provided in both sections through the period of extended operation.

Although a basis is established that ongoing corrosion of the shell embedded in concrete should not be expected and repairs/modifications have been performed to limit or prevent water from reaching the internal surface of the drywell shell, AmerGen has now established that the existence of water in contact with the internal surface of the drywell shell and concrete at and below the floor elevation will be assumed to be a normal operating environment. AmerGen will further enhance the Oyster Creek ASME Section XI, Subsection IWE aging management program to require periodic inspection of the drywell shell subject to concrete (with water) environment in the internal embedded shell area and water environment within the trench area.

The staff reviewed the operating experience provided in the LRA, PBD, and the December 3, 2006, letter and interviewed the applicant's technical personnel. The staff concludes that the OCGS plant-specific operating experience is unique and not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's ASME Section XI, Subsection IWE Program will adequately manage the aging effects identified in the LRA and PBD-AMP-B.1.27 for which this AMP is credited.

The staff determined that the ASME Section XI, Subsection IWE Program described in LRA Section B.1.27, is consistent with the GALL AMP XI.S1, "ASME Section XI, Subsection IWE," with an exception and enhancements. However, operating experience indicated that the program had not been effective in managing the effects of aging in the drywell. The drywell degradation issue includes concerns associated with monitoring and eliminating water leakage, corrosion in the upper drywell region, corrosion in the former sand bed region, and pitting corrosion in the suppression chamber torus. The staff evaluated the applicant's Commitment 27, "ASME Section XI, Subsection IWE," which includes 21 items. In Section 4.7.2 in this SER, the staff reviewed applicant responses to five open items associated with the drywell degradation issue. On the basis of its evaluation of the program description, additional commitments, and the responses to the five open items, the staff determined that the ASME Section XI, Subsection IWE Program will provide assurance that the effects of aging on the drywell and torus will be adequately managed.

<u>UFSAR Supplement</u>. In LRA Section A.1.27 and letters dated April 4, May 1, June 23, December 3, and December 15, 2006, and February 15, 2007, the applicant provided the UFSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this Section and determined that the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and found that this information reflects the resolution of the five open items and provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.24 ASME Section XI, Subsection IWF

<u>Summary of Technical Information in the Application</u>. In LRA Section B.1.28, the applicant described the existing ASME Section XI, Subsection IWF Program as consistent, with an exception and enhancements, with GALL AMP XI.S3, "ASME Section XI, Subsection IWF."

The ASME Section XI, Subsection IWF 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 material. Bolting, included with these components, is inspected for loss of material and for loss of preload from missing, detached, or loosened bolts. Procurement controls and installation practices, defined in plant procedures, apply only approved lubricants and torques. The program is implemented through corporate and station procedures for inspection and acceptance criteria consistent with the requirements of ASME Code Section XI, 1995 Edition with 1996 Addenda.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.24. The staff reviewed the exception and enhancements and their justifications to determine whether the AMP, with the exception and enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the ASME Section XI, Subsection IWF Program for which the applicant claimed consistency with GALL AMP XI.M6 and found them consistent. Furthermore, the staff concludes that the applicant's ASME Section XI, Subsection IWF Program provides reasonable assurance that the aging effects and mechanisms from such conditions as general corrosion and wear of carbon steel components and piping supports will be properly managed for the period of extended operation. The staff found that the applicant's ASME Section XI, Subsection IWF Program conforms to the recommended GALL AMP XI.S3, with an exception and enhancements described below.

Exception. In the LRA, the applicant stated an exception to the GALL Report program description. Specifically, the exception stated:

> 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 10 CFR50.55a, 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.

The staff noted that the 1995 ASME Code Section XI, including 1996 addenda, was the edition incorporated into 10 CFR 50.55a at the time the applicant was required to declare its inspection basis for the current 10-year IWF 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. As this incorporation is consistent with the intent of the GALL Report guidance, the staff did not consider it an actual exception to the GALL Report and found it acceptable.

Enhancement 1. In the LRA, the applicant stated an enhancement in meeting the GALL Report program element "scope of program." Specifically, the enhancement stated:

> 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.

During the audit, the staff asked the applicant for clarifications about this enhancement to understand better what MC supports are in the ASME Section XI, Subsection IWF Program and will be added to the program and also to confirm that all MC supports under IWF are included in the program. In its response, the applicant stated that:

(1) The MC supports 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

(2) 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 (2) to confirm the current inspection practice. All MC supports will be included.

(3) 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 (3) 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 ASME Section XI, Subsection IWF Program for all underwater MC supports will be complete before the period of extended operation. The staff concludes that the applicant's response sufficiently defined the enhanced scope for inspection of MC supports.

The staff finds this enhancement acceptable because when implemented the ASME Section XI, Subsection IWF Program will be consistent with GALL AMP XI.S3 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.28, the applicant explained that the operating experience of the ISI programs, which include ASME Section XI, Subsection IWF Program activities, shows no adverse trend of program performance. Periodic self-assessments of the ISI programs have been performed to identify areas that need improvement to maintain program quality.

There is sufficient confidence that the Component Support ISI Program Plan, as described in the ISI Program, will effectively monitor the condition of the component supports within the scope of license renewal so that their design function will be maintained during the extended license period. The applicant submitted data reports for inservice inspections covering the OCGS refueling outage 20 (1R20) examinations between October 28, 2002 and November 22, 2004. The reports include the first period of the fourth ISI interval examinations performed in accordance with the ASME Code. There were challenges during this inspection. Scope expansion was required due to unacceptable conditions on rod hangers evaluated or repaired, as required, and determined acceptable for return to service.

The staff reviewed several corrective action processes and noted problems with supports in the core spray system dating back to 2000. The staff asked the applicant for information on corrective actions taken to prevent recurrence. In its response, the applicant stated that the core spray system 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:

- Installation of a keep full system.
- Installation of frequency controllers on the test valves V-20-26 and V-20-27, which slow down the opening stroke.
- Modification of the pump recirculation piping to provide a continuous venting path and minimize the risk of piping voiding.
- Implementation of a weekly PM to verify that the system is filled and vented.
- Modification of the counter weight assisted check valves (i.e., V-20-51 and V-20-52) to minimize the risk of their 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 staff concludes that the applicant's course of action for these 2 occurrences provides reasonable confirmation that its ASME Section XI, Subsection IWF Program is effective.

The staff reviewed the operating experience provided in the LRA and PBD and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's ASME Section XI, Subsection IWF Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.28, the applicant provided the UFSAR supplement for the ASME Section XI, Subsection IWF Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI, Subsection IWF Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.25 Structures Monitoring Program

Summary of Technical Information in the Application. In LRA Section B.1.31, the applicant described the existing Structures Monitoring Program as consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program." The applicant revised the scope of the Structures Monitoring Program in letters dated October 12, 2005, and December 9, 2005, to include components within the scope of license renewal from the Station Blackout System Forked River Combustion Turbine Power Plant and the Meteorological Tower (Met Tower), respectively.

The Structures Monitoring Program was developed to implement the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program relies on periodic visual inspections to monitor the condition of structures and structural components. Specifically, concrete structures are inspected for loss of material, cracking, and change in material properties. Steel components are inspected for loss of material due to corrosion. Masonry walls are inspected for cracking, and elastomers are monitored for change in material properties. Earthen water-control structures and the fire pond dam are inspected for loss of material and loss of form. Component supports are 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 loss of preload. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torques are applied consistent with the GALL Report bolting integrity program.

The scope of the program will be enhanced to include structures not currently monitored but requiring monitoring during the period of extended operation. Details of the enhancements are that inspection frequency is every 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 provides for more frequent inspections to ensure that observed conditions with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.25. The staff noted that the applicant did not identify any exceptions in the LRA. However, in its PBD the applicant identified an exception to the GALL Report program element "detection of aging effects." The staff's review of this exception is discussed below.

The staff reviewed those portions of the Structures Monitoring Program for which the applicant claimed consistency with GALL AMP XI.S6 and found them consistent. Furthermore, the staff concludes that the applicant's Structures Monitoring Program provides reasonable assurance that the aging of structures within the scope of the program will be properly managed for the period of extended operation. The staff found that the applicant's Structures Monitoring Program conforms to the recommended GALL AMP XI.S6 with an exception and enhancements described below.

Exception. In the LRA, the applicant did not identify exceptions to AMP XI.S6 in the GALL Report. However, in its PBD for this AMP (PBD-AMP B.1.31), the applicant identified an exception to the GALL Report program element "detection of aging effects" not in the LRA. Specifically, the exception stated:

> The program takes exception to the inspection frequency of at least once per refueling cycle specified in NUREG-1801, XI.M36, "External Surfaces Monitoring," Revision 1, for monitoring external surfaces of mechanical components. The specified frequency by the Oyster Creek (structures monitoring) program is every 4 years.

In its letter dated March 30, 2006, the applicant stated that it will revise the LRA to add the exception identified in its PBD for the Structures Monitoring Program, stating that the program takes exception to the inspection frequency of at least once per refueling cycle specified in GALL AMP XI.M36, "External Surfaces Monitoring," Revision 1, for monitoring external surfaces of mechanical components. The frequency specified by the Structures Monitoring Program is every 4 years.

The applicant provided in the PBD the following technical justifications for this exception:

> 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 reasonable 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.

On the basis that monitoring the external surfaces of mechanical components on a 4-year frequency is adequate to ensure their structural integrity, the staff determined that this exception is acceptable.

Enhancement 1. In PBD-AMP-B.1.31 for the Structures Monitoring Program, the applicant stated an enhancement to the GALL Report element "scope of program." Specifically, the enhancement stated:

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 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.

In 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 staff reviewed the enhancements to the program element "scope of program" and the applicant's basis and determined that, with these enhancements, the applicant's Structures Monitoring Program is consistent with the GALL Report.

<u>Enhancement 2</u>. In PBD-AMP-B.1.31 for the structures monitoring program, the applicant stated an enhancement to the GALL Report element "parameters monitored or inspected." Specifically, the enhancement stated:

> 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 new commitment based on the reconciliation of this aging management program from draft January 2005 NUREG-1801, Revision 1 to the approved September 2005 NUREG-1801, Revision 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.

In its letter dated March 30, 2006, the applicant committed (Commitment No. 31) to enhance the Structures Monitoring Program to require visual inspection of external surfaces of mechanical steel components 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).

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 3/4 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, "Structures Monitoring Program," and XI.M36, "External Surfaces Monitoring Program," attributes are satisfied.

The staff reviewed the enhancements to the program element "parameters monitored or inspected" and the applicant's justification and determined that, with these enhancements, the applicant's Structures Monitoring Program is consistent with the GALL Report.

Enhancement 3. In PBD-AMP-B.1.31 for the Structures Monitoring Program, the applicant stated an enhancement to the GALL Report program element "detection of aging effects." Specifically, the enhancement stated:

> 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 staff 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 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, which states that a baseline inspection of submerged water control structures should be performed prior to period of extended operation, a second inspection 6 years after this baseline inspection, and a third 8 years after the second. After each inspection an evaluation should determine whether the identified degradations warrant more frequent inspections or corrective actions. The applicant was asked to explain why the Structures Monitoring Program was not consistent with the new RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, commitment. In its response to the staff's inquiry the applicant stated that both PBD-AMP-B.1.31, and the LRA will be revised to add an enhancement to the Structures Monitoring Program to include an inspection frequency for submerged water-control structures consistent with the enhancement described in PBD-AMP-B.1.32, Section 2.4, "Summary of Enhancements."

In its letter dated April 17, 2006, the applicant committed (Commitment No. 31) to revise the Structures Monitoring Program in the LRA to include an inspection frequency for submerged portions of water control structures consistent with the new commitment in PBD-AMP-B.1.32 for RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.

The staff's evaluation of RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, is documented in SER Section 3.0.3.2.26. The staff finds this enhancement 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 staff reviewed the revised enhancement to the program element "detection of aging effects" and determined that, with this enhancement, the applicant's Structures Monitoring Program is consistent with the GALL Report.

Enhancement 4. In PBD-AMP-B.1.31 for the Structures Monitoring Program, the applicant stated an enhancement to the GALL Report program element "acceptance criteria." Specifically, the enhancement stated:

> 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 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 will 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, American Institute of Steel Construction (AISC). Development of acceptance criteria considers industry and 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 staff reviewed the enhancements and its basis and determined that, with these enhancements, the applicant's Structures Monitoring Program is consistent with the GALL

Report. On that basis the enhancements are acceptable.

Operating Experience. In LRA Section B.1.31, the applicant explained that program documentation and other plant operating experience before the program was implemented identified cracking of reinforced exterior walls of the reactor building, drywell shield wall above elevation 95', and the spent fuel pool support beam. Cracking of the reactor building exterior walls was generally minor and attributed to early concrete shrinkage and temperature changes. Engineering evaluation concluded that the structural integrity of the walls was unaffected by the cracks. Repairs to areas of concern were made to prevent water intrusion and corrosion of concrete rebar. The cracks and repaired areas are monitored under the program to detect any changes that will require further evaluation and corrective action.

Cracking of the drywell shield wall was attributed to high temperature in the upper elevation of the containment drywell. Engineering analysis concluded that stresses are well below allowable limits, considering the existing cracked condition. Recent inspections identified no significant change in the cracked area.

Cracking of the spent fuel storage pool concrete support beams was identified in mid-1980. Subsequently, crack monitors were installed to monitor crack growth and an engineering evaluation was performed. Based on the evaluation results and additional NDE to determine the depth of the cracks, the applicant concluded that the beams will perform their intended function and that continued crack monitoring is not required.

Inspection of the intake canal 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 (UHS). However the inspector recommended repair of the degradations to prevent further deterioration. A project to repair the canal banks has been initiated.

Inspections conducted in 2002 concluded that degradations have not become worse and remain essentially the same as those identified in previous inspections. In addition minor cracking, rust stains, water stains, localized exposed rebars and rebar corrosion, and damage to siding were observed, evaluated, and determined to have no impact on structural integrity. In operating experience the program is effective for managing aging effects of structures, structural components, and water-control structures.

The staff noted that the applicant's discussion of operating experience identified three conditions of concrete degradation: cracking of the reactor building 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 staff asked the applicant for additional information describing the degradation, the assessment performed, the acceptance criteria applied, future monitoring recommendations, and any corrective action taken. The staff also requested that the applicant describe the monitoring activities that are or will be conducted under the Structures Monitoring Program for each of the three regions. In response, the applicant indicated that the requested information is included in the Structures Monitoring Program basis document (PBD-AMP-B.1.31) notebook, which was available for the staff's review during the second AMP audit. The staff reviewed this information and conducted additional reviews of these conditions as part of the AMR audit. See SER Section 3.5.2 for documentation of the staff's review and assessment.

The staff reviewed the operating experience provided in the LRA and PBD-AMP-B.1.31, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Structures Monitoring Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

In its letter dated December 3, 2006, the applicant provided additional plant-specific operating experience related to inspections of the trenches in the drywell concrete floor. The applicant provided the following information.

> In 1986, as part of an ongoing effort at the Oyster Creek Generating Station to investigate the Impact of water on the outer drywell shell, concrete was excavated at two locations Inside the drywell (referred to as trenches) to expose the drywell shell below the Elevation 10'-3" concrete floor slab level to allow ultrasonic (UT) measurements to be taken to characterize the vertical profile of corrosion in the sand bed region outside the shell. The trenches (approximately 18" wide) were located in Bays #5 and #17 with the bottom of the trenches at approximate elevations 8'-9" and 9'-3" respectively (The elevation of the sand bed region floor outside the drywell is approximately 8'-11").
>
> Following UT examinations in 1986 and 1988, the exposed shell in the trenches was prepped and coated and the trenches were filled with Dow Corning 3-6548 silicone RTV foam covered with a protective layer of Promatic low density silicone elastomer to the height of the concrete floor slab (elevation 10'-3"). At that time it was expected that these materials would prevent water that might be present on the concrete floor slab from entering the trenches. Before the 2006 outage these materials had not been removed from the trenches since 1988.
>
> During the October 2006 refueling outage, the filler material from the two trenches was removed to allow Inspection of the shell In accordance with license renewal commitment number 27, item number 5 (AmerGen Letter No. 2130-06-20358 dated July 7,2006). Upon removal of the filler material, approximately 5" of the standing water was discovered in the trench located in bay #5. The trench area in bay #17 was damp, but no standing water was observed. Water samples taken from the bay #5 trench were tested and determined to be non-aggressive with pH (8.40 - 10.21), chlorides (13.6 - 14.6 ppm), and sulfates (228 - 230 ppm). The high pH in water is typical of the concrete alkaline environment. This condition was entered into the Corrective Action Process (IR 546049).
>
> As a result of identifying standing water inside the bay #5 trench and dampness in the bay #17 trench, investigations were conducted to identify the entry point of water into the concrete below the floor slab level. The investigations concluded that the likely entry point for the water was a deteriorated connection in the Sub-Pile Room (room within the reactor pedestal, below the CRD housings) drainage trough drainpipes, at a void in the bottom of Sub-Pile Room drainage trough, and at the unsealed gap at the elevation 10'-3" concrete slab curb and the Interior surface of the drywell shell. Field repairs/modifications were implemented to mitigate/minimize future water intrusion into the area between the shell and the

concrete floor slab. Engineering evaluations were conducted to assess the impact of the water environment on the structural integrity of the drywell shell and reinforced concrete. Evaluation of the drywell shell is discussed in detail in LRA Section 3.5.2.2.1.4 and in Appendix B.1.27. Evaluation of the reinforced concrete fill slab is discussed below.

Visual inspection of the reinforced concrete slab was conducted in accordance with this program (Structures Monitoring Program, B.1.31) during the October 2006 refueling outage. The structural engineer who conducted the inspection noted that the concrete floor slab outside the reactor pedestal is in good condition with no visible evidence of rebar corrosion (cracking, spalling), or other structural defects. The edge of the concrete curb where it meets the drywell shell was uneven. Some concrete had chipped off due to sharp edges. The loss of material is not a structural concern but the gap where chipped concrete was observed could be a possible path for water Intrusion (this area was later sealed). Inspection of the reactor pedestal wall and the floor slab of the Sub-Pile Room were observed to be In good condition.

In summary, engineering evaluation of the inspection results concluded that water Intrusion into the concrete has no impact on the structural integrity of the slab. The observed condition of the concrete is typical of concrete in other areas of the plant. There is no evidence of rebar corrosion, significant cracking, or other concrete degradations. Such degradations would not be expected due to the high pH, and the low chlorides and sulfates content of the concrete/water environment.

The staff reviewed the operating experience provided in the LRA, PBD, and the December 3, 2006, letter and interviewed the applicant's technical personnel. The staff concludes that the OCGS plant-specific operating experience is unique and not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Structures Monitoring Program will adequately manage the aging effects identified in the LRA and PBD-AMP-B.1.31 for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.31 and letters dated March 30, April 17, and December 3, 2006, the applicant provided the UFSAR supplement for the Structures Monitoring Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Structures Monitoring Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that 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 staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.26 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Summary of Technical Information in the Application. In LRA Section B.1.32, the applicant described the existing RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as consistent, with enhancements, with GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The RG 1.127, Revision 1, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," AMP, part of the Structures Monitoring Program, is based on the guidance of RG 1.127 and ACI 349.3R and periodically inspects the intake structure and canal (UHS), the fire pond dam, and the dilution structure. The program will 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. Inspection frequency is every 4 years except for submerged portions of the structures inspected when the structures are dewatered or on a frequency not to exceed 10 years. The program will be enhanced to provide reasonable assurance that aging effects of water-control structures are adequately managed during the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.26. The staff reviewed the enhancements and their justifications to determine whether the AMP, with the enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power program for which the applicant claimed consistency with GALL AMP XI.S7 and found them consistent. Furthermore, the staff concludes that the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Program provides reasonable assurance that the OCGS water control structures will be adequately managed for the period of extended operation. The staff 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, with an exception and enhancements described below.

Exception. The applicant did not state any exception to the GALL Report program in the LRA. However, PBD-AMP-B.1.32 states an exception to the GALL Report program element "detection of aging effects." Specifically, the exception stated:

> 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.

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 reasonable 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 with reasonable assurance 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 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. This constitutes a new exception not previously identified in the LRA.

In its letter dated March 30, 2006, the applicant committed (Commitment No. 32) to revise the LRA to add the exception to the inspection frequency specified in GALL AMP XI.S7 and stated in PBD-AMP-B.1.32. The applicant has committed to a baseline inspection prior to the period of period of extended operation, a second inspection 6 years after the baseline inspection, and a third 8 years after the second and has committed to evaluate the degradations to determine whether more frequent inspections are warranted.

The staff finds this exception 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 extended period of operation.

In the LRA and in PBD-AMP-B.1.32, the applicant stated the following enhancements in meeting the GALL Report program elements "scope of program," "parameters monitored or inspected," and "detection of aging effects." Specifically, the enhancements stated:

(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 staff noted that "enhancement" (7) related to the program element "detection of aging effects" is not an enhancement to meet the GALL Report recommendations. The applicant's new commitment for inspection of submerged water control structures, a significant improvement over the original LRA commitment, is still an exception to the GALL Report recommendations. The staff evaluated this "enhancement" as an exception described above.

Enhancement 1. In the LRA, the applicant stated enhancements in meeting the GALL Report program element "scope of program." Specifically, the enhancements stated "the OCGS AMP will be enhanced to include the following:

(1) The program will provide for monitoring of submerged structural components and trash racks.

(2) 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.

(3) The program will be enhanced to include periodic inspection of the fire pond dam for loss of material and loss of form.

As justification for this enhancement, the applicant stated that the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program applies to water control structures of the emergency cooling water system. Water control structures in scope of license renewal are included in the scope of the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. These structures are the intake structure and canal (UHS), the dilution structure, and the intake structure trash racks. Structural components and commodities of the structures 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 credited for flood protection and no safety and performance instrumentation like seismic, horizontal and vertical movement, uplift, and other instrumentation incorporated in the design of the water control structures.

The staff compared the program scope of the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, including enhancements, to the program scope of GALL Report AMP XI.S7 and finds them to be consistent.

On this basis, the staff finds the enhancements to the "scope of program" program element acceptable because when implemented the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Program will be consistent with GALL AMP XI.S7 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2. In the LRA, the applicant stated enhancements in meeting the GALL Report program element "parameters monitored or inspected." Specifically, the enhancements stated, "the OCGS AMP will be enhanced to include the following:"

(1) Parameters monitored for concrete will be enhanced to include change in material properties, due to leaching of calcium hydroxide, and aggressive chemical attack.

(2) Parameters monitored will include inspection of steel components for loss of material due to corrosion and pitting.

(3) Parameters monitored will include inspection of wooden piles and sheeting for loss of material and change in material properties.

As justification for this enhancement, 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 like erosion and cavitation, cracking due to various aging mechanisms like settlement, and change in material properties due to leaching of calcium hydroxide. Steel components of earthen water control structures (intake canal, embankments), the fire pond dam, and trash racks are monitored for loss of material due to pitting and corrosion. Wooden components are monitored/inspected for loss of material and change in material properties. Slopes for earthen water control structures at junctions 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 or 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 staff compared the parameters monitored or inspected in the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, including enhancements, to the parameters monitored or inspected in GALL Report AMP XI.S7 and finds them consistent.

On this basis, the staff finds the enhancements to the program element "parameters monitored or inspected" acceptable because when implemented the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Program will be consistent with GALL AMP XI.S7 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.32, the applicant explained 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 the mid-1980s. Recent inspection (2002) of the intake structure and the dilution structure noted some concrete spalling and cracking. However, these aging effects were determined to be insignificant with no adverse impact on the intended function(s) of the structures. Inspection of the intake canal 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 staff reviewed the operating experience provided in the LRA and PBD-AMP-B.1.32, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.32 and letter dated March 30, 2006, the applicant provided the UFSAR supplement for the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.27 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. In LRA Section B.1.33, the applicant described the existing Protective Coating Monitoring and Maintenance Program as consistent with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program."

The 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 sandbed region. Service Level I coatings are used in areas where coating failure could affect the operation of post-accident fluid systems adversely and thereby impair safe shutdown. OCGS was not originally committed to Regulatory Guide (RG) 1.54 for Service Level I coatings because the plant was licensed prior to the issuance of this RG in 1974. Currently, OCGS is committed to a modified version of this RG 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 decontamination ability in areas outside of the primary containment 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 sandbed region Service Level II coatings to function as intended.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.27.

During the audit the staff requested that the applicant clarify which coatings are credited for corrosion protection of metal surfaces. In its response, 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, the applicant does not credit them for corrosion protection for the internal surface of the drywell shell 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 time-limited aging analysis (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 that for loss of coolant accident debris generation and transport, the drywell coating is qualified for such an environment. The mass of coating released following a loss of coolant accident jet impingement was conservatively estimated at 47 pounds. No additional coating flaking was assumed due to the harsh environment because the coating is qualified. Coating within the vent system and torus is expected to contribute 0 pounds of debris to the suction strainer load following a loss of coolant accident. However, the analysis conservatively assumed 10 pounds of debris attributed to the vent system and torus coating.

The staff also requested that the applicant clarify whether any Service Level III coatings are credited for corrosion protection for license renewal. In its 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 affect normal plant operation or orderly and safe plant shutdown adversely. Service Level III coatings are also used in areas outside the reactor containment where failure could affect the safety function of a safety-related structure, system, or component adversely. 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 credited only for corrosion protection for the external surfaces of piping and fittings exposed to a soil (external) environment in the emergency service water (ESW) system, service water (SW) system, and roof drain and overboard discharge system (RDODS). These coatings are managed under the Buried Piping Inspection Program. Other than the Service Levels 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 staff also noted that the discussion in LRA Table 3.5.1, item 3.5.1-15, appears to identify a scope larger than that identified in the AMP description. The staff requested that the applicant clarify the scope of this program. In its response, the applicant stated that the structures or components and environments "rolled-up" into LRA Table 3.5.1 item 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 hatches 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 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 from this component type exposed to an indoor air environment.

In its letter dated April 17, 2006, the applicant stated that LRA Tables 3.5.2.1.1 and 3.5.1 will be revised to delete the Protective Coating Monitoring and Maintenance Program from line items to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatches 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.

The staff finds the applicant's clarifications acceptable because they defined the scope of coatings credited for corrosion protection and also defined the coatings specifically monitored and maintained by the Protective Coating Monitoring and Maintenance Program for license renewal.

During its review of plant-specific operating experience related to containment degradation, the staff asked a number of questions about the implementation of the Protective Coating Monitoring and Maintenance Program for the exterior surface of the sand bed region and for the submersed interior surface of the torus. The staff's inquiries and assessments of the applicant's responses are documented in the evaluation of the applicant's ASME Section XI, Subsection IWE Program summarized in SER Section 3.0.3.2.23. The applicant made new commitments related to monitoring of these primary containment coatings in accordance with ASME Section XI, Subsection IWE (Commitment No. 33).

Subsequent to the audit, in response to RAI 4.7.2-1, by letter dated June 20, 2006, the applicant provided additional information regarding the coatings credited for corrosion mitigation for primary containment and activities associated with drywell shell corrosion. The staff's evaluation of the applicant's information and commitments is documented in SER Section 4.7.2.

Although the LRA did not identify any enhancements for the Protective Coating Monitoring and Maintenance Program, the applicant's program basis document, (PBD)-AMP-B.1.33, "OCGS Program Basis Document: Protective Coating Monitoring and Maintenance Program," Revision 0, identified the following enhancement to meet the GALL Report program elements:

Enhancement. The applicant identified an enhancement to its program elements "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the enhancement stated that:

> 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 staff requested that the applicant clarify what changes were necessary to make the Protective Coating Monitoring and Maintenance Program consistent with ASME Code Section XI, Subsection IWE requirements. In its response, the applicant stated that the requirements for coating inspections are included in OCGS 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 invoke all of the requirements of ASME Code 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. Disposition of suspect areas shall be by engineering evaluation or correction 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. Disposition of suspect areas shall be by engineering evaluation or correction 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, the applicant committed (Commitment No. 27) 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.

On this basis, the staff finds this enhancement to the protective coating monitoring and maintenance program acceptable because it ensures that the requirements of ASME Code IWE related to coatings inspection will be implemented during the period of extended operation.

Operating Experience. In LRA Section B.1.33, the applicant explained that it has successfully identified indications of age-related degradation in Service Level I coatings prior to the loss of intended function(s) and has taken appropriate corrective actions through evaluation or repair in accordance with the Service Level I coatings procedures and specifications. Torus and vent header vapor space Service Level I coating inspections performed in 2002 found the coating in these areas in good condition. Inspection of the immersed coating in the torus identified blistering that 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 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 Service Level II coating effort completed in the 14R refueling outage has been effective in mitigating corrosion in the sand bed area. This effort was accomplished while the vessel thickness was sufficient to satisfy ASME Code requirements, so 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. To date, no age-related degradation has been detected in the sandbed region Service Level II coating.

In 2003, the replacement motor for the "A" recirculation motor was found to be top-coated with a non-design basis accident qualified coating on the motor housing, end bells, and stator. Engineering analysis concluded that negligible additional suction strainer debris loading will be created by the failure of this additional unqualified coating.

The staff reviewed the operating experience provided in the LRA and PBD and also interviewed the applicant's technical personnel. The staff concludes that the plant-specific operating experience with containment degradation is unique and not bounded by industry experience. The staff's review of operating experience led to a number of questions about the implementation of the Protective Coating Monitoring and Maintenance Program. As a result, the staff identified OI 4.7.2-3, regarding the extent of drywell shell coated surfaces examined during each inspection. The staff's evaluation and resolution of this OI is documented in SER Section 4.7.2.

UFSAR Supplement. In LRA Section A.1.33 and letters dated April 4, April 17, May 1, and June 23, 2006, the applicant provided the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this Section and determined that the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) of primary containment will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.28 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrument Circuits

Summary of Technical Information in the Application. In LRA Section B.1.35, the applicant described the existing Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program as consistent, with enhancements, with GALL AMP XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program manages aging for cables and connections in sensitive instrumentation circuits with low-level signals. 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 located in areas where the cables and connections could be exposed to adverse environments of heat, radiation, or moisture. These adverse environments can reduce insulation resistance, causing increases in leakage currents. For the IRM and LPRM/APRM systems, the program is implemented by station procedures that perform current/voltage and time domain reflectometry (TDR) cable testing and have proven effective in determining cable insulation condition. Testing is performed every refueling outage. For the reactor building high radiation monitoring and air ejector offgas radiation monitoring systems, the program is implemented by station procedures used for calibration testing required by the technical specifications. When an instrumentation channel is found to be out of tolerance or out of calibration, such corrective action as recalibration or circuit trouble-shooting of the instrumentation cable system is taken.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.26. The staff reviewed the enhancements and their justifications to determine whether the AMP, with the enhancements, remained adequate to manage the aging effects for which it is credited.

The staff reviewed those portions of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrument Circuits Program for which the applicant claimed consistency with GALL AMP XI.E2. The staff found that the applicant's program conforms to the recommended GALL AMP XI.E2, with enhancements described below.

Enhancement 1. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending." Specifically, the enhancement stated:

> Section XI.E2 of NUREG-1801 requires 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 off-gas radiation monitoring systems calibration results for cable aging degradation before the period of extended operation and every 10 years thereafter.

The staff noted 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. Review of the results obtained during calibration will detect severe aging degradation before loss of the cable's or connection's intended function.

The staff finds this enhancement acceptable because when implemented the program will be consistent with GALL AMP XI.E2 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2. In the LRA, the applicant stated an enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending." Specifically, the enhancement stated:

> Section XI.E2 of NUREG-1801 requires 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 staff noted 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. Review of the results obtained during cable testing will detect severe aging degradation before the loss of the cable's or connection's intended function.

The staff finds this enhancement acceptable because when the enhancement is implemented the program will be consistent with GALL AMP XI.E2 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.1.35, the applicant explained that the cable testing and calibrations for this AMP currently have proven effective in identifying degradation in 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 replacement of 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 process and appropriate actions are taken.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes 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 identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.35, the applicant provided the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.29 Metal Fatigue of Reactor Coolant Pressure Boundary

Summary of Technical Information in the Application. In LRA Section B.3.1, the applicant described the existing Metal Fatigue of Reactor Coolant Pressure Boundary (RCPB) Program as consistent, with an enhancement, with GALL AMP XI.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary."

The Metal Fatigue of Reactor Coolant Pressure Boundary Program provides for aging management of select components in the RCPB by tracking and evaluating key plant events selected from 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 program provides management of operating transients, calculates fatigue usage factors, 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, components selected in NUREG/CR-6260 by appropriate environmental fatigue factors. The RCPB design basis metal fatigue analyses 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. 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, providing 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.27. In the LRA, the applicant stated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program is consistent with GALL AMP X.M1 with enhancements. The staff reviewed the program elements (see SER Section 3.0.2.1) of the Metal Fatigue of Reactor Coolant Pressure Boundary Program and basis documents to determine their consistency with GALL AMP X.M1.

In reviewing this program the staff noted that, in LRA Section 4.3.4, the applicant stated that the allowable CUF value is 1.0. The applicant stated that the CLB fatigue CUF limit for the RPV had been changed to 1.0 in accordance with 10 CFR 50.59. The applicant stated in a letter dated December 9, 2005, that it will revise the UFSAR to update the CLB to reflect that a CUF of 1.0 will be used in fatigue analyses for RCPB components, as endorsed in 10 CFR 50.55a, before the period of extended operation. The staff's TLAA review is discussed in SER Section 4.

The staff 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 staff noted that the PORC had approved the CUF limit change with some recommendations and conditions. The staff requested that the applicant clarify the methodology for the determination of the fatigue CUF, to clarify the original design intent to limit the CUF 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 with ASME Code Section III Class 1 analysis. In its response, the applicant stated:

> 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 Boiler and Pressure Vessel Code Section III, the General Electric Company developed a method for performing a fatigue analysis which will provide assurance that vessels installed in General Electric designed nuclear power plants will 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 will 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 will 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 Boiler and Pressure Vessel Code Section III methodology to revise its design basis fatigue analyses for the reactor vessel; and the NRC has approved the use of ASME Boiler and Pressure Vessel Code Section III via 10 CFR50.55a, which is within the limitations of the Oyster Creek Licensing Basis. Therefore, implementing the ASME Boiler and Pressure Vessel 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 Boiler and Pressure Vessel 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 Boiler and Pressure Vessel 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 Boiler and Pressure Vessel 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 Boiler and Pressure Vessel 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 10 CFR50.55a 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 also stated that all supporting calculations and reports prepared by Structural Integrity Associates (SIA) for the fatigue activities associated with the LRA 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 Boiler and Pressure Vessel Code (in accordance with the referenced Edition and Addenda) for Class 1 fatigue analysis. In its letter dated May 1, 2006, the applicant committed (Commitment No. 44) 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. The staff determined that the applicant's response was acceptable because it meets the methods established in NRC approved ASME Boiler and Pressure Vessel Code Section III.

The staff reviewed those portions of the Metal Fatigue of Reactor Coolant Pressure Boundary Program for which the applicant claimed consistency with GALL AMP X.M1 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program provides reasonable assurance that the effects of fatigue will be adequately managed. The staff found that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program conforms to the recommended GALL AMP X.M1, with an enhancement described below.

Enhancement. In the LRA, the applicant stated the following enhancement in meeting the GALL Report program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and acceptance criteria." Specifically, the applicant stated the following:

> 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

In reviewing this enhancement, the staff noted that, in the LRA, the applicant stated that the EPRI-licensed FatiguePro computer program calculates stress cycles and fatigue usage factors from operating cycles, automatically counts fatigue stress cycles, and automatically calculates and tracks fatigue CUFs. The applicant also stated that the program will calculate and track the CUFs 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 locations where the predicted 40-year cumulative fatigue usage had been predicted to be 0.4 or greater and the locations specified in NUREG/CR-6260 when applicable.

The staff 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 staff determined that FatiguePro is appropriate 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.

The staff finds this enhancement acceptable because when implemented the Metal Fatigue of Reactor Coolant Pressure Boundary Program will be consistent with GALL AMP X.M1 and will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In LRA Section B.3.1, the applicant explained that it had reviewed both industry and plant-specific operating experience relating to the Metal Fatigue of Reactor Coolant Pressure Boundary 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 Metal Fatigue of Reactor Coolant Pressure Boundary Program had been revised to incorporate changes in design basis analysis cycles. The changes were made because certain types of operating events were found to be more frequent than anticipated in the original design. Others were found to be less frequent. The changes reduced the assumed design basis number of the less frequent and increased the assumed number of the more frequent events.

In response to staff concerns that early-life operating cycles at some units had caused fatigue usage factors to increase at a rate greater than anticipated in the design analyses, the industry sponsored the development of the FatiguePro computer program. The program ensures that ASME Code limits are not exceeded for the remainder of the licensed life and incorporates operating experience.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no degradation not bounded by industry experience. The fatigue evaluations confirm that significant margin remains for the CUF limit, and implementation of the proposed program will prevent exceeding the limit.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.3.1 and letters dated December 9, 2005, and May 1, 2006, the applicant provided the UFSAR supplement for the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.30 Bolting Integrity - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.12A," Bolting Integrity - FRCT," AMP is consistent with GALL AMP XI.M18, "Bolting Integrity," with exceptions.

The Bolting Integrity - FRCT Program will be used to monitor the condition of bolts and bolted joints within the scope of license renewal at the Forked River Combustion Turbine (FRCT) station. The FRCT station was originally designed and supplied by GE. This program is based on the GE recommendations for proper bolting material selection, lubrication, preload application, installation, and maintenance of 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the Bolting Integrity - FRCT Program is consistent with GALL AMP XI.M18 with exceptions. The staff reviewed the program elements (see SER Section 3.0.2.1) of the Bolting Integrity - FRCT Program and basis documents to determine their consistency with GALL AMP XI.M18.

The staff reviewed those portions of the Bolting Integrity - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M18 and found them consistent. Furthermore, the staff concludes that the applicant's Bolting Integrity - FRCT Program provides reasonable assurance that aging effects will be adequately managed so that the intended functions of bolting within the scope of license renewal at the FRCT station are maintained consistent with the CLB during the period of extended operation. The staff found that the applicant's Bolting Integrity - FRCT Program conforms to the recommended GALL AMP XI.M18 with exceptions described below.

Exception 1. In its response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "scope of program," "preventive actions," "parameters monitored/inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." Specifically, the exception stated:

> 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 XI.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 applicant stated, in its response to RAI 2.5.1.19-1 dated November 11, 2005, 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/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 will 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 will 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 staff noted that there are no safety-related or NSSS components supporting the operation of FRCT station and hence the guidance for the ASME Code Section XI inspection requirements, selection of bolting material, and the use of lubricants and sealants of NUREG-1339, EPRI TR-104213, and EPRI NP-5769 does not apply. On this basis, the staff finds this exception acceptable.

Exception 2. In its response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience. In its response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that in March 2004 (FRCT Unit 1) GE Energy Services performed major inspection and maintenance and documented all work in an inspection report 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 of 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 FRCT Unit 1 inspection was major maintenance, the first major inspection of 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 causing 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 unit operability and reliability were not affected. Critical bolting of the combustion turbine assembly is inspected during maintenance inspections and replaced if required.

Numerous bolts and bolted joints were observed visually during walkdowns during the FRCT 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 found 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 FRCT Units 1 and 2 and common auxiliary systems.

The operating experience with the FRCT includes a significant number of past inspections including observations of bolting and bolted joints. The documented inspection results provide objective evidence that existing environmental conditions do not result in significant bolting degradation that could cause a loss of the bolting intended functions. Past inspections have been at 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 for reasonable assurance that the aging effects will be adequately managed for the period of extended operation.

The staff reviewed the operating experience provided in the basis document and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Bolting Integrity - FRCT Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Bolting Integrity - FRCT Program in response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.31 Closed-Cycle Cooling Water System - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.14A, "Closed-Cycle Cooling Water System - FRCT," is consistent with GALL AMP XI.M21, "Closed-Cycle Cooling Water System," with exceptions.

The program manages aging of pumps, tanks, piping, piping components, piping elements, and heat exchangers included in the scope of license renewal and exposed to a closed cooling water environment at the FRCT station. This program incorporates experience with existing activities of the closed cooling water system at the FRCT station. The closed cooling water environment at the FRCT station is blended water-glycol. This program includes preventive measures to minimize corrosion and SCC and 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 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. Then EPRI TR-1007820 Section 5.9 requires that the corrosion inhibitor concentrations be monitored to within the range recommended by the 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 indicates degradation in closed-cycle cooling water systems with plant operating conditions indicates degradation in frequently operated systems. In addition, station maintenance inspections monitor the condition 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the Closed-Cycle Cooling Water System - FRCT Program is consistent with GALL AMP XI.M21 with exceptions. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP XI.M21.

The staff reviewed those portions of the Closed-Cycle Cooling Water System - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M21 and found them consistent. Furthermore, the staff concludes that the applicant's Closed-Cycle Cooling Water System - FRCT Program provides reasonable assurance that aging effects of the closed cycle cooling water system at the FRCT station will be adequately managed during the period of extended operation. The staff found that the applicant's Closed-Cycle Cooling Water System - FRCT Program conforms to the recommended GALL AMP XI.M21, with exceptions described below.

Exception 1. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria."

Specifically, the exception stated:

> 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 requirements of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

During the audit, 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 the GALL Report, and EPRI TR-1007820, “Closed Cooling Water Chemistry Guideline,” Revision 1, which is the 2004 revision implemented by OCGS. 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 requirements of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems and effectively mitigate many aging effects.

In addition, the applicant stated that as part of its comparative review of the guideline documents it had contacted Anthony Selby, the author of EPRI TR-107396 and EPRI TR-1007820, to confirm that the new guidance provided in TR-1007820 was not contrary to the guidance in TR-107396.

The staff 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 to effectively mitigate many aging effects. On this basis, the staff finds this exception acceptable.

Exception 2. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements “corrective actions,” “confirmation process,” and “administrative controls.” Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, “Quality Assurance for Aging Management Programs.” On this basis, the staff finds this exception acceptable.

Operating Experience. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the FRCT system has not experienced a loss of component intended function due to corrosion product buildup, through-wall loss of material, or SCC for components within the scope of license renewal subject to a closed-cycle cooling water environment.

The FRCT units undergo periodic major inspection outages in accordance with manufacturer recommendations. In March 2004, GE Energy Services performed major inspection and maintenance of FRCT Unit 1 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 FRCT Unit 2. 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 for each combustion turbine unit. GE did not identify any significant degradation of these heat exchangers in the FRCT Unit 1 outage final report. The FRCT Unit 2 lube oil heat exchangers were visually inspected during the current (October 2005) outage and found 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.

FRCT system components within 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 experienced no loss of intended function failures due to age-related degradation.

The combustion turbine operating experience provides objective evidence that the FRCT components subject to closed cooling water experience no significant age-related degradation and that the closed-cycle cooling water chemistry has been maintained adequately to manage the effects of aging. This new Closed-Cycle Cooling Water System - FRCT Program will include additional chemistry controls and component condition monitoring activities, providing further assurance that a non-corrosive environment is maintained to continue to minimize aging-related degradation.

The staff reviewed the operating experience provided in the November 11, 2005, supplemental response to RAI 2.5.1.19-1, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Closed-Cycle Cooling Water System - FRCT Program will adequately manage the aging effects identified in the applicant's LRA AMRs for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Closed-Cycle Cooling Water System - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) of the combustion turbine components exposed to closed cooling water environments within the scope of license renewal will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.32 Aboveground Steel Tanks - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.21A, "Aboveground Steel Tanks - FRCT," is consistent with GALL AMP XI.M29, "Aboveground Carbon Steel Tanks," with an exception.

The Aboveground Steel Tanks - FRCT Program will provide 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 an 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 have no caulking or sealing. Therefore, sealant or caulking inspection at the tank-foundation interface does not apply.

The Aboveground Steel Tanks - FRCT Program is a new program. External tank inspections will be at a frequency of every 2 years. Bottom surface UT inspections will be at a frequency of once every 20 years based on plant-specific operating experience with the FRCT system 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; therefore, it is not necessary to perform this initial inspection again prior to 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 not to exceed 20 years before the next internal inspection will be necessary. Therefore, UT inspections of the tank floor are not necessary prior to the period of extended operation and will be performed again prior to October 2020.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that Aboveground Steel Tanks - FRCT Program is consistent with GALL AMP XI.M29 with an exception. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP XI.M29.

The staff reviewed those portions of the Aboveground Steel Tanks - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M29 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's Aboveground Steel Tanks - FRCT Program provides reasonable assurance that aging effects are adequately managed so that the intended functions of above-ground steel tanks within the scope of license renewal at the FRCT station will be maintained consistent with the CLB during the period of extended operation. The staff found that the applicant's Aboveground Steel Tanks - FRCT Program conforms to the recommended GALL AMP XI.M29 with an exception described below.

Exception. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that painting has protected the external surfaces of outdoor steel tanks adequately and 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 with no impact on 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 the potential impact on the tank intended function. These periodic inspections of tank coatings provide reasonable 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 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 VT of the entire tank structure.

The results of the MFL/UT inspection to detect floor underside corrosion indicated that some isolated underside corrosion occurs. A total of eight MFL indications were found and evaluated with the deepest underside corrosion pit measuring 0.185 inches remaining floor thickness. An analysis of corrosion rates since initial tank installation determined that a minimum 0.230 inches 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 inches thickness, and these locations were repaired with seal-welded patch plates.

Visual inspection of the floor internal surface revealed 15 pits with the deepest measuring 0.060 inches deep measured with a pit gauge. These pits were weld-repaired. UT inspections at a number of locations on the shell and roof, coupled with a complete VT 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 1/4 of an inch.

The main fuel oil tank was found to be generally in good condition. With the repair of the identified floor corrosion, the professional opinion of the inspection firm was 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.

FRCT Unit 2 began a major outage inspection in October 2005 with components disassembled and 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 showed no signs of significant paint degradation or metal corrosion. The main fuel oil storage tanks were walked down, including ascents of the stairs up the side of the tank to the roof. The tank walls showed no signs of significant paint degradation or metal corrosion. The tank roof was observed to have early signs of coating failure as had been noted in the tank inspection report. 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 above-ground steel tanks at the FRCT station provides objective evidence that existing environmental conditions cause no 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 confirm that corrosion of the tank bottom occurs 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 2 years and that internal inspection of the main fuel oil storage tank will be at least every 20 years for reasonable assurance that the aging effects will be adequately managed for the period of extended operation.

The staff reviewed the operating experience provided in the basis document and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review and discussions with the applicant's technical personnel, the staff concludes that the applicant's Aboveground Steel Tanks Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

<u>UFSAR Supplement</u>. The applicant provided its UFSAR supplement for the Aboveground Steel Tanks - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate

summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. The staff's review and audit of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff has reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.33 Fuel Oil Chemistry - FRCT

Summary of Technical Information in the Application. In its November 11, 2005 supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.22A, "Fuel Oil Chemistry - FRCT," is consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions.

The new Fuel Oil Chemistry - FRCT Program assures 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 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, 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the Fuel Oil Chemistry - FRCT Program is consistent with GALL AMP XI.M30 with exceptions. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP XI.M30.

In reviewing this AMP, the staff noted that the "detection of aging effects" program element description for the Fuel Oil Chemistry - FRCT Program stated that based on the results of the October 2000 inspections and repairs the FRCT fuel oil storage tank was certified as 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 will be necessary. The applicant was asked for the technical basis for establishing the 20-year inspection interval.

In its response, the applicant stated that the FRCT 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 ISIs conducted at 5-year intervals along with operation and maintenance consistent with industry standards.

The staff reviewed the applicant's response as well as the 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, ISIs are required every 5 years, including 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
- inspection of piping manifolds for leaks or damage

The certification also noted that the tank had been constructed in 1989. The staff determined that the ISIs together with the periodic draining of water and sediment from the tank will 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 staff concludes that the 20-year interval for internal inspections is acceptable.

The staff reviewed those portions of the Fuel Oil Chemistry - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M30 and found them consistent. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the aging effects for which this program is credited will be adequately managed. The staff found that the applicant's Fuel Oil Chemistry - FRCT Program conforms to the recommended GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions described below.

Exception 1. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "preventive actions," "parameters monitored or inspected," and "detection of aging effects." Specifically, the exception stated:

> 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

As part of the justification for this exception, the staff noted that the FRCT license renewal document stated that the diesel starter engine fuel oil tanks are small in size with a high turnover rate of fuel stored as a result of routine engine operations and that stratification of the fuel is not likely due to this high turnover rate. The applicant was asked for additional information as to (1) whether the tanks have the capability to be inspected, (2) what the day tank fuel turnover rate is and the basis for concluding that stratification will not occur, and (3) the operating experience with water and sediment buildup in the FRCT fuel storage tank.

In its response, the applicant stated that the diesel starter engine 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 and 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 its 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. Because 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 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 in October 2000 found no evidence of water accumulation 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, the deepest 0.060 inches as measured with a pit gauge. These were 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. As the internal inspection revealed no significant water accumulation, there is no need to drain the tank bottom periodically.

The applicant also stated in its response that one-time inspections on a number of components in the fuel oil supply system will confirm the effectiveness of the Fuel Oil Chemistry - FRCT Program. An effective Fuel Oil Chemistry - FRCT Program will preclude aging degradation of the diesel engine supply tanks without the need to disassemble and inspect them. If the results of one-time inspections indicate that fuel oil chemistry controls have been ineffective, corrective actions will be implemented, including evaluation or inspection of additional system components potentially affected, including the diesel fuel tanks.

The staff 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 reduces the potential for condensation forming inside them. In operating experience with the FRCT fuel oil storage tank, moisture intrusion has not been a problem. If corrosion due to moisture intrusion occurred, the one-time inspections of the FRCT system components will detect it promptly. On this basis, the staff concludes that this exception is acceptable.

Exception 2. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "scope of program," and "monitoring and trending." Specifically, the exception stated:

> 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 staff requested additional information on the specifications that will be used to determine whether 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 consistent with GE Specification GEI-41047H for the FRCT.

The staff reviewed the applicant's response and determined that the specifications to establish acceptance criteria for the fuel oil samples are based on ASTM Standard D 975 consistent with GE specification GEI-41047H for the FRCT. On this basis, the staff concludes that this exception is acceptable.

Exception 3. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, Section B.1.22A, the applicant stated that fuel oil chemistry activities have been proven effective in managing the aging effects of 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 requirements 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 FRCT fuel oil storage tank including UT and VT inspection of the floor by an API-653 certified tank inspector after 10 years of service (the date of original tank's construction was 1989). The following is a summary of the tank floor inspections: VT inspection of the floor revealed 15 "product side" pits with the deepest 0.060 inches (measured by pit gauge). The pitting was weld-repaired. The floor is equipped with a 24 inches sump serviced by a 4 inches 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.

On these findings the professional opinion of the qualified inspector was that the Forked River fuel oil storage tank will be suitable for the storage of number 2 fuel oil for a period not to exceed 20 years before the next internal inspection. In October 2001 (FRCT Unit 2) and March 2004 (FRCT Unit 1) GE Energy Services performed major inspection and maintenance and documented all work 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 of 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 staff reviewed the operating experience provided for the FRCT fuel oil system and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Fuel Oil Chemistry - FRCT Program will adequately manage the aging effects identified in the LRA AMRs for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Fuel Oil Chemistry - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.34 One-Time Inspection - FRCT

Summary of Technical Information in the Application. In its November 11, 2005 supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.24A, "One-Time Inspection - FRCT," will be consistent with GALL AMP XI.M32, "One-Time Inspection," with exceptions.

The new One-Time Inspection - FRCT Program will provide reasonable assurance that the loss of material and loss of heat transfer aging effects will not occur or occur so slowly as not to affect fuel oil and lubricating oil system component intended functions during the period of extended operation and therefore will require no additional aging management. The program is credited for components in fuel oil and lubricating oil environments where either (1) an aging effect is not expected to occur but there is insufficient data to rule it out completely, (2) 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 (3) the characteristics of the aging effect include a long incubation period.

The One-Time Inspection - FRCT Program 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 do not occur or that the aging effects are insignificant. It will not be used to confirm that aging does not occur or is insignificant in other FRCT environments.

The One-Time Inspection - FRCT Program will be used to verify that the fuel oil and lubricating oil system activities are effective in preventing or minimizing aging to the extent that it will not cause loss of intended function during the period of extended operation. The program will require inspection at locations of low or stagnant flow susceptible to water pooling and gradual accumulation or concentration of agents that promote loss of material and loss of heat transfer. The program will inspect either to verify that unacceptable loss of material or loss of heat transfer does not occur or to initiate additional actions to assure that intended functions of affected components will be maintained during the period of extended operation. The new program elements include (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that will be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup 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 identify appropriate corrective actions.

The inspection sample includes "worst-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 or volumetric examinations. Acceptance criteria are based on FRCT design codes and standards and manufacturer recommendations. The One-Time Inspection - FRCT Program will be implemented prior to the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the One-Time Inspection - FRCT Program is consistent with GALL AMP XI.M32 with exceptions. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP XI.M32.

In reviewing this AMP, the staff noted in the FRCT license renewal document program description for the One-Time Inspection - FRCT Program that the description of the "parameters monitored or inspected" AMP element stated that inspection methods consist of NDE including visual, volumetric, and surface techniques. The One-Time Inspection - FRCT Program is not based on the requirements of the ASME Code, as stated in the first exception for this AMP, and the applicant was asked to describe the rationale to be used in selecting the inspection method for the various types of components in the AMP scope.

In its response, the applicant stated that this AMP 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 visually 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 also will be inspected by 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 by 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 a loss of material aging effect. Mechanical components will be inspected by VT or UT techniques to determine the extent of loss of material by evaluation of loss of wall thickness. The technique selected will depend on the component type and on whether the inspection involves disassembly. For combustion turbine components, the most appropriate technique will be determined based on the manufacturer's experience and recommendations for the component. Piping can be inspected for wall thickness by UT techniques. VT techniques are appropriate for pump casings, strainer bodies, filter housings, and valve bodies when disassembled for maintenance. Such component inspections will confirm the effectiveness of the Fuel Oil Chemistry - FRCT and Lubricating Oil Analysis - FRCT Programs.

The staff reviewed the applicant's response and determined that these inspection techniques are reasonable for the fuel oil system and the lubricating oil system for the FRCTs and will provide reasonable assurance that the aging effects for which this program is credited will be managed. On this basis, the staff concludes that the applicant's rationale for selecting inspection techniques was acceptable.

Upon further review of this AMP, the staff noted in the FRCT license renewal document description for the One-Time Inspection - FRCT Program that the program element "detection of aging effects" addresses sample selection; however, the rationale for selecting the sample was not provided. The applicant was asked for additional information on how the sample for the one-time inspection will be selected.

In its response, the applicant stated that the component sample inspection requirements for the FRCT components will be based on an evaluation of operating experience with these and similar GE combustion turbine units 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 recommendations. A considerable amount of operating experience is available for combustion turbines, and the staff determined that the use of operating experience is an acceptable means of assuring that an appropriate sample will be obtained. On this basis, the staff determined that the applicant's response was acceptable.

The staff reviewed those portions of the applicant's One-Time Inspection - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M32 and found them consistent. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the aging effects for which this program is credited will be adequately managed. The staff found that the applicant's One-Time Inspection - FRCT Program conforms to the recommended GALL AMP XI.M32, with exceptions described below.

<u>Exception 1</u>. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "parameters monitored or

inspected" and "detection of aging effects." Specifically, the exception stated:

> 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 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 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 FRCTs as discussed in the Corrective Actions, Confirmation Process, and Administrative Controls elements.

The staff 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 for the inspections. The staff 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 staff determined that this exception is acceptable.

<u>Exception 2</u>. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

<u>Operating Experience</u>. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that in October 2001 (FRCT Unit 2) and March 2004 (FRCT Unit 1) GE Energy Services performed major inspection and maintenance and documented all work 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 of 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 FRCT Unit 1 inspection was major maintenance, the first major inspection of the unit since initial installation in 1988. During the FRCT Unit 1 inspection, the fuel forwarding pumps and emergency DC lube oil pumps were removed and sent to the GE service shop for cleaning, inspection, and repairs. The GE report does not indicate any 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 FRCT Unit 2 inspection was of the fuel nozzle and combustion section. The lube oil filters were replaced. Included were a borescope and combustion inspection, removal of exhaust frame cooling piping, 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. FRCT Unit 2 began a major outage inspection in October 2005 with components disassembled and visually inspected for age-related degradation. The internal surfaces of disassembled stainless steel piping and flexible hoses showed no corrosion or wall thinning. The combustion turbine lube oil heat exchangers were disassembled, cleaned, and inspected. The carbon steel and copper alloy heat exchanger components normally exposed to lubricating oil were found in excellent condition. The standby heat exchanger not normally in service was found to have some minor accumulation of sediment that was cleaned off. Carbon steel pump casings normally submerged in the lubricating oil reservoir were visually observed to be in excellent condition with no corrosion. The carbon steel internal surfaces of the lubricating oil reservoir were also observed to be in excellent condition with no corrosion.

The staff reviewed the operating experience provided for the FRCT to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's One-Time Inspection - FRCT Program will adequately manage the aging effects identified in the LRA AMRs for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the One-Time Inspection - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.35 Selective Leaching of Materials - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.25A," Selective Leaching of Materials - FRCT," is consistent with GALL AMP XI.M33, "Selective Leaching of Materials," with an exception.

The Selective Leaching of Materials - FRCT Program will ensure the integrity of components that may be susceptible to selective leaching at the FRCT station. The AMP includes a one-time visual inspection and hardness measurement of selected components to determine whether loss of materials due to selective leaching occurs and whether the process will affect the ability of the components to perform intended functions 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 susceptible materials at the FRCT site are comprised of copper alloy materials exposed to treated water (closed cooling water) environments. The purpose of the program is to determine whether loss of material due to selective leaching of the zinc component of the alloy (dezincification) occurs. If selective leaching is found, the program evaluates the effect it will have on the ability of the affected components to perform intended functions for the period of extended operation.

The new Selective Leaching of Materials - FRCT will be implemented in the final 10 years of the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the Selective Leaching of Materials - FRCT Program is consistent with GALL AMP XI.M33 with exceptions. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP XI.M33.

The staff reviewed those portions of the Selective Leaching of Materials - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M18 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the loss of material aging effects due to selective leaching will be effectively managed so that the intended functions of components within the scope of license renewal at the FRCT station are maintained consistent with the CLB during the period of extended operation. The staff found that the applicant's Selective Leaching of Materials - FRCT Program conforms to the recommended GALL AMP XI.M33 with an exception described below.

Exception. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience: In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the selective leaching one-time inspection process is consistent with industry and staff guidance in the inspection techniques utilized and the selection of components inspected.

Selective leaching has not been identified at the FRCT station. In March 2004, GE Energy Services performed major inspection and maintenance in FRCT Unit 1. The work was documented in an inspection report dated June 7, 2004. All work was carried out closely following the instructions and guidance of 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 FRCT Unit 1 inspection was major maintenance, the first major inspection of the unit since initial installation in 1988. During the FRCT 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 and no degradation of these components was identified. FRCT Unit 2 began a major outage inspection in October 2005. The combustion turbine lubricating oil heat exchangers were dissembled, cleaned, and inspected. 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 showed no 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 a concern. This operating experience demonstrates that either the FRCT closed cooling water environment is not conducive to selective leaching or that selective leaching occurs so slowly as to be not yet evident. Because selective leaching is a slow corrosion process, this program will include inspections for selective leaching within the final 10 years of the period of extended operation.

The staff reviewed the operating experience provided in the basis document and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Selective Leaching of Materials - FRCT Program will adequately manage the aging effects and mechanism identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Selective Leaching of Materials - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.36 Buried Piping Inspection - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, 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.

The new Buried Piping Inspection - FRCT 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 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 during maintenance excavations. Within 10 years prior to the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this period. During the period of extended operation, inspection of buried piping will be performed again within the first 10 years unless an opportunistic inspection occurs during this period.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the Buried Piping Inspection - FRCT Program is consistent with GALL AMP XI.M34 with an exception. The staff reviewed the program elements and associated basis documents to determine their consistency with GALL AMP XI.M34.

The staff reviewed those portions of the Buried Piping Inspection - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M34 and found them consistent. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that aging effects will be adequately managed so that intended functions of buried pipe within the scope of license renewal are maintained consistent with the CLB during the period of extended operation. The staff found that the applicant's Buried Piping Inspection - FRCT Program conforms to the recommended GALL AMP XI.M34 with an exception described below.

Exception. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the new Buried Piping Inspection - FRCT Program will be effective in managing aging degradation for the period of extended operation by promptly detecting aging effects and implementing 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 FRCT station. The buried piping included in the scope of license renewal is the glycol-filled cooling water piping 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.

In plant operating experience, coatings and wrappings have protected the external surfaces of buried piping adequately and 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 intended functions will be maintained. Inspections will be performed within 10 years of the period of extended operation and again within the first 10 years of the period of extended operation unless opportunistic inspections occur within these periods.

The staff reviewed the operating experience provided in the basis document and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Buried Piping Inspection - FRCT Program will adequately manage the aging effects and mechanism identified in the LRA for which this AMP is credited

UFSAR Supplement. The applicant provided its UFSAR supplement for the Buried Piping Inspection - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion: On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.37 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT," will be consistent with GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," with an exception.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program, as implemented for the FRCT system, 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 not covered by other AMPs. These components are subject to an internal environment of indoor air assumed to have sufficient moisture for 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 during scheduled maintenance activities when the surfaces are accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions do not cause material degradation that could result in loss of component intended functions.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program is consistent with GALL AMP XI.M38 with an exception. The staff reviewed the program elements and associated basis documents to determine their consistency with GALL AMP XI.M38.

The staff reviewed those portions of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M38 and found them consistent. Furthermore, the staff concludes that the applicant's program provides reasonable assurance that the aging effects for which this program is credited will be adequately managed. The staff 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 an exception described below.

Exception. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that in October 2001 (FRCT Unit 2) and March 2004 (FRCT Unit 1), GE Energy Services performed major inspection and maintenance and documented all work 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 of 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 FRCT Unit 1 inspection was major maintenance, the most comprehensive inspection performed on the combustion turbine units. The interval between major inspections is based on operating experience with these and similar combustion turbine installations and such factors affecting part life as fuel type and starting frequency. The purpose of this type of maintenance inspection is to identify equipment degradation and, if identified, to replace or refurbish the affected component in accordance with manufacturer specifications so the unit will perform reliably through the next operating interval. This major inspection was the first for the unit since initial installation in 1988.

The applicant further stated that during the FRCT Unit 1 inspection bare paint spots with surface rust were identified in the filter housing and 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 identified in the compressor bleed valves 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 FRCT Unit 2 inspection was of the fuel nozzle and combustion section. The FRCT Unit 2 inspection found the inlet filter housing to be in good condition, with no visual defects. Included were 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. FRCT Unit 2 began a major outage inspection in October 2005 with components disassembled and visually inspected for signs of age-related degradation. The internal surfaces of disassembled ductwork, fan housings, and several damper housings were observed and showed no 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 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 operating experience with the FRCTs includes a significant number of past inspections of steel components in the indoor air and diesel exhaust environment. The documented inspection results provide objective evidence that environmental conditions do not cause material degradation that could result in a loss of component intended functions. Past inspections have been at a frequency as long as 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 staff reviewed the operating experience provided for the FRCT to confirm that plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program will adequately manage the aging effects identified in the LRA AMRs for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Inspection of Internal

Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.38 Lubricating Oil Analysis - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that the new AMP B.1.39," Lubricating Oil Analysis Program - FRCT," AMP is consistent with GALL AMP XI.M39, "Lubricating Oil Analysis Program," with exceptions.

The Lubricating Oil Analysis - FRCT Program will include measures to verify that the oil environment in mechanical equipment is maintained to the required quality. The Lubricating Oil Analysis - FRCT Program maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment 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 indicate leakage and corrosion product buildup.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.19-1, the applicant stated that Lubricating Oil Analysis - FRCT Program is consistent with GALL AMP X.M39 with exceptions. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP X.M39.

The staff reviewed those portions of the Lubricating Oil Analysis - FRCT Program for which the applicant claimed consistency with GALL AMP XI.M39 and found them consistent with the GALL Report AMP. Furthermore, the staff concludes that the applicant's program ensures that combustion turbine oil systems will be effectively managed to provide an acceptable oil environment so that intended functions of components within the scope of license renewal at the FRCT station are maintained consistent with the CLB during the period of extended operation. The staff found that the applicant's Lubricating Oil Analysis - FRCT Program conforms to the recommended GALL AMP XI.M39, with exceptions described below.

Exception 1. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program element "parameters monitored or inspected." Specifically, the exception stated:

> Parameters Monitored/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 applicant stated in its supplemental response that no components with periodic oil changes had intended functions. Components with intended functions with no regular oil changes are supplied oil from the lubricating oil system. A particle count and check for water on the lubricating oil in the lubricating oil system will 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's 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 Report as a quality control measurement when purchasing new oil and not a primary measurement to determine presence of contaminants.

The staff did not agree with the applicant's position. The staff determined that basis for exceptions was not valid because the flash point of an industrial lubricant is an important test to determine whether light-end hydrocarbons get into the oil through seal leaks or other means. It is an effective way to monitor seal performance in light-end hydrocarbon compressors. Low flash points pose a safety hazard that can generate heat above the flash point of the oil in the event of a component like a bearing. The applicant was asked to justify not monitoring the flash point of lubricating oil at the FRCT, why this exception will be acceptable for managing the effects of aging for which it is credited.

In its letter dated April 17, 2006, the applicant committed (Commitment No. 59) to revise the Lubricating Oil Analysis - FRCT Program to include flash point measurement.

Exception 2. In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

As discussed in SER Section 3.0.4, the applicant stated that a QA program based on the recommendations of RG 1.155, Appendix A, will be used to implement the corrective actions, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. This QA program contains attributes that are equivalent to the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." On this basis, the staff finds this exception acceptable.

Operating Experience: In its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, the applicant stated that the new Lubricating Oil Analysis - FRCT Program will be effective in managing aging degradation for the period of extended operation by periodically sampling and analyzing lubricating oil for timely detection of degradation in lubricating oil properties and in taking appropriate corrective actions prior to loss of system or component intended functions. In October 2001 (FRCT Unit 2) and March 2004 (FRCT Unit 1), GE Energy Services performed major inspection and maintenance and documented all work 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 of 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 FRCT Unit 1 inspection was major maintenance, the first major inspection of the unit since initial installation in 1988. During the FRCT 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 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 FRCT Unit 2 inspection was of the fuel nozzle and combustion section. The lubricating oil filters were replaced. The GE report does not identify any issues with the lubricating oil system or components. FRCT Unit 2 began a major outage inspection in October 2005 with components disassembled and visually inspected for signs of age related degradation. The internal surfaces of disassembled stainless steel piping and flexible hoses observed had no corrosion or wall thinning. The combustion turbine lubricating oil heat exchangers were dissembled, cleaned, and inspected. The carbon steel and copper alloy heat exchanger components normally exposed to lubricating oil were found in excellent condition. The standby heat exchanger not normally in service was found to have some minor accumulation of sediment that was cleaned off. Carbon steel pump casings normally submerged in the lubricating oil reservoir were visually observed to be in excellent condition with no corrosion. The carbon steel internal surfaces of the lubricating oil reservoir were also observed to be in excellent condition with no 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 will result in aging degradation. This new program will provide additional assurance that water and contaminant concentrations and age-related degradation will continue to be minimized.

The Lubricating Oil Analysis - FRCT Program will monitor for adverse trends in performance. Problems identified will not impact intended functions of the FRCT system, and adequate corrective actions will be taken to prevent recurrence. There is sufficient confidence that the implementation of the Lubricating Oil Analysis - FRCT Program 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 personnel, the staff concludes that the applicant's Lubricating Oil Analysis - FRCT Program will adequately manage the aging effects and mechanism identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Lubricating Oil Analysis - FRCT Program in its supplemental response to RAI 2.5.1.19-1 and letter dated April 17, 2006. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the applicant's commitment, the exceptions, and their justifications and determined that the AMP, with the exceptions and its commitment, is adequate to manage the aging effects for which it is credited. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.39 Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply

Summary of Technical Information in the Application. In its December 9, 2005, supplemental applicant's response to RAI 2.5.1.15-1, the applicant stated that AMP B.1.26B, "Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply," is consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection," with exceptions.

The Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program is a new AMP that relies on coating, wrapping, and periodic inspection as preventive measures to mitigate and manage the effects of corrosion on the pressure-retaining capacity of carbon steel and copper piping and fittings and carbon steel tanks 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 during maintenance excavations. Buried piping components will be inspected within 10 years prior to the period of extended operation unless an opportunistic inspection occurs within this period. In the period of extended operation, inspection of buried piping components will again be performed within the first 10 years unless an opportunistic inspection occurs during this period. The AMP activities will be coordinated with First Energy, as necessary, pursuant to an Easement, License, and Restrictive Covenant Agreement.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its supplemental response to RAI 2.5.1.15-1 dated December 9, 2005, the applicant stated that the Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program is consistent with GALL AMP X.M34 with exceptions. The staff reviewed the program elements and basis documents to determine their consistency with GALL AMP X.M34.

The staff reviewed those portions of the Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program for which the applicant claimed consistency with GALL AMP XI.M34 and found them consistent. Furthermore, the staff concludes that the applicant's program ensures that aging effects will be adequately managed to maintain intended functions of buried pipe within the scope of license renewal consistent with the CLB during the period of extended operation. The staff found that the applicant's Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program conforms to the recommended GALL AMP XI.M34, "Buried Piping and Tanks," with exceptions described below.

Exception 1. In its response to RAI 2.5.1.15-1 dated December 9, 2005, the applicant stated an exception to the GALL Report program elements "preventive actions," "parameters monitored or inspected," and "detection of aging effects." Specifically, the exception stated:

> 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 microbiologically influenced corrosion.

In its response the applicant stated that, in accordance with industry practice, portions of the underground piping and tank at the Forked River Met 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 not coated or wrapped will be inspected for loss of material due to general, pitting, crevice, and MIC. Inspections will confirm that coating and wrapping are intact and determine the extent of potential corrosion of buried piping components not coated or wrapped. These inspections effectively ensure that corrosion of external surfaces has not occurred and that intended function has been maintained. The buried piping and tank will be opportunistically inspected whenever excavated for maintenance. The inspections will be of all areas made accessible for the maintenance activity.

The staff noted that the applicant follows the recommendations specified in the GALL Report for inspections of underground piping coatings and wrappings and that underground piping not coated or wrapped will be inspected for loss of material due to general, pitting, crevice, and MIC. On this basis, the staff finds this exception acceptable.

Exception 2. In its supplemental response to RAI 2.5.1.15-1 dated December 9, 2005, the applicant stated an exception to the GALL Report program elements "corrective actions," "confirmation process," and "administrative controls." Specifically, the exception stated:

> 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.

In its supplemental response to RAI 2.5.1.15-1 dated June 7, 2006, the applicant stated that this exception was eliminated and that these elements will be accomplished in accordance with the requirements of 10 CFR Part 50, Appendix B. In the response the applicant also stated that it will meet the guidance in Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs." The adequacy of the applicant's 10 CFR 50, Appendix B program for these elements is addressed in SER Section 3.0.4. On this basis, the staff finds this exception acceptable.

Operating Experience. In its response to RAI 2.5.1.15-1 dated December 9, 2005, the applicant stated that the new Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program will be effective in managing aging degradation for the period of extended operation by timely detecting aging effects and implementing appropriate corrective actions prior to loss of system or component intended functions. The buried piping and tank at the Forked River Met Tower included in the scope of license renewal are below-grade, propane-filled, and next to the Forked River meteorological tower. There is no history of buried pipe or tank leaks in this system.

In 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 ensures that intended functions will be maintained. Inspections will be within 10 years of the period of extended operation, and again within the first 10 years of period of extended operation, crediting opportunistic inspections that may occur within each of these periods. The staff concludes that the applicant's Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program will adequately manage the aging effects and mechanism identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Buried Piping and Tank Inspection - Met Tower Repeater Engine Fuel Supply Program in its supplemental response to RAI 2.5.1.15-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). To date, there have been no leaks from the Met Tower repeater engine fuel supply buried pipe and tanks. The staff also reviewed the UFSAR supplement for this program and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as plant-specific:

- Periodic Testing of Containment Spray Nozzles (B.2.1)
- Lubricating Oil Monitoring Activities (B.2.2)
- Generator Stator Water Chemistry Activities (B.2.3)
- Periodic Inspection of Ventilation Systems (B.2.4)
- Periodic Inspection Program (B.2.5)
- Wooden Utility Pole Program (B.2.6)
- Periodic Monitoring of Combustion Turbine Power Plant (B.2.7)
- Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)
- Periodic Inspection Program - FRCT (B.2.5A)

The staff reviewed AMPs not consistent with or not addressed in the GALL Report completely to determine whether these AMPs are adequate to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in the following sections of this SER.

3.0.3.3.1 Periodic Testing of Containment Spray Nozzles

Summary of Technical Information in the Application. In LRA Section B.2.1, the applicant described the existing, plant-specific Periodic Testing of Containment Spray Nozzles Program.

Periodic tests address a GALL Report Section V.D2 concern that flow orifices and spray nozzles in the drywell and torus spray subsystems are subject to plugging by rust from carbon steel piping components and therefore a plant-specific AMP is to be evaluated. The OCGS containment (drywell and torus) spray nozzles are stainless steel. There are no carbon steel flow orifices in the system piping within the scope of license renewal. However, upstream carbon steel piping is subject to possible general corrosion. These periodic tests every fifth refueling outage use approved plant procedures to verify that the drywell and torus spray nozzles are free from plugging that could result from corrosion product buildup from upstream sources.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.2.1 on the applicant's Periodic Testing of Containment Spray Nozzles Program to determine whether the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff's evaluation of this program, which follows, is on the basis of the 10-element program as described in branch technical position Appendix A-1 of the SRP-LR.

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is contained separately in this SER. The remaining seven elements are evaluated below.

The staff's review of LRA Section B.2.1 identified areas in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

(1) Scope of Activity: The tests include the containment (drywell and torus) spray nozzles. The tests provide verification that the spray nozzles are not blocked and are available to perform their intended function. The staff finds that the applicant has adequately described the scope of the activity.

(2) Preventive Actions: The spray nozzle tests do not provide any preventive actions. The spray nozzle tests provide condition monitoring to detect the degradation prior to a loss of function. The concurs with the applicant that the spray nozzle tests do not provide any preventive actions.

(3) Parameters Monitored/Inspected: The flow tests demonstrate that the drywell and torus spray nozzles are not blocked by debris or corrosion products, and thereby demonstrate that the nozzles are available to provide the drywell and torus steam quenching functions. The nozzles are tested with compressed air. Test procedures require that flow be demonstrated through each individual nozzle.

As stated in the LRA, the applicant conducts flow tests with air rather than water. The staff believes that the reaction forces on the supports and the spray nozzles are substantially less with air flow versus water and that the periodic flow tests simply assure that there is no clogging of the spray nozzles but do not test the structural integrity of the spray system under actual operating conditions. The staff's concern is that the piping supports and nozzles may not be able to withstand forces exerted during accident conditions when water is turned on, and a potential for failure of the spray system exists.

In RAI B.2.1-2 dated March 30, 2006, the staff requested that the applicant provide justification to assure maintenance of the structural integrity of the system under accident conditions during the period of extended operation.

In its response dated April 28, 2006, the applicant stated:

> Pre-operational testing of the containment spray piping was performed with water at design flow to assure the structural integrity of the system under accident conditions. During those water flow tests, the piping supports and nozzles were shown to be able to withstand the forces exerted during actual operating conditions. The airflow tests were subsequently implemented to demonstrate that the nozzles were clear without wetting the spray piping and containment equipment. The ASME Section XI Subsection IWF program B.1.28 addresses aging management and the continued structural integrity of the ASME Class 2 containment spray piping supports during the period of extended operation, as shown in LRA Table 3.5.2.1.18

The staff finds the applicant's response and the parameters monitored/inspected, reasonable and acceptable because the ASME Section XI Subsection IWF Program addresses aging management and the continued structural integrity of the ASME Code Class 2 containment spray piping supports during the period of extended operation. Therefore air testing of the spray system is considered adequate.

(4) Detection of Aging Effects: The periodic drywell and torus spray nozzle flow tests detect plugging by corrosion products from the degradation of carbon steel piping and fittings.

The periodic tests, performed every fifth refueling outage verify that the drywell and torus spray nozzles are free from plugging that could result from corrosion product buildup from upstream sources. However malfunction of the spray nozzles due to failure of the supports is not discussed in this AMP.

In RAI B.2.1-1 dated March 30, 2006, the staff requested that the applicant discuss any aging mechanisms for the piping support materials in the containment air environment. In addition, the applicant was asked to provide the bases for identifying these aging mechanisms or no aging mechanism for the environment and material combination.
In its response dated April 28, 2006, the applicant stated:

> The ASME Section XI Subsection IWF program B.1.28 addresses aging management for piping supports for the ASME Class 2 containment spray piping in the containment air environment, as shown in LRA Table 3.5.2.1.18. For carbon and low alloy steel support materials in an air - indoor uncontrolled environment, which is how the containment air environment is conservatively treated for piping supports, the aging effect of loss of material is due to the mechanisms of general and pitting corrosion, in accordance with GALL line item III.B1.2-8 (T-24). No aging effect or program is credited for cumulative fatigue damage of these piping supports under GALL item III.B1.2-7 (T-26), as cumulative fatigue is not a TLAA in the Oyster Creek CLB. The aging effect of loss of mechanical function of carbon and low alloy steel supports is due to the aging mechanisms of corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads, in accordance with GALL line item III.B1.3-2 (T-28).

The staff finds the applicant's response and the detection of aging effects, reasonable and acceptable because the applicant clarified that the ASME Section XI Subsection IWF Program addresses aging management for piping supports for the ASME Code Class 2 containment spray piping in the containment air environment.

(5) Monitoring and Trending: The results of the spray nozzle tests are monitored but are not trended. If flow to a nozzle is blocked or restricted the degraded condition is evaluated and corrective actions are taken to restore normal flow. The staff finds the monitoring of the spray nozzles reasonable and acceptable. The staff also concurs with the applicant that the results of the spray nozzle tests need not be trended.

(6) Acceptance Criteria: The test procedures contain acceptance criteria that require that flow be observed from each individual drywell and torus spray nozzle. The test uses a mechanical indicator (flow streamer or other device). The staff finds the acceptance criteria, which are contained in the test procedures, acceptable.

(7) Operating Experience. In LRA Section B.2.1, the applicant explained that in 2000 the torus spray nozzle air test revealed no flow of air in two torus nozzles. An evaluation determined that design basis accidents could be successfully mitigated with the nozzles plugged. The cause of the plugging was determined to be rust particles from the cyclic wetting and drying of the piping when the system had been flow-tested monthly by a method no longer used. A revision to the system testing procedure to return torus test water through the drywell vent system precludes flushing water through the nozzle piping and the nozzles are air-tested. The nozzles were flushed clear and re-tested satisfactorily. The OCGS facility demonstrates good operating experience in maintaining the operability of the drywell and torus spray headers and spray nozzles. The periodic air flow tests effectively manage the plugging aging effect so that the intended function of providing a quenching spray will be maintained during the period of extended operation.

The staff's review of the operating experience at OCGS found that the applicant had successfully determined the root cause of previous problems with the spray nozzles and taken appropriate corrective measures. The operating experience also indicates that the applicant's maintenance practices have been generally successful in managing the plugging aging effects of the spray nozzles

UFSAR Supplement. In LRA Section A.2.1, the applicant provided the UFSAR supplement for the Periodic Testing of Containment Spray Nozzles Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Periodic Testing of Containment Spray Nozzles Program and RAI responses the staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Lubricating Oil Monitoring Activities

Summary of Technical Information in the Application. In LRA Section B.2.2, the applicant described the existing, plant-specific Lubricating Oil Monitoring Activities Program.

The Lubricating Oil Monitoring Activities Program manages loss of material, cracking, and fouling in lubricating oil coolers, systems, and components within the scope of license renewal. These activities include measures to minimize corrosion and to mitigate loss of material and cracking in heat exchangers by monitoring lubricating oil properties. Sampling, testing, and trending verify lubricating oil properties and ensure that the intended functions of the coolers are not lost. Oil analysis permits identification of specific wear mechanisms, contamination, and oil degradation within operating machinery and components. The activities manage physical and chemical properties in lubricating oil. The complete AMP for lubricating oil heat exchangers also includes secondary side (heat sink) chemistry controls or testing.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.2.2 on the applicant's demonstration of the Lubricating Oil Monitoring Activities Program to ensure that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff reviewed the Lubricating Oil Monitoring Activities Program against the AMP elements in SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., "program scope," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience").

The applicant indicated that "corrective actions," "confirmation process," and "administrative controls" are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program - The "scope of program" program element in SRP-LR Section A.1.2.3.1 requires that the program scope include the specific structures and components addressed with this program.

The applicant stated that the EDG lubricating oil coolers and the fire protection pump gear box lubricating oil coolers are subject to this program.

In addition, the applicant stated that the following systems and their components are also subject to this program: EDGs system, main turbine and auxiliaries system, main generator and auxiliaries system, reactor recirculation system, CRD system, RWCU system, fire protection system, feedwater system, RBCCW system, SW system, and miscellaneous floor and equipment drains system.

The staff determined that the specific components for which the program manages aging effects are identified by the applicant, satisfying SRP-LR Section A.1.2.3.1. On this basis, the staff finds the applicant's proposed program scope acceptable.

(2) Preventive Actions - The "preventive actions" program element in SRP-LR Section A.1.2.3.2 states 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 them preventive actions need not be provided.

The applicant stated that the existing Lubricating Oil Monitoring Activities Program manages aging of components by maintaining proper lubricating oil physical and chemical properties and by verifying maintenance of heat exchanger intended functions. The program includes specifications for known oil degradation indicators and characteristics, sampling and analysis frequencies, and corrective actions for control of lubricating oil properties. Monitoring and control of oil impurities and properties mitigate the loss of material, cracking, and loss of heat transfer (fouling) in lubricating oil systems by preserving an environment not conducive to loss of material, cracking, or reduction of heat transfer aging effects.

Lubricating oil physical and chemical properties are tested to standard ASTM and ISO methods for the applicable oil type for accurate numbers with repeatable results. Oil is analyzed for indications of degraded chemistry, contamination, and wear parameters depending on oil type and type of service. Normal, alert, and fault levels have been established for the various physical parameters, wear metals, additives, and contaminant levels based on information from oil manufacturers, equipment manufacturers, and industry guidelines. Samples are taken and surveillance testing verifies proper heat exchanger performance to support system operation.

As noted, monitoring and control of oil impurities and properties mitigate the loss of material, cracking, and loss of heat transfer in lubricating oil systems by preserving an environment not conducive to loss of material, cracking, or reduction of heat transfer aging effects. OCGS procedures and specifications provide for sampling and monitoring to verify proper lubricating oil properties and assure that the ability of the lubricating oil heat exchangers and other system components to perform intended functions is not lost due to aging effects.

The staff determined that the "preventive actions" program element satisfies SRP-LR Section A.1.2.3.2. The applicant is using industry standards (ASTM and ISO) to establish preventive actions. On this basis, the staff finds the applicant's preventive actions acceptable.

(3) Parameters Monitored or Inspected - The "parameters monitored or inspected" program element in SRP-LR Section A.1.2.3.3 states that:

- 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 a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.
- For a 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 controlled to prevent or mitigate aging effects.

The applicant stated that the Lubricating Oil Monitoring Activities Program monitors and maintains lubricating oil physical and chemical properties to provide assurance that contaminants or loss of vital characteristics that could cause or promote corrosion is kept to a minimum. Lubricating oil condition monitoring is classified into three main categories;

1. chemistry: kinematic viscosity (ASTM D445), total acid number (TAN)(ASTM D664), total base number (TBN)(ASTM D664, D4739), rotating bomb oxidation test (RBOT)(ASTM D2272), water separability (ASTM D1401), foaming characteristics, and air release

2. contamination: ISO 4406 particle count, fuel and combustion by-products, bottom sediment (solids) and water (BS&W), Karl Fischer water (ASTM D1744, D4928, D6304-C), emission spectrometry (ICP).

3. wear: DR ferrography, analytical ferrography, emission spectrometry (ICP).

The physical properties of lubricants are tested to standard ASTM methods as discussed in ASTM D6224.
To establish action levels for the various physical parameters, wear metals, additives, and contaminant levels, information from oil manufacturers, equipment manufacturers, and industry guidelines was reviewed. In addition, historical trends from existing analysis were evaluated.

The Lubricating Oil Monitoring Activities Program monitors the effects of corrosion by sampling and analyzing various lubricating oils in accordance with ASTM and ISO standards to evaluate system and component performance. Proper lubricating oil properties are monitored to mitigate corrosion. The One-Time Inspection Program will be used to confirm the absence of aging effects (loss of material) in low flow or stagnant areas in lubricating oil systems.

Monitoring and control of oil impurities and properties mitigate the loss of material, cracking, and loss of heat transfer (fouling) in lubricating oil systems by preserving an environment not conducive to such aging effects, thus assuring that the components within the scope of the program remain capable of performing intended functions. Testing activities verify maintenance of heat exchanger intended functions.

Surveillance procedures for the diesel-driven fire protection system pumps will be enhanced to verify flow through the gearbox lubricating oil coolers. The EDG lubricating oil coolers do not require a similar procedural enhancement because temperature monitoring for these coolers exists.

The Lubricating Oil Monitoring Activities Program includes specifications for known oil degradation indicators and characteristics, sampling and analysis frequencies, and corrective actions for control of lubricating oil properties. Lubricating oil physical properties are tested to standard ASTM and ISO methods for the applicable oil type for accurate numbers with repeatable results (Reference: MA-AA-716-230-1001). Samples are taken and analyzed for indications of degraded chemical and physical properties depending on oil type and type of service. Surveillance testing verifies proper heat exchanger performance to support system operation.

The Lubricating Oil Monitoring Activities Program manages the aging effects of loss of material, cracking, and reduction of heat transfer by preserving an environment not conducive to these aging effects.

Flash point can be a measure to detect the contamination of lubricating oils by fuel oil, as is the case for diesel engine lubricating oil. Therefore, oil analysis guidelines will be enhanced to include measurement of flash point for diesel engine lubricating oil. Flash point is not measured for all lubricating oil in service. Flash point is a quality control measurement when purchasing new oil. It is not a primary measurement to determine the presence of water or contaminants, the parameters for assessing the environment of concern.

Monitoring for the presence of chloride ions is not performed. Based on past precedents the staff concludes that monitoring for chloride ions in lubrication oil is not required. Industry guidance addresses oil environments in general and lubricating oil environments for heat exchangers, respectively. Appendix C (EPRI 1003056) identifies damaging effects of chlorides in fuel environments but not for lubricating oil environments. Appendix G (EPRI 1003056) does not identify any applicable aging effects from chlorides for lubricating oil environments in heat exchanger components. Additionally, there is no OCGS site operating experience of failure or degradation in oil environments attributed to the presence of chlorides.

The Lubricating Oil Monitoring Activities Program will be enhanced as follows:

> *Surveillance procedures for the diesel driven fire protection system pumps will be enhanced to verify flow through the gearbox lubricating oil coolers.*
>
> Oil analysis guidelines will be enhanced to include measurement of flash point for diesel engine lubricating oil. This is a new enhancement based on the reconciliation of this AMP from the draft January 2005 NUREG 1800, Revision 1 to the approved September 2005 NUREG-1801, Revision 1.

The staff determined that this program element satisfies SRP-LR Section A.1.2.3.3 because it includes specific parameters being controlled to achieve prevention or mitigation of aging effects. Although the applicant classified this program as plant-specific, enhancements have been added to ensure flow through the gearbox lubrication oil coolers. The staff finds these enhancements acceptable because verification of flow through the gearbox lubrication oil coolers will significantly increase the ability to detect the effects of aging. Although the applicant has identified this program as plant-specific these enhancements make the program consistent with the recommendations for lubricating oil monitoring programs in the GALL Report.

The staff noted that the enhancement related to the flash points was not identified in the LRA. Subsequently, the applicant committed (Commitment No. 38) to revise LRA Section B2.2 to state that oil analysis guidelines will be enhanced to include measurement of flash point for diesel engine lubricating oil. The staff finds this commitment (Commitment No. 38) acceptable as it follows the recommendations in the GALL Report.

(4) Detection of Aging Effects - The "detection of aging effects" program element in SRP-LR Section A.1.2.3.4 states that the applicant should:

- Provide information that links the parameters to be monitored or inspected to the aging effects 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 and sample size when sampling is used to inspect a group of SCs. The SCs inspected should be based on such aspects as a similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects.

The applicant stated in the Lubricating Oil Monitoring Activities Program for the "detection of aging effects" program element that oil analysis has become an accurate method for identifying specific wear mechanisms, contamination, and oil degradation characteristics within operating machinery. Lube oil contaminants like metals, solids, and water can be used to indicate degradation in components in lubricating oil systems. The existing Lubricating Oil Monitoring Activities Program maintains lubricating oil physical and chemical properties within predefined limits to mitigate the effects of aging. Monitoring of diagnostic parameters in lubricating oil systems indicates degradation due to aging effects (e.g., presence of metals in lube oil sample) prior to loss of intended function. Normal, alert, and fault action levels for oil chemical and physical properties, wear metals, contaminants, and additives for the specific oil type and application are established. Increased impurities and degraded oil properties indicate degradation of materials in lubricating oil systems.

Periodic samples are taken and analyzed for indications of degraded chemical and physical properties depending on oil type and type of service. Surveillance testing verifies proper heat exchanger performance to support system operation.

The existing Lubricating Oil Monitoring Activities Program manages aging of components by maintaining proper lubricating oil physical and chemical properties and by verifying maintenance of heat exchanger intended functions. The program includes specifications for known oil degradation indicators and characteristics, sampling and analysis frequencies, and corrective actions for control of lubricating oil properties. Normal, alert, and fault action levels for oil chemical and physical properties, wear metals, contaminants and additives for the specific oil type and application are established. Oil properties are controlled to minimize contaminant concentration (primarily water and particulates), preserving an environment not conducive to aging mechanisms that could lead to the aging effects of loss of material, cracking, and reduction of heat transfer, thus assuring that components within the scope of the program remain capable of performing intended functions.

Samples are taken periodically and analyzed for indications of degraded chemical and physical properties depending on oil type and type of service. Surveillance testing verifies proper heat exchanger performance to support system operation. Monitoring frequencies have been established depending on the component and service. For example, the EDG crankcase is monitored four times a year while EDG lube oil and turbine lube oil are monitored twice a year. Sampling frequency is increased if plant and equipment operating conditions indicate a need.

Periodic sampling and heat exchanger testing are in accordance with controlling procedures. As noted, controlling procedures are based on industry standards and plant-specific experience.

Representative sampling techniques are not used. A hundred percent of the equipment within the scope of the Lubricating Oil Monitoring Activities Program is sampled.

The staff determined that the "detection of aging" program element satisfies SRP-LR Section A.1.2.3.4. The staff finds that the applicant follows industry-accepted methods and plant-specific operational history to detect aging effects and for frequency of testing. On this basis, the staff finds the applicant's description of the detection of aging effects is acceptable.

(5) Monitoring and Trending - The "monitoring and trending" program element in SRP-LR Section A.1.2.3.5 states that:

- 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 the Lubricating Oil Monitoring Activities Program for the "monitoring and trending" program element that lubricating oil analysis results are evaluated for acceptability in accordance with interpretation guidelines developed from industry standards and plant-specific operating experience. Normal, alert, and fault action levels for oil chemical and physical properties, wear metals, contaminants, and additives for the specific oil type and application are established, monitored, and trended to assure timely corrective action. Increased impurities and degraded oil properties indicate degradation of materials in lubricating oil systems. Oil analysis results are monitored and trended in accordance with the maintenance program and timely corrective actions are initiated.

Periodic sampling and heat exchanger testing are in accordance with controlling procedures. As noted, normal, alert, and fault action levels for oil chemical and physical properties, wear metals, contaminants, and additives for the specific oil type and application are established, monitored, and trended to assure timely corrective action. Oil analysis results are monitored and trended in accordance with the maintenance program.

The staff determined that for visual inspection, the "monitoring and trending" program element satisfies SRP-LR Section A.1.2.3.5. The staff finds that lubricating oil analysis results are evaluated for acceptability in accordance with interpretation guidelines developed from industry standards and plant-specific operating experience. On this basis, the staff finds the applicant's description of the monitoring and trending acceptable.

(6) Acceptance Criteria - The "acceptance criteria" program element in SRP-LR Section A.1.2.3.6 states that:

- The acceptance criteria of the program and their bases should be described. The acceptance criteria against which the need for corrective actions will be evaluated should ensure that 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 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 the Lubricating Oil Monitoring Activities Program that lubricating oil properties are tested to standard ASTM, ISO, and other industry standard methods for the applicable oil type for accurate numbers with repeatable results. Normal, alert, and fault levels for oil physical properties, wear metals, additives, and contaminant levels are established based on information from oil manufacturers, equipment manufacturers, and industry guidelines for the specific oil type and application. Tolerance bands are established as appropriate for the specific parameter. The program maintains contaminant and parameter limits within the application-specific limits. The procedures outline potential actions to be taken at alert and fault levels and actions can be chosen based on the level of deviation. Aging effects or unacceptable results are evaluated and appropriate corrective actions are taken.

The procedures outline potential actions (corrective) to be taken at alert and fault levels. Additionally, the One-Time Inspection Program will be used to confirm the absence of aging effects in low flow or stagnant areas in lubricating oil systems.

Specific numerical values are established for each action level (normal, alert, and fault) for oil physical properties, wear metals, additives, and contaminant levels for the specific oil type and application to verify proper lubricating oil properties and assure the ability of the lubricating oil heat exchangers and other system components to perform their functions is not lost due to aging effects. Tolerance bands are established as appropriate for the specific parameter.

Oil analysis results are monitored and trended in accordance with the maintenance program. The Lubricating Oil Monitoring Activities Program does not employ qualitative inspections. This program is not part of ASME Code(s).

The staff reviewed the "acceptance criteria" program element to determine whether it satisfies SRP-LR Section A.1.2.3.6. The staff finds that lubricating oil analysis results are evaluated for acceptability in accordance with interpretation guidelines developed from industry standards and plant-specific operating experience. On this basis, the staff finds the applicant's description of the acceptance criteria acceptable.

(10) Operating Experience - The "operating experience" program element in SRP-LR Section A.1.2.3.10 states that:

- Operating experience should provide objective evidence for 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 future for new programs to confirm their effectiveness.

In LRA Section B.2.2, the applicant explained that the overall effectiveness of lubricating oil monitoring activities is indicated by the OCGS operating experience. Lubricating oil sampling and analysis have detected particulate or water contamination (or both) in lubricating oil systems. In some cases systems were declared inoperable until repaired and until the oil was flushed and replaced. Operating experience has produced procedure and program changes which have improved the effectiveness of lubricating oil testing and inspection activities:

- In 2001, a core spray pump oil analysis detected a high ratio of large to small particles after an oil change. Further investigation determined there had been no increase in pump vibration levels for an extended period and that the source of the particles in the changed oil was contamination from the reservoir when the oil change occurred. The reservoir was flushed to remove particles and new oil was added. An increased oil surveillance frequency was established to confirm oil condition.
- In 2002, a CRD pump oil analysis indicating high wear particle concentration resulted in flushing of the bearing, adding new oil, and monitoring further for bearing wear. A followup oil sample was scheduled for more data for analysis in addition to the scheduled pump vibration analysis.

The staff noted that the operating experience for the Lubricating Oil Monitoring Activities Program showed no adverse trend in performance. Problems identified will not cause significant impact to safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is confidence that implementation of the Lubricating Oil Monitoring Activities Program will effectively maintain proper lubricating oil properties. Periodic self-assessments of the program identify areas that need improvement to maintain the quality performance of the program.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's Lubricating Oil Monitoring Activities Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Lubricating Oil Monitoring Activities Program in LRA Section A.2.2, which stated that the existing Lubricating Oil Monitoring Activities Program manages loss of material, cracking, and fouling in lubricating oil heat exchangers, systems, and components within the scope of license renewal by monitoring physical and chemical properties in lubricating oil. Sampling, testing, and monitoring verify lubricating oil properties. Oil analysis identifies specific wear mechanisms, contamination, and oil degradation within operating machinery and system components within the scope of license renewal. The Lubricating Oil Monitoring Activities Program will be enhanced to add surveillance for verification of flow through the fire protection system diesel-driven pump gearbox lubricating oil cooler. In addition, the program will be enhanced to include sampling and measurement for flashpoint of diesel engine lubricating oil to detect contamination of lubricating oil by fuel oil. These enhancements will be implemented prior to the period of extended operation.

The staff also reviewed the commitment (Commitment No. 38) to confirm that this program will be implemented prior to the period of extended operation.

The staff's review of the UFSAR supplement finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's program the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Generator Stator Water Chemistry Activities

Summary of Technical Information in the Application. In LRA Section B.2.3, the applicant stated that the Generator Stator Water Chemistry Activities Program is plant-specific and not included within the GALL Report AMPs. OCGS chemistry activities manage loss of material aging effects in components exposed to stator cooling water. Stator cooling water chemistry activities monitor and control water chemistry by an OCGS procedure and process based on GE Company Document GEK 45942, "Stator Winding Cooling Water System Operation and Flushing," and EPRI TR-105504, "Primer on Maintaining the Integrity of Water Cooled Generator Stator Windings," which provide guidelines for stator cooling water chemistry control.

Control of stator cooling water chemistry in accordance with GE and EPRI guidelines maintains the water to a high degree of purity with no areas of low flow where pitting corrosion could occur while the system is in operation whenever the main generator is on line. Flow instruments cause automatic actions to reduce generator electrical output if low flow occurs. This condition will cause an investigation of the low flow condition and actions to restore normal flow.

Staff Evaluation. LRA Section B.2.3 describes the applicant's Generator Stator Water Chemistry Activities Program. This AMP will manage aging effects of the stator generator caused by the cooling water. The Generator Stator Water Chemistry Activities Program is a plant-specific program not conforming to the GALL AMPs. Therefore, the staff's evaluation focused on management of aging effects through incorporation of the AMP program elements from Branch Technical Position RLSB-1 (SRP-LR, Appendix A).

The staff reviewed the Generator Stator Water Chemistry Activities Program against the AMP elements found in SRP-LR Section A.1.2.3 and focused on how the program manages aging effects through the effective incorporation of 10 program elements (i.e., "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience").

The applicant indicated that the "corrective actions," "confirmation process," and "administrative controls" program elements are parts of the site-controlled QA program. The staff's evaluation of the QA program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program - In LRA Section B.2.3, the applicant stated that stator cooling water is monitored continuously for purity by installed conductivity cells and analyzed periodically for impurities and dissolved oxygen. These conductivity cells annunciate alarms in the event water purity decreases to a predetermined limit. Additionally, water chemistry parameters are maintained in accordance with GE and EPRI guidelines for stator cooling water systems. Maintaining these parameters within specifications mitigates the aging effects caused by crevice and pitting corrosion.

The applicant also stated that SCC is not considered an aging mechanism requiring aging management. SCC of stator cooling water components is unlikely as contaminants are maintained at very low levels and the system is normally operated at temperatures less than 140 °F. The system is equipped with both filters and a resin bed that continuously filters a portion of the system flow.

The staff believes that the procedure allows maintenance of generator stator cooling water at a high degree of purity. The staff finds that these activities will provide sufficient safeguards to ensure that the components in the generator stator will not be damaged by the corrosion caused by cooling water.

The staff confirmed that the "scope of the program" program element satisfies SRP-LR Section A.1.2.3.1 and concludes that this program attribute is acceptable.

(2) Preventive Actions - In LRA Section B.2.3, the applicant stated that loss of material due to crevice and pitting corrosion is mitigated by maintaining the stator cooling water chemistry parameters within specifications and by maintaining adequate system flow. Although not required for crevice corrosion, high levels of impurities or high temperatures significantly increase the rate at which crevice corrosion occurs. Low flow and the presence of impurities are required for pitting corrosion. Therefore, maintaining adequate flow and low levels of impurities mitigates pitting corrosion and maintaining low levels of *impurities along with low normal system operating temperatures mitigates crevice* corrosion.

The applicant also stated that SCC of stator cooling water components is unlikely as contaminants are maintained at very low levels in accordance with GE and EPRI guidelines, and the system is normally operated at temperatures less than 140 °F. As discussed in "scope of program" program element, SCC of stator cooling water system components is unlikely to occur with the high water purity and the low operating temperature of the system.

The staff agrees with the applicant that loss of the material by crevice and pitting corrosion could be reduced significantly by a low level of impurities and an adequate flow of cooling water. Also, the chemistry parameters should be maintained at their optimum values. In plant procedure conductivity and dissolved oxygen concentration are maintained at specified limits and iron, copper, and hydrogen in cover gas are trended monthly. When low flow occurs in the generator stator special instrumentation detects it and generator output is lowered automatically. The staff believes that an AMP based on the OCGS plant procedure will prevent damage to the generator stator by cooling water.

The staff confirmed that the "preventive actions" program element satisfies SRP-LR Section A.1.2.3.2 and concludes that this program attribute is acceptable.

(3) Parameters Monitored and Inspected - *In LRA Section* B.2.3, the applicant stated that water conductivity is monitored continuously to ensure purity. Additionally, site procedures require periodic (monthly) analyses of water chemistry samples for conductivity, dissolved oxygen, iron, and copper. Chemistry parameters are monitored in accordance with the guidelines provided by GE and EPRI.

The applicant monitors water conductivity to maintain it below 0.5 μS/cm and dissolved oxygen above 1 ppm. It also evaluates the trends for iron, copper, and hydrogen in the cover gas. These measurements are made at monthly intervals and allow the applicant to maintain coolant chemistry at the level needed for managing aging of components exposed to generator stator cooling water. The staff finds the parameter monitoring program acceptable because by monitoring proper parameters the applicant will exercise control of coolant water chemistry and prevent damage to the generator stator.

The staff confirmed that the "parameters monitored and inspected" program element satisfies SRP-LR Section A.1.2.3.3 and concludes that this program attribute is acceptable.

(4) Detection of Aging Effects - In LRA Section B.2.3, the applicant stated that this program mitigates loss of material aging effects. It is not credited for detection of aging effects. The staff finds this statement acceptable.

The staff confirmed that the "detection of aging effects" program element satisfies SRP-LR Section A.1.2.3.4 and concludes that this program attribute is acceptable.

(5) Monitoring and Trending - In LRA Section B.2.3, the applicant stated that water conductivity is monitored continuously with an alarm if pre-established limits are reached. Chemistry parameters are maintained in accordance with the guidelines provided by GE and EPRI.

The staff believes that OCGS plant water chemistry is monitored continuously and that if predetermined limiting values are reached an alarm will be activated, warning the operators to take appropriate corrective actions. The staff finds that with this precaution the system will not be operated at conditions where damage can occur.

The staff confirmed that the "monitoring and trending" program element satisfies SRP-LR Section A.1.2.3.5 and concludes that this program attribute is acceptable.

(6) Acceptance Criteria - In LRA Section B.2.3, the applicant stated that water chemistry parameters are maintained within the guidelines provided by GE and EPRI as discussed in program element (2). The staff finds this statement acceptable.

The staff confirmed that the "acceptance criteria" program element satisfies SRP-LR Section A.1.2.3.6 and concludes that this program attribute is acceptable.

(10) Operating Experience - In LRA Section B.2.3, the applicant stated that OCGS has exhibited a good operating history with the stator cooling water system long-lived components. There has been no age-related degradation of stator cooling water system components within the scope of license renewal. The current water chemistry activities have been proven effective in managing aging of the stator cooling water system components.

The staff believes that OCGS has exhibited a good operating history with the generator stator cooling water system. Visual inspections of the generator stator for corrosion and copper plating by the applicant during each refueling outage have indicated no degradation of system components. Therefore, current activities within the AMP described by the applicant proved to be effective.

The staff confirmed that the "operating experience" program element satisfies SRP-LR Section A.1.2.3.10 and concludes that this program attribute is acceptable.

UFSAR Supplement. In LRA Section A.2.3 the applicant provided its UFSAR supplement for the Periodic Inspection Program - FRCT Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review, the staff's concludes that the applicant has demonstrated that the Generator Stator Water Chemistry Activities Program will adequately manage aging effects from cooling water consistent with the CLB for the period of extended operation as required by 10 CFR 54.29(a). The staff also reviewed the UFSAR supplement for this program and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Periodic Inspection of Ventilation Systems

Summary of Technical Information in the Application. In LRA Section B.2.4, the applicant described the existing, plant-specific Periodic Inspection of Ventilation Systems Program.

The Periodic Inspection of Ventilation Systems Program includes periodic visual inspections of the ventilation systems within the scope of license renewal. Periodic visual inspections are performed during system preventive maintenance activities on a frequency not exceeding 5 years. Components subject to visual inspections include:

- buried ventilation ductwork
- flexible connections
- fan housing
- filter and heater housings
- damper housings
- access door seals
- valves
- piping and fittings
- cooling and heating coils
- thermowells
- flow elements and restricting orifices

The exterior surfaces of ventilation ducts and damper housings will be inspected by the Structures Monitoring Program. The Periodic Inspection of Ventilation Systems Program inspects internal and external surfaces of ventilation system components to identify and assess aging effects that may occur. The program includes surface inspections for such indications of loss of material 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 and for loss of material due to wear. Existing maintenance activities will be enhanced to include ducts exposed to soil, instrument piping and valves, restricting orifices and flow elements, and thermowells.

Staff Evaluation. The staff reviewed the information in LRA Section B.2.4 on the applicant's Periodic Inspection of Ventilation Systems Program to determine whether the effects of aging will be adequately managed so that intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff's evaluation of this program, which follows, is on the basis of the 10-element program as described in branch technical position Appendix A-1 of the SRP-LR.

The applicant indicated that the confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is contained separately in this SER. The remaining eight elements are evaluated below.

(1) Scope of Activity: Oyster Creek performs visual inspections of ventilation systems in the scope of license renewal. The scope of existing inspections includes flexible connections, fan and filter housings, and access door seals. The program will be enhanced to include duct exposed to soil, instrument piping and valves, restricting orifices and flow elements, and thermowells. Inspections of carbon steel fan and filter housings are considered representative of the internal surfaces of the carbon steel damper housings in the system. If aging degradation is identified on the fan or filter housing internal carbon steel surfaces, the condition will be evaluated to determine if the carbon steel damper housings will require inspection. The exterior surfaces of ventilation ducts and damper housings will be inspected by the Structures Monitoring Program.

The staff's review of LRA Section B.2.4 identified areas in the scope of the program in which additional information was necessary to complete the review of the applicant's program element. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.4-1 dated March 30, 2006, the staff noted that LRA Section B.2.4 states that existing ventilation system periodic preventive maintenance activities will be enhanced as follows:

> Instrument piping and valves, restricting orifices and flow elements, thermowells and Standby Gas Treatment System ducts exposed to soil will be added to the scope of the plant implementation documents.

The staff requested that the applicant provide a listing of the line items in the LRA AMR tables within the scope of this AMP that will be credited.

In its response dated April 28, 2006, the applicant stated:

> Seven systems credit the Periodic Inspection of Ventilation Systems program. They include the 480V Switchgear Room Ventilation, Battery and MG Set Room Ventilation, C Battery Room, Heating & Ventilation, Control Room HVAC, Radwaste Area Heating and Ventilation System, Reactor Building Ventilation System and the Standby Gas Treatment System (SGTS). The line items in the program are included in the License Renewal Application AMR Tables 3.3.2.1.03,3.3.2.1.04, 3.3.2.1.01, 3.3.2.1.10, 3.3.2.1.28, 3,3,2,1,31 and 3.2.2.1.3 respectively.

The list of the items crediting the Periodic Inspection of Ventilation Systems Program was also provided by the applicant. The staff finds the applicant's response reasonable and acceptable because the applicant had identified the systems and items within the scope of this AMP.

Based on its review, the staff finds the applicant's description of the scope of the program, adequate and acceptable.

(2) Preventive Actions: The ventilation system inspections do not provide any preventive actions. The inspections provide for condition monitoring to detect degradation prior to a loss of system intended function.

LRA Section B.2.4 states that existing ventilation system periodic preventive maintenance activities will be enhanced to add specific guidance for identification of applicable aging effects to preventive maintenance documents. The information in the LRA suggests that the identification of the aging effects is based currently on qualitative acceptance criteria.

In RAI B.2.4-2 dated March 30, 2006, the staff requested that the applicant discuss the enhancements described in LRA Section B.2.4 to indicate whether any aging effects will be identified on the basis of such quantitative acceptance criteria as durometer reading limits for identifying aging effects in elastomers.

In its response dated April 28, 2006, the applicant stated:

> The general inspection acceptance criteria for components in the Periodic Inspection of Ventilation Systems program is qualitative. When aging effects are identified as not meeting acceptance criteria, such as penetrating corrosion for metals and loss of material, hardening or tears in elastomers, or fouling of heat transfer surfaces, the issue will be entered into the corrective action program and will be evaluated. The corrective action program will ensure that conditions adverse to quality are addressed. An exception to this is the quantitative inspection incorporated into ventilation program inspection criteria to determine loss of material of buried Standby Gas Treatment System ducts as modified with internal aluminum sleeves. Refer to RAI 3.2-2 item a) response for the discussion of this inspection process.

The staff finds the applicant's response reasonable and acceptable because the applicant provided adequate information on its acceptance criteria as requested.

The staff concurs with the applicant that condition monitoring and associated inspections with the enhancements as discussed above would detect degradation prior to a loss of system intended function.

(3) Parameters Monitored/Inspected: Visual inspections of the ventilation system ductwork and components determine if penetrating corrosion indicating a loss of material aging degradation is occurring. Heat transfer surfaces are also inspected for fouling. Flexible connections are inspected to ensure they are free of cracking and damage. Door seals are inspected for cracking, damage or loss of material when the associated access door is opened, or are inspected for leakage when the door in closed and the system is in service. The flexible connections and door seals are evaluated if cracking, damage or leakage is identified. Existing plant implementing documents will be enhanced to ensure that ventilation system components are properly inspected for age related degradation. For the Standby Gas Treatment, Reactor Building Ventilation and Control Room Ventilation Systems, the results of the inspections are verified by the performance of system leakage tests and filter efficiency tests. These inspections and tests manage the aging effects that could impact system and component

pressure boundary integrity, providing reasonable assurance that ventilation system intended functions will be maintained consistent with the current licensing basis, for the period of extended operation.

Based on its review, the staff finds the applicant's description of the parameters monitored/inspected, adequate and acceptable.

(4) Detection of Aging Effects: Ventilation system components are subject to the following aging effects:

- Loss of Material
- Change in Material Properties (Elastomer materials)
- Reduction of Heat Transfer

Aging effects are detected by periodic visual inspections and system tests. These inspections and tests are performed on a frequency not to exceed five years. Visual inspections are performed by qualified and experienced maintenance personnel. The preventive maintenance procedures will be enhanced to provide the following specific guidance to inspect for aging effects:

- Loss of Material: Inspect for corrosion, rust, pitting or wear
- Change in Material Properties: Inspect for cracking, perforations or other damage

Visual inspections, with the above enhancements, will be included as part of the preventive maintenance activities that are performed on the various ventilation systems that are in the scope of license renewal at Oyster Creek.

These preventive maintenance activities are focused on the ventilation system fans, filters, dampers, fan flexible connections and door seals. These activities will be enhanced to include inspection of Instrument piping and valves, restricting orifices and flow elements, thermowells, and Standby Gas Treatment System duct exposed to soil. Inspections are performed at a frequency not to exceed five years, to detect aging prior to loss of system function.

Based on its review, the staff finds the applicant's description of detection of aging effects, adequate and acceptable.

(5) Monitoring and Trending: The periodic visual examinations are used to provide assurance that penetrating corrosion of ventilation system duct and components are not occurring or are occurring at an acceptable rate. The condition of the elastomers used in ventilation systems are monitored and the results of the inspections are reviewed to assure intended functions are maintained. Flexible connections and access door seals are repaired or replaced if damage or deterioration is detected.

Based on its review, the staff finds the applicant's description of monitoring and trending, reasonable and acceptable.

(6) Acceptance Criteria: Ventilation duct and components are checked for signs of loss of material. Elastomers are inspected for cracking, damage and loss of material. Elastomers are repaired or replaced if a degraded condition is found. Heat transfer surfaces are inspected for corrosion and fouling. Identified aging effects are evaluated by engineering to determine a) if penetrating corrosion indicating a loss of material aging is occurring, and if so, b) the rate at

which the material is being lost. Engineering evaluations will also c) determine the need for follow-up examinations to monitor the progression of aging degradation, and d) identify appropriate corrective actions to mitigate any excessive rates of degradation discovered.

Based on its review, the staff finds the applicant's description of the acceptance criteria, adequate and acceptable.

(7) Corrective Actions: Evaluations are performed for inspection results that identify penetrating corrosion or elastomer degradation, or test results that do not satisfy established criteria, and an Issue Report is initiated to document the concern 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 an action plan is developed to preclude recurrence.

Based on its review, the staff finds the applicant's description of the corrective actions, adequate and acceptable.

LRA Section B.2.4 states that existing ventilation system periodic preventive maintenance activities will be enhanced to add specific guidance for identification of applicable aging effects to preventive maintenance documents. The information in the LRA suggests that the identification of the aging effects is based currently on qualitative acceptance criteria.

Operating Experience. In LRA Section B.2.4, the applicant explained that OCGS has experienced surface corrosion of outdoor equipment housings and ducts damage to elastomers and deterioration of flexible connections resulting in leakage of ventilation systems. These conditions were identified and corrected prior to loss of function of the systems. Maintenance procedures were revised to include steps to inspect for corrosion of outdoor equipment housings. Periodic preventive maintenance inspections of ventilation system components, including specific guidance to identify applicable aging effects, will effectively monitor the condition of system components to continue to identify degradation prior to loss of intended functions. A buried section of SGTS duct failed due to external corrosion of the aluminum duct exposed to a soil environment. The failure occurred after approximately 30 years in service. The failed section was repaired with a sleeve and there will be periodic inspections of the buried duct section.

A review of the operating experience of the outdoor ventilation system components noted that failures have been identified prior to loss of function of the system. With revised inspection procedures to monitor corrosion more effectively, degradation is likely to be identified earlier than in the past.

UFSAR Supplement. In LRA Section A.2.4, the applicant provided the UFSAR supplement for the Periodic Inspection of Ventilation Systems Program. The staff reviewed this section and finds that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Periodic Inspection of Ventilation Systems Program and RAI responses the staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.5 Periodic Inspection Program

Summary of Technical Information in the Application. In LRA Section B.2.5, the applicant described the new, plant-specific Periodic Inspection Program.

The Periodic Inspection Program will address systems within the scope of license renewal requiring periodic monitoring of aging effects and not covered by other periodic monitoring programs. Activities will consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of aging effects. The inspections will be condition monitoring examinations intended to assure that environmental conditions cause no material degradation that could result in a loss of system intended functions. This program will confirm that:

- Change in material properties due to aging does not occur in elastomer expansion joints, flexible hoses and flexible connections, and in polymer tanks exposed to oil, treated water, and raw water.
- *Reduction of heat transfer due to aging does not occur in heat exchangers exposed to* an outdoor environment.
- Loss of material in components like piping, piping components, piping elements, heat exchangers, filters, ductwork and fan housings is insignificant in a variety of environments.

The program elements will include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.2.5, including PBD-AMP-B.2.05, "Periodic Inspection," and interviewed the applicant's technical personnel about the applicant's demonstration of the Periodic Inspection Program to determine whether the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Periodic Inspection Program against the AMP elements of SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience").

The applicant indicated that the "corrective actions," "confirmation process," and "administrative controls" are parts of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program - The “scope of program” program element in SRP-LR Section A.1.2.3.1 states that the program scope should include the specific structures and components addressed with this program.

The applicant stated in LRA Section B.2.5 that the scope of this program includes systems within the scope of license renewal that require periodic monitoring of aging effects and are not covered by other periodic monitoring programs. Inspections will be at susceptible locations in such systems.

The staff determined that the specific components for which the program manages aging effects have been identified by the applicant, satisfying SRP-LR Section A.1.2.3.1. The staff agrees that systems within the scope of license renewal that require periodic inspections not covered by periodic monitoring programs should be in the Periodic Inspection Program. On this basis, the staff finds the applicant's proposed “program scope” program element acceptable.

(2) Preventive Actions - The “preventive actions” program element in SRP-LR Section A.1.2.3.2 states that the activities for prevention and mitigation programs be described but that preventive actions need not be provided for condition or performance monitoring programs that do not rely on them.

The applicant stated in LRA Section B.2.5, that the Periodic Inspection Program activities will be condition monitoring activities to detect degradation prior to change in material properties, loss of material, and reduction of heat transfer aging effects as applicable for the material and environment. No mitigating or preventive attributes are associated with the Periodic Inspection Program activities.

The Periodic Inspection Program monitors conditions and does not rely on preventive actions.

The staff determined that the “preventive actions” program element satisfies SRP-LR Section A.1.2.3.2. The staff agrees that the Periodic Inspection Program monitors conditions and does not rely on preventive actions. On this basis, the staff finds the applicant's “preventive actions” program element acceptable.

(3) Parameters Monitored/Inspected - The “parameters monitored or inspected” program element in SRP-LR Section A.1.2.3.3 states that:

- 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 a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.
- For a performance monitoring program, a link should be established between degradation of the particular structure or component intended function(s) and the parameter monitored.
- For prevention and mitigation programs, the parameter monitored should be the specific parameter controlled to prevent or mitigate aging effects.

The applicant stated in LRA Section B.2.5 that the parameters to be monitored or inspected will be identified and linked to the degradation of the particular structure and component intended function (i.e. filter, heat transfer, leakage boundary, and pressure boundary) through specific work orders.

The condition monitoring program will inspect for change in material properties, loss of material, and reduction of heat transfer in accordance with station procedures based on applicable codes and standards. Examination methods include visual examination, (VT-1 or VT-3) of disassembled components, NDE (UT) measurements, or any other specific examination appropriate for detection of the specific aging effect.

The staff determined that "parameters monitored or inspected" program element satisfies SRP-LR Section A.1.2.3.3. The staff agrees that by use of applicable codes and standards and station procedures the parameter monitored or inspected will be adequate for the period of extended operation. On this basis, the staff finds the applicant's description of the "parameters monitored or inspected" program element acceptable.

(4) Detection of Aging Effects - The "detection of aging effects" program element in SRP-LR Section A.1.2.3.4 states that the applicant should:

- Provide information that links the parameters to be monitored or inspected to the aging effects 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 and sample sizes when sampling is used to inspect a group of SCs. The SCs inspected should be based on such aspects as similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects.

The applicant stated in LRA Section B.2.5 that the Periodic Inspection Program will inspect for change in material properties, loss of material, and reduction of heat transfer and will detect degradation of the component prior to loss of its intended function. Inspection for change in material properties will be specified by engineering through specific work orders and be based on OCGS procedures or accepted industry practices. Inspection for loss of material will consist of thickness measurements by NDE (UT), visual examination (VT-1 or VT-3) of disassembled components, or other accepted industry practices. Inspection for loss of heat transfer will be specified by engineering through specific work orders and be based on OCGS procedures or accepted industry practices.

The initial inspections will be before the period of extended operation. Subsequent periodic inspections will be at intervals not to exceed 10 years. OCGS will perform periodic inspections of a representative sample of the total component type, not less than 10 percent, to confirm that unacceptable degradation does not occur and the intended function of components will be maintained during the period of extended operation.

In addition to detecting degradation with the Periodic Inspection Program condition monitoring also will be used to ensure component availability to perform intended functions as designed when called upon. This program will detect age-related degradation prior to component failure.

The Periodic Inspection Program ensures that initial inspections will be near the end of the current operating term but before the period of extended operation. Subsequent periodic inspections will be at intervals not to exceed 10 years. OCGS will perform periodic inspections of a representative sample of the total component type, not less than 10 percent, to confirm that unacceptable degradation has not occurred and that component intended function will be maintained during the period of extended operation. Inspection locations for systems will be determined in the work orders generated. Visual and volumetric inspections will be performed based on OCGS procedures and accepted industry practices.

Methods and frequencies of such inspections for degradation are in accordance with accepted industry standards. Examination methods include visual examination, (VT-1 or VT-3) of disassembled components, NDE (UT) measurements, or any other specific examination appropriate for detection of the specific aging effect. Operating experience in Section 3.10 of this PBD supports this inspection frequency.

The 10 percent sample size determination is based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience. System components and locations selected for inspection are representative for the component, material, environment, and aging effect. Inspection results are evaluated to assess the need for followup examinations to monitor aging progression for age-related degradation found that could jeopardize an intended function before the end of the period of extended operation. Unacceptable inspection results will require expansion of the sample size and locations until the extent of the problem is determined. Engineering will determine the sample size and location expansion based on evaluations of the unacceptable inspection results.

The staff determined that this program element satisfies SRP-LR Section A.1.2.3.4. The staff agrees that by the use of applicable codes and standards and station procedures the detection of aging effects will be adequate for the period of extended operation. The staff determined that the 10-year inspection frequency and sample size determination is consistent with industry experience, codes and standards. On this basis, the staff finds the applicant's description of the "detection of aging effects" program element acceptable.

(5) Monitoring and Trending - The "monitoring and trending" program element in SRP-LR Section A.1.2.3.5 states that:

- 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 LRA Section B.2.5 that visual and volumetric inspection techniques performed on a 10-year frequency are appropriate for detecting the loss of material, change in material properties, and reduction of heat transfer aging effects prior to loss of intended functions based on plant-specific and industry operating experience. Results of the periodic inspection activities will be monitored. Indications of loss of material, change in material properties, and reduction of heat transfer in excess of established acceptance criteria will require initiation of a condition report for engineering evaluation that will determine the need for followup examinations to monitor the progression of aging for age-related degradation found that could jeopardize an intended function before the end of the period of extended operation. In addition, the engineering evaluation will either demonstrate acceptability or specify the appropriate repair or replacement.

The data collected will be evaluated and quantified by engineering, and appropriate corrective actions will be taken for any adverse findings. Engineering evaluation requires an assessment of the rate of degradation to schedule the next inspection before a loss of intended function. Condition reports are trended within the corrective action process. Follow-up examinations will be required if necessary to determine the extent of the degraded condition, thus expanding the sample size and locations of inspections or adjusting the inspection frequency as appropriate.

The staff determined that for visual inspection the "monitoring and trending" program element satisfies SRP-LR Section A.1.2.3.5. The staff agrees that by use of applicable engineering analyses and station procedures monitoring and trending will be adequate for the period of extended operation. On this basis, the staff finds the applicant's description of the "monitoring and trending" program element acceptable.

(6) Acceptance Criteria - The "acceptance criteria" program element in SRP-LR Section A.1.2.3.6 states that::

- 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 the ASME Code and through approved site-specific programs.

The applicant stated in LRA Section B.2.5 that examination results will be evaluated by engineering to determine whether change in material properties, loss of material, and reduction of heat transfer aging is occurring. Changes in material properties are identified by visual inspection for cracking and indications of elastomer hardening. For loss of material, loss of wall thickness will be evaluated against design requirements or accepted industry standards. The heat transfer intended function of a component will be assured by inspecting for corrosion and fouling. If change in material properties, loss of material, and reduction of heat transfer aging is identified engineering will determine the rate at which the aging effect is occurring. Engineering evaluations of the examination results will also (1) determine the need for followup examinations to monitor the progression of aging degradation and (2) identify appropriate corrective actions to mitigate any excessive rates of change in material properties, loss of material, and reduction of heat transfer discovered or specify the appropriate repair or replacement. Corrective actions, if necessary, will expand to include other components.

Change in material properties, loss of material, and reduction of heat transfer will be evaluated by engineering consistent with original design or evaluation codes and criteria. Age-related degradations that could result in a spatial interaction of a nonsafety-related system with a safety-related system, as determined by this evaluation, will be corrected.

Any acceptance criteria not currently defined in the UFSAR will be defined by engineering and accepted based on station procedures and industry practices. Qualitative acceptance criteria for expansion joints and flexible connections and hoses include indications of cracking, hardening, or tears of elastomers. Exterior surfaces of heat exchangers will be inspected for corrosion and fouling. Loss of material will be identified by visual or volumetric inspection of components. Component function will be maintained by the periodic monitoring of the components.

All qualitative inspections will be performed to the same predetermined criteria as quantitative inspections in accordance with ASME Code and approved site procedures.

The staff reviewed the "acceptance criteria" program element to determine whether it satisfies SRP-LR Section A.1.2.3.6. The staff determined that the acceptance criteria element is satisfactory because it adheres to accepted procedures and accepted industry practice and ASME Code and approved site procedures. In addition, the staff determined that all qualitative inspections will be performed to the same predetermined criteria as quantitative inspections in accordance with the ASME Code and approved site procedures. On this basis, the staff finds the applicant's description of the "acceptance criteria" program element acceptable.

(10) Operating Experience - The "operating experience" program element criteria in SRP-LR Section A.1.2.3.10 states that:

- Operating experience should provide objective evidence for 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 future for new programs to confirm their effectiveness.

In LRA Section B.2.5, the applicant stated that the Periodic Inspection Program is new; therefore, no programmatic operating experience has been gained. OCGS has experienced leaks of the plant heating system resulting in the replacement of components. These plant heating system leaks were found and corrected promptly and did not result in a loss of function of any safety-related SSCs. The Periodic Inspection Program is adjusted continually to account for industry and station experience and research. As additional operating experience is obtained, lessons learned will be used to adjust this program as needed.

Operating experience, both internal and external, is used in two ways at OCGS to enhance plant programs and to prevent repeat events and events at other plants from occurring at OCGS. The first way in which operating experience is used is through the operating experience process, which screens, evaluates, and acts on 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.

These processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), GE documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10 CFR Part 21 Reports, NERs, etc.). Internal operating experience may include 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.

Demonstration of the effective management of the effects of aging is through objective evidence showing that aging effects like change in material properties, loss of material, and reduction of heat transfer are effectively managed. The following examples of operating experience are objective evidence that the Periodic Inspection Program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation.

OCGS operating experience was searched for instances where change in material properties, loss of material, or reduction of heat transfer was identified as a contributing cause of an incident. The following are the results of that search:

- CAP 02005-2339 documents the identification of build-up of rusted metal parts in the bottom of ductwork determined to be heat transfer fins for an electric heater that did not impact intended functions.
- CAP 02005-0786 documents the identification of an s-leak on a heating coil found during operator rounds. This problem was identified before heating to the reactor building was lost and did not impact any safety systems.
- CAP 02002-1116 documents the identification of a reduction of heat transfer through an M1A transformer high temperature alarm. The oil coolers were fouled and a long-term cooling capability was established.
- CAP 02003-0511 documents the identification of a reduction of heat transfer in the main condenser due to fouling resolved through backwashing to restore vacuum.

Operating experience shows that the mean time to failure for rubber expansion joints is 12-15 years. The performance-centered maintenance template directs that rubber expansion joints be inspected and replaced on appropriate intervals depending on the joint classification. This combination of inspection and replacement assures that the Periodic Inspection Program will find premature degradation.

This operating experience provides objective evidence that OCGS is able to recognize change in material properties, loss of material, and loss of heat transfer before these aging effects become problems and supports implementation of the new Periodic Inspection Program for effective aging management.

The operating experience of the parameters to be covered under the Periodic Inspection Program showed no adverse trend in performance. Problems identified caused no significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that implementation of the Periodic Inspection Program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Periodic Inspection Program identify areas that need improvement to maintain the quality performance of the program.

This program is new and there is no specific operating history. The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Periodic Inspection Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Periodic Inspection Program in LRA Section A.2.2, which stated that the new Periodic Inspection Program will consist of periodic inspections of selected systems to verify integrity and confirm the absence of aging effects. The initial inspections are scheduled for implementation prior to the period of extended operation. The purpose of the inspection is to determine whether a specified aging effect has occurred. If the aging effect has occurred an evaluation will be performed to determine its effect on the ability of affected components to perform their intended functions for the period of extended operation, and appropriate corrective action will be taken. Inspection methods may include visual, surface, or volumetric examinations. Acceptance criteria are in accordance with industry guidelines, codes, and standards. When inspection results fail to meet established acceptance criteria, an evaluation will be conducted, in accordance with the corrective action process, to establish additional actions or measures necessary to provide reasonable assurance that component intended function is maintained during the period of extended operation. This new program will be implemented prior to the period of extended operation.

The staff also reviewed the commitment (Commitment No. 41) to confirm that this program will be implemented prior to the period of extended operation.

The staff reviewed the UFSAR supplement and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's program finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.6 Wooden Utility Pole Program

Summary of Technical Information in the Application. In LRA Section B.2.6, the applicant described the new, plant-specific Wooden Utility Pole Program.

The Wooden Utility Pole Program will be used to manage loss of material and change of material properties for wooden utility poles in or near the OCGS 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. The program consists of inspection at 10-year intervals by a qualified inspector. The wooden poles will be inspected for loss of material due to insects and moisture damage and for change in material properties due to moisture damage. This new program will be implemented prior to the period of extended operation.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.2.6 on the applicant's demonstration of the Wooden Utility Pole Program to ensure that the effects of aging will be adequately managed so that intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Wooden Utility Pole Program against the AMP elements in SRP-LR Section A.1.2.3 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., "program scope," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience").

The applicant indicated that the "corrective actions," "confirmation process," and "administrative controls" are parts of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program -The "scope of program" program element in SRP-LR Section A.1.2.3.1 states that (1) the specific program necessary for license renewal should be identified and (2) the scope of the program should include the specific structure and components for which the program manages aging.

In LRA Section B.2.6, the applicant stated that the Wooden Utility Pole Program applies to all wooden utility poles which support an intended function for the offsite power system and the 480/208/120V utility (JCP&L) non-vital power system.

The staff determined that the specific program and the components for which the program manages aging effects are identified by the applicant, satisfying SRP-LR Section A.1.2.3.1. On this basis, the staff finds the applicant's proposed "scope of program" program element acceptable.

(2) Preventive Actions - The "preventive actions" program element in SRP-LR Section A.1.2.3.2 states 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 preventive actions need not be provided.

The applicant stated that this program is a condition monitoring activity. It is a means of detecting, not preventing, aging and has no preventive or mitigative actions.

The staff determined that the applicant had described the program as a condition monitoring activity and not a preventive actions program, and this description satisfies the SRP-LR Section A.1.2.3.2. The applicant uses a condition monitoring program to inspect for loss of material due to insects and moisture damage and for change in material properties due to moisture damage. On this basis, the staff finds the "preventive actions" program element acceptable.

(3) Parameters Monitored or Inspected - The "parameters monitored or inspected" program element in SRP-LR Section A.1.2.3.3, related to condition monitoring programs, states that:

- 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 a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The applicant stated that wooden poles within the scope of this program will be inspected *for loss of material due to insects and moisture damage and for change in material* properties due to moisture damage and that the parameters monitored or inspected are capable of detecting the effects of aging.

The staff determined that the applicant has identified the parameters to be monitored or inspected, is able to detect the presence and extent of aging effects, and that the program element satisfies SRP-LR Section A.1.2.3.3. On this basis, the staff finds the applicant's proposed "parameters monitored or inspected" program element acceptable.

(4) Detection of Aging Effects - The "detection of aging effects" program element in SRP-LR Section A.1.2.3.4, related to condition monitoring programs, states that:

- Detection of aging effects should occur before there is a loss of the structure and component intended function(s).
- The method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The applicant stated that inspection of wooden poles every 10 years by a qualified inspector will assure that aging effects are detected prior to loss of intended function, and that industry experience over several decades indicates that a 10-year inspection interval is adequate.

The staff determined that the use of demonstrated industry experience of inspecting wooden poles by a qualified inspector every 10 years is a reasonable method for detecting aging and that the program element satisfies SRP-LR Section A.1.2.3.4. On this basis, the staff finds the applicant's description of the "detection of aging effects" program element acceptable.

(5) Monitoring and Trending - The "monitoring and trending" program element in SRP-LR

Section A.1.2.3.5, related to condition monitoring programs, states that monitoring and trending activities and the methodology for analyzing the inspection should be described.

In LRA Section B.2.6, the applicant stated that monitoring involves a combination of visual, sounding, boring, and excavation to determine the condition of a pole sufficiently to predict the extent of degradation so that timely corrective or mitigative actions are possible.

The staff determined that the program provides a combination of methods to monitor or inspect wooden pole conditions related to aging and that this program element satisfies SRP-LR Section A.1.2.3.5. On this basis, the staff finds the applicant's description of the "monitoring and trending" program element acceptable.

(6) Acceptance Criteria. The "acceptance criteria" program element in SRP-LR Section A.1.2.3.6, related to condition monitoring programs, states that:

- 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 structure and components 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.

The applicant stated that acceptance criteria will be provided in the specification for inspection of wooden poles carried out by approved maintenance contractors experienced in the inspection, treatment, and reinforcement of wooden poles. The inspector, through a combination of visual, sounding, boring, and excavation will determine the condition of the pole. Remedial actions will be taken based on inspection findings.

The staff determined that the use of an acceptance criteria developed by an experienced wooden pole inspector is reasonable and that this program element satisfies SRP-LR Section A.1.2.3.6. On this basis, the staff finds the applicant's description of the "monitoring and trending" program element acceptable.

(10) Operating Experience. The "operating experience" program element criteria in SRP-LR Section A.1.2.3.10 states that:

- 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 future for new programs to confirm their effectiveness.

The applicant stated that although this program is new, inspections of wooden utility poles has been conducted by the industry for many years. Utility experience over several decades indicates that a 10-year inspection interval is adequate to detect age-related degradation before a loss of intended function.

The staff determined that the applicant provided industry experience to support an adequate 10-year inspection interval for wooden poles and that this program element satisfies SRP-LR Section A.1.2.3.10. On this basis, the staff finds the applicant's description of the "operating experience" element acceptable.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Wooden Utility Pole Program in LRA Section A.2.6, which stated that this new program will be used to manage loss of material and change of material properties for wooden utility poles in or near the OCGS substation providing structural support for the conductors connecting the offsite power system and the 480/208/120V utility (JCP&L) non-vital power system. The program consists of inspection on a 10-year interval by a qualified inspector. The wooden poles will be inspected for loss of material due to insects and moisture damage and for change in material properties due to moisture damage. This new program will be implemented prior to the period of extended operation. The staff also reviewed the commitment (Commitment No. 42) to confirm that this program will be implemented prior to the period of extended operation. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Wooden Utility Pole Program, the staff concludes that the applicant has demonstrated that the effects of aging 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 staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.7 Periodic Monitoring of Combustion Turbine Power Plant

In its response to RAI 2.5.1.19-1 dated October 12, 2005, the applicant stated that it had revised its approach to aging management for the OCGS SBO combustion turbine power plant. Specifically, the applicant has taken a more detailed approach to scoping, screening, AMRs, and AMPs. As a result, the Periodic Monitoring of Combustion Turbine Power Plant Program has been deleted. Therefore, the staff did not review this program.

3.0.3.3.8 Periodic Monitoring of Combustion Turbine Power Plant Electrical

Summary of Technical Information in the Application. In its October 12, 2005, response to RAI 2.5.1.19-1, the applicant stated that the new plant-specific Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program 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 Bus."

The Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program will be used to manage aging effects for the electrical commodities that support FRCT operation. The new 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 program will include elements of GALL AMP XI.E1 for accessible electrical cables and connections; GALL AMP XI.E3 for manholes, pits, and cable trenches; and GALL AMP XI.E4 for the phase bus, connections, and phase bus insulators.

This 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 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 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. 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 Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program scope for 13.8 kV cables that distribute the output of the FRCT to both the 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. The first tests and inspections will be before the period of extended operation 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Attachment 7. In its response to RAI 2.5.1.19-1, the applicant stated that the Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program is consistent with elements of GALL AMPs XI.E1, XI.E3, and XI.E4. The staff reviewed the program elements and associated basis documents to determine their consistency with GALL AMPs XI.E1, XI.E3, and XI.E4.

The staff asked the applicant whether the 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 or debris intrusion. The staff concludes 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, phase bus and connections, phase bus insulators, and phase bus enclosure internal surfaces for reasonable assurance that intended functions of the electrical commodities supporting the FRCTs will be maintained consistent with the CLB during the period of extended operation. The staff finds 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.

Operating Experience. In its response to RAI 2.5.1.19-1 dated October 12, 2005, the applicant stated that although this program is new, the FRCT has experienced no 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 station or a combustion turbine reliability below the 95 percent requirement.

The staff reviewed the operating experience provided in PBD-AMP-B.1.37 and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Periodic Monitoring of Combustion Turbine Power Plant - Electrical Program in its supplemental response to RAI 2.5.1.19-1. In its letter dated May 9, 2006 and June 2, 2006, the applicant committed (Commitment No. 43) to perform twice per year visual inspections of high voltage insulators. These letters also reflect that cable connections (metallic parts) located at the FRCT power plant are part of the population from which a sample will be selected for testing under the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and finds that it provides an adequate summary description of the program as required by 10 CFR 54.21(d).

3.0.3.3.9 Periodic Inspection Program - FRCT

Summary of Technical Information in the Application. In its November 11, 2005, supplemental response to RAI 2.5.1.19-1, the applicant stated that AMP B.2.5A, "Periodic Inspection Program - FRCT" is a new program.

The Periodic Inspection Program - FRCT Program will address FRCT system components within the scope of license renewal requiring periodic monitoring of aging effects and not covered by other AMPs. Activities will consist of a periodic inspection of selected components to verify integrity and confirm the absence of aging effects. The inspections will be condition monitoring examinations intended to assure that environmental conditions do not cause material degradation that could result in a loss of intended functions. This program is used to confirm that:

- Change in material properties due to aging does not occur in elastomer expansion joints and flexible connections exposed to fuel oil, indoor air, or outdoor air environments.

- Reduction of heat transfer due to aging does not occur in heat exchangers exposed to indoor air or outdoor air environments.
- Loss of material in various steel and stainless steel components subject to an intermittent combustion turbine exhaust gas environment is monitored so there is no loss of component intended functions.
- Loss of material in copper heat exchanger components subject to an indoor air or outdoor air environment is monitored so there is no loss of component intended functions.
- Cracking in stainless steel components subject to an intermittent combustion turbine exhaust gas environment is monitored so there is no loss of component intended functions.

The program elements will include (1) determination of appropriate inspection sample size, (2) identification of inspection locations, (3) selection of examination technique with acceptance criteria, and (4) evaluation of results to determine the need for additional inspections or other corrective actions. The sample size will be based on such aspects 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) will be expected to occur. The inspection locations will be based on such aspects as similarity of materials of construction, fabrication, operating environment, or aging effects. Inspection methods may include visual, surface, or volumetric examinations or other established 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 that change in material properties, loss of material, cracking, and reduction of heat transfer does not occur or that the aging effect occurs at a rate that will not affect component intended functions. The program will provide inspection criteria, require evaluation of the results of the inspections, and recommend 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 on a frequency not to exceed once every 10 years. The initial inspections in program will be at the next major inspection outage for each unit. Based on the established inspection frequency of 10 years, the next inspection for FRCT Unit 1 will be by May 2014, and the next inspection for FRCT Unit 2 will be by November 2015.

Staff Evaluation. The staff reviewed the Periodic Inspection Program - FRCT Program against the AMP elements in SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," "administrative controls," and "operating experience").

(1) Scope of Program - In its description of the Periodic Inspection Program - FRCT Program the applicant stated that the scope of this program includes systems within the scope of license renewal requiring periodic monitoring of aging effects and not covered by other existing periodic monitoring programs. Inspections will be at susceptible locations in such systems.

The staff determined that the specific components for which the program manages aging effects are identified by the applicant, satisfying SRP-LR Section A.1.2.3.1. On this basis, the staff finds the applicant's proposed "program scope" program element acceptable.

(2) Preventive Actions - In its description of the Periodic Inspection Program - FRCT Program the applicant stated that the program activities will be condition monitoring activities to detect degradation prior to change in material properties, loss of material, cracking, or reduction of heat transfer aging effects as applicable for the material and environment with no preventive or mitigating attributes.

The staff determined that the "preventive actions" program element satisfies SRP-LR Section A.1.2.3.2. On this basis, the staff finds the applicant's "preventive actions" program element acceptable.

(3) Parameters Monitored/Inspected - In its description of the Periodic Inspection Program - FRCT Program for the "parameters monitored or inspected" program element the applicant stated that this program will inspect 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 NDE techniques.

The staff determined that the "parameters monitored or inspected" program element satisfies SRP-LR Section A.1.2.3.3. On this basis, the staff finds the applicant's description of the "parameters monitored or inspected" program element acceptable.

(4) Detection of Aging Effects - In its description of the Periodic Inspection Program - FRCT Program for the "detection of aging effects" program element the applicant stated that this program includes inspections for change in material properties, loss of material, cracking, and reduction of heat transfer on a representative sample of susceptible locations. Inspection for loss of material will consist of surface inspections, thickness measurements by NDE (UT), or visual examination of disassembled components.

A representative sample of locations will be inspected to confirm that unacceptable degradation does not occur and that the intended function of components will be maintained during the period of extended operation. Unacceptable inspection results will require expansion of the sample size and locations 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 on a frequency not to exceed once every 10 years.

The initial inspections in this program will be at the next major inspection outage for each unit. As discussed under Operating Experience, the last FRCT Unit 1 major inspection outage was in 2004. The outage began in March 2004 and was completed in May 2004. The last FRCT Unit 2 major inspection outage began in October 2005 and was scheduled for completion in November 2005. All work was carried out closely following the instructions and guidance of the original equipment manufacturer's design, maintenance, and inspection manuals. 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 observed and the as-left internal component conditions following the maintenance outages, additional internal inspections are not warranted prior to the period of extended operation. Based on the established inspection frequency of 10 years, the next inspection for FRCT Unit 1 will be by May 2014, and the next inspection for FRCT Unit 2 will be by November 2015.

The staff determined that the "detection of aging effects" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.4. On this basis, the staff finds the applicant's description of the "detection of aging effects" program element acceptable.

(5) Monitoring and Trending - In its description of the Periodic Inspection Program - FRCT Program for the "monitoring and trending" program element, the applicant stated 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 either to demonstrate acceptability or to 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. Examination methods include visual examination, (VT-1 or VT-3) of disassembled components, NDE (UT) measurements, or any other specific examination appropriate for detection of the specific aging effect.

The staff determined that for visual inspection the "monitoring and trending" program element satisfies SRP-LR Section A.1.2.3.5. On this basis, the staff finds the applicant's description of the "monitoring and trending" program element acceptable.

(6) Acceptance Criteria - In its description of the Periodic Inspection Program - FRCT Program, for the "acceptance criteria" program element, the applicant stated that results of the examinations will be evaluated to determine whether change in material properties, loss of material, cracking, or reduction of heat transfer aging has occurred and, if so, its rate. Evaluation of the examination results also will (1) determine the need for followup examinations to monitor the progression of aging degradation and (2) identify appropriate corrective actions, including repairs or replacements, to mitigate any excessive rates of aging degradation. Corrective actions, if necessary, will expand to include other components. Change in material properties, loss of material, cracking, and reduction of heat transfer will be evaluated consistently with original design or evaluation codes and criteria or manufacturer's standards.

The staff reviewed the "acceptance criteria" program element to determine whether it satisfies SRP-LR Section A.1.2.3.6. On this basis, the staff finds the applicant's description of the "acceptance criteria" program element acceptable.

(7) Corrective Actions - The adequacy of the applicant's program for this element is evaluated in SER Section 3.0.4.

The staff reviewed other aspects of this program element to determine whether it satisfies SRP-LR Section A.1.2.3.7. The staff noted that the FRCTs and supporting systems are nonsafety-related and are not subject to 10 CFR 50 Appendix B requirements in the CLB. The applicant has elected not to include this program under 10 CFR 50 Appendix B Program. Instead, processes and procedures will be established to ensure that conditions adverse to quality are identified and corrected promptly. 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. Any condition significantly adverse to quality will require that the cause be determined, action to preclude repetition be taken, and the condition be reported to the appropriate level of management. In its responses to RAI 2.5.1.19-1 dated October 12 and November 11, 2005, 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 staff finds the applicant's description of the "corrective actions" program element acceptable.

(8) Confirmation Process - The adequacy of the applicant's program for this element is evaluated in SER Section 3.0.4.

The staff reviewed other aspects of the "confirmation process" program element to determine whether it satisfies SRP-LR Section A.1.2.3.8. The staff noted that the confirmation process for the FRCT will focus on followup actions that must be taken to verify effective implementation of corrective actions and preclude repetition of conditions significantly adverse to quality. The established process and procedures require that measures be taken to preclude repetition of conditions significantly adverse to quality. These measures include actions to verify effective implementation of the proposed corrective actions, determination of root cause, tracking of open corrective actions to completion, and reviews of corrective action effectiveness.

In its responses to RAI 2.5.1.19-1 dated October 12, 2005, and November 11, 2005, 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 staff finds the applicant's description of the "confirmation process" program element acceptable.

(9) Administrative Controls - The adequacy of the applicant's program for the "administrative controls" program element is evaluated in SER Section 3.0.4. The staff noted that FRCT procedures include administrative controls that provide for formal review and approval of aging management activities.

The staff reviewed other aspects of this program element to determine whether it satisfies SRP-LR Section A.1.2.3.9. In its responses to RAI 2.5.1.19-1 dated October 12, 2005, and November 11, 2005, 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 staff finds the applicant's description of the "administrative controls" program element acceptable.

(10) Operating Experience - In its description of the Periodic Inspection Program - FRCT Program for the "operating experience" program element, the applicant stated that the new Periodic Inspection Program - FRCT Program will effectively manage aging degradation for the period of extended operation by timely detecting aging effects and implementing 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 to maintain intended functions of the combustion turbines.

The applicant stated that in October 2001 (FRCT Unit 2) and March 2004 (FRCT Unit 1), GE Energy Services performed inspection and maintenance activities and documented all work 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 of 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 FRCT Unit1 inspection was major maintenance, the most comprehensive inspection of the combustion turbine units. The interval between major inspections is based on operating experience with these and similar combustion turbine installations and such factors that affect part life as fuel type and starting frequency. The purpose of this type of maintenance inspection is to identify equipment degradation and, if identified, to replace or refurbish the affected component in accordance with manufacturer specifications so the unit will perform reliably through the next operating interval. This major inspection was the first on the unit since initial installation in 1988. During the FRCT 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 noted with the copper tubes. Maintenance personnel stated that the tubes were found in good condition.

The FRCT Unit 2 inspection was of the fuel nozzle and combustion section. The FRCT Unit 2 inspection found the inlet filter housing 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.

FRCT Unit 2 began a major outage inspection in October 2005 with components disassembled and visually inspected for signs of age-related degradation. The internal surfaces of disassembled exhaust system ductwork and turbine casing sections were observed. Cracked exhaust system components were replaced and casing cracks were 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 during an SBO event. The glycol-cooling water heat exchanger tubes and fins at the mechanical draft cooling tower were visually inspected and showed no signs of significant corrosion. External surfaces of elastomer flexible connections were inspected and did not appear cracked or deteriorated.

The operating experience with the FRCTs includes a significant number of inspections of components in the scope of this Periodic Inspection Program - FRCT Program. The documented inspection results confirm that environmental conditions have not caused material degradation that could result in a loss of component intended functions. Past inspections have been at a frequency as long at 16 years with the units performing reliably between inspections. Implementation of this new program will continue these inspections 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 staff reviewed the operating experience provided in the LRA, and interviewed the applicant's technical personnel to confirm that plant-specific operating experience revealed no 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 personnel, the staff concludes that the applicant's Periodic Inspection Program - FRCT Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Periodic Inspection Program - FRCT Program in its supplemental response to RAI 2.5.1.19-1. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's program and RAI response finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 QA Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in Application

Section 3.0, "Aging Management Review Results," of the LRA provided an AMR summary for each unique component type or commodity group at OCGS determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management and AMPs managing these aging effects. In LRA Sections A.0.5 and B.0.3, "Quality Assurance Program and Administrative Controls," the applicant described the "corrective action," "confirmation process," and "administrative controls" attributes applied to both safety-related and nonsafety-related SSCs within the scope of license renewal. In LRA Sections B.1 and B.2 the applicant further described the "corrective action," "confirmation process," and "administrative controls" attributes for each AMP.

The existing QA program meeting the requirements of 10 CFR 50, Appendix B, and a separate QA program based on Appendix A of RG 1.155, "Station Blackout," will implement the AMP "corrective action," "confirmation process," and "administrative controls" attributes. The existing QA program that meets the requirements of 10 CFR 50, Appendix B, will be applied to all but the mechanical AMPs for the FRCT. A QA program based on Appendix A of RG 1.155 will be applied to the FRCT mechanical AMPs described in LRA Sections B.1.12A, B.1.14A, B.1.21A, B.1.22A, B.1.24A, B.1.25A, B.1.26A, B.1.38, B.1.39, and B.2.05A. A separate QA program based on Appendix A of RG 1.155 is necessary because the existing QA program that meets the requirements of 10 CFR 50, Appendix B, is not implemented for activities not performed by the applicant. The applicant will establish an agreement with the FRCT owner to ensure that the processes and procedures that address the AMP "corrective action," "confirmation process," and "administrative controls" attributes applicable to the nonsafety-related FRCT mechanical system AMPs are established prior to the period of extended operation. The existing QA program that meets the requirements of 10 CFR 50, Appendix B, will be applied to the FRCT structural and electrical AMP “corrective action,” “confirmation process,” and “administrative controls” attributes.

3.0.4.2 Staff Evaluation

Pursuant to 10 CFR 54.21(a)(3), a license renewal applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. SRP-LR, Branch Technical Position RLSB-1, “Aging Management Review - Generic,” describes 10 attributes of an acceptable AMP. Three of these 10 attributes are associated with the QA activities of corrective action, confirmation process, and administrative control. Table A.1-1, “Elements of an Aging Management Program for License Renewal,” of Branch Technical Position RLSB-1 describes these quality attributes:

- Corrective actions, including root cause determination and prevention of recurrence, should be timely.
- The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Administrative controls should provide a formal review and approval process.

SRP-LR, Branch Technical Position IQMB-1 noted that those aspects of the AMP that affect quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for nonsafety-related SCs subject to an AMR the applicant's existing Appendix B to 10 CFR Part 50 QA program may be used to address the elements of “corrective action,” “confirmation process,” and “administrative control.” Branch Technical Position IQMB-1 provides the following guidance for the QA attributes of AMPs:

> SR SCs are subject to Appendix B to 10 CFR Part 50 requirements which are adequate to address all quality related aspects of an AMP consistent with the CLB of the facility for the period of extended operation. For NSR SCs that are subject to an AMR for LR, an applicant has an option to expand the scope of its Appendix B to 10 CFR Part 50 program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the Final Safety Analysis Report supplement in accordance with 10 CFR 54.21(d).

The staff reviewed the “corrective action,” “confirmation process,” and “administrative controls” attributes described in LRA Sections A.0.5 and B.0.3 to ensure that the aging management activities were consistent with the staff's guidance described in SRP-LR Section A.2 for QA attributes of the AMPs. The staff also reviewed the AMP descriptions for each program in LRA Sections B.1 and B.2 and found that the three attributes of corrective action, confirmation process, and administrative document control were specifically described and included adequate reference to the application of the existing QA program meeting the requirements of 10 CFR 50, Appendix B, with the exception of the FRCT AMP.

As discussed in SER Section 2.5, in RAI 2.5.1.19-1 dated September 28, 2005, the staff requested that the applicant further describe the FRCT AMP. In its responses to RAI 2.5.1.19-1 dated October 11 and November 12, 2005, the applicant stated that a QA program based on

Appendix A of RG 1.155 will be used to implement the corrective action, confirmation process, and administrative controls attributes for the FRCT mechanical AMPs. The existing QA program that meets the requirements of 10 CFR 50, Appendix B, will be applied to FRCT structural and electrical AMPs. The RAI response also added a new commitment (Commitment No. 65) to ensure that procedures are established to implement the program elements of the "corrective action," "confirmation process," and "administrative controls" attributes for the FRCT AMPs prior to the period of extended operation.

The staff's evaluation of the descriptions of the AMPs quality attributes provided in LRA Sections A.0.5, B.0.3, B.1, and B.2 and the applicant's responses to the RAI 2.5.1.19-1 concludes that the program descriptions of the "corrective action," "confirmation process," and "administrative controls" attributes are acceptable. The existing QA program meets the requirements of 10 CFR 50, Appendix B, and is consistent with the staff's position and the Branch Technical Position discussed in IQMB-1. The alternative means to address "corrective actions," "confirmation process," and "administrative controls" applied to the FRCT mechanical AMPs is consistent with Appendix A of RG 1.155 which provides the staff's guidance for implementation of the SBO rule. The staff finds this acceptable as the QA program to be used for FRCT AMPs is equivalent to the Branch Technical Position discussed in IQMB-1.

3.0.4.3 Conclusion

The staff concludes that the QA attributes ("corrective action," "confirmation process," and "administrative control") of the applicant's AMPs are consistent with 10 CFR 54.21(a)(3).

3.1 <u>Aging Management of Reactor Vessel, Internals, and Reactor Coolant System</u>

This section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and reactor coolant system (RCS) components and component groups associated with the following systems:

- isolation condenser system
- nuclear boiler instrumentation system
- reactor head cooling system
- reactor internals
- reactor pressure vessel
- reactor recirculation system

3.1.1 Summary of Technical Information in the Application

In LRA Section 3.1, the applicant provided AMR results for the reactor vessel, internals, and RCS components and component groups. In 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 AMRs with the AMRs evaluated in the GALL Report for the reactor vessel, internals, and RCS components and component groups.

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 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and RCS components 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 staff conducted an onsite audit of AMRs, during the weeks of October 3-5, 2005, January 23-27, February 13-17, and April 19-20, 2006, to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report, Section 3.1.2.1 and are summarized in SER Section 3.1.2.1.

In the onsite audit, the staff also selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.1.2.2. The staff's audit evaluations are documented in the Audit and Review Report Section 3.1.2.2 and are summarized in SER Section 3.1.2.2.

The staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The technical review included evaluating whether all plausible aging effects had been identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's evaluations are documented in SER Section 3.1.2.3.

For AMRs that the applicant identified as not applicable or not requiring aging management, the staff conducted a review of the AMR line items, and the plant's operating experience, to verify the applicant's claims. Details of these reviews are documented in the Audit and Review Report.

Finally, the staff 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 RCS components.

Table 3.1-1, provided below, includes a summary of the staff's evaluation of components, aging effects and mechanisms, and AMPs listed in LRA Section 3.1 that are addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Internals, and Reactor Coolant System 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	This TLAA is evaluated in SER Section 4.3. (See SER 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)	This TLAA is evaluated in SER Section 4.3. Acceptable-Cracking due to fatigue for FW and CRDRL nozzle thermal sleeves will be managed in accordance with 10 CFR 54.21(c)(1)(iii). (See SER 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	This TLAA is evaluated in SER Section 4.3. (See SER 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	This TLAA is evaluated in SER Section 4.3. (See SER Section 3.1.2.2.1)
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)	This TLAA is evaluated in SER Section 4.3. Acceptable- Cracking due to fatigue will be managed in accordance with 10 CFR 54.21(c)(1)(iii) (See SER Section 3.1.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 OCGS top head enclosure is clad with stainless steel. (See SER Section 3.1.2.2.2)
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 SER Section 3.1.2.2.2)
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 SER Section 3.1.2.2.2)
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor coolant pressure boundary components exposed to reactor coolant (Item 3.1.1-15)	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 SER Section 3.1.2.2.2)
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 50 and RG 1.99. The applicant may choose to demonstrate that the materials of the nozzles are not controlling for the TLAA evaluations.	TLAA, evaluated in accordance with Appendix G of 10 CFR 50 and RG 1.99.	This TLAA is evaluated in SER Section 4.2. (See SER Section 3.1.2.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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. (See SER Section 3.1.2.2.3)
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 aging management program 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 SER Section 3.1.2.2.4)
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 SER Section 3.1.2.2.4)
Stainless steel jet pump sensing line (Item 3.1.1-25)	Cracking due to cyclic loading	A plant-specific aging management program is to be evaluated.	Not applicable	Not applicable, since OCGS does not have jet pumps and jet pump sensing lines. (See SER Section 3.1.2.2.8)
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 SER Section 3.1.2.2.8)
Stainless steel steam dryers exposed to reactor coolant (Item 3.1.1-29)	Cracking due to flow-induced vibration	A plant-specific aging management program 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 SER Section 3.1.2.2.11)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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)	Consistent with GALL. The SS thermal sleeve will be managed by the BWR vessel internals program (B.1.9). (See SER Section 3.1.2.2.1)
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)	Consistent with GALL. The nickel alloy thermal sleeves will be managed by the BWR vessel internals program (B.1.9). (See SER Section 3.1.2.2.1)
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 (Item 3.1.1-40)	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)	Consistent with GALL. AMP B.1.9 provides additional assurance. (See SER Section 3.1.2.1)
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 SER 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 SER 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 SER Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.1.2.1)
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 SER Section 3.1.2.1)
Nickel alloy core shroud and core plate access hole cover (mechanical covers) (Item 3.1.1-46)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	Not applicable	Not applicable, since OCGS does not have access hole covers.
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 Program 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 SER Section 3.1.2.1.3)
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 SER Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 OCGS does not have access hole covers.
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 SER Section 3.1.2.1)
Cast austenitic stainless steel jet pump assembly castings; orificed fuel support (Item 3.1.1-51)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	Thermal Aging and Neutron Irradiation Embrittlement of CASS (B.1.10)	Consistent with GALL. (See SER 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 SER 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 OCGS has no such components within the scope of license renewal.
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 OCGS has no such components within the scope of license renewal.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.1.2.1)
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 OCGS has no such components within the scope of license renewal.
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 SER 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 SER Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER 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 OCGS has no such components in the RCS within the scope of license renewal.

The staff's review of the reactor vessel, internals, and RCS component groups followed one of several approaches. One approach, documented in SER Section 3.1.2.1, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.1.2.2, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.1.2.3, discusses the staff's review of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the reactor vessel, internals, and RCS components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.1.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the effects of aging related to the reactor vessel, internals, and RCS components:

- 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)

Staff Evaluation. In LRA Tables 3.1.2.1.1 through 3.1.2.1.6, the applicant provided a summary of AMRs for the reactor vessel, internals, and RCS components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. 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 has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the Audit and Review Report Section 3.1.2.1. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

3.1.2.1.1 Cracking due to Stress Corrosion Cracking (SCC), Intergranular Stress Corrosion Cracking (IGSCC), and Irradiation Assisted Stress Corrosion Cracking (IASCC)

LRA Table 3.1.2.1.4 for the reactor internals credits the BWR Vessel Internals and Water Chemistry Programs to manage cracking due to SCC, IGSCC, and IASCC in the stainless steel and nickel alloy reactor vessel top guide.

During the audit, the staff noted that several INs, including IN 95-17, addressed cracking of BWR top guides within the operating experience of domestic and foreign reactors. The top guide at OCGS 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 Programs, 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, a crack was found on the underside of a top guide beam. During the 14R and 15R refueling outages in 1992 and 1994, additional cracks were found on the underside of top guide beams. As a result of these findings, UT inspections of the complete top guide during the 16R refueling outage in 1996 found 5 mid-span cracks and 12 UT indications in the notches used to interlock the beams. The majority of the cracks and indications was located in the northeast 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 IASCC. Furthermore, a flaw growth evaluation was prepared for the most significant crack to predict future crack growth and to evaluate its effects upon the structural integrity of the top guide. The flaw evaluation predicted a maximum crack growth of 1.6 inches within 2 cycles of operation and determined that, even if this growth 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 2 operating cycles since the previous inspection. The crack was still well within evaluation limits and did not impair the structural integrity of the top guide. Additional visual inspections during the 20R refueling outage in 2004 to monitor crack growth indicated that there had been no additional crack growth during the previous 2 operating cycles.

The applicant further stated that it plans to inspect the top guide during the next refueling outage by UT examination. As a minimum, the complete northeast quadrant of the top guide will be inspected to determine whether the cracking has been mitigated. If significant crack growth is found in the northeast quadrant, additional inspections will be performed as necessary to characterize crack growth. As discussed in BWRVIP-26-A, OCGS 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 reasonable 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 (R-98), for top guides with neutron fluence exceeding the IASCC threshold prior to the period of extended operation, the applicant shall inspect 10 percent of the top guide locations using enhanced visual inspection technique EVT-1 within 12 years with one-half of the inspections (i.e., 5 percent of locations) to be completed within the first 6 years of 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 statement is consistent with the GALL Report recommendations.

The staff determined that the applicant's aging management activities to manage cracking of the top guide are consistent with the recommendations in the GALL Report.

LRA Table 3.1.2.1.4 for the reactor internals credits the BWR Vessel Internals and Water Chemistry Programs to manage cracking due to SCC, IGSCC, and IASCC in the stainless steel and nickel alloy reactor vessel core shroud.

The staff noted that industry experience confirms the observation of cracking in core shrouds at both horizontal (GL 94-03) and vertical (IN 97-17) welds. The core shroud has cracked and has operated in its repaired configuration. In light of this condition, the staff asked the applicant 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 Programs, 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 Types 304 and 304L stainless steel. In 1994 OCGS examined the shroud comprehensively and found significant cracking in the core shroud H4 circumferential weld and additional minor cracking in the H2 and H6 welds. The examinations were visual with cleaning and UT examinations wherever practical. During the same refueling outage, repair hardware was installed to ensure the shroud could continue to perform its intended function. The repair hardware 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 support the shroud structure reliably. Following the guidelines of BWRVIP-76, the applicant 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 inches) acceptable by BWRVIP-76 acceptance criteria.

The applicant further stated that it will complete inspection of all vertical welds in accordance with BWRVIP-76 guidelines by 2008. Currently, the vertical welds are scheduled to be inspected by 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 10 years by either EVT-1 or UT examination methods. Repair assemblies will be inspected by 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 found the applicant will evaluate them and take appropriate corrective actions.

The staff reviewed the current status of the repaired hardware and the overall structural integrity of the shroud. No particular degradation was found since the shroud had been repaired. The applicant has augmented inspections of the shroud, as well as the repaired hardware, following the BWRVIP-76 recommendations. The staff determined that the applicant's aging management of cracking of the core shroud is consistent with the recommendations in the GALL Report.

LRA Table 3.1.2.1.4 for reactor internals credits the BWR Vessel Internals and Water Chemistry Programs to manage cracking due to SCC, IGSCC, and IASCC in stainless steel and nickel alloy reactor vessel spargers.

The staff noted that instances of cracking in BWR core spray spargers have been reviewed in NRC Bulletin 80-13. Core spray spargers at OCGS have experienced cracking since the late seventies. In light of this condition, the staff asked the applicant 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 Programs, as stated in LRA Table 3.1.2.1.4, during the period of extended operation.

In its response, the applicant stated that it had found 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 found 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 and as a result nine additional mechanical clamps were installed. All four tee boxes on both spargers were clamped. The primary root cause of the cracking problems found in 1978 and 1980 was reported to be high residual stresses on the sparger pipes from having been forced 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 any 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 the good condition of the repair clamps. Inspection of the core spray piping welds has confirmed the success of the mitigation efforts of the Water Chemistry Program as no new crack indications have been found. The core spray piping and spargers inside the reactor vessel 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 Code Section XI requirements for the core spray internals. As prescribed by BWRVIP-18-A, during each refueling outage the following components are evaluated by EVT-1 enhanced visual examination methods: accessible core spray piping fillet welds, 25 percent of the core spray piping brackets, 25 percent of the core spray piping butt welds, end cap welds, and T-box cover plate welds. The following components are examined by 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 the inspections identified above will be continued in accordance with BWRVIP-18-A guidelines. If indications are found the applicant will evaluate them and take appropriate corrective actions.

The staff reviewed the status of the repaired hardware and the overall structural integrity of the core spray piping and spargers. No particular degradation was found since the core spray spargers had been repaired. The applicant has augmented inspections of the core spray piping and the repaired hardware following the BWRVIP-18-A recommendations accepted by the staff. The staff concludes that the applicant adequately manages aging of the core spray spargers.

3.1.2.1.2 Cracking Due to SCC of Control Rod Drive Stub Tubes

LRA Table 3.1.2.1.5 for the RPV credits the BWR Penetrations, BWR Vessel Internals, and Water Chemistry Programs to manage cracking due to SCC, IGSCC, and cyclic loading in stainless steel and nickel alloy penetrations for CRD stub tubes exposed to reactor coolant.

During the audit, the staff noted that several CRD stub tubes at OCGS had been leaking recently and that roll expansion repairs had been performed to limit this leakage. In light of this condition, the staff asked the applicant 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 Programs, as stated in LRA Table 3.1.2.1.5, during the period of extended operation.

In its response, the applicant stated that due to the stub tube leakage in the bottom head found in 2000, OCGS has committed to perform inspections for leakage whenever the drywell is made accessible during outages. 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, then weld repairs will be made for leaking stub tubes that cannot be made leak tight by a roll repair prior to restarting the plant.

The staff reviewed the current status of the stub tubes and their repair, and the overall structural integrity of the vessel bottom head. No degradation was found since the stub tubes had been repaired. The applicant has augmented inspections of these stub tubes following the BWRVIP recommendations accepted by the staff.

In its response to RAI B1.9-3 dated April 18, 2006, the applicant committed (Commitment No. 9) to revise LRA Section B.1.9 to clarify its position on the use of roll/expansion techniques for the repair of leaking CRD stub tubes to result in no leakage of the CRD of the stub tubes during the period of extended 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.

On the basis of its review, the staff finds that the applicant has appropriately addressed the aging effect and mechanism based on the commitment and that the programs provide reasonable assurance that the CRD stub tube welds will perform their intended functions during the period of extended operation.

3.1.2.1.3 Loss of Material Due to Pitting and Crevice Corrosion

The staff 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 RVI components exposed to reactor water, GALL Report item 3.1.1-47. This new AMR was not in the January 2005 draft 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 the BWR Vessel Internals Program to manage this aging effect.

In its letter dated March 30, 2006, the applicant committed (Commitment No. 9) to revising 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 Program will manage this aging effect.

The staff reviewed the applicant's commitment and noted that the GALL Report recommends both the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and Water Chemistry Programs to manage loss of material for these RVI components. The staff reviewed the BWR Vessel Internals Program and determined that it is part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. In addition, although the applicant did not specifically identify the Water Chemistry Program as one of the AMPs to manage this aging effect, the staff recognized these RVI components are exposed to reactor water and that the quality of this water is treated in accordance with BWRVIP-130. Thus, because the applicant will follow the recommendations established in BWRVIP-130, the staff finds the use of the BWR Vessel Internals Program to manage this aging effect acceptable.

3.1.2.1.4 Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS)

The staff reviewed the aging effects due to thermal aging and neutron embrittlement of CASS materials in the RVI components listed in LRA Table 3.1.2.1.4.

The GALL Report recommends GALL AMP XI.M13, "Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel," for managing thermal aging and neutron embrittlement of CASS materials in the following RVI components:

- control rod assemblies (housing and guide tube)
- core spray lines
- core spray nozzle elbows
- fuel support pieces.

In LRA Table 3.1.2.1.4, the applicant indicated that the Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel Program will be implemented to monitor the aging effect due to thermal aging and neutron embrittlement of the CASS RVI components.

The staff's review of LRA Section 3.1.2.1 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.1.1-5 dated March 20, 2006, the staff requested that the applicant provide information on these components for an assessment of their susceptibility to thermal and neutron irradiation embrittlement. Specifically, the staff requested that the applicant provide the following information:

- type of casting (i.e., centrifugal or static)
- composition of CASS (i.e., molybdenum content and delta ferrite values)
- previous plant-specific experience with the components cracked due to neutron and thermal embrittlement and the type and extent of subsequent inspection of CASS orificed fuel support components with fluence values based on the end of the period of extended operation.

In its response dated April 18, 2006, the applicant stated that it would obtain information on the type and the composition of the CASS material in RVI components and evaluate their susceptibility to thermal and neutron irradiation embrittlement prior to the period of extended operation. The staff requested that the applicant submit this evaluation to the staff for review and approval prior to the period of extended operation.

In its supplemental letter dated July 7, 2006, the applicant modified the UFSAR and its commitment (Commitment No. 10) to specify that the following will be submitted for NRC review at least 1 year prior to entering the period of extended operation:

- type and composition of CASS RVI components within the scope of license renewal
- results of evaluations performed to determine susceptibility to thermal aging and neutron irradiation embrittlement

The staff finds this acceptable because the applicant's proposed Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel Program for monitoring the aging effect of the CASS materials is consistent with GALL AMP XI.M13. The staff's concern described in RAI 3.1.1-5 is resolved.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes, that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.1.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.1.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report, for the reactor vessel, internals, and RCS components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to stress corrosion cracking and intergranular stress corrosion cracking
- crack growth due to cyclic loading
- loss of fracture toughness due to neutron irradiation embrittlement and void swelling
- cracking due to stress corrosion cracking
- cracking due to cyclic loading
- loss of preload due to stress relaxation
- loss of material due to erosion
- cracking due to flow-induced vibration
- cracking due to stress corrosion cracking and irradiation-assisted stress corrosion cracking
- cracking due to primary water stress corrosion cracking
- wall thinning due to flow-accelerated corrosion
- changes in dimensions due to void swelling
- cracking due to stress corrosion cracking and primary water stress corrosion cracking
- cracking due to stress corrosion cracking, primary water stress corrosion cracking, and irradiation-assisted stress corrosion cracking
- quality assurance for aging management of nonsafety-related components

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant had claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria of SRP-LR Section 3.1.2.2. Details of the staff's audit are documented in the Audit and Review Report Section 3.2.1.1. The staff's evaluation of the aging effects is discussed in the following sections.

3.1.2.2.1 Cumulative Fatigue Damage

In 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). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

The staff 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 CUFs), because the plant was originally designed based on ASME Power Piping Code B31.1. Specifically, in LRA Tables 3.1.2.1.4 and 3.1.2.1.5, the applicant credited TLAA to manage cumulative fatigue damage for certain components. The applicant was asked to confirm that the CUFs 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 AMP in LRA Tables 3.1.2.1.4 and 3.1.2.1.5 indicates that the CLB 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 AMP for the cumulative fatigue aging effect have no fatigue analyses. These components include the reactor internals (LRA Table 3.1.1, item number 3.1.1-5) and the CRD return line nozzle and feedwater nozzle thermal sleeves (LRA Table 3.1.1, item number 3.1.1-2). With no 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, the applicant revised the AMR line items in LRA Tables 3.1.2.1.4 and 3.1.2.1.5 to delete the reference to TLAA for components where a TLAA does not exist. Further, the appropriate AMP 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."

The staff reviewed the applicant's response and finds that, although there is no fatigue analysis for several 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.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.1.2.2.2 and Attachment 7, items RP-25 and RP-27, of the applicant's reconciliation document against the criteria in SRP-LR Section 3.1.2.2.2.

In LRA Section 3.1.2.2.2.1, the applicant addressed loss of material due to general, pitting, and crevice corrosion 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.

SRP-LR Section 3.1.2.2.2.1 states 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 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.1.2.2.2.1 states that this is applicable to PWRs only. The staff finds the applicant's evaluation acceptable.

In LRA Section 3.1.2.2.2.2 the applicant addressed loss of material due to pitting and crevice corrosion in stainless steel BWR isolation condenser components exposed to reactor coolant.

SRP-LR Section 3.1.2.2.2.2 states 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.1.2.2.2.2 states that the Water Chemistry Program will be used to manage aging of stainless steel tube side components of the isolation condenser system exposed to reactor coolant. The program activities monitor and control water chemistry by 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 will be used with the Water Chemistry Program to manage loss of material. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be enhanced to inspect 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 does not occur and the component intended function will be maintained during the period of extended operation. Observed conditions with the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The staff's review of LRA Section 3.1.2.2.2.2 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

During a teleconference on February 2, 2006, the applicant indicated that thus far there had been no augmented inspections on isolation condenser components that the proposed augmented inspections will be applicable as parts of an AMP during the period of extended operation.

In RAI-3.1.1-1 dated March 20, 2006, the staff requested that the applicant provide information for an assessment of the effectiveness of the future augmented inspection program of the isolation condenser and its components. Specifically, the staff requested that the applicant provide the following:

- previous experience related to the frequency of occurrence of pitting and crevice corrosion in the isolation condenser and its components
- previous inspection methods and frequency implemented prior to the replacement of some of the isolation condenser components
- criteria for establishing future augmented inspection frequency

In its response dated April 18, 2006, the applicant stated the following:

> 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 piping at Oyster Creek require cutting and re-welding of pressure boundary piping in order to perform eddy current inspections of the tubes and gain access to the tubesheet and internal surfaces of the channel head. 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.

In a followup discussion, the staff requested that the applicant clarify its planned corrective action activities if any tube leakage was observed. In its letter dated May 3, 2006, the applicant stated:

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 staff reviewed the applicant's response and determined that the Water Chemistry and ASME Section XI ISI, Subsection IWB, IWC, and IWD Programs and the commitment (Commitment No. 24) to perform one-time UT inspection of "B" isolation condenser are adequate to manage loss of material due to pitting and crevice corrosion in stainless steel BWR isolation condenser components. As identified above, the staff concludes that the loss of material in the isolation condenser components exposed to reactor coolant will be adequately managed by the ASME Section XI ISI, Subsection IWB, IWC, and IWD, and Water Chemistry Programs.

The staff finds that, based on these programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.2.2 for further evaluation. The staff also finds 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. The staff's concerns described in RAI 3.1.1-1 are resolved.

In Attachment 7, items RP-25 and RP-27, of its reconciliation document, the applicant addressed 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.

SRP-LR Section 3.1.2.2.2.3 states that loss of material due to pitting and crevice corrosion can 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

Attachment 7, item RP-25, of the applicant's reconciliation document states 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 by 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, the applicant revised 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.

The staff reviewed the applicant's Water Chemistry Program and verified that this AMP includes activities for managing loss of material due to pitting and crevice corrosion. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that this AMP includes inspections of the reactor pressure vessel (RPV) to detect loss of material as a means of verifying the effectiveness of the Water Chemistry Program. The staff concludes 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.

Attachment 7, item RP-27, of the applicant's reconciliation document states that for piping, piping components, and piping elements in RCPB systems and systems with RCPB interface the LRA refers to 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) by the Water Chemistry and One-Time Inspection Programs in conformance with the September 2005 GALL Report.

The staff reviewed GALL Report line items EP-32, A-58, and AP-57 and determined that these line items address loss of material due to pitting and crevice corrosion of stainless steel in treated water and recommend the Water Chemistry and One-Time Inspection Programs to manage this aging. Therefore, the staff finds the applicant's evaluation acceptable because it follows the recommendations in the GALL Report. The staff concludes that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.2.3 for further evaluation.

The applicant did not address 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 for the further evaluation in SRP-LR Section 3.1.2.2.2.4, which applies to PWRs only. The staff finds that this aging effect does not apply to OCGS because it is a BWR plant.

The staff concludes that the applicant has met the criteria of SRP-LR Section 3.1.2.2.2. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is following the recommendations in the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reactor Vessel Internal (RVI) Components. GALL Report item IV.B1-15 requires implementation of GALL AMPs XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD," and XI.M2, "Water Chemistry," to manage aging effects due to pitting and crevice corrosion in stainless steel and nickel-alloy materials in RVI components. This requirement was not included in LRA Table 3.1.2.1.4.

The staff's review identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.1.2.1-2 dated March 20, 2006, the staff requested that the applicant address these aging effects in LRA Table 3.1.2.1.4.

In its response dated April 18, 2006, the applicant stated that it would revise the Reactor Vessel Internals Program to monitor pitting and crevice corrosion in RVI components. The applicant claimed that by control of RCS water chemistry and by frequent inspections per the ASME Code Section XI ISIs, the aging effects would be adequately managed during the period of extended operation. The applicant committed (Commitment No. 9) to include this new inspection requirement in the UFSAR.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.1.2.2.2. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is following the recommendations of the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the criteria in SRP-LR Section 3.1.2.2.3.

In LRA Section 3.1.2.2.3.1, the applicant addressed neutron irradiation embrittlement for all ferritic materials with a neutron fluence greater than 10^{17} n/cm^2.

SRP-LR Section 3.1.2.2.3.1 states 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/cm^2 (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.

LRA Section 3.1.2.2.3.1 states that the effects of increased neutron fluence on the fracture toughness of the reactor vessel beltline plates and welds is discussed in LRA Section 4.2. The impact on the vessel's pressure-temperature curves and weld exam requirements are also discussed in LRA Section 4.2.

TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is evaluated in SER Section 4.2.

In LRA Section 3.1.2.2.3.2, the applicant addressed loss of fracture toughness for reactor vessel beltline shell, nozzle, and welds.

SRP-LR Section 3.1.2.2.3.2 states 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 Surveillance Program monitors neutron irradiation embrittlement of the reactor vessel. The Reactor Vessel Surveillance Program is plant-specific, depending on such matters 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 in GALL Report Chapter XI, Section M31.

LRA Section 3.1.2.2.3.2 states that the Reactor Vessel Surveillance Program is based on the BWR ISP and satisfies the requirements of 10 CFR Part 50, Appendix H. The Reactor Vessel Surveillance Program includes periodic testing of metallurgical surveillance samples to monitor the progress of neutron embrittlement of the RPV as a function of neutron fluence, in accordance with 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. The applicant will continue the ISP during the period of extended operation by implementing the requirements of BWRVIP-116 and by addressing any additional actions required by the SER associated with BWRVIP-116 after it is approved. Observed conditions that have potential impact on the intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Reactor Vessel Surveillance Program and concludes that, according to the recommendations in the GALL Report, it is adequate 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.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.1.2.2.3. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is following the recommendations of the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

In LRA Section 3.1.2.2.4.2, the applicant addressed cracking due to SCC and IGSCC in the stainless steel and nickel alloy BWR top head enclosure vessel flange leak detection lines.

SRP-LR Section 3.1.2.2.4.1 states that cracking due to SCC and IGSCC can occur in the stainless steel and nickel alloy BWR top head enclosure vessel flange leak detection lines. The GALL Report recommends evaluation of a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting cracking due to SCC and IGSCC.

In LRA Section 3.1.2.2.4.2, the applicant stated that it will use the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to ensure that the reactor vessel flange leak detection lines do not experience aging effects caused by SCC and IGSCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD 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 potential impact on the intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it is consistent with the GALL Report and will adequately manage the effects of SCC 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 staff concludes that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.4.1 for further evaluation.

In LRA Section 3.1.2.2.4.3, the applicant addressed cracking due to SCC and IGSCC in stainless steel BWR isolation condenser components exposed to reactor coolant.

SRP-LR Section 3.1.2.2.4.2 states that cracking due to SCC and IGSCC can 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 Code Section XI ISI. However, the existing program should be augmented to detect cracking due to SCC and IGSCC. The GALL Report recommends that an augmented program 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.

LRA Section 3.1.2.2.4.3 states that the Water Chemistry Program will be used to manage aging of stainless steel tube side components of the isolation condenser system exposed to reactor coolant. The program provides for monitoring and controlling of water chemistry by station procedures and processes for the prevention or mitigation of cracking due to SCC and IGSCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used with the Water Chemistry Program to manage the aging effects of SCC and IGSCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be enhanced to inspect 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 does not occur and that the component intended function will be maintained during the period of extended operation. Observed conditions with a potential impact on the intended function will be evaluated or corrected in accordance with the corrective action process.

During a teleconference dated February 2, 2006, the applicant indicated that thus far no augmented inspections had been performed on isolation condenser components and that the proposed augmented inspections will be applicable as a part of an AMP during the period of extended 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:

- previous experience related to the frequency of occurrence of SCC and IGSCC in the isolation condenser and its components
- previous inspection methods and frequency implemented prior to the replacement of some of the isolation condenser components
- criteria for establishing future augmented inspection frequency

In its response dated April 18, 2006, the applicant stated:

> 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.

In a followup discussion, the staff asked the applicant to clarify its planned corrective action activities if any tube leakage was observed. In its letter 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 staff reviewed the applicant's response, Water Chemistry Program, and ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program and determined that these programs and the commitment (Commitment No. 24) to perform one-time UT inspection of “B” isolation condenser are adequate to manage cracking due to SCC and IGSCC in stainless steel BWR isolation condenser components exposed to reactor coolant. The staff determined that the aging effects due to SCC and IGSCC of isolation condenser system components will be adequately managed by the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD, and Water Chemistry Programs. As identified above, the staff concludes that the applicant's programs met the criteria of SRP-LR Section 3.1.2.2.4.2 for further evaluation. The staff's concerns described above are resolved.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.1.2.2.4. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant's programs are consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation.

Stainless Steel Reactor Vessel Attachment Welds. The AMPs recommended by the GALL Report for managing cracking due to SCC, IGSCC, and cyclic loading for the RPV attachment welds are GALL AMPs XI.M4, "BWR Vessel Inner Diameter (ID) Attachment Welds," and XI.M2, "Water Chemistry."

In LRA Table 3.1.2.1.5, the applicant identified SCC as an aging effect for the stainless steel RPV attachment welds. The applicant stated that the Water Chemistry Program will be used to manage this aging effect. The applicant further stated that the Water Chemistry Program is consistent with GALL AMP XI.M2 with one exception. In SER Section 3.0.3.2.2, the staff evaluated the requirements of the Water Chemistry Program and determined that it is consistent with the recommendations of GALL AMP XI.M2.

The applicant indicated that the BWR Vessel ID Attachment Welds Program will manage aging degradation of the RPV attachment welds. The BWR Vessel ID Attachment Welds Program invokes the inspection requirements specified in the BWRVIP-48 Report, "Vessel ID Attachment Weld Inspection and Evaluation Guidelines," and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is consistent with GALL AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, IWD," with one exception. In SER Section 3.0.3.2.1, the staff evaluated the requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it is consistent with the recommendations of GALL AMP XI.M1.

The staff's review of LRA Section 3.1.2.2.4 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.1.1-2 dated March 20, 2006, the staff requested that the applicant provide details on the frequency and the method of inspection (as specified in the BWRVIP-48 Report,"Vessel ID Attachment Weld Inspection and Evaluation Guidelines") that will be implemented for the attachment welds. According to Section 2.2.3 of the BWRVIP-48 Report, furnace-sensitized stainless steel vessel ID attachment welds are highly susceptible to IGSCC. The applicant should identify whether there are any furnace-sensitized stainless steel attachment welds at the OCGS unit and explain what type of AMP is implemented, including details on any augmented inspections, for any existing furnace-sensitized stainless steel attachment welds.

In its response dated April 18, 2006, the applicant stated that the bracket materials and nickel-alloy attachment welds at OCGS were determined to have been furnace-sensitized during vessel fabrication. However, results of the previous inspections did not indicate any flaws in these attachment welds. As no flaws were identified in the furnace-sensitized attachment welds, as identified above, the staff concludes that so far there has been no aging degradation in these attachment welds. The applicant further stated that the attachment welds would be inspected in accordance with the requirements of ASME Code Section XI and the BWRVIP-48 Report.

The staff finds that, by implementing these inspection requirements, the applicant has demonstrated that it would adequately manage the aging degradation of the RPV attachment welds for the period of extended operation. The staff also concludes that the implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, Chemistry Control Program, and the BWR ID Attachment Welds Program would be consistent with the GALL AMPs XI.M1, XI.M2 and XI.M4, respectively. Based on its review, the staff finds this implementation acceptable. The staff's concern described in RAI 3.1.1-2 is resolved.

Reactor Vessel Penetrations. AMPs recommended by the GALL Report for managing cracking due to IGSCC for the RPV penetrations are GALL AMPs XI.M8, "BWR Penetrations," and XI.M2, "Water Chemistry." The GALL AMP XI.M8, recommends that inspection and flaw evaluation guidelines specified in the BWRVIP-27 Report, "BWR Standby Liquid Control System/Core Plate delta P Inspection and Flaw Evaluation Guidelines," should be implemented for the RPV penetrations. The GALL AMP for the RPV penetrations also includes implementation of guidelines specified in the BWRVIP-49 Report, "Instrumentation Penetration Inspection and Flaw Evaluation Guidelines."

In LRA Table 3.1.2.1.5, the applicant indicated that nickel-alloy and stainless steel materials in the RPV penetration welds experience cracking due to SCC when exposed to a treated-water environment. The applicant stated that the Water Chemistry Program will monitor this aging effect. In SER Section 3.0.3.2.2 the staff evaluated the requirements of the Water Chemistry Program and determined that it would be consistent with the recommendations specified in GALL AMP XI.M2. The applicant also credits the BWR Penetrations Program to manage this aging effect. The BWR Penetrations Program references the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for monitoring aging effects of the RPV penetrations. In SER Section 3.0.3.2.1, the staff evaluated the requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it would be consistent with the recommendations specified in GALL AMP XI.M1.

GALL AMP XI.M8 recommends that the inspection requirements specified in the staff's approved versions of the BWRVIP-27 and BWRVIP-49 reports and in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program should be implemented for inspecting the BWR RPV penetration welds (i.e., category B-E for pressure-retaining partial penetration welds, category B-D for full penetration nozzle-to-vessel welds, category B-F for pressure-retaining dissimilar metal nozzle-to-safe end welds, and category B-J for similar metal nozzle-to-safe end welds). The extent and schedule of inspection prescribed by the staff's approved versions of BWRVIP-27 and BWRVIP-49 reports and in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program would ensure that the aging effects will be discovered and repaired before the loss of intended function of the RPV penetration welds.

The applicant provided PBD-B.1.08, "Oyster Creek License Renewal Project BWR Penetration," which addresses the inspection methods, inspection frequency, and mitigation methods implemented in the AMP for the RPV penetration welds (including dissimilar welds). The staff reviewed this document and concludes that the applicant has adequately demonstrated its capability in managing the aging degradation of the RPV penetration welds for the period of extended operation. Furthermore, implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and BWR Penetrations Programs would be consistent with GALL AMPs XI.M2 and XI.M8. The staff finds this implementation acceptable.

Reactor Vessel Nozzles and Safe Ends. The AMPs recommended by the GALL Report for managing cracking due to SCC, IGSCC, and cyclic loading for the RPV nozzles and safe ends are GALL AMPs XI.M7, "BWR Stress Corrosion Cracking," and XI.M2, "Water Chemistry."

In LRA Table 3.1.2.1.5, the applicant identified IGSCC as an aging effect for the stainless steel RPV safe ends, safe end-to-nozzle welds, and safe end-to-piping welds. The applicant stated that the Water Chemistry Program will be used to manage this aging effect. In SER Section 3.0.3.2.2, the staff evaluated the requirements of the Water Chemistry Program and determined that it would be consistent with the recommendations specified in GALL AMP XI.M2. The applicant indicated that it would credit the BWR Stress Corrosion Cracking Program for managing the aging degradation of the RPV safe ends, safe end-to-nozzle welds, and safe end-to-piping welds. The BWR Stress Corrosion Cracking Program refers to the requirements of the following documents in the AMP for the RPV safe ends, safe end-to-nozzle welds, and safe end-to-piping welds:

- NUREG-0313, Revision 2, "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 BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules"
- BWRVIP-130, "BWR Vessel and Internals Project, BWR Water Chemistry Guidelines"
- ASME Code Section XI, "Rules For Inservice Inspection of Nuclear Power Plant Components"

In RAI 3.1.1-4(B) dated March 20, 2006, the staff requested that the applicant state whether the dissimilar metal welds between RPV nozzles and their safe ends had previously experienced cracking due to SCC, IGSCC, or cyclic loading and the extent of any cracking. The staff also requested that the applicant provide information regarding the extent of mitigative techniques (i.e., structural overlay, mechanical stress improvement) implemented to mitigate crack propagation due to IGSCC in the dissimilar metal welds between RPV nozzles and their safe ends. The applicant was also requested to provide information on the inspection methods, sample size, and the inspection frequency used thus far for these welds and the inspection results. Finally, the applicant was requested to provide its basis for using the current inspection program as an effective AMP in monitoring the aging effect due to IGSCC in the welds.

In its response dated April 18, 2006, the applicant stated that previous inspections of the dissimilar metal welds in nozzles, safe end components, and piping revealed no cracking. The applicant further stated that it had implemented mechanical stress improvement, hydrogen water chemistry, and induction heating stress improvement as mitigative methods to reduce the susceptibly to IGSCC. The applicant claimed that by implementing these mitigative methods it could effectively manage the aging effects due to IGSCC in the dissimilar welds between the RPV nozzles and their safe ends.

The staff finds the response acceptable because the applicant's proposed mitigation and inspection methods for the similar and dissimilar metal welds between the RPV nozzle and safe end and between the safe end and connected piping would enable the applicant to identify IGSCC promptly. Implementation of the Water Chemistry and BWR Stress Corrosion Cracking Programs would be consistent with GALL AMPs XI.M2 and XI.M7, respectively. The staff finds this implementation acceptable. Therefore, the staff's concern described in RAI 3.1.1-4(B) is resolved.

Reactor Head Closure Studs. GALL AMP XI.M3, "Reactor Head Closure Studs," recommends implementation of preventive actions specified in RG 1.65, "Materials and Inspections for RPV Closure Studs," to manage the cracking due to SCC for the reactor head closure studs.

In LRA Table 3.1.2.1.5, the applicant indicated that the Reactor Head Closure Studs Program will be implemented to monitor the aging effect due to SCC of the reactor head closure studs. This program credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage SCC. In SER Section 3.0.3.2.1, the staff evaluated the requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it would be consistent with the recommendations specified in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD." The applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is an established AMP with appropriate requirements for inspecting the reactor head closure studs. The applicant also stated that the following requirement will be included in the Reactor Head Closure Studs Program:

> Mitigation of cracking is achieved by complying with the recommendations of RG 1.65, "Materials and Inspections for RPV Closure Studs." Approved lubricants will be used to minimize the potential for cracking of the non-metal-plated reactor head closure studs.

Previous industry experience indicates that SCC occurs in metal-plated BWR reactor head closure studs. The applicant stated that there are no metal-plated reactor head closure studs in use at OCGS and that approved lubricants are used to prevent seized studs or nuts. The applicant claimed that with the lack of metal plating and the preventive use of approved lubricants, the Reactor Head Closure Studs Program has been effective in managing SCC of the reactor head closure studs. The applicant concluded in its LRA that the program provides reasonable assurance that the aging effect due to cracking in the reactor head closure studs is adequately managed so that intended functions will be maintained consistent with the CLB during the period of extended operation.

The applicant provided Program Basis Document PBD-B.1.03, "Oyster Creek License Renewal Project Reactor Head Closure Studs," which addresses the inspection methods, inspection frequency, and mitigation methods implemented in the AMP for the reactor head closure studs. The staff reviewed this document and concludes that the applicant had adequately demonstrated its capability in managing the aging degradation of the reactor head closure studs for the period of extended operation.

The staff reviewed the Reactor Head Closure Studs Program and concludes that the reactor head closure studs would be less likely to experience SCC because these closure studs were not metal plated and approved lubricants were used for their maintenance at OCGS. The staff finds that the implementation of the Reactor Head Closure Studs Program would enforce frequent inspections which would adequately identify aging effects of the reactor head closure studs. In addition, satisfying RG 1.65 guidance provides adequate assurance that the integrity of the reactor head closure studs will be maintained. The staff also concludes that the implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and Reactor Head Closure Studs Programs would be consistent with the GALL AMPs XI.M1 and XI.M3, respectively. The staff finds this implementation acceptable.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5 states that cracking due to cyclic loading of PWR vessel shells with reference to further evaluation in SRP-LR Section 3.1.2.2.5, applies to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable to OCGS because it is a BWR plant.

Feedwater Nozzles. The AMP recommended by the GALL Report for managing cracking due to cyclic loading for the feedwater nozzles is GALL AMP XI.M5, "BWR Feedwater Nozzle," which recommends implementation of the inspection requirements specified in the GE NE-523-A71-0594 Report, "Alternate BWR Feedwater Nozzle Inspection Requirements," for the feedwater nozzles.

The applicant included the BWR Feedwater Nozzle Program for managing the aging effect of cracking due to cyclic loading in the feedwater nozzles at the OCGS unit. The applicant also credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for monitoring the aging degradation of the feedwater nozzles. In SER Section 3.0.3.2.1, the staff evaluated the requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it would be consistent with the recommendations specified in GALL AMP XI.M1. The applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is an established AMP with appropriate requirements for inspecting the feedwater nozzle components. The applicant also stated that by implementing the recommendations of the GE-NE-523-A71-0594 Report in conjunction with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program the aging degradation of the feedwater nozzle would be identified promptly.

The applicant provided Program Basis Document PBD-B.1.05, "Oyster Creek License Renewal Project BWR Feed Water Nozzle," which addresses the inspection methods, inspection frequency, and mitigation methods implemented in the AMP for the feedwater nozzle. The staff reviewed this document and concludes that the applicant has adequately demonstrated its capability in managing the aging degradation of the feedwater nozzle for the period of extended operation. Furthermore, implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and BWR Feedwater Nozzle Programs would be consistent with GALL AMPs XI.M1 and XI.M5, respectively. The staff finds this implementation acceptable.

The staff's review of LRA Section 3.1.2.2.5 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.1.1-4(A) dated March 20, 2006, the staff stated that the BWR Feedwater Nozzle Program refers to the GE-NE-523-A71-0594 Report, which is not the staff-approved version. The staff requested that applicant to confirm that it will implement the recommendations of Revision 1, Version A, of the report (GE-NE-523-A71-0594-A, Revision 1) approved by the staff.

In its response dated April 18, 2006, the applicant committed (Commitment No. 5) to implement the recommendations of the GE-NE-523-A71-0594-A, Revision 1, Report as a part of the BWR Feedwater Nozzle Program. Based on applicant's response, the staff determined that its concern described in RAI 3.1.1-4(A) is resolved.

CRD Return Line Nozzle. GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle," recommends that enhanced inspection recommendations in NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," should be implemented for the CRD return line nozzles for managing the cracking due to cyclic loading for the CRD return line nozzle.

LRA Table 3.1.2.1.5 refers to the BWR Control Rod Drive Return Line Nozzle Program for managing this aging effect in the CRD return line. The applicant indicated that inspections specified in NUREG-0619 will be implemented for monitoring the aging degradation in the CRD return line. The BWR Control Rod Drive Return Line Nozzle Program in turn credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. In SER Section 3.0.3.2.1, the staff evaluated the requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and determined that it would be consistent with the recommendations in GALL AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, IWD." The BWR Control Rod Drive Return Line Nozzle Program has appropriate requirements for inspecting the CRD return line nozzle components and is consistent with the GALL AMP XI.M6. The applicant's augmented ISI program for the CRD return line nozzle includes UT in lieu of liquid PT. The applicant previously requested and received staff approval to substitute UT examinations for the PT examinations recommended for the CRD return line nozzle welds by NUREG-0619.

The staff's review identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAIs as discussed below.

In RAI 3.1.1-3(A) dated March 20, 2006, the staff stated that LRA Table 3.1.1, item number 3.1.1-36, indicates that augmented inspection for the CRD return line weld is required in accordance with the requirements of NUREG-0619, which recommends a periodic examination by a PT technique to evaluate the aging effects in the CRD return line weld. The BWR Control Rod Drive Return Line Nozzle Program states that the applicant obtained approval from the staff to substitute UT for PT as a part of the augmented inspection program and that this approval applies to the current ISI interval. Therefore, the staff requested that the applicant provide justification for continuing UT inspections in lieu of PT for the subject weld during the period of extended operation.

In response dated April 18, 2006, the applicant stated that the staff's approval for the substitution of UT for PT for the CRD nozzle was not limited to the current ISI interval and would be valid for the period of extended operation. The applicant claimed that the application of the latest PDI technology in the UT examinations would provide equivalent or improved means of detecting cracking as compared to the PT examinations. In addition, the application of PT methods would require removal of the thermal sleeve, resulting in exposure of plant personnel to significant radiation.

The staff reviewed the applicant's response and concludes that the application of the PDI qualified UT examinations will adequately identify any cracks in the CRD nozzle promptly and, therefore, the staff's concern described in RAI 3.1.1-3(A) is resolved.

In RAI 3.1.1-3(B) dated March 20, 2006, the staff requested that the applicant provide information on whether the CRD return line nozzle had been capped. If the CRD return line nozzle had been capped, the staff requested that the applicant provide the following information about the cap and the weld:

(1) Configuration, location, and material of construction of the capped nozzle including the existing base material for the nozzle, piping (if piping remnants exist) and cap material, and any welds.

(2) Inspection criteria for this weld and cap in accordance with the guidelines of BWRVIP-75, "BWR Vessel and Internals Project (BWRVIP), Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule."

(3) The effect of the event at Pilgrim Nuclear Power Station (leaking weld at capped nozzle, September 30, 2003) on the OCGS unit. The staff's IN 2004-08, "Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds," dated April 22, 2004, stated that the cracking occurred in a nickel-alloy 182 (trade name) weld previously repaired extensively. The staff requested that the applicant provide information on the plant experience with previous leakage at the capped nozzle including the past inspection techniques applied, the results obtained, and mitigative strategies imposed.

In its response dated April 18, 2006, the applicant stated that the CRD return line has not been capped and therefore, RAIs 3.1.1-3(B) (1) through (3) would not be applicable to OCGS. The applicant claimed that implementation of the BWR Control Rod Drive Return Line Nozzle Program and the prior installation of an improved thermal sleeve design inside the nozzle bore ensures that the aging effect in the CRD return line nozzle is effectively managed.

The staff finds that the implementation of the BWR CRD Return Line Nozzle and ASME Section XI Inservice Inspection Programs for the CRD return lines would be consistent with GALL AMP XI.M6. The staff finds this implementation acceptable. The staff's concerns described in RAI 3.1.1-3(B) are resolved.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

LRA Section 3.1.2.2.6 states that loss of fracture toughness of PWR reactor internals with reference to the further evaluation in SRP-LR Section 3.1.2.2.6 applies to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.7 Cracking Due to Stress Corrosion Cracking

LRA Section 3.1.2.2.7 states that cracking due to SCC for PWR stainless steel reactor flange leak detection lines with reference to the further evaluation in SRP-LR Section 3.1.2.2.7.1, applies to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect does not apply to OCGS because it is a BWR plant.

LRA Section 3.1.2.2.7 states that cracking due to SCC of PWR Class 1 CASS piping, piping components, and piping elements, with reference to the further evaluation in SRP-LR Section 3.1.2.2.7.2, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.8 Cracking Due to Cyclic Loading

The staff reviewed LRA Sections 3.1.2.2.8 and 3.1.2.2.4.3 against the criteria in SRP-LR Section 3.1.2.2.8.

LRA Section 3.1.2.2.8 states that cracking due to cyclic loading for jet pump sensing lines, with reference to the further evaluation in SRP-LR Section 3.1.2.2.8.1, does not apply. OCGS has no jet pumps or jet pump sensing lines. The staff determined that the OCGS reactor has no jet pumps and, therefore, the staff finds acceptable the applicant's assessment that this aging effect and mechanism is not applicable.

In LRA Section 3.1.2.2.4.3, the applicant addressed cracking due to cyclic loading in steel and stainless steel BWR isolation condenser components exposed to reactor coolant.

SRP-LR Section 3.1.2.2.8.2 states that cracking due to cyclic loading can occur in steel and stainless steel BWR isolation condenser components exposed to reactor coolant. The existing program relies on ASME Code Section XI ISI, but 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.

LRA Section 3.1.2.2.4.3 states that the Water Chemistry Program will be used to manage aging of stainless steel tube side components of the isolation condenser system exposed to reactor coolant. The program activities monitor and control water chemistry by station procedures and processes for the prevention or mitigation of cracking due SCC and IGSCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used with the Water Chemistry Program to manage the aging effects of SCC and IGSCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be enhanced to inspect 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 does not occur and that the component intended function will be maintained during the period of extended operation. Observed conditions with potential impact on the intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Programs 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 staff finds that the augmented inspections proposed by the applicant for the ASME Section XI ISI, Subsections IWB, IWC, and IWD Program are consistent with the GALL Report recommendations. The staff concludes that the applicant's programs meet the criteria of SRP-LR Section 3.1.2.2.8.2 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.1.2.2.8. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant's programs are consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR Part 54.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

LRA Section 3.1.2.2.9 states that loss of preload due to stress relaxation of PWR RVI components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.9, applies to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.10 Loss of Material Due to Erosion

LRA Section 3.1.2.2.10 states that loss of material due to erosion of PWR steam generator components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.10, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11.

In LRA Section 3.1.2.2.11, the applicant addressed cracking due to flow-induced vibration for the BWR stainless steel steam dryers exposed to reactor coolant.

SRP-LR Section 3.1.2.2.11 states that cracking due to flow-induced vibration can occur in BWR stainless steel steam dryers exposed to reactor coolant. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of this aging effect.

LRA Section 3.1.2.2.11 states that the BWR Vessel Internals Program will be used to manage 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 with potential impact on the intended function are evaluated or corrected in accordance with the corrective action process.

During the audit, the applicant was asked to describe how cracking in the steam dryer will be managed by the BWR Vessel Internals and Water Chemistry Programs during the period of extended operation. In its response, the applicant 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 OCGS inspection is not impacted by the comments on SIL 644 from the staff to the BWROG in January 2005 (Letter Report from Robert A Gramm of NRC to Kenneth S Putnam of BWROG, January 12, 2005). The NRC comments primarily address concerns about extended power uprate (EPU). The applicant has not implemented EPU, nor is such an implementation 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. The applicant will comply with the BWRVIP recommendations on steam dryer inspections. Any flaws found during inspections will be evaluated and reinspected if required. Performing the inspections in accordance with BWRVIP-139 provides reasonable assurance that the steam dryer will perform its intended function during the period of extended operation.

The staff 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 whether any new cracking is occurring and requiring further action. The staff concludes that the applicant's approach is acceptable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.1.2.2.11. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant's programs are consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR Part 54.

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking (IASCC)

LRA Section 3.1.2.2.12 states that cracking due to SCC and IASCC of PWR RVI components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.12, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.13 Cracking Due to Primary Water Stress Corrosion Cracking (PWSCC)

LRA Section 3.1.2.2.13 states that cracking due to primary water SCC of PWR components inside the reactor vessel, with reference to the further evaluation in SRP-LR Section 3.1.2.2.13, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

LRA Section 3.1.2.2.14 states that wall thinning due to flow-accelerated corrosion of PWR steam generator feedwater inlet ring and supports, with reference to the further evaluation in SRP-LR Section 3.1.2.2.14, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

LRA Section 3.1.2.2.15 states that changes in dimensions due to void swelling of PWR RVI components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.15, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.16 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

LRA Section 3.1.2.2.16.1 states that cracking due to SCC and primary water SCC of PWR CRD penetration components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.16.1, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

LRA Section 3.1.2.2.16.2 states that cracking due to SCC and primary water SCC of PWR pressurizer head spray components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.16.2, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it 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

LRA Section 3.1.2.2.17 states that cracking due to SCC, primary water SCC, and IASCC of PWR RVI components, with reference to the further evaluation in SRP-LR Section 3.1.2.2.17, applies to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect does not apply to OCGS because it is a BWR plant.

3.1.2.2.18 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program for safety-related and nonsafety-related components.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff determined that the applicant has adequately addressed the issues further evaluated. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.1.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.1.2.1.1 through 3.1.2.1.6, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.1.2.1.1 through 3.1.2.1.6, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is discussed in the following sections.

3.1.2.3.1 Isolation Condenser System – LRA Table 3.1.2.1.1

The staff reviewed LRA Table 3.1.2.1.1, which summarizes the results of AMR evaluations for the isolation condenser system component groups.

The applicant stated that it will manage Loss of Preload aging effect by implementing the Bolting Integrity Program. The Bolting Integrity Program complies with the recommendations of GALL AMP XI.M18, "Bolting Integrity," which recommends application of ASME Code Section XI, Subsection IWB, Table IWB 2500-1 requirements for the bolts included in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to monitor this aging effect. In addition, GALL AMP XI.M18 invokes the guidelines specified in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation Failure in Nuclear Power Plants." NUREG-1339 provides adequate technical bases and inspection guidelines as a part of the AMP for safety-related bolting. For bolts not included in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the applicant proposed to use routine inspection methods in its maintenance activities to identify any degradation of the closure bolting in the isolation condenser systems. The applicant's proposed AMP complies with the recommendations of NUREG-1339 for safety-related bolting and is consistent with the recommendations of GALL AMP XI.M18. The staff determined that the applicant's compliance with the recommendations specified in NUREG-1339 and in GALL AMP XI.M18 provides reasonable assurance that the aging degradation of safety-related bolting in the isolation condenser systems will be adequately managed at OCGS.

The applicant provided Program Basis Document PBD-B.1.12, "Oyster Creek License Renewal Project, Bolting Integrity Program," which addresses the inspection methods, inspection frequency, and mitigation methods implemented in the AMP for the closure bolting components. The staff reviewed this document and concludes that the applicant had adequately demonstrated its capability in managing the aging degradation of the closure bolting in the isolation condenser systems for the period of extended operation. The staff finds that, by implementing the Bolting Integrity Program, the applicant has demonstrated that the aging effect due to loss of pre-load in the stainless steel closure bolting (covered by ASME Code Section XI) will be adequately managed during the period of extended operation. The staff, however, recommended that the applicant comply with the inspection frequency specified in the "monitoring and trending" program element of the GALL AMP XI.18 for stainless steel closure bolting not covered by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff also concludes that the implementation of the Bolting Integrity Program would be consistent with the GALL AMP XI.M18.

In its supplemental letter dated July 7, 2006, the applicant modified its Bolting Integrity Program UFSAR to specify that if these non-ASME pressure retaining bolted joint connections are observed to be leaking, then the leakage will be evaluated as part of the corrective action process. The process may allow for pressure retaining components (not covered by ASME Code

Section XI) that are reported to be leaking to be inspected daily. If the leak rate does not increase, the inspection frequency will be decreased to biweekly or weekly. The staff finds this acceptable because it follows the recommendations in the GALL Report.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the isolation condenser system components 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).

3.1.2.3.2 Nuclear Boiler Instrumentation – LRA Table 3.1.2.1.2

The staff reviewed LRA Table 3.1.2.1.2, which summarizes the results of AMR evaluations for the nuclear boiler instrumentation component groups.

The applicant stated that it will manage Loss of Preload aging effect by implementing the Bolting Integrity Program. The Bolting Integrity Program complies with the recommendations of GALL AMP XI.M18, "Bolting Integrity." GALL AMP XI.M18 recommends application of ASME Code Section XI, Subsection IWB, Table IWB 2500-1 for bolts included in the ASME Code Section XI Program to monitor this aging effect. In addition, GALL AMP XI.M18 invokes the guidelines specified in NUREG-1339, which provides adequate technical bases and inspection guidelines as a part of the AMP for safety-related bolting. For closure bolts not included in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the applicant proposed to use routine inspection methods in its maintenance activities to identify any degradation of the closure bolting in the nuclear boiler instrumentation systems. The applicant's proposed AMP is consistent with the recommendations of NUREG-1339 for safety-related bolting and is consistent with the recommendations of GALL AMP XI.M18.

The staff determined that the applicant's consistency with the recommendations specified in NUREG-1339 and in GALL AMP XI.M18 provides reasonable assurance that the aging degradation of safety-related bolting in the nuclear boiler instrumentation systems will be adequately managed at OCGS.

The applicant provided Program Basis Document PBD-B.1.12, "Oyster Creek License Renewal Project, Bolting Integrity Program," which addresses the inspection methods, inspection frequency, and mitigation methods implemented in the AMP for the closure bolting components. The staff reviewed this document and concludes that the applicant had adequately demonstrated its capability in managing the aging degradation of the closure bolting in the nuclear boiler instrumentation system components for the period of extended operation. The staff determined that by implementing the Bolting Integrity Program the applicant demonstrated that the aging effect due to loss of pre-load of the stainless steel closure bolting in the nuclear boiler instrumentation systems (covered by ASME Code Section XI) will be adequately managed during the period of extended operation. The staff, however, recommended that the applicant adopt the inspection frequency specified in the "monitoring and trending" program element of the GALL AMP XI.18 for stainless steel closure bolting not covered by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff also concludes that implementation of the Bolting Integrity Program would be consistent with GALL AMP XI.M18.

In its supplemental letter dated July 7, 2006, the applicant modified its Bolting Integrity Program UFSAR to specify that if these non-ASME pressure retaining bolted joint connections are observed to be leaking, then the leakage will be evaluated as part of the corrective action process. The process may allow for pressure retaining components (not covered by ASME Code Section XI) that are reported to be leaking to be inspected daily. If the leak rate does not increase, the inspection frequency will be decreased to biweekly or weekly. The staff finds this acceptable because it follows the recommendations in the GALL Report.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear boiler instrumentation components 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).

3.1.2.3.3 Reactor Head Cooling System – LRA Table 3.1.2.1.3

The staff reviewed LRA Table 3.1.2.1.3, which summarizes the results of AMR evaluations for the reactor head cooling system component groups.

LRA Table 3.1.2.1.3 did not identify any aging effect for the carbon steel valve body exposed to RCS water. However, LRA Table 3.1.2.1.3 footnotes I-3 and I-4 state that the carbon steel valve body is not susceptible to SCC and IGSCC and that thus far no failures in carbon steel valve bodies due to SCC or IGSCC have been reported.

The staff's review identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.1.2.1-1(B) dated March 20, 2006, the staff requested that the applicant address whether there was any previous plant experience with cracking (due to SCC or IGSCC) in carbon steel valve bodies of the RPV head cooling system when exposed to treated water.

In its response dated April 18, 2006, the applicant stated that there are no carbon steel valve bodies in the reactor head cooling system. As there are no carbon steel valve bodies in the reactor head cooling system, the staff's concern described in RAI 3.1.2.1-1(B) is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor head cooling system components 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).

3.1.2.3.4 Reactor Internals – LRA Table 3.1.2.1.4

The staff reviewed LRA Table 3.1.2.1.4, which summarizes the results of AMR evaluations for the reactor internals component groups.

LRA Table 3.1.2.1.4 states that the AMRs for the reactor internals either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.1.2.1 and 3.1.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor internals components 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).

3.1.2.3.5 Reactor Pressure Vessel – LRA Table 3.1.2.1.5

The staff reviewed LRA Table 3.1.2.1.5, which summarizes the results of AMR evaluations for the RPV component groups.

LRA Table 3.1.2.1.5 identifies cracking as an aging degradation mechanism in the SA 105 Grade II carbon steel RPV components. The applicant stated that it will credit the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and Water Chemistry Programs to monitor this aging effect in the following RPV components:

- bottom head drain nozzle
- feedwater and main steam nozzles and safe ends
- vessel shell flange
- recirculation nozzles
- core spray nozzle
- isolation condenser nozzle
- top head nozzles
- top head flange
- bottom head
- RPV shell welds

The staff's review of LRA Section 3.1.2.1 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.1.2.1-1(A) dated March 20, 2006, the staff requested that the applicant provide the following information on the subject aging effect in the carbon steel components:

(1) previous plant experience with cracking in carbon steel RPV components when exposed to treated water

(2) any established mechanism of the cracking in carbon steel RPV components

(3) the scope and the techniques of the past inspections, the results obtained, applied mitigative methods, repairs, frequency of the inspections, and any other relevant information related to identification of the subject aging effect

In its response dated April 18, 2006, the applicant stated that thus far the only cracking experienced in the components was due to thermal fatigue of the feedwater nozzles, which were subsequently repaired. The applicant also has inspected the components (except the bottom head drain nozzle) in accordance with the ASME Code Section XI requirements and found no cracking. The applicant did not inspect the bottom head drain nozzles because they are exempt from ASME Code Section XI inspection (UT) requirements. Previous industry experience indicates that carbon steel bottom head nozzles are not prone to cracking.

The staff reviewed the applicant's response and concludes that there is no active aging degradation due to SCC in the bottom head nozzles. The carbon steel RPV components are not susceptible to SCC and with no previous failures identified in inspections of these components, the staff determined that there is no active aging degradation in these carbon steel RPV components. Therefore, the staff's concerns described in RAI 3.1.2.1-1(A) are resolved.

LRA Table 3.1.2.1.5 did not identify any aging effect specified in GALL Report Table V.C-1 for the carbon and low alloy steel RPV components. This table identifies loss of material due to general corrosion as an aging effect of the carbon and low alloy steel materials of the RPV components externally exposed to inside (atmospheric) environments. The applicant stated that based on past precedents (NUREG-1796, "Safety Evaluation Report Related to the License Renewal of Dresden Nuclear Power Station, Units 2 and 3 and Quad Cities Nuclear Power Station, Units 1 and 2," Section 3.1.2.4.1) the staff had concluded that the loss of material due to corrosion is not considered a credible aging effect for carbon steel components in a containment nitrogen environment because a negligible amount of free oxygen (less than 4 percent by volume) is present in this environment 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, the applicant determined that loss of material due to general corrosion would not be applicable to the following carbon steel RPV components:

- bottom head drain nozzle
- core spray nozzle
- CRD return line nozzle
- feedwater nozzle
- main steam nozzle
- isolation condenser nozzle
- re-circulation inlet and outlet nozzle
- top head flange
- top head enclosure head
- vessel bottom head
- vessel shell
- vessel shell flange
- nozzle safe ends (feedwater & main stream)

The staff finds the applicant's evaluation acceptable because the carbon and low-alloy steel components are exposed to negligible amounts of free oxygen and, therefore, are not likely to experience corrosion. In addition, the external surface of the carbon and low-alloy steel RPV components are exposed to an inside (atmospheric) environment containing no aggressive ions to cause loss of material due to corrosion. The staff concludes that in the absence of oxygen the carbon steel RPV components are not susceptible to corrosion when externally exposed to inside (atmospheric) environments. Based on this review consistent with the industry experience, the staff determined that the exclusion of the aging effect (general corrosion) from carbon steel RPV materials listed in LRA Table 3.1.2.1.5 is acceptable.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the RPV components 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).

3.1.2.3.6 Reactor Recirculation System – LRA Table 3.1.2.1.6

The staff reviewed LRA Table 3.1.2.1.6, which summarizes the results of AMR evaluations for the reactor recirculation system component groups.

LRA Table 3.1.2.1.6 does not identify any aging effect specified in GALL Report Table VII.I-7 for the carbon and low alloy steel materials used in reactor recirculation system piping and valve components. Table VII.I-7 of the GALL Report identified loss of material due to general corrosion as an aging effect for the carbon and low alloy steel materials of the reactor recirculation system piping and valve components externally exposed to inside (atmospheric) environments. The applicant stated that based on past precedence (NUREG-1796 Section 3.1.2.4.1) the staff had concluded that the loss of material due to corrosion is not considered a credible aging effect for carbon steel components in a containment nitrogen environment because a negligible amount of free oxygen (less than 4 percent by volume) is present in this environment 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, the applicant determined that loss of material due to general corrosion would not be applicable to the carbon and low alloy steel materials of the reactor recirculation system piping and valve components.

The staff finds the applicant's evaluation acceptable because the carbon and low-alloy steel reactor recirculation system components are exposed to negligible amounts of free oxygen and, therefore, are not likely to experience corrosion. In addition, the external surface of the carbon and low-alloy steel reactor recirculation system components is exposed to inside (atmospheric) environment that does not contain any aggressive ions that would cause loss of material due to corrosion. The staff concludes that in the absence of oxygen the carbon and low-alloy steel reactor recirculation system components are not susceptible to corrosion when externally exposed to inside (atmospheric) environments. Based on this review, consistent with the industry experience, the staff determined that the exclusion of the aging effect (general corrosion) from carbon steel RPV materials listed in LRA Table 3.1.2.1.6 is acceptable.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor recirculation system components 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).

Conclusion. On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results involving material, environment, AERMs, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and RCS 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).

3.2 Aging Management of Engineered Safety Features

This section of the SER documents the staff's review of the applicant's AMR results for the engineered safety features (ESF) components and component groups of the following systems:

- containment spray system
- core spray system
- standby gas treatment system

3.2.1 Summary of Technical Information in the Application

In LRA Section 3.2, the applicant provided AMR results for the ESF system components and component groups. In LRA Table 3.2.1, "Summary of Aging Management Evaluations for the Engineered Safety Features," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the ESF systems components and component groups.

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.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the ESF system components 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 staff conducted an onsite audit of AMRs *during the weeks of October 3-5, 2005,* January 23-27, February 13-17, and April 19-20, 2006, to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and summarized in SER Section 3.2.2.1.

In the onsite audit, the staff also selected AMRs consistent with the GALL Report for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.2.2.2. The staff's audit evaluations are documented in the Audit and Review Report and summarized in SER Section 3.2.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with, or not addressed in, the GALL Report. The technical review included evaluating whether all plausible aging effects had been identified and whether the aging effects listed were appropriate for the combinations of materials and environments specified. The staff's evaluations are documented in SER Section 3.2.2.3.

For SCCs that the applicant identified as not applicable or not requiring aging management the staff conducted a review of the AMR line items, and the plant's operating experience, to verify the applicant's claims. Details of these reviews are documented in the Audit and Review Report.

Finally, the staff 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 ESF systems components.

Table 3.2-1, provided below, includes a summary of the staff's evaluation of components, aging effects and mechanisms, and AMPs, listed in LRA Section 3.2, that are addressed in the GALL Report.

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	This TLAA is evaluated in Section 4.3. (See SER 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 SER Section 3.2.2.2.3)
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 aging management program is to be evaluated.	Not applicable	Not applicable, since OCGS has no such ESF components within the scope of license renewal. (See SER Section 3.2.2.2.3)
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 SER Section 3.2.2.2.3)
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 OCGS has no such ESF components within the scope of license renewal. (See SER Section 3.2.2.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 aging management program is to be evaluated for pitting and crevice corrosion of tank bottoms because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering.	Not applicable	Not applicable, since OCGS has no such ESF components within the scope of license renewal. (See SER Section 3.2.2.2.3)
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 aging management program is to be evaluated.	Not applicable	Not applicable, since OCGS has no such ESF components within the scope of license renewal. (See SER Section 3.2.2.2.3)
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 OCGS has no such ESF components within the scope of license renewal. (See SER Section 3.2.2.2.4)
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 SER Section 3.2.2.2.4)
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 aging management program is to be evaluated.	Periodic Inspection of Ventilation Systems (B.2.4)	Consistent with GALL, which recommends further evaluation. (See SER 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 aging management program is to be evaluated.	Not applicable	Not applicable, since OCGS has stainless steel spray nozzles and orifices. (See SER Section 3.2.2.2.7)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.2.2.2.8)
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 SER Section 3.2.2.2.8)
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 OCGS has no such ESF components within the scope of license renewal. (See SER Section 3.2.2.2.8)
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 SER 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 OCGS has no such ESF components within the scope of license renewal.
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	Not applicable	Not applicable since OCGS has no such ESF components within the scope of license renewal.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
Steel bolting and closure bolting exposed to air - outdoor (external), or air - indoor uncontrolled (external) (Item 3.2.1-23)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	Bolting Integrity (B.1.12)	Consistent with GALL. (See SER 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 SER 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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
Stainless steel and copper alloy heat exchanger tubes exposed to closed cycle cooling water (Item 3.2.1-30)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since OCGS has no such ESF components within the scope of license renewal.
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 SER Section 3.2.2.1.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER 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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
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.
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 OCGS has no such ESF components within the scope of license renewal.
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 applicable	Not applicable, since OCGS has no such ESF components within the scope of license renewal.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 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.
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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
Gray cast iron piping, piping components, piping elements exposed to closed-cycle cooling water (Item 3.2.1-42)	Loss of material due to selective leaching	Selective Leaching of Materials	Not applicable	Not applicable, since OCGS has no such ESF components within the scope of license renewal.
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 OCGS has no such ESF components within the scope of license renewal.
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 SER Section 3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff 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 SER 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 SER 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 SER 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 SER 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 OCGS has no such ESF components within the scope of license renewal.
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.2.1-55)	None	None	Not applicable	Not Applicable, since OCGS has no such ESF components within the scope of license renewal.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 OCGS has no such ESF components within the scope of license renewal.

The staff's review of the ESF systems component groups followed one of several approaches. One approach, documented in SER Section 3.2.2.1, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.2.2.2, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.2.2.3, discusses the staff's review of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the ESF systems components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.2.2.1, the applicant identified the materials, environments, AERMs, and the following programs that manage the effects of aging related to the ESF systems components:

- 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)

Staff Evaluation. In LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant provided a summary of AMRs for the ESF systems components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with

Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. 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 has the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

3.2.2.1.1 Loss of Material Due to General Corrosion

LRA Table 3.2.2.1.3 for the standby gas treatment system included AMR line items that credited the Periodic Inspection of Ventilation Systems Program to manage loss of material due to general corrosion for piping, piping components, piping elements, and fan and damper housings exposed to indoor air (internal) or outdoor air (external). 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 AMP was credited. The GALL Report recommended GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for this aging effect.

The staff reviewed the applicant's Periodic Inspection of Ventilation Systems Program and verified that this AMP includes activities consistent with the recommendations of GALL AMP XI.M38 to manage loss of material in components with an indoor air (internal) or outdoor air (external) environment. As identified above, the staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

LRA Tables 3.2.2.1.1 to 3.2.2.1.3 for the ESF systems included AMR line items that credited the Structures Monitoring Program to manage loss of material due to general corrosion for the external surfaces of steel piping, piping components, piping elements, and ducting in indoor air or outdoor air environments. 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 AMP was credited. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," for this aging effect.

The staff reviewed the applicant's Structures Monitoring Program and verified that this AMP includes activities consistent with GALL AMP XI.M36 to manage the loss of material in components exposed to indoor or outdoor air external environments. The staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

3.2.2.1.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Section 3.2.2.2.8.2 states that the ESF systems have no steel piping, piping components, or piping elements (internal surfaces) exposed to condensation, treated water, or air-indoor uncontrolled environments.

The staff noted that the containment isolation system includes steel components exposed to treated water on the internal surface. Therefore, the applicant was asked to clarify why it had 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 letter dated April 17, 2006, the applicant revised the further evaluation in LRA Section 3.2.2.2.8.2 to state that OCGS ESF 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.

The staff reviewed LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and confirmed that no steel components exposed to condensation are identified for the ESF systems. Therefore, the staff finds that the applicant's revision of the further evaluation in LRA Section 3.2.2.2.8.2 acceptable.

On the basis of its review, the staff finds 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.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application. In LRA Section 3.2.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report, for the ESF systems components and information about how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general corrosion
- loss of material due to pitting and crevice corrosion
- reduction of heat transfer due to fouling
- hardening and loss of strength due to elastomer degradation
- loss of material due to erosion
- loss of material due to general corrosion and fouling
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion (MIC)
- quality assurance for aging management of nonsafety-related components

Staff Evaluation. For component groups evaluated in the GALL Report, for which the applicant had claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria of SRP-LR Section 3.2.2.2. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

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). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

3.2.2.2.2 Loss of Material Due to General Corrosion

LRA Section 3.2.2.2.2 states that loss of material due to general corrosion of carbon steel PWR charging pump casings, with reference to the further evaluation in SRP-LR Section 3.2.2.2.2, is applicable to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable to OCGS because it is a BWR plant.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.3 against the criteria in SRP-LR Section 3.2.2.2.3.

In LRA Section 3.2.2.2.3.1, the applicant addressed loss of material due to pitting and crevice corrosion for internal surfaces of stainless steel containment isolation piping, piping components, and piping elements exposed to treated water.

SRP-LR Section 3.2.2.2.3.1 states that loss of material due to pitting and crevice corrosion can occur on 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.2.2.2.3.1 states that the Water Chemistry Program will be used to manage aging of stainless steel piping and components exposed to treated water 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 by station procedures and processes for the prevention or mitigation of loss of material aging effects. The One-Time Inspection Program will be used in each of these systems for verification of chemistry control and confirmation of the absence of loss of material. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to inspect the isolation condenser stainless steel tubes and tube side components to ensure that significant degradation does not occur and that the component intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Water Chemistry and One-Time Inspection Programs and determined that these programs are adequate to manage aging of stainless steel piping and components exposed to treated water. As identified above, the staff concludes that, based on these programs, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3.1 for further evaluation.

In LRA Section 3.2.2.2.3.2, the applicant addressed loss of material from pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to soil.

SRP-LR Section 3.2.2.2.3.2 states that loss of material from pitting and crevice corrosion can occur in stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of this aging effect.

LRA Section 3.2.2.2.3.2 states that the AMR for this further evaluation is not used at OCGS. The ESF systems have no stainless steel piping, piping components, or piping elements in contact with soil, untreated, or raw water (including internal condensation). OCGS has no external or partially encased stainless steel tanks within the scope of license renewal.

The staff reviewed the AMR line items for the ESF 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 within the scope of license renewal. Therefore, the staff finds acceptable the applicant's conclusion that this AMR is not applicable.

In LRA Section 3.2.2.2.3.3, the applicant addressed loss of material from pitting and crevice corrosion for BWR stainless steel and aluminum piping, piping components, and piping elements exposed to treated water.

SRP-LR Section 3.2.2.2.3.3 states that loss of material from pitting and crevice corrosion can occur in 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 in stagnant flow conditions. Therefore, the effectiveness of the Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.2.2.2.3.1 states that the Water Chemistry and the One-Time Inspection Programs will be used to manage loss of material from pitting and crevice corrosion for stainless steel piping components, and piping elements exposed to treated water.

The staff reviewed the applicant's Water Chemistry and One-Time Inspection Programs and determined that they are adequate to manage loss of material from pitting and crevice corrosion for stainless steel piping components and piping elements exposed to treated water. The staff noted that the applicant had not provided a further evaluation for aluminum piping exposed to treated water. The staff reviewed the AMR line items in LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and determined that there is no aluminum piping exposed to treated water in the ESF systems. Therefore, there was no need for a further evaluation for this material. The staff concludes that, based on the programs identified above, the applicant has met the criteria of SRP-LR

Section 3.2.2.2.3.3 for further evaluation.

The staff noted that the applicant had not credited 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, addressed in SRP-LR Section 3.2.2.2.3.4 for the ESF systems. This new AMR was not in the January 2005 draft GALL Report. The applicant was asked to clarify which AMPs it 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 ESF systems.

In its letter dated April 17, 2006, the applicant revised LRA Table 3.2.1, item number 3.2.1-34, as to stainless steel piping, piping components, and piping elements exposed to lubricating oil in the ESF systems, to state that this material and environment combination is not applicable.

The staff reviewed the AMR line items in LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and verified that no stainless steel or copper alloy components exposed to lubricating oil are present in ESF systems. Therefore, the staff finds acceptable the applicant's conclusion that this further evaluation is not applicable.

In LRA Section 3.2.2.2.3.2, the applicant addressed loss of material from pitting and crevice corrosion for partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering.

SRP-LR Section 3.2.2.2.3.5 states that loss of material from pitting and crevice corrosion can occur in 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 adequate management of the aging effect. The GALL Report recommends evaluation of a plant-specific AMP because moisture and water can egress under the tank if the perimeter seal is degraded

LRA Section 3.2.2.2.3.2 states that the ESF systems have no stainless steel piping, piping components, or piping elements in contact with soil, untreated, or raw water (including internal condensation). OCGS has no external or partially encased stainless steel tanks within the scope of license renewal.

The staff reviewed the AMR line items in LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and confirmed that these ESF systems have no stainless steel piping, piping components, or piping elements in contact with soil, untreated, or raw water (including internal condensation). Therefore, the staff finds acceptable the applicant's conclusion that this further evaluation is not applicable.

In LRA Section 3.2.2.2.3.2, the applicant addressed loss of material from pitting and crevice corrosion for stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation.

SRP-LR Section 3.2.2.2.3.6 states that loss of material from pitting and crevice corrosion can 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 adequate management of the aging effect

LRA Section 3.2.2.2.3.2 states that the ESF systems have no stainless steel piping, piping components, or piping elements in contact with soil, untreated, or raw water (including internal condensation). OCGS has no external or partially encased stainless steel tanks within the scope of license renewal.

The staff reviewed the AMR line items in LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and confirmed that the ESF systems have no stainless steel piping, piping components, or piping elements in contact with soil, untreated, or raw water (including internal condensation). Therefore, the staff finds acceptable the applicant's conclusion that this further evaluation is not applicable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.2.2.2.3. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.2.2.2.4 and Attachment 3, item EP-34, of the applicant's reconciliation document against the criteria in SRP-LR Section 3.2.2.2.4.

The staff noted that the applicant had not credited 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 with reference to the further evaluation in SRP-LR Section 3.2.2.2.4.1. This new AMR was not in the January 2005 draft GALL Report. The applicant was asked to clarify which AMPs it 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 ESF systems.

In its response, the applicant stated that Section 3.2.2.2.4.1 of the September 2005 SRP-LR addresses line items EP-40, EP-47, and EP-50, all new line items not included in the January 2005 draft SRP-LR and consequently not in the LRA. This material and environment combination is not present in ESF systems. The LRA credits the Lubricating Oil Monitoring Activities 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-LR does not contain these material and environment combinations, therefore, plant-specific notes were applied to these line items.

The staff reviewed the AMR line items in LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and confirmed that the ESF systems have no stainless steel or copper alloy heat exchanger tubes exposed to lubricating oil. Therefore, the staff finds acceptable the applicant's conclusion that this further evaluation is not applicable.

In Attachment 3, item EP-34, of the applicant's reconciliation document, the applicant addressed reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to treated water.

SRP-LR Section 3.2.2.2.4.2 states that reduction of heat transfer due to fouling can occur in 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 be inadequate. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program be verified to ensure that reduction of heat transfer due to fouling does not occur. A one-time inspection is an acceptable method to ensure that reduction of heat transfer does not occur and that the component's intended function will be maintained during the period of extended operation.

Attachment 3, item EP-34, of the applicant's reconciliation document states that the line item for stainless steel heat exchanger tubes in treated water, addressing reduction of heat transfer due to fouling, credited the Water Chemistry Program with no further evaluation recommended, per the January 2005 draft GALL Report. This draft was changed in the September 2005 GALL Report to the one-time inspection with an evaluation of aging effects recommended. There are two instances of this line item in the LRA, both in the isolation condenser system, for heat exchanger tubes, internal and external.

In its letter dated March 30, 2006, the applicant revised LRA Table 3.1.2.1.1 for the isolation condenser system to include two new line items crediting the One-Time Inspection Program 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 new additions are based on reconciliation of the LRA with the January 2005 draft GALL Report and the approved September 2005 GALL Report.

The staff finds that based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.4.2 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.2.2.2.4 and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5.

In LRA Section 3.2.2.2.5, the applicant addressed hardening and loss of strength due to elastomer degradation in elastomer seals and components of the BWR standby gas treatment system ductwork and filters exposed to air-indoor uncontrolled.

SRP-LR Section 3.2.2.2.5 states that hardening and loss of strength due to elastomer degradation can occur in elastomer seals and components of 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 adequate management of the aging effect.

LRA Section 3.2.2.2.5 states the Periodic Inspection of Ventilation Systems Program will be used to evaluate elastomer door seals and flexible connections in the standby gas treatment system. Periodic inspections of elastomer door seals and flexible connections will identify leakage or detrimental changes in material properties evidenced by cracking, material perforations, material. Observed conditions with potential impact on an intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Periodic Inspection of Ventilation Systems Program and determined that it is adequate to detect hardening and loss of strength of elastomer seals and components.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.2.2.2.5. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.6 Loss of Material Due to Erosion

LRA Section 3.2.2.2.6 states that loss of material due to erosion of the PWR high pressure safety injection pump mini flow orifice, with reference to the further evaluation in SRP-LR Section 3.2.2.2.6, is applicable to PWRs only. The staff finds acceptable the applicant's assessment that this aging effect is not applicable to OCGS because it is a BWR plant.

3.2.2.2.7 Loss of Material Due to General Corrosion and Fouling

The staff reviewed LRA Section 3.2.2.2.9 against the criteria in SRP-LR Section 3.2.2.2.7.

In LRA Section 3.2.2.2.9, the applicant addressed loss of material due to general corrosion and fouling for steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air - indoor uncontrolled.

SRP-LR Section 3.2.2.2.7 states that loss of material due to general corrosion and fouling can occur on steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air - indoor uncontrolled and could plug the spray nozzles and flow orifices. This aging mechanism and effect applies because the spray nozzles and flow orifices are occasionally wetted, even though most 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 adequate management of the aging effect.

LRA Section 3.2.2.2.9 states that the AMR associated with this further evaluation is not applicable because the containment spray nozzle and orifice assemblies used are stainless steel.

The staff reviewed the AMR line items in LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and verified that the containment spray nozzle and orifice assemblies used are stainless steel, not steel. Therefore, the staff agrees with the applicant's conclusion that this further evaluation is not applicable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.2.2.2.9. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.8 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.8 against the criteria in SRP-LR Section 3.2.2.2.8.

In LRA Section 3.2.2.2.8.1, the applicant addressed loss of material due to general, pitting, and crevice corrosion of BWR steel piping, piping components, and piping elements exposed to treated water.

SRP-LR Section 3.2.2.2.8.1 states that loss of material due to general, pitting, and crevice corrosion can occur in BWR steel piping, piping components, and piping elements exposed to treated water. The existing AMP relies on monitoring and control of BWR water chemistry 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.2.2.2.8.1 states that the Water Chemistry Program will be used to manage aging effects 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 RPV. The program activities provide for monitoring and controlling of water chemistry by station procedures and processes for the prevention or mitigation of loss of material aging effects. The One-Time Inspection Program will be used in each of these systems for verification of chemistry control and confirmation of the absence of loss of material. The Periodic Testing of Containment Spray Nozzles Program will also be used to manage corrosion of steel piping and piping components in the containment spray system. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry and One-Time Inspection Programs and determined that these programs are adequate to manage loss of material for steel piping, piping components, and piping elements exposed to a treated water environment. The staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.8.1 for further evaluation.

The staff noted that the applicant had not credited the GALL Report AMR for steel containment isolation components exposed to treated water, with reference to the further evaluation in SRP-LR Section 3.2.2.2.8.2. This was a new AMR that was not identified in the January 2005 draft GALL Report.

The staff reviewed LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and noted that other GALL Report AMR line items that address same material and environment combinations were appropriately credited. Therefore, as identified above, the staff concludes that this further evaluation is not applicable.

The staff noted that the applicant had not credited the GALL Report AMR for steel piping, piping components, and piping elements exposed to lubricating oil, with reference to the further evaluation in SRP-LR Section 3.2.2.2.8.3. This new AMR was not identified in the January 2005 draft GALL Report.

The applicant was asked which AMPs it 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 ESF systems. In its response, the applicant stated that Section 3.2.2.2.8.3 of the September 2005 SRP-LR addresses new line item EP-46, which is not in the January 2005 draft SRP-LR. This material and environment combination is not present in ESF systems. The LRA credits 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 staff reviewed LRA Tables 3.2.2.1.1 through 3.2.2.1.3 and confirmed that no steel components exposed to lubricating oil were identified. Therefore, the staff finds the applicant's response acceptable and concludes that this further evaluation is not applicable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.2.2.2.8. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion (MIC)

The staff reviewed LRA Section 3.2.2.2.8.3 against the criteria in SRP-LR Section 3.2.2.2.9.

In LRA Section 3.2.2.2.8.3, the applicant addressed loss of material due to general, pitting, crevice, and MIC for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil.

SRP-LR Section 3.2.2.2.9 states that loss of material due to general, pitting, crevice, and MIC can occur in 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 to ensure that loss of material does not occur.

LRA Section 3.2.2.2.8.3 states that a Buried Piping Inspection Program will be implemented 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process. ESF systems have no buried steel tanks within the scope of license renewal.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.2.2.2.9. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program for safety-related and nonsafety-related components.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff concludes that the applicant has adequately addressed the issues further evaluated. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.2.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the staff reviewed additional details concerning the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is discussed in the following sections.

3.2.2.3.1 Containment Spray System (CSS) Summary of Aging Management Evaluation – LRA Table 3.2.2.1.1

The staff reviewed LRA Table 3.2.2.1.1, which summarizes the results of AMR evaluations for the CSS component groups.

In LRA Table 3.2.2.1.1 the applicant states that there are no aging effects for carbon and low alloy piping and fittings providing a pressure boundary function in a containment atmosphere environment (internal and external). The staff finds this acceptable because the containment atmosphere environment has a relatively small amount of moisture which is not likely to result in any significant corrosion of the carbon steel and low alloy piping and fittings. Based on operating experience, the staff concludes that the extent of any corrosion which may occur is not likely to affect the pressure boundary function.

The applicant also stated that there are no aging effects for stainless steel spray nozzles providing pressure boundary and spray functions in a containment atmosphere environment (internal and external). The staff finds this acceptable because moisture in the containment atmosphere forms a passive film on stainless steel surfaces which prevents further progression. The spray and pressure boundary functions of the nozzles are not likely to be affected in this environment. Therefore, the staff finds that the intended function of the stainless steel components will not be affected.

On the basis of its review, as discussed above, the staff concludes that there are no aging effects associated with core spray system components which would impair the intended functions of the core spray system components. 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).

3.2.2.3.2 Core Spray (CS) System Summary of Aging Management Evaluation – LRA Table 3.2.2.1.2

The staff reviewed LRA Table 3.2.2.1.2, which summarizes the results of AMR evaluations for the CS system component groups.

In LRA Table 3.2.2.1.2, the applicant stated that the AMRs for the CS system components either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.2.2.1 and 3.2.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the CS system components 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).

3.2.2.3.3 Standby Gas Treatment System (SGTS) Summary of Aging Management Evaluation – LRA Table 3.2.2.1.3

The staff reviewed LRA Table 3.2.2.1.3, which summarizes the results of AMR evaluations for the SGTS component groups.

The staff's review of LRA Table 3.2.2.1.3 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

LRA Table 3.2.2.1.3 states that there are no AERMs for stainless steel closure bolting in an indoor air (external) environment. In RAI 3.2-1 dated March 30, 2006, the staff requested that the applicant provide the following information:

(a) justification for excluding loss of preload and loss of closure integrity as aging mechanisms

(b) specific industry guidance for ventilation closure bolting relating to AERMs (e.g., EPRI documents, published reports, operating experience, etc.)

(c) sizes and locations of the bolting

In its response dated April 28, 2006, the applicant stated:

(a) Ventilation system duct bolting is similar to structural bolting in that it provides structural support for ventilation system assemblies, which is functionally different from piping system pressure retaining closure bolting. Typical ventilation system operating pressures and temperatures do not result in significant loads on the closure bolting such that ventilation system joint integrity would be compromised. Ventilation bolting applications at Oyster Creek do not require specific predetermined bolting preload to assure the associated intended functions are maintained. Loss of preload or loss of closure integrity for stainless steel ventilation system bolting in an indoor air environment is not a significant aging effect requiring management.

(b) NUREG-1801 does not specifically address ventilation closure bolting. NUREG-1801 item TP-5 identifies stainless steel bolted connections in an indoor air environment, with no aging effects or aging management program required. No other industry reports were identified specifically relating to ventilation closure bolting AERMs. Oyster Creek has not experienced age related degradation failures of stainless steel ventilation closure bolting in an indoor air environment.

(c) Ventilation bolting is used at fan and damper connections, filter unit connections, valve connections, flexible connections, access ports, duct support locations, and connections between duct sections. Most bolting is less than one-half inch nominal diameter. Larger bolting is used when ducting is connected to large butterfly valves, because the design of the butterfly valve flange is based on pipe flange applications and not ducting connections.

The staff finds the applicant's response acceptable because it adequately justified the exclusion of loss of preload and loss of closure integrity as aging mechanisms for stainless steel ventilation system bolting in an indoor air environment.

LRA Table 3.2.2.1.3 states that loss of material in a number of components is managed by the Periodic Inspection of Ventilation Systems Program.

In RAI 3.2-2 dated March 30, 2006, the staff requested that the applicant provide the specific tests and inspections including frequency and methods of inspections, preventive actions, parameters monitored and inspected, detection of aging effects, acceptance criteria, and operating experience in the applicant's program that relate to each of the following line items in the standby gas treatment system:

(a) Loss of material in aluminum duct work in an external soil environment.

(b) Loss of material in brass piping and fitting in an outdoor air (external) environment and the specific brass composition.

(c) Loss of material in copper piping and fittings in an outdoor air (external) environment and the specific copper composition.

In its response dated April 28, 2006, the applicant stated :

(a) The buried ductwork at Oyster Creek is contained in the Standby Gas Treatment System (SGTS). It is comprised of two aluminum duct exhaust lines that pass through approximately six feet of structural backfill above the roof of the Exhaust Tunnel. Above ground, the ducts connect to the Ventilation Stack. Oyster Creek has experienced age related material degradation failure of aluminum duct in this application. Corrosion of one of the original buried aluminum ducts near the roof of the Exhaust Tunnel required modification and repair after 25 years of service. The duct was internally sleeved with type B209 aluminum sheet with a wall thickness greater than the original duct and the surrounding backfill stabilized. The redundant buried duct was also modified such that all aluminum ducts with an external soil environment are now sleeved.

UT thickness measurements will be performed to detect the aging effect of loss of material of the buried aluminum duct. The acceptance criteria is measured loss of material of the sleeve caused by corrosion. Measured loss of material of the sleeve will be entered into the corrective action program and trended as required. The inspection frequency is every five years. There are no preventive actions associated with these components.

(b) There is no brass pipe in the SGTS system. Brass fittings are used with copper tubes for the flow instrumentation downstream of the SGTS outdoor fans. Brass fittings are included under the listed component type piping and fittings since they are part of the copper tubing assembly. The brass fittings are visually inspected. The acceptance criteria is no evidence of penetrating corrosion. Identification of penetrating corrosion will be entered into the corrective action program. The inspection frequency is yearly. Identification of aging effects does not require determination of the specific material composition in this application. Therefore, the specific brass composition was not researched. Oyster Creek has not experienced aged related material degradation failures of tubing fittings in this application. There are no preventive actions associated with these components.

(c) Copper tubing as listed under piping and fittings is used for the flow instrumentation downstream of the SGTS outdoor fans. The tubing is visually inspected. The acceptance criteria is no evidence of penetrating corrosion. Identification of penetrating corrosion will be entered into the corrective action program. The inspection frequency is yearly.

Identification of aging effects does not require determination of the specific material composition in this application. Therefore, the specific copper composition was not researched. Oyster Creek has not experienced age related material degradation failures of tubing in this application. There are no preventive actions associated with these components. The function of the SGTS is routinely demonstrated by the monthly surveillance tests.

The staff finds the applicant's response acceptable because the applicant had provided an adequate description of the tests and inspections for managing the loss of material in aluminum duct work in an external soil environment and brass and copper piping and fitting in an outdoor air (external) environment.

LRA Table 3.2.2.1.3 identifies no AERMs for Plexiglass duct work in an internal and external indoor air environment. In RAI 3.2-3 dated March 30, 2006, the staff requested that the applicant discuss its current maintenance practices as well as vendor recommendations for Plexiglass in this environment. In addition, the staff requested that the applicant identify the specific composition of this Plexiglass material and its operating experience.

In its response dated April 28, 2006, the applicant stated that Plexiglass duct panels are installed on the absolute filter inlet and exhaust boxes of each SGTS train. As no maintenance or cleaning is performed, the industry cleaning and care recommendations to preclude scratching or crazing when cleaning are not implemented. Although not identified, the specific material composition of the Plexiglass is not required as there are no aging effects for acrylics (thermoplastics) in an indoor air environment. Acceptability for the use of thermoplastics is a design-driven criterion. After the appropriate material is chosen, there are no aging effects. Thermoplastics are susceptible to aging effects due to such stressors as high temperature, chemicals, radiation, and UV rays. None of these are present in this application. OCGS has experienced no aged-related material degradation failures of Plexiglass in the SGTS system.

The staff finds that the stressors which may produce aging effects in acrylics are not present in this application. The staff finds acceptable the applicant's evaluation because there are no aging effects associated with the Plexiglass duct panels.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that either there are no aging effects or the aging effects associated with the SGTS components 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).

Conclusion. On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results involving material, environment, AERMs, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.2.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the ESF systems 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).

3.3 Aging Management of Auxiliary Systems

This section of the SER documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups associated with the following systems:

- "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 heating, ventilation, and air conditioning (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
- water treatment & distribution system

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant provided AMR results for the auxiliary systems components and component groups. In LRA Table 3.3.1, "Summary of Aging Management Evaluations for the

Auxiliary Systems," the applicant provided a summary comparison of its AMRs with those evaluated in the GALL Report for the auxiliary systems components and component groups.

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.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components 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 staff conducted an onsite audit of AMRs during the weeks of October 3-7, 2005, January 23-27, February 13-17, and April 19-20, 2006, to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and are summarized in SER Section 3.3.2.1.

In the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.3.2.2. The staff's audit evaluations are documented in the Audit and Review Report, and are summarized in SER Section 3.3.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with, or not addressed in, the GALL Report. The technical review 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 staff's evaluations are documented in SER Section 3.3.2.3.

For AMRs that the applicant identified as not applicable or not requiring aging management, the staff conducted a review of the AMR line items and the plant's operating experience, to verify the applicant's claims. Details of these reviews are documented in the Audit and Review Report.

Finally, the staff 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 components.

Table 3.3-1, provided below, includes a summary of the staff's evaluation of components, aging effects, and mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary Systems 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 Standard Review Plan, Section 4.7 for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1).	TLAA	This TLAA is evaluated in Section 4.3. (See SER Section 3.3.2.2.1)
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	This TLAA is evaluated in Section 4.3. (See SER 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 SER 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 SER Section 3.3.2.2.3)
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 aging management program is to be evaluated.	One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 aging management program is to be evaluated.	Not Applicable	Not applicable since the diesel engine exhaust piping is carbon steel. (See SER Section 3.3.2.2.3)
High-strength steel closure bolting exposed to air with steam or water leakage. (Item 3.3.1-10)	Cracking due to stress corrosion cracking, cyclic loading	Bolting Integrity The AMP is to be augmented by appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.	Bolting Integrity (B.1.12)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.4)
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 aging management program is to be evaluated	Periodic Inspection of Ventilation Systems (B.2.4) and Structures Monitoring (B.1.31)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.5)
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 aging management program is to be evaluated.	Periodic Inspection (B.2.5)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.5)
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 aging management program is to be evaluated	None	Acceptable since operating experience shows that aging effects for this component are insignificant. (See SER 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 (See SER Section 3.3.2.2.7)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 Part 50, Appendix R Section III.O of 10 CFR does not apply because the containment is inerted during normal operation. (See SER Section 3.3.2.2.7)
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 Part 50, Appendix R Section III.O of 10 CFR does not apply because the containment is inerted during normal operation. (See SER Section 3.3.2.2.7)
Steel piping, piping components, and piping elements exposed to treated water (Item 3.3.1-17)	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) or Water Chemistry (B.1.2) and ASME Section XI, Subsection IWF (B.1.28)	Consistent with GALL, which recommends further evaluation (See SER Section 3.3.2.2.7)
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 aging management program is to be evaluated	Periodic Inspection (B.2.5)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.7)
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 microbiologically influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection (B.1.26) and Aboveground Outdoor Tanks Program (B.1.21)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.8)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 microbiologically influenced corrosion, 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 SER Section 3.3.2.2.9)
Steel heat exchanger components exposed to lubricating oil (Item 3.3.1-21)	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, 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. (See SER Section 3.3.2.2.9)
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) or Water Chemistry (B.1.2) and ASME Section XI, Subsection IWF (B.1.28)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.10)
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 SER Section 3.3.2.2.10)
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (Item 3.3.1-24)	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 SER Section 3.3.2.2.10)
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 aging management program is to be evaluated.	Periodic Inspection of Ventilation Systems (B.2.4)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.10)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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. (See SER Section 3.3.2.2.10)
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 aging management program is to be evaluated.	One-time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.3.2.2.10)
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 aging management program 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 LRA. (See SER Section 3.3.2.2.10)
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 aging management program 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 LRA. (See SER Section 3.3.2.2.10)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution (Item 3.3.1-30)	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 SER Section 3.3.2.2.10)
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 SER Section 3.3.2.2.11)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 microbiologically influenced corrosion	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 SER Section 3.3.2.2.12)
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 microbiologically influenced 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. (See SER Section 3.3.2.2.12)
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 aging management program is to be evaluated.	Periodic Inspection of Ventilation Systems (B.2.4)	Consistent with GALL, which recommends further evaluation. (See SER 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 SER 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 SER Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (> 140 °F) (Item 3.3.1-38)	Cracking due to stress corrosion cracking	BWR Stress Corrosion Cracking and Water Chemistry	Not Applicable	Not applicable since OCGS has no stainless steel non-RCPB shutdown cooling system piping exposed to treated water >140 °F.
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 <140 °F.
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 SER 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.
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.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 (B.1.12), or ASME Section XI, Subsection IWE (B.1.27), or Inspection of Overhead Heavy Load and Light Load Handling System (B.1.16), or Structures Monitoring (B.1.31)	Consistent with GALL for AMRs crediting the OCGS bolting integrity program. Acceptable for AMRs crediting the OCGS ASME Section XI, Subsection IWE, inspection of overhead heavy load and light load handling system, or structures monitoring programs since they are consistent with the GALL bolting integrity program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)
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.
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 the OCGS bolting integrity program. Acceptable for AMRs crediting the OCGS ASME Section XI, Subsection IWE Program, since it is consistent with the GALL bolting integrity program for this component group/ aging effect combination. (See SER Section 3.3.2.1.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 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.
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) 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 SER Section 3.3.2.1)
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 microbiologically influenced corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL. (See SER 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) 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 SER Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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) 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 SER 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 SER 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 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 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 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.1.31), or Periodic Inspection (B.2.5) or Periodic Inspection of Ventilation Systems (B.2.4)	Acceptable since the OCGS structures monitoring, periodic inspection, and periodic inspection of ventilation systems programs are consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)
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, structures monitoring, and periodic inspection of ventilation systems programs are consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)
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 Inspection of Ventilation Systems (B.2.4)	Acceptable since the OCGS fire protection, fire water system, structures monitoring, and periodic inspection of ventilation systems programs are consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	Structures Monitoring (B.1.31)	Acceptable since the OCGS structures monitoring program is consistent with GALL external surfaces monitoring program for this component group/aging effect combination. (See SER Section 3.3.2.1.3)
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 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 one-time inspection, fire protection, fire water system, structures monitoring, and periodic inspection of ventilation systems programs are consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)

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 SER Section 3.3.2.1.6)
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)	Acceptable since the OCGS fire water system program is consistent with GALL fire protection program for this component group/aging effect combination. (See SER Section 3.3.2.3)
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 SER 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 SER 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 Program	Fire Protection (B.1.19) and Structures Monitoring (B.1.31)	Consistent with GALL. (See SER Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 Program	Fire Protection (B.1.19) and Structures Monitoring (B.1.31)	Consistent with GALL. (See SER Section 3.3.2.1)
Reinforced concrete structural fire barriers - walls, ceilings and floors exposed to air - outdoor or air - indoor uncontrolled (Item 3.3.1-67)	Loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring Program	Fire Protection (B.1.19) and Structures Monitoring (B.1.31)	Consistent with GALL. (See SER Section 3.3.2.1)
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 microbiologically influenced corrosion, and fouling	Fire Water System	Fire Water System (B.1.20)	Consistent with GALL. (See SER 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 SER 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 microbiologically influenced corrosion, and fouling	Fire Water System	Fire Water System (B.1.20)	Consistent with GALL. (See SER 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	Periodic Inspection (B.2.5)	Acceptable since the OCGS periodic inspection program is consistent with GALL inspection of internal surfaces in miscellaneous piping and ducting components program for this component group/aging effect combination. (See SER Section 3.3.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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) microbiologically influenced corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Periodic Inspection of Ventilation Systems (B.2.4)	Acceptable since the OCGS periodic inspection of ventilation systems program is consistent with the GALL inspection of internal surfaces in miscellaneous piping and ducting components program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)
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 SER 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 (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 SER Section 3.3.2.1)
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)	Acceptable since the OCGS periodic inspection program is consistent with the GALL open-cycle cooling water system program for this component group/ aging effect combination. (See SER Section 3.3.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 microbiologically influenced corrosion, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	Periodic Inspection (B.2.5), Open-Cycle Cooling Water system (B.1.13), and One-Time Inspection (B.1.24)	Acceptable since the OCGS periodic inspection, open-cycle cooling water system, and one-time inspection programs are consistent with GALL open-cycle cooling water system program for this component group/aging effect combination. (See SER Sections 3.3.2.1 and 3.3.2.3)
Steel heat exchanger components exposed to raw water (Item 3.3.1-77)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically influenced corrosion, and fouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13)	Consistent with GALL. (See SER 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 program. 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 SER Section 3.3.2.1.5)
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 SER Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (Item 3.3.1-80)	Loss of material due to pitting, crevice, and microbiologically influenced corrosion	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 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 microbiologically influenced corrosion, 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. Acceptable for AMRs crediting the OCGS periodic inspection program since it is consistent with the GALL open-cycle cooling water system program for this component group/ aging effect combination. (See SER Section 3.3.2.1.5)
Copper alloy heat exchanger components exposed to raw water (Item 3.3.1-82)	Loss of material due to pitting, crevice, galvanic, and microbiologically influenced corrosion, 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 SER Section 3.3.2.1.5)
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 SER Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.3.2.1)
Gray cast iron piping, piping components, and piping elements exposed to soil, raw water, treated water, or closed-cycle cooling water (Item 3.3.1-85)	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials (B.1.25)	Consistent with GALL. (See SER Section 3.3.2.1)
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 SER 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	Consistent with GALL. (See SER Section 3.3.2.1)
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 SER Section 3.3.2.1)
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 SER Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel and aluminum piping, piping components, and piping elements exposed to air - indoor controlled (external) (Item 3.3.1-95)	None	None	None	Consistent with GALL. (See SER Section 3.3.2.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.3.1-96)	None	None	None	Consistent with GALL. (See SER Section 3.3.2.1)
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (Item 3.3.1-97)	None	None	None	Consistent with GALL. (See SER Section 3.3.2.1)
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air (Item 3.3.1-98)	None	None	None	Consistent with GALL. (See SER Section 3.3.2.1)

The staff's review of the auxiliary systems component groups followed one of several approaches. One approach, documented in SER Section 3.3.2.1, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.3.2.2, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.3.2.3, discusses the staff's review of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.3.2.1, the applicant identified the materials, environments, AERMs, and the following programs that manage the effects of aging related to the auxiliary systems components:

- 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)
- Open-Cycle Closed Cooling Water System (B.1.13)
- Closed-Cycle Closed Cooling Water System (B.1.14)
- Boraflex Rack Management Program (B.1.15)
- Compressed Air Monitoring (B.1.17)
- BWR Reactor Water Cleanup 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)

Staff Evaluation. In LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant provided a summary of AMRs for the auxiliary systems components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. 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 has the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

3.3.2.1.1 Loss of Material Due to Pitting and Crevice Corrosion

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 exposed to auxiliary steam and steam traps constructed of copper alloy exposed to boiler treated water on the internal surface. The applicant credited the One-Time Inspection Program to manage loss of material for these components. The applicant was asked to justify the conclusion that the One-Time Inspection Program alone was sufficient to manage loss of material for these components.

In its letter dated April 17, 2006, the applicant revised LRA Table 3.3.2.1.18 to include the Water Chemistry Program to address loss of material due to pitting and crevice corrosion for heating and process steam system copper and copper alloy components exposed to auxiliary steam and boiler treated water.

The staff determined that the addition of the Water Chemistry Program would make these line items consistent with the GALL Report recommendations for managing loss of material due to pitting and crevice corrosion and, therefore, acceptable.

The staff finds that, by using the Water Chemistry Program 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 so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.2.1.41 for the water treatment and distribution system includes AMR line items for loss of material in brass and bronze valve bodies exposed to treated water on the internal surface. The applicant credited the Selective Leaching of Materials Program to manage loss of material for these components. The staff reviewed the program and determined that it manages loss of material due to selective leaching, but not 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 response dated April 17, 2006, the applicant revised LRA Table 3.3.2.1.41 to address aging management of loss of material due to pitting and crevice corrosion of brass and bronze valve bodies 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

The staff reviewed the applicant's response and determined that the line items to be added were consistent with the GALL Report recommendations for managing loss of material due to pitting and crevice corrosion and, therefore, acceptable.

The staff finds that, by using the Water Chemistry Program 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 so that intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.2 Reduction of Heat Transfer Due to Fouling

LRA Table 3.3.2.1.13 for the EDG and auxiliary system includes AMR line items for the lube oil cooler and radiator heat exchangers exposed to closed-cycle cooling water. The staff noted that the aging effect for reduction of heat transfer due to fouling was not addressed. The applicant was asked to clarify why this aging effect was not identified for these components.

In its letter dated April 17,2006, the applicant revised LRA Table 3.3.2.1.13 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 Closed-Cycle Cooling Water System Program.

The staff reviewed the applicant's revision and determined that the addition of line items to address reduction of heat transfer due to fouling using the Closed-Cycle Cooling Water System Program is consistent with the GALL Report recommendations and, therefore, acceptable.

3.3.2.1.3 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the ASME Section XI, Subsection IWE, Inspection of Overhead Heavy Load and Light Load Handling System, or Structures Monitoring Program 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. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends the Bolting Integrity Program for this aging effect.

The staff reviewed the applicant's ASME Section XI, Subsection IWE, Inspection of Overhead Heavy Load and Light Load Handling System, and Structures Monitoring Programs and verified that these programs include activities consistent with the recommendations in GALL AMP XI.M18 to manage loss of material due to general, pitting, and crevice corrosion on the external surfaces of structural and closure bolting. The staff concludes that these AMPs are adequate to manage the aging effect for which they are credited.

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the One-Time Inspection Program with the 10 CFR Part 50, Appendix J Program to manage the loss of material due to general, pitting, and crevice corrosion in primary containment boundary steel piping, piping components, and piping elements exposed to indoor air internal environments. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," for this aging effect.

The staff reviewed the applicant's 10 CFR Part 50, Appendix J, Program and verified that it includes activities consistent with the recommendations in GALL AMP XI.M36 to manage loss of material in components exposed to indoor air internal environments. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified it 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 staff concludes that these AMPs are adequate to manage the aging effect for which they are credited.

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Fire Protection Program to manage the loss of material due to general, pitting, and crevice corrosion for the internal surfaces of steel piping, piping components, and piping elements with an indoor air internal environment for halon/carbon dioxide fire suppression systems. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report but, a different AMP was credited. The report recommends GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for this aging effect.

The staff reviewed the applicant's Fire Protection Program and verified that this AMP includes activities consistent with the recommendations in GALL AMP XI.M38 to manage loss of material in components in indoor air internal environments. The staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Fire Water System Program to manage loss of material due to general, pitting, and crevice corrosion for the internal surfaces of steel piping, piping components, and piping elements with an indoor air internal environment for water-based fire protection systems. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M38 for this aging effect.

The staff reviewed the applicant's Fire Water System Program and verified that this AMP includes activities consistent with the recommendations in GALL AMP XI.M38 to manage loss of material on internal surfaces of components in indoor air internal environments. The staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Periodic Inspection Program to manage the loss of material due to general, pitting, and crevice corrosion for EDG ventilation system steel components exposed to indoor air internal or external environments. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMPs XI.M36 or XI.M38 for this aging effect.

The staff reviewed the applicant's Periodic Inspection Program and determined that it is consistent with the recommendations in GALL AMPs XI.M36 and XI.M38 to manage the loss of material for the external or internal surfaces, respectively, of steel components exposed to an indoor air external or internal environment. The staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Periodic Inspection of Ventilation Systems Program to manage the loss of material in ventilation system steel piping, piping components, and piping elements exposed to indoor air internal or external environments. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M36 for managing this aging effect on external surfaces and GALL AMP XI.M38 for managing this aging effect on internal surfaces.

The staff reviewed the applicant's Periodic Inspection of Ventilation Systems Program and determined that it is consistent with the recommendations in GALL AMPs XI.M36 and XI.M38 to manage the loss of material in ventilation system steel piping, piping components, and piping elements exposed to an indoor air external or internal environment, respectively. The staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Structures Monitoring Program to inspect the external surfaces of steel piping, piping components, piping elements, and ductwork exposed to indoor air external or outdoor air external environments in the EDG and auxiliary system, chlorination system, and control room HVAC system. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M36 for this aging effect.

The staff reviewed the applicant's Structures Monitoring Program and verified that this AMP includes activities consistent with the recommendations in GALL AMP XI.M36 to manage the loss of material in components exposed to indoor or outdoor air external environments. The staff concludes that this AMP is adequate to manage the aging effect for which it is credited.

3.3.2.1.4 Loss of Preload Due to Stress Relaxation

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the ASME Section XI, Subsection IWE, Program or the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling System Program 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 environments. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity Program," for this aging effect.

The staff reviewed the applicant's ASME Section XI, Subsection IWE, Program and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling System Program and verified that these programs are consistent with the recommendations in GALL AMP XI.M18 to manage loss of preload due to stress relaxation of structural and closure bolting. The staff concludes that these AMPs are adequate to manage the aging effect for which they are credited.

3.3.2.1.5 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion, and Fouling

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Fire Water System, One-Time Inspection, or Periodic Inspection Program to manage loss of material due to pitting and crevice corrosion 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. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," for this aging effect.

The staff reviewed the applicant's Fire Water System, One-Time Inspection, and Periodic Inspection Programs and verified that they include activities consistent with the recommendations in GALL AMP XI.M20 to manage loss of material due to pitting and crevice corrosion and MIC and fouling on the internal surfaces of piping and fittings. The staff concludes that these AMPs are adequate to manage the aging effects for which they are credited.

3.3.2.1.6 Increased Elastomer Hardness, Shrinkage and Loss of Strength due to Weathering

LRA Tables 3.3.2.1.1 through 3.3.2.1.41 include AMR line items that credit the Structures Monitoring Program to manage increased elastomer hardness, shrinkage, and loss of strength due to weathering for elastomer fire barrier penetration seals exposed to air-outdoor or indoor uncontrolled environments. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report, but a different AMP was credited. The GALL Report recommends GALL AMP XI.M26, "Fire Protection" for this aging effect.

The staff reviewed the applicant's Structures Monitoring Program and verified that it is consistent with the recommendations in GALL AMP XI.M26 to manage increased elastomer hardness, shrinkage, and loss of strength due to weathering for elastomer fire barrier penetration seals exposed to uncontrolled air. The staff concludes that this AMP is adequate to manage the aging effects for which it is credited.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.3.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.3.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report for the auxiliary systems components, and information about how it will manage the following aging effects:

- cumulative fatigue damage
- reduction of heat transfer due to fouling
- cracking due to stress corrosion cracking
- cracking due to stress corrosion cracking and cyclic loading
- hardening and loss of strength due to elastomer degradation
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, microbiologically-influenced corrosion and fouling
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and galvanic corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to wear
- loss of material due to cladding breach
- quality assurance for aging management of nonsafey-related components

Staff Evaluation. For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.3.2.2. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

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). SER Section 4.3 documents the staff's evaluation of this TLAA.

3.3.2.2.2 Reduction of Heat Transfer Due to Fouling

The staff reviewed Attachment 3, item AP-62, of the reconciliation document against the criteria in SRP-LR Section 3.3.2.2.2.

In Attachment 3, item AP-62, of its reconciliation document, the applicant addressed reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to treated water.

SRP-LR Section 3.3.2.2.2 states that reduction of heat transfer due to fouling can occur in 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 be inadequate. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program be verified to ensure that reduction of heat transfer due to fouling does not occur. A one-time inspection is an acceptable method to ensure that reduction of heat transfer does not occur and that the component's intended function will be maintained during the period of extended operation.

Attachment 3, item AP-62, of the applicant's reconciliation document states that the SRP-LR line item for stainless steel heat exchanger tubes in treated water, addressing reduction of heat transfer due to fouling, recommends the Water Chemistry Program with no further evaluation required in the January 2005 draft SRP-LR, which was changed in the September 2005 SRP-LR to recommend both the Water Chemistry and One-Time Inspection Programs with an evaluation of aging effects. There are two instances of this line item in the LRA applicable to the treated water side of heat exchanger components in the RBCCW system. In the LRA, there are 229 line item instances of one-time inspections of stainless steel components in treated water environments. These instances are applied to aging effects of loss of material or cracking and provide ample inspection opportunity for the condition of the components. Observed conditions with potential impact on intended function are evaluated and corrected, as necessary, in accordance with the corrective action process. As 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 addressed in this line item, the treated water environment is reactor coolant. The Water Chemistry Program requirements for reactor water quality provide added assurance that an environment conducive to fouling does not exist. The applicant concluded that no change is required in the LRA due to this item.

The staff reviewed the applicant's reconciliation document as well as LRA Table 3.3.2.1.29 for the RBCCW system. The staff noted that the One-Time Inspection Program 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 Program 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 staff determined that the applicant adequately manages reduction of heat transfer due to fouling for stainless steel heat exchanger components exposed to treated water in the RBCCW system and that no change is required in the LRA.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.2. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.3 against the criteria in SRP-LR Section 3.3.2.2.3.

In LRA Section 3.3.2.2.3.1, the applicant addressed cracking due to SCC 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).

SRP-LR Section 3.3.2.2.3.1 states that cracking due to SCC can occur in BWR standby liquid control system stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution greater than 60 °C (>140 °F). The existing AMP 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 conditions can cause SCC. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program be verified to ensure that SCC does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that SCC does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.3.1 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage SCC of stainless steel components exposed to a sodium pentaborate environment in the standby liquid control system (liquid poison system). The management of SCC of standby liquid control 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 because 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 with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that this AMP includes activities that will mitigate cracking due to SCC. In addition, the staff reviewed the applicant's

One-Time Inspection Program and verified that it 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 staff finds acceptable the applicant's approach to manage SCC of standby liquid control system components exposed to sodium pentaborate by monitoring and controlling liquid poison tank makeup water chemistry because the sodium pentaborate would mask most of the chemistry parameters monitored by the Water Chemistry Program. The staff 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 staff concludes that, that applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.3.1 for further evaluation.

In LRA Section 3.3.2.2.3.2, the applicant addressed cracking due to SCC in stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60 °C (>140 °F).

SRP-LR Section 3.3.2.2.3.2 states that cracking due to SCC can 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 AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.3.2 states that 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 SCC. The reactor water cleanup (RWCU) system non-regenerative heat exchanger shell side components are carbon steel and are not susceptible to cracking due to SCC. RWCU system regenerative heat exchanger stainless steel tube and shell side components, and non-regenerative heat exchanger stainless steel tube side components are exposed to treated water environments >140 °F and are susceptible to cracking due to SCC. OCGS will implement a One-Time Inspection Program for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage SCC of stainless steel RWCU heat exchanger components exposed to treated water environments >140 °F. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that this AMP includes activities that will mitigate cracking due to SCC. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections of the RWCU 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 staff determined that these AMPs will adequately manage the aging effect for which they are credited. Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.3.2 for further evaluation.

In LRA Section 3.3.2.2.3.2, the applicant addressed cracking due to SCC in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust.

SRP-LR Section 3.3.2.2.3.3 states that cracking due to SCC can occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommends further evaluation of any plant-specific AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.3.2 states that LRA Table 3.3.1, item number 3.3.1-5, for stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust gases is not used. EDG components exposed to diesel exhaust gases are carbon steel not susceptible to cracking due to SCC.

The staff reviewed LRA Table 3.3.2.2.1.13, which addresses aging management of the EDG and auxiliary system, and confirmed that the diesel engine exhaust piping is identified as constructed of carbon and low alloy steel, not stainless steel. Therefore, the staff finds acceptable the applicant's conclusion that this further evaluation is not applicable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.3. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.4 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

The staff reviewed LRA Section 3.3.2.2.4 against the criteria in SRP-LR Section 3.3.2.2.4.

LRA Section 3.3.2.2.4.2 states that cracking due to SCC and cyclic loading of stainless steel heat exchanger components exposed to treated borated water, with reference to the further evaluation in SRP-LR Section 3.3.2.2.4.1, is applicable to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable to OCGS because it is a BWR plant.

In LRA Section 3.3.2.2.4.3, the applicant stated that cracking due to SCC and cyclic loading of stainless steel regenerative heat exchanger components exposed to treated borated water, with reference to the further evaluation in SRP-LR Section 3.3.2.2.4.2, is applicable to PWRs only. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable to OCGS because it is a BWR plant.

The staff noted that the applicant did not address cracking due to SCC or cyclic loading for PWR high pressure pumps in the chemical and volume control system, with reference to the further evaluation in SRP-LR Section 3.4.2.2.3, for the OCGS plant. The concludes that this further evaluation is not applicable to OCGS because it is a BWR plant.

In LRA Section 3.3.2.2.4.1, the applicant addressed cracking due to SCC and cyclic loading for high-strength steel closure bolting in auxiliary systems exposed to air with steam or water leakage.

SRP-LR Section 3.3.2.2.4.4[1] states that cracking due to SCC and cyclic loading can occur for high-strength steel closure bolting in auxiliary systems exposed to air with steam or water leakage. The GALL Report recommends the Bolting Integrity Program to manage this aging effect and that this AMP be augmented by appropriate inspection to detect cracking if the bolts

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[1] The staff noted that Section 3.3.2.2.4.4 had been omitted unintentionally from the SRP-LR (NUREG-1800, Revision 1, September 2005); however, this section is cited in the SRP-LR summary tables (e.g., Table 3.3-1, Item 10).

are not otherwise replaced during maintenance.

LRA Section 3.3.2.2.4.1 states that the only auxiliary system that contains high-strength steel closure bolting exposed to air with steam or water leakage is the CRD. The Bolting Integrity Program addresses aging management requirements for this ASME Code Class 1 high-strength steel closure bolting. Bolting integrity management follows published EPRI guidelines and other industry recommendations for material selection and testing, 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 CRD system is in accordance with ASME Code Section XI and assures that detection of leakage or fastener degradation will occur prior to loss of system or component intended function. Observed conditions with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Bolting Integrity Program and verified that this AMP includes activities that will manage cracking of high-strength steel closure bolting due to SCC and cyclic loading. This program includes ISI of high-strength bolting as part of the ASME Code Section XI ISI requirements; therefore, the requirements for augmented inspection are met. The staff determined that this AMP will adequately manage cracking of high-strength steel closure bolting due to SCC and cyclic loading in the CRD system. The staff concludes that the applicant's program meets the criteria of SRP-LR Section 3.3.2.2.4.4 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.4. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The staff reviewed LRA Section 3.3.2.2.5 against the criteria in SRP-LR Section 3.3.2.2.5.

In LRA Section 3.3.2.2.5.1, the applicant addressed hardening and loss of strength due to elastomer degradation in elastomer seals and components of heating and ventilation systems exposed to air - indoor uncontrolled (internal/external) environments.

SRP-LR Section 3.3.2.2.5.1 states that hardening and loss of strength due to elastomer degradation can occur in elastomer seals and components of heating and ventilation systems exposed to air - indoor uncontrolled (internal/external) environments. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.5.1 states that a Periodic Inspection of Ventilation Systems Program will be implemented for the internal and external inspection of elastomer components exposed to indoor air internal or external environments 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 of elastomer door seals and flexible connections identify detrimental changes in material properties, as evidenced by cracking, perforations in the material, or leakage. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Periodic Inspection of Ventilation Systems Program and determined that it is adequate to inspect the internal and external environments of elastomer components exposed to indoor air internal or external environments.

LRA Section 3.3.2.2.5.1 also states that a Structures Monitoring Program will be implemented for the external inspections of expansion joint and flexible connection elastomers exposed to indoor air external environments in the circulating water system, heating and process steam system, fire protection system, process sampling system, condensate system, and condensate transfer system. OCGS utilizes the Structures Monitoring Program to inspect the external surfaces of piping, piping components, and piping elements when no AMPs 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 with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Structures Monitoring Program and verified that this AMP includes external inspections of expansion joint and flexible connection elastomers exposed to indoor air external environments. The staff concludes that these AMPs will adequately manage hardening and loss of strength of elastomer seals and components due to elastomer degradation in elastomer components in auxiliary systems in the circulating water system, heating and process steam system, fire protection system, process sampling system, condensate system, and condensate transfer system. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.5.1 for further evaluation.

In LRA Section 3.3.2.2.5.2, the applicant addressed hardening and loss of strength due to elastomer degradation in elastomer linings of the filters, valves, and ion exchangers in spent fuel pool cooling and cleanup systems exposed to treated water.

SRP-LR Section 3.3.2.2.5.2 states that hardening and loss of strength due to elastomer degradation can 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 recommends evaluation of a plant-specific AMP to determine and assess the qualified life of the linings in the environment to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.5.2 states that a Periodic Inspection Program will be implemented for the internal inspection of expansion joint and flexible connection elastomers exposed to treated water internal environments in the condensate system, condensate transfer system, heating and process steam system, and process sampling system. The Periodic Inspection Program is used to 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 treated water internal environments to ensure that there is no loss of intended function. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Periodic Inspection Program and determined that it is adequate 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 staff finds that the applicant's program meets the criteria of SRP-LR Section 3.3.2.2.5.2 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.5. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

The staff reviewed LRA Section 3.3.2.2.14 against the criteria in SRP-LR Section 3.3.2.2.6.

In LRA Section 3.3.2.2.14, 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.

SRP-LR Section 3.3.2.2.6 states that reduction of neutron-absorbing capacity and loss of material due to general corrosion can occur in the neutron-absorbing sheets of BWR spent fuel storage racks exposed to treated water. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.14 states that the aging effects of the Boral spent fuel storage racks exposed to treated water environments 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, "Safety Evaluation Report Related to the License Renewal of Virgil C. Summer Nuclear Station," Section 3.5.2.4.2) and determined to be insignificant. In the year 2000, four spent fuel storage racks manufactured by HOLTEC International that utilized Boral neutron absorbing material were installed at OCGS. 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 g/cm^2, meaning 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, therefore, no AMP is required.

The staff reviewed HOLTEC International Report No. HI-2043279, "Summary Report of the Examination of Oyster Creek Nuclear Station Boral Surveillance Coupon No. HO910070-2-6," October 19, 2004, which concludes 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 g/cm^2, meaning that Boron-10 has not been lost from the coupon. In addition, the staff reviewed Holtec International Report No. HI-2033000, Revision 1, "Examination of Oyster Creek Nuclear Station Boral Surveillance Coupon No. HO920023-2-6," April 8, 2003, which concludes that the coupon tested showed no blisters, pits, or other degradation. Neutron transmission tests on the irradiated coupon showed an average Boron-10 areal density of 0.0194 g/cm^2, meaning that Boron-10 has not been lost from the coupon. Based on these reports, the staff 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 treated water environments are insignificant and require no aging management.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.6. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.7 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.7 against the criteria in SRP-LR Section 3.3.2.2.7.

In LRA Sections 3.3.2.2.7.1 and 3.3.2.2.7.3, the applicant addressed loss of material due to general, pitting, and crevice corrosion 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).

SRP-LR Section 3.3.2.2.7.1 states that loss of material due to general, pitting, and crevice corrosion can 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 AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to prevent corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Monitoring Activities Program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

In addition, the SRP-LR states that corrosion can 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 does not occur. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, to include the thickness of the lower portion of the tank. A one-time inspection is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.7.1 states that item numbers 3.3.1-15 and 3.3.1-16 are not applicable. Part 50, Appendix R Section III.O of 10 CFR does not apply because the containment is inert during normal operation.

The staff recognized that the containment is inert during normal operation, effectively eliminating the possibility of a fire. Therefore, the requirements of 10 CFR Part 50, Appendix R, Section III.O for a reactor coolant pump oil collection system do not apply. The staff finds acceptable the applicant's conclusion that this aging effect is not applicable.

LRA Section 3.3.2.2.7.3 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Lubricating Oil Monitoring Activities Program to manage the loss of material in steel piping, piping components, and piping elements exposed to lubricating oil internal or external environments in the EDG and auxiliary system, reactor recirculation system, RWCU system, RBCCW system, CRD 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 with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Lubricating Oil Monitoring Activities Program and determined that it is adequate to manage the loss of material in steel piping, piping components, and piping elements exposed to lubricating oil internal or external environments. The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.1 for further evaluation.

In LRA Section 3.3.2.2.7.2, the applicant addressed loss of material due to general, pitting, and crevice corrosion in steel piping, piping components, and piping elements in the BWR RWCU and shutdown cooling systems exposed to treated water.

SRP-LR Section 3.3.2.2.7.2 states that loss of material due to general, pitting, and crevice corrosion can occur in steel piping, piping components, and piping elements in the BWR RWCU and shutdown cooling systems exposed to treated water. The existing AMP 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.7.2 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage the loss of material in steel and aluminum piping, piping components, and piping elements exposed to treated water environments in the CRD system, post-accident sampling system, process sampling system, reactor head cooling system, reactor recirculation system, RWCU system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment and 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 treated water environments. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. With steel ASME Code Class MC components and steel ASME Classes 2 and 3 piping and components in treated water environments, the applicant will use the ASME Section XI, Subsection IWF, Program to verify the effectiveness of the Water Chemistry Program to mitigate loss of material. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it includes activities that will mitigate loss of material due to general, pitting, and crevice corrosion. In addition, the staff reviewed the applicant's One-Time Inspection and ASME Section XI, Subsection IWF, Programs and verified that they include 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 staff concludes that these AMPs will adequately manage loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to treated water. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.7.2 for further evaluation.

In 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.

SRP-LR Section 3.3.2.2.7.3 states that loss of material due to general (steel only) pitting and crevice corrosion can occur for steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.7.3 states that a Periodic Inspection Program will be implemented to manage the loss of material in steel EDG 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 cause no material degradation that could result in the loss of system intended functions. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Periodic Inspection Program and determined that it is adequate to manage the loss of material in steel piping, piping components, and piping elements exposed to lubricating oil internal or external environments. The staff finds that the applicant's program meets the criteria of SRP-LR Section 3.3.2.2.7.3 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.7. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.8 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion (MIC)

The staff reviewed LRA Section 3.3.2.2.8 against the criteria in SRP-LR Section 3.3.2.2.8.

LRA Section 3.3.2.2.8.1 addresses loss of material due to general, pitting, and crevice corrosion and MIC for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil.

SRP-LR Section 3.3.2.2.8 states that loss of material due to general, pitting, and crevice corrosion and MIC can occur for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The Buried Piping 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 Inspection Program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

LRA Section 3.3.2.2.8.1 states that a Buried Piping Inspection Program will be implemented to manage the loss of material in steel piping, piping components, and piping elements exposed to soil in the SW system, ESW system, fire protection system, drywell floor and equipment drain system, miscellaneous floor and equipment drain system, spent fuel pool cooling system, RBCCW 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 with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Buried Piping Inspection Program and verified that it includes inspections to detect loss of material of steel piping, piping components, and piping elements due to general, pitting, and crevice corrosion and MIC. The staff determined that, for each of the material and 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 the period of extended operation in addition to a focused inspection within the first 10-year period of the period of extended operation for objective evidence that the component coatings were in acceptable condition and that no significant aging was present for these buried components. The staff concludes that the Buried Piping Inspection Program will adequately manage loss of material in steel piping, piping components, and piping elements exposed to soil.

The LRA further states that an Aboveground Outdoor Tanks Program will be implemented 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 with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. OCGS has no buried tanks within the scope of license renewal.

The staff reviewed the applicant's Aboveground Outdoor Tanks Program and verified that this AMP includes inspections to manage the loss of material from the bottom of outdoor steel tanks supported by earthen foundations in the fire protection system. The staff concludes that this AMP will adequately manage loss of material from the bottom of outdoor steel tanks supported by earthen foundations.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.8. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, Microbiologically-Influenced Corrosion and Fouling

The staff reviewed LRA Section 3.3.2.2.9 against the criteria in SRP-LR Section 3.3.2.2.9.

In LRA Section 3.3.2.2.9.1, the applicant addressed loss of material due to general, pitting, and crevice corrosion, MIC, and fouling for steel piping, piping components, piping elements, and tanks exposed to fuel oil.

SRP-LR Section 3.3.2.2.9.1 states that loss of material due to general, pitting, and crevice corrosion, MIC, and fouling can occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The existing AMP relies on the Fuel Oil Chemistry Program to monitor and control 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 does not occur. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.9.1 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Fuel Oil Chemistry Program to manage the loss of material in steel piping, piping components, and piping elements exposed to a fuel oil internal environment in the EDG and auxiliary system, main fuel oil storage and transfer system, and fire protection system. Verification of the Fuel Oil Chemistry Program to manage the loss of material in steel fuel oil tanks is through the Fuel Oil Chemistry Program tank inspection, which requires that fuel oil tanks be periodically drained, cleaned, and internally inspected to ensure that corrosion does not occur and that there is no loss of intended function. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Fuel Oil Chemistry Program and verified that it includes activities that will mitigate loss of material due to general, pitting, and crevice corrosion, MIC, and fouling. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections to detect loss of material due to general, pitting, and crevice corrosion, MIC, and fouling as a means of verifying the effectiveness of the Fuel Oil Chemistry Program. The staff concludes that these AMPs will adequately manage loss of material due to general, pitting, and crevice corrosion, MIC, and fouling for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.9.1 for further evaluation.

In LRA Section 3.3.2.2.9.2, the applicant addressed loss of material due to general, pitting, and crevice corrosion, MIC, and fouling for steel heat exchanger components exposed to lubricating oil.

SRP-LR Section 3.3.2.2.9.2 states that loss of material due to general, pitting, and crevice corrosion, MIC, and fouling can occur for steel heat exchanger components exposed to lubricating oil. The existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to prevent corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.9.2 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Lubricating Oil Monitoring Activities Program to manage the loss of material in steel heat exchanger shell side components exposed to lubricating oil in the EDG and auxiliary system, RWCU 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 with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Lubricating Oil Monitoring Activities Program and determined that it is adequate to manage the loss of material in steel heat exchanger shell side components exposed to lubricating oil. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.9.2 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.9. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria in SRP-LR Section 3.3.2.2.10.

In the LRA Section 3.3.2.2.10.1, the applicant addressed loss of material due to pitting and crevice corrosion in BWR steel piping with elastomer lining or stainless steel cladding exposed to treated water.

SRP-LR Section 3.3.2.2.10.1 states that loss of material due to pitting and crevice corrosion can occur in BWR steel piping with elastomer lining or stainless steel cladding exposed to treated water if the cladding or lining is degraded. The existing AMP 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.10.1 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program 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 treated water environments in the CRD system, post-accident sampling system, process sampling system, RBCCW system, RWCU system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment and distribution system, reactor head cooling system, and in the primary containment. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. The applicant will implement a One-Time Inspection Program for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage the loss of material in stainless steel fuel storage and handling equipment and structures exposed to treated water environments 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 treated water environments in the reactor building structure. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. For stainless steel ASME Class MC components and to stainless steel ASME Classes 2 and 3 piping and components in treated water environments, the applicant will use the ASME Section XI, Subsection IWF, Program to verify the effectiveness of the Water Chemistry Program to mitigate loss of material. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it includes activities that will manage loss of material due to pitting and crevice corrosion. In addition, the staff reviewed the applicant's One-Time Inspection and ASME Section XI, Subsection IWF, Programs and verified that these AMPs include 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 staff concludes that these AMPs will adequately manage loss of material due to pitting and crevice corrosion in BWR steel piping with elastomer lining or stainless steel cladding exposed to treated water. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.10.1 for further evaluation.

In LRA Sections 3.3.2.2.10.1 and 3.3.2.2.7.2, 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.

SRP-LR Section 3.3.2.2.10.2 states that loss of material due to pitting and crevice corrosion can 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 AMP 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 Water Chemistry Program should be verified to ensure that corrosion does not occur. The GALL Report recommends 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.10.1 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program 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 treated water environments in the CRD system, post-accident sampling system, process sampling system, RBCCW system, RWCU system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment and distribution system, reactor head cooling system, and in the primary containment. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. The applicant will implement a One-Time Inspection Program for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage the loss of material in stainless steel fuel storage and handling equipment and structures exposed to treated water environments 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 treated water environments in the reactor building structure. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. When applied to stainless steel ASME Code Class MC components in treated water environments and to stainless steel ASME Code Classes 2 and 3 piping and components in treated water environments, the ASME Section XI, Subsection IWF, Program will be used to verify the effectiveness of the Water Chemistry Program to mitigate loss of material. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it includes activities that will manage loss of material due to pitting and crevice corrosion. In addition, the staff reviewed the applicant's One-Time Inspection and ASME Section XI, Subsection IWF, Programs and verified that these AMPs include 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 staff concludes 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 Code Class MC and Classes 2 and 3 piping and components exposed to treated water environments.

LRA Section 3.3.2.2.7.2 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage the loss of material in steel and aluminum piping, piping components, and piping elements exposed to treated water environments in the CRD system, post-accident sampling system, process sampling system, reactor head cooling system, reactor recirculation system, RWCU system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment and 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 treated water environments. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process. When applied to steel ASME Code Class MC components in treated water environments and to steel ASME Code Classes 2 and 3 piping and components in treated water environments, the ASME Section XI, Subsection IWF, Program will be used to verify the effectiveness of the Water Chemistry Program to mitigate loss of material. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that this AMP includes activities that will mitigate loss of material due to general, pitting, and crevice corrosion. In addition, the staff reviewed the applicant's One-Time Inspection and ASME Section XI, Subsection IWF, Programs and verified that they include 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 staff concludes that these AMPs will adequately manage a loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to treated water. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.10.2 for further evaluation.

In LRA Section 3.3.2.2.10.2, the applicant addressed loss of material due to pitting and crevice corrosion for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external).

SRP-LR Section 3.3.2.2.10.3 states that loss of material due to pitting and crevice corrosion can occur for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external). The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.10.2 states that a Periodic Inspection of Ventilation System Program will be implemented to manage the loss of material in copper heat exchanger coils exposed to an indoor air/condensation external environment in the Control Room HVAC System. The program will inspect the external surfaces of ventilation system components to identify and assess aging effects that may be occurring. The program will include surface inspections of copper alloy components for indications of 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 staff reviewed the applicant's Periodic Inspection of Ventilation System Program and concludes that it is adequate to detect loss of material due to pitting and crevice corrosion for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external). The staff finds that the applicant's program meets the criteria of SRP-LR Section 3.3.2.2.10.3 for further evaluation.

In LRA Section 3.3.2.2.11, the applicant addressed loss of material due to pitting and crevice corrosion can occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil.

SRP-LR Section 3.3.2.2.10.4 states that loss of material due to pitting and crevice corrosion can occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing AMP 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 be adequate to prevent corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Monitoring Activities Program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.11 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Lubricating Oil Monitoring Activities Program 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 SW system, RWCU system, EDG 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 with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Lubricating Oil Monitoring Activities Program and determined that it is adequate to manage the loss of material in copper alloy piping, piping components, piping elements, and heat exchangers exposed to a lubricating oil environment. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.10.4 for further evaluation.

LRA Section 3.3.2.2.10.2 addresses loss of material due to pitting and crevice corrosion for HVAC aluminum piping, piping components, and piping elements, and stainless steel ducting and components exposed to condensation.

SRP-LR Section 3.3.2.2.10.5 states that loss of material due to pitting and crevice corrosion can occur in HVAC aluminum piping, piping components, and piping elements, and stainless steel ducting and components exposed to condensation. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.10.2 states that a One-Time Inspection Program will be implemented to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a condensation internal environment in the hydrogen and oxygen monitoring system, and nitrogen supply system. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's One-Time Inspection Program and determined that it is adequate to manage loss of material of stainless steel components exposed to condensation. The staff concludes that the applicant had appropriately addressed loss of material in stainless steel piping, piping components, and piping elements exposed to a condensation internal environment in the hydrogen and oxygen monitoring system and the nitrogen supply system. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.10.5 for further evaluation.

The staff 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), with reference to the further evaluation in SRP-LR Section 3.3.2.2.10.6. This new AMR was not in the January 2005 draft GALL Report. The staff reviewed LRA Tables 3.3.2.1.1 through 3.3.2.1.41 and determined that AMR line items that address the same material and environment combinations were appropriately credited. Therefore, the staff concludes that this further evaluation is not applicable as the material and environment combinations have been evaluated.

The staff 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, with reference to the further evaluation in SRP-LR Section 3.3.2.2.10.7. This new AMR was not in the January 2005 draft GALL Report. The staff reviewed LRA Tables 3.3.2.1.1 through 3.3.2.1.41 and noted that other GALL Report AMR line items that address same material and environment combinations were appropriately credited. Therefore, the staff concludes that this further evaluation is not applicable.

LRA Section 3.3.2.2.10.1 addresses loss of material due to pitting and crevice corrosion of the BWR standby liquid control system stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution.

SRP-LR Section 3.3.2.2.10.8 states that loss of material due to pitting and crevice corrosion can occur in BWR standby liquid control system stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution. The existing AMP 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 conditions could cause loss of material due to pitting and crevice corrosion. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program be verified to ensure that this aging does not occur. 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.10.1 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program 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 treated water environments in the CRD system, post-accident sampling system, process sampling system, RBCCW system, RWCU system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment and distribution system, reactor head cooling system, and in the primary containment. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it will manage loss of material of steel piping in the standby liquid control system due to pitting and crevice corrosion. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it 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 staff concludes 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 staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.10.8 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.10. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.11 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion

The staff reviewed Attachment 3, item AP-64, of the applicant's reconciliation document against the criteria in SRP-LR Section 3.3.2.2.11.

In Attachment 3, item AP-64, of its reconciliation document, the applicant addressed loss of material due to pitting, crevice, and galvanic corrosion of copper alloy piping, piping components, and piping elements exposed to treated water.

SRP-LR Section 3.3.2.2.11 states that loss of material due to pitting, crevice, and galvanic corrosion can occur on copper alloy piping, piping components, and piping elements exposed to treated water. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program be verified to ensure that this aging does not occur. 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

Attachment 3, item AP-64, of the applicant's reconciliation document states that the AMR line item for copper alloy piping elements in treated water, addressing loss of material due to corrosion, recommends the Closed-Cycle Cooling Water System Program with no further evaluation in the January 2005 draft GALL Report that was changed in September 2005 to recommend the Water Chemistry and One-Time Inspection Programs with further evaluation of detected aging effects. There are four instances of this line item used in the condensate transfer and RBSSW systems. In the LRA, these instances already specify the Water Chemistry and One-Time Inspection Programs (with generic Note E stating that an AMP different from that specified in the January 2005 draft GALL Report was credited). Therefore, the LRA implements the One-Time Inspection Program consistent with the GALL Report. Observed conditions with potential impact on Intended function are evaluated or corrected in accordance with the corrective action process, and there is high confidence that the aging effect will be adequately managed.

The staff reviewed the applicant's Water Chemistry Program and verified that it 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 staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections to detect loss of material as a means of verifying the effectiveness of the Water Chemistry Program. The staff concludes 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.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.11. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.12, and Attachment 3, item AP-54, of the applicant's reconciliation document against the criteria in SRP-LR Section 3.3.2.2.12.

LRA Section 3.3.2.2.12.1 addresses loss of material due to pitting, crevice, and MIC for aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil. In Attachment 3, item AP-54, of its reconciliation document, the applicant addressed loss of material due to pitting and crevice corrosion and MIC of stainless steel piping, piping components, and piping elements exposed to fuel oil.

SRP-LR Section 3.3.2.2.12.1 states that loss of material due to pitting and crevice corrosion and MIC can occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil. The existing AMP relies on the Fuel Oil Chemistry Program to monitor and control 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 does not occur. The GALL Report recommends further evaluation of programs to manage corrosion 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.12.1 states that a One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Fuel Oil Chemistry Program 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 EDG and auxiliary system, main fuel oil storage and transfer system, and fire protection system. Observed conditions with potential impact on intended function will be evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Fuel Oil Chemistry Program and verified that it will mitigate loss of material due to pitting and crevice corrosion and MIC. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections to detect loss of material due to pitting and crevice corrosion and MIC as a means of verifying the effectiveness of the Fuel Oil Chemistry Program. The staff concludes that these AMPs will manage loss of material due to pitting and crevice corrosion and MIC for aluminum and copper alloy piping, piping components, piping elements, and tanks exposed to fuel oil in the EDG and auxiliary system, main fuel oil storage and transfer system, and fire protection system.

Attachment 3, item AP-54, of the applicant's reconciliation document states that the line item for stainless steel piping elements in fuel oil, addressing loss of material due to corrosion, recommends the Fuel Oil Chemistry Program with no further evaluation required per the January 2005 draft GALL Report that was changed in the September 2005 GALL Report to recommend the Fuel Oil Chemistry and One-Time Inspection Programs with a further evaluation of detected aging effects to be consistent with other line items applicable to fuel oil environments. There are six instances of this line item used in the EDG and auxiliary systems, and in the main fuel oil storage and transfer system. 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 Program requirements to detect 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 of potential impact on intended function evaluated and corrected as necessary in accordance with the corrective action process) provide ample opportunity to verify 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 LRA for this item.

The staff reviewed LRA Tables 3.3.2.1.13 and 3.3.2.1.21 for the EDG and auxiliary system and for the main fuel oil transfer system, respectively, and noted multiple line items for components constructed of carbon steel, copper, and aluminum exposed to fuel oil that already credit both the Fuel Oil Chemistry and One-Time Inspection Programs to manage loss of material. Stainless steel is expected to be more resistant to corrosion than carbon steel, copper, and aluminum, and the latter materials can be considered leading indicators expected to be included in the scope of the one-time inspection sample basis. One-time inspection of the stainless steel components would not significantly change the one-time inspection sample basis. On this basis, the staff concludes 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 staff finds acceptable the applicant's conclusion that no change was needed to the LRA for this item as the line items have been addressed under the above programs. Based on its review, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.1 for further evaluation.

In LRA Section 3.3.2.2.12.2, the applicant addressed loss of material due to pitting and crevice corrosion and MIC in stainless steel piping, piping components, and piping elements exposed to lubricating oil.

SRP-LR Section 3.3.2.2.12.2 states that loss of material due to pitting and crevice corrosion and MIC can 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, preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to prevent corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Monitoring Activities Program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.3.2.2.12.2 states that a One-Time Inspection Program of susceptible locations will verify the effectiveness of the Lubricating Oil Monitoring Activities Program to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment in the EDG 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 with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Lubricating Oil Monitoring Activities Program and determined that it is adequate to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment. The staff finds that the applicant's programs meet the criteria of SRP-LR Section 3.3.2.2.12.2 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.12. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.13 Loss of Material Due to Wear

The staff reviewed LRA Section 3.3.2.2.13 against the criteria in SRP-LR Section 3.3.2.2.13.

In LRA Section 3.3.2.2.13, the applicant addressed loss of material due to wear that can occur in the elastomer seals and components exposed to air indoor uncontrolled (internal or external).

SRP-LR Section 3.3.2.2.13 states that loss of material due to wear can occur in the elastomer seals and components exposed to air indoor uncontrolled (internal or external) environments. The GALL Report recommends further evaluation to ensure adequate management of these aging effects.

LRA Section 3.3.2.2.13 states that Periodic Inspection of Ventilation Systems Program will be implemented for the inspection of elastomer door seals exposed to indoor air internal or external environments 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 of elastomer door seals identify detrimental changes in material properties, as evidenced by cracking, perforations in the material, or leakage. Observed conditions with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Periodic Inspection of Ventilation Systems Program and concludes that it is adequate to detect loss of material of elastomer seals and components.

Based on the program identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.3.2.2.13. For those LRA line items to which this SRP-LR section applies, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.14 Loss of Material Due to Cladding Breach

The staff noted that the applicant did not address loss of material due to cladding breach for PWR steel charging pump casings with stainless steel cladding exposed to treated borated water, with reference to the further evaluation in SRP-LR Section 3.3.2.2.14, applicable to PWR plants. The staff concludes that this further evaluation is not applicable to OCGS because it is a BWR plant.

3.3.2.2.15 Quality Assurance for Aging Management of Nonsafey-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program for safety-related and nonsafety-related components. The staff concluded that the program descriptions of the "corrective action," "confirmation process," and "administrative controls" attributes are acceptable.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff concludes that the applicant has adequately addressed the issues further evaluated. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA *Tables* 3.3.2.1.1 *through* 3.3.2.1.41, *the applicant indicated, via* Notes F *through* J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed LRA Table 3.3.1, which summarizes aging management evaluations for the auxiliary systems evaluated in the GALL Report.

LRA Table 3.1.1, items 3.3.1-16 and 3.3.1-12 state that loss of material of piping and fittings and valve bodies constructed from carbon and low alloy steel in the containment inerting system, the CRD system, the RBCCW system, the reactor building ventilation system, the RWCU system, the spent fuel pool cooling system, and the water treatment and distribution system due to exposure to the containment atmosphere (internal) is not applicable.

The staff finds acceptable the applicant's evaluation because that the containment atmosphere is blanketed with nitrogen and does not cause loss of material for carbon and low alloy steel except during refueling outages.

LRA Table 3.1.1, item 3.1.1-9 states that SSC and IGSCC of piping and fittings, valve bodies and flow elements constructed from carbon and low alloy steel in the CRD and the shutdown cooling systems due to exposure to treated water (internal) is not applicable.

This conclusion is a result of work completed by EPRI and reported in EPRI Mechanical Tools Appendix A. The staff finds this conclusion acceptable because the applicant had followed EPRI recommendations.

LRA Table 3.1.1, item 3.3.1-12 state that loss of material of piping and fittings, heat exchangers, pump casings, and valve bodies constructed from carbon and low alloy steel in the drywell floor and equipment drains due to exposure to the containment atmosphere (internal) is not applicable.

The staff understands that the containment atmosphere is blanketed with nitrogen and does not cause loss of material for carbon and low alloy steel except during short periods of time during the refueling outages.

LRA Table 3.1.1, items 3.3.1-16 and 3.3.1-12 state that the loss of material of accumulators, piping and fittings, and valve bodies constructed from carbon and low alloy steel in the instrument (control) air system due to exposure to the containment atmosphere (internal) is not applicable. The reason is that the containment atmosphere is blanketed with nitrogen and does not cause loss of material for carbon and low alloy steel except during refueling outages. The staff finds this statement acceptable.

LRA Table 3.1.1, items 3.3.1-16 and 3.3.1-12 state that SCC and IGSCC of piping and fittings, valve bodies, and heat exchangers (drywell equipment drain tank) constructed from carbon and low alloy steel in the post-accident sampling system and RBCCW system due to exposure to the *treated water (internal) is not applicable.*

This conclusion is a result of work completed by the industry. The staff finds this acceptable because the applicant had followed EPRI recommendations.

In LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified line-items where no aging effects were identified from its aging review process.

The applicant stated that no aging effects are considered applicable to components fabricated from stainless steel material exposed to indoor air environments.

On the basis of its review of current industry research and operating experience, the staff finds that indoor air on stainless steel will not cause aging of concern during the period of extended operation. Stainless steel forms a passive film that indoor air does not affect. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for stainless steel components exposed to indoor air environments.

The applicant stated that no aging effects are considered applicable to components fabricated from polypropylene material exposed to outdoor air environments.

On the basis of its review of current industry research and operating experience, the staff finds that outdoor air environments on polypropylene material will not cause aging of concern during the period of extended operation. The staff questioned the applicant about the presence of such stressors as ultraviolet, thermal, radiation, or ozone that would cause aging effects for polypropylene exposed to outdoor air. Based on industry standards, the applicant responded that there are no stressors present. Therefore, the staff concludes that there are no applicable aging effects requiring management for polypropylene components exposed to outdoor air environments because the material does not react in these environments.

The applicant stated that no aging effects are considered applicable to components fabricated from polyvinyl chloride (PVC, CPVC) materials exposed to outdoor air (exterior), raw water (interior), and indoor air (exterior) environments.

On the basis of its review of current industry research and operating experience, the staff finds that outdoor air (exterior), raw water (interior), and indoor air (exterior) on PVC, CPVC will not cause aging of concern during the period of extended operation. The staff questioned the applicant about the presence of such stressors as ultraviolet, thermal, radiation, or ozone that would cause aging effects for polypropylene exposed to outdoor air (exterior), raw water (interior), and indoor air (exterior) environments and the applicant responded that the presence of stressors is precluded by industry standards. Therefore, the staff concludes that there are no applicable aging effects requiring management for PVC, CPVC components exposed to outdoor air (exterior), raw water (interior), and indoor air (exterior) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from carbon and low alloy steel material exposed to treated water (interior), containment air (exterior), and containment air (internal) environments.

On the basis of its review of current industry research and operating experience, the staff finds that treated water (interior), containment air (exterior), and containment air (internal) environments on carbon and low alloy steel will not cause aging of concern during the period of extended operation. SCC and IGSCC of carbon and low alloy steel are not considered applicable aging mechanisms in treated water per EPRI Mechanical Tools Appendix A.

Based on NRC-approved past precedent, the staff determined that this material and environment combination has been found acceptable. The staff concludes that loss of material due to corrosion 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. The staff finds the applicant's statement of no loss of material for the carbon steel components exposed to a containment nitrogen environment acceptable because, with the negligible amounts of free oxygen, anodic reactions do not take place and the corrosion cell does not form. Therefore, loss of material due to corrosion is not a significant aging effect in the containment atmosphere environment.

During operation, plant technical specifications require oxygen levels to be maintained below 5 percent. Prior to startup following an outage where the primary containment has been opened for maintenance activities, the drywell and torus are purged with nitrogen until oxygen levels are brought below the technical specification limit. A review of operating data indicates that the oxygen level continues to decrease over the next several weeks following startup until the level falls below 1 percent. During the remainder of the operating cycle, the oxygen level is normally maintained below 1 percent. Therefore, the staff concludes that there are no applicable aging effects requiring management for carbon and low alloy steel components exposed to treated water (interior), containment air (exterior), and containment air (internal) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from galvanized steel material exposed to concrete (exterior) environments.

On the basis of its review of current industry research and operating experience, the staff finds that concrete (exterior) environments on galvanized steel will not cause aging of concern during the period of extended operation. There is no aging effect for galvanized steel encased in concrete. This finding is consistent with industry guidance. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for galvanized steel components exposed to indoor air (internal) and concrete (exterior) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from cast iron material exposed to containment air (internal) and containment air (external) environments.

On the basis of its review of current industry research and operating experience, the staff finds that containment air (internal), containment air (external) environments on cast iron will not cause aging of concern during the period of extended operation. The staff concludes that the loss of material due to corrosion is not considered a credible aging effect for cast iron 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. The staff finds the applicant's statement of no loss of material for the carbon steel components exposed to a containment nitrogen environment acceptable because, with the negligible amounts of free oxygen, anodic reactions do not take place and the corrosion cell does not form. Therefore, loss of material due to corrosion is not a significant aging effect in the containment atmosphere environment. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for cast iron components exposed to containment air (internal) and containment air (external) environments

The applicant stated that no aging effects are considered applicable to components fabricated from brass (tubing) material exposed to closed cooling water environments.

On the basis of its review of current industry research and operating experience, the staff finds that closed cooling water environment on brass (tubing) will not cause aging of concern during the period of extended operation. Aging effects on heat transfer function are based on industry standards. Fouling is not a significant aging mechanism for brass tubes in closed cooling water environments. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for brass components exposed to closed cooling water environments.

The applicant stated that no aging effects are considered applicable to components fabricated from glass material exposed to closed cooling water (internal) and treated water <140 °F (internal) environments.

On the basis of its review of current industry research and operating experience, the staff finds that closed cooling water (internal) and treated water <140 °F (internal) environments on glass will not cause aging of concern during the period of extended operation. There is no aging effect for glass in the closed cooling water or treated water <140 °F environments. This finding is consistent with industry standards and the GALL Report for treated water and raw water. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for glass components exposed to closed cooling water (internal) and treated water <140 °F (internal) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from polyethylene material exposed to dry gas (internal) and indoor air (external) environments.

On the basis of its review of current industry research and operating experience, the staff finds that dry gas (internal) and indoor air (external) environments on polyethylene will not cause aging of concern during the period of extended operation. Polyethylene does not react with dry gas or indoor air. There are no stressors for polyethylene like ultraviolet, thermal, radiation, or ozone that would cause aging effects in dry gas (internal) or indoor air (external). Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for polyethylene components exposed to dry gas (internal) or indoor air (external) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from zinc material exposed to dry gas (internal) or indoor air (external) environments.

On the basis of its review of current industry research and operating experience, the staff finds that dry gas (internal) or indoor air (external) environments on zinc will not cause aging of concern during the period of extended operation. The environment of dry gas was used for the instrument air system. The compressed air monitoring program is applied to the Instrument Air system components to confirm that the internal environment remains sufficiently dry to prevent aging effects. Indoor air also will not cause any aging effects on zinc components. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for zinc components exposed to dry gas (internal) or indoor air (external) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from aluminum material exposed to concrete (external) environments.

On the basis of its review of current industry research and operating experience, the staff finds that concrete environments on aluminum materials will not cause aging of concern during the period of extended operation. There is no aging effect for galvanized steel and aluminum encased in concrete. This finding is consistent with industry guidance. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for aluminum components exposed to concrete (external) environments.

The applicant stated that no aging effects are considered applicable to components fabricated from titanium (tubes) material exposed to closed cooling water (external) and outdoor air (external) environments.

On the basis of its review of current industry research and operating experience, the staff finds that closed cooling water (external) and outdoor air (external) environments on titanium (tubes) will not cause aging of concern during the period of extended operation. Titanium is not addressed in the GALL Report and the aging effects are based on industry standards. The staff concludes, based on industry operating experience, that aging of titanium tubes in closed cooling water (external) and outdoor air (external) environments is not an applicable aging effect requiring management.

The applicant stated that no aging effects are considered applicable to components fabricated from polymers material exposed to indoor air (external) and treated water (internal) environments.

On the basis of its review of current industry research and operating experience, the staff finds that indoor air (external) on polymers will not cause aging of concern during the period of extended operation. According to industry operating experience aging of thermoplastics in indoor air and treated water environments is not an applicable aging effect. Therefore, as identified above, the staff concludes that there are no applicable aging effects requiring management for polymer components exposed to indoor air (external) and treated water (internal) environments.

On the basis of its audit and review of the applicant's program, the staff finds 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).

3.3.2.3.1 Fire Protection System – LRA Table 3.3.2.1.15

The staff reviewed LRA Table 3.3.2.1.15, which summarizes the results of AMR evaluations for the fire protection system component groups.

The staff review identifies areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.3.2.1.15-1 dated January 5, 2006, the staff noted that LRA Table 3.3.2.1.15, "Fire Protection System," shows no AERM and no AMP for fire barrier walls and slabs made of gypsum board exposed to indoor air. The staff requested that the applicant explain why gypsum board requires no AMP for indoor environment.

In its response dated February 3, 2006, the applicant stated that the gypsum board within the scope of license renewal is installed in a location protected from weather, not in a destructive environment. Review of OCGS operating experience with gypsum board fire barriers indicates no significant age-related degradation that would require an AMP. This operating experience was confirmed by the Fire Protection System manager.

The applicant stated that there are no aging effects for gypsum board and therefore no AMPs required. The applicant's AMR conclusion for the gypsum board is consistent with GALL Report, which calls for aging management of only fire barriers exposed to outdoor environments. The gypsum board in LRA Table 3.3.2.1.15 is exposed only to indoor air environment. Consistent with guidance in the GALL Report, as identified above, the staff concludes that gypsum board requires no aging management for the period of extended operation. Therefore, the staff's concern described in RAI 3.3.2.1.15-1 is resolved.

In RAI 3.3.2.1.15-2 dated January 5, 2006, the staff noted that LRA Table 3.3.2.1.15 shows no AERM and no AMP for flexible hose made of polyethylene (teflon) exposed to internal and external environments. The staff requested that the applicant explain why polyethylene (teflon) requires no AMP for internal and external environments.

In its response, by letter dated February 3, 2006, the applicant stated that the polyethylene (Teflon) flexible hose is located in the halon system and subject to dry air internally and indoor air externally, not to significant radiation (including ultraviolet radiation) or high temperatures. The full chemical name for this polyethylene is Polytetrafluoroethylene (PTFE). DuPont's *trademark for this compound is Teflon®. PTFE is a thermoplastic member of the fluoropolymer* family of plastics. PTFE has a low coefficient of friction, excellent insulating properties, and is chemically inert to most substances. PTFE can withstand high heat applications and is well known for its anti-stick properties. PTFE material has no significant aging effects in the halon fire protection system environment at OCGS and therefore requires no AMR.

Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.15-2 acceptable because the flexible hose in question is located in the halon system and subject to dry air internally and indoor air externally environment. Furthermore, halon system flexible hose is not subject to significant radiation (including ultraviolet radiation) or high temperatures. In addition, the Fire Protection Program provides inspection guidance for external surfaces of the CO_2 and halon fire suppression system components for corrosion and mechanical damage. Therefore, the staff's concern described in RAI 3.5.2.1.15-2 is resolved.

In RAI 3.3.2.1.15-3, dated January 5, 2006, the staff noted that LRA Table 3.3.2.1.15 lists spray nozzles (CO_2 and halon) but not spray nozzles (water). The staff requested that the applicant explain why water spray nozzles require no AMP.

In its response dated February 3, 2006, the applicant stated that for the fire water systems all spray nozzles are included under "sprinkler heads."

Based on its review, the staff finds the applicant's response to RAI 3.3.2.1.15-3 acceptable because it explains that the spray nozzles in question are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a). Further, the applicant stated that the spray nozzles are represented in the LRA table by the component type "sprinkler heads." Therefore, the staff's concern described in RAI 3.5.2.1.15-3 is resolved.

On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects of the fire protection system components 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).

3.3.2.3.2 Fuel Storage and Handling Equipment – LRA Table 3.3.2.1.16

The staff reviewed LRA Table 3.3.2.1.16, which summarizes the results of AMR evaluations for the fuel storage and handling equipment component groups.

Boral is a neutron-absorbing material used for reactivity control in the spent fuel pool.
The GALL Report does not address the issue of its aging effect. LRA Table 3.3.2.1.16 indicates that when Boral is exposed to the treated water at the temperature of $\leq$140 °F it exhibits no

aging effects; therefore, no AMP is needed. The applicant based its assertion on a precedent in a similar plant where use of Boral was approved by the NRC in NUREG-1787. The NRC approved the use of Boral because its aging effects were found to be insignificant. In addition to this precedent, in 2000 the applicant performed its own verifying tests on Boral by installing four spent fuel racks, manufactured by HOLTEC International, that utilize Boral neutron-absorbing material. The applicant also installed Boral coupons in the spent fuel storage pool. In 2002 and 2004, these coupons were removed and inspected.

The inspection results showed no blisters, pits, dimensional changes, or other age-related degradations. Neutron transmission tests on the irradiated coupon showed an average boron-10 areal density in the irradiated coupon of 0.0209 g/cm^2, meaning that, within the experimental accuracy, boron-10 had not been lost from the coupons. These results and plant operating experience were consistent with the staff's conclusions in NUREG-1787.

The staff review identifies an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.3.2.1.16-1 dated March 10, 2006, the staff requested that the applicant provide information on the location of the test coupons relative to the spent fuel racks, the way they were mounted, and whether they are fully exposed to the spent fuel pool water. Also, requested was what specific testing procedures had been used for determining boron-10 density, surface corrosion, and blister formation, if any. The staff also expressed its concern over the effect of blisters on plant performance if they ever form and the appropriate action by plant personnel to manage this aging effect.

In its response dated April 7, 2006, the applicant stated that the coupons are mounted in a coupon tree in an environment similar to that of the in-service Boral panels and located in a spent fuel storage rack cell. The coupons in the coupon tree, like those in-service panels, are fully exposed to the spent fuel pool water. Therefore, it can be assumed that any mechanisms for Boral degradation will be similar.

OCGS Procedure 1002.7, "In-service Surveillance Program fo Boral Poison Racks," is used to verify the integrity of Boral neutron absorber. Neutron attenuation measurements are per Procedure Section 6.3, "Neutron Attenuation," to verify acceptable values of boron-10. All measurements are performed with a sufficient counting interval to obtain the desired confidence limits. Degree of attenuation is obtained by comparing the areal density of the irradiated coupon to its pre-irradiated value. Therefore, the neutron transmission tests by the applicant demonstrated that within measurement accuracy no boron-10 loss occurred. This demonstration indicates expected Boral performance in the spent fuel pool.

Surface corrosion and blister formation on coupons are characterized through visual examination and measurement of coupon weight, length, width, and thickness. Blisters are characterized by a local area where the Boral aluminum cladding separates from the aluminum-boron carbide core, most probably due to internal pressure buildup in the Boral core. Blisters in Boral that occur under a relatively thin stainless steel wrapper can cause its deformation. Although no blisters were observed, in BWR fuel racks, as at OCGS, blisters in the Boral can occur. If they occur in more than one Boral plate at any coincident axial location in the same rack cell, the deformed wrapper may impede fuel insertion and withdrawal from the spent fuel rack or displace water from the flux trap region, increasing the reactivity state. However, this occurrence would not apply to OCGS because the plant does not utilize flux traps for thermalizing neutrons and has not experienced such because no blisters have formed. If they form in the future, visual inspection and the operation of fuel insertion and withdrawal would alert plant personnel of their presence.

Although Boral blistering may become an operational concern if sufficient blistering occurs to impede rack cell use, Boral blisters are not a safety concern because of OCGS rack design and industry operational and testing experience. Any Boral aging effect will be observed as part of the surveillance program and the use of the Boraflex Rack Management Program.

The staff found that the applicant had presented evidence that Boral neutron-absorbing material in the spent fuel racks will not undergo aging effects which would negate its function of controlling reactivity of the spent fuel in the spent fuel pool. The applicant compared its Boraflex Rack Management Program to the program in a similar plant that had been approved by the staff. The applicant also described its methods for demonstrating the stability of Boral in the environment of treated water at $\leq 140\ ^\circ F$ temperature.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the fuel storage and handling equipment components 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).

Conclusion. On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results involving material, environment, AERMs, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the auxiliary systems 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).

3.4 Aging Management of Steam and Power Conversion System

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion system components and component groups of the following systems:

- condensate system
- condensate transfer system
- feedwater system
- main condenser
- main generator and auxiliary system
- main steam system
- main turbine and auxiliary system

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant provided AMR results for the steam and power conversion system components and component groups. LRA Table 3.4.1, "Summary of Aging Management Evaluations for the Steam and Power Conversion System," provides a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the steam and power conversion system components and component groups.

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.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components 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 staff conducted an onsite audit of AMRs during the weeks of October 3-7, 2005, January 23-27, February 13-17, and April 19-20, 2006, to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and summarized in SER Section 3.4.2.1.

In the onsite audit, the staff also selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.4.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.4.2.2.

The staff also conducted a technical review of the remaining AMRs that were not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's evaluations are documented in SER Section 3.4.2.3.

For AMRs that the applicant identified as not applicable, or not requiring aging management, the staff conducted a review of the AMR line items, and the plant's operating experience, to verify the applicant's claims. Details of these reviews are documented in the Audit and Review Report.

Finally, the staff 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, provided below, includes a summary of the staff's evaluation of components, aging effects and mechanisms, and AMPs, listed in LRA Section 3.4, that are addressed in the GALL Report.

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 SER Section 3.4.2.2.2)
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 SER Section 3.4.2.2.2)
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 SER 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 SER Section 3.4.2.2.7 and 3.4.2.2.2 for steel tanks)
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. (See SER Section 3.4.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 microbiologically-influenced corrosion, and fouling	Plant specific	Not Applicable	Not applicable, refers to auxiliary feedwater system of a PWR and is not applicable to OCGS. (See SER 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 OCGS (See SER Section 3.4.2.2.4)
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)	Acceptable (See SER Section 3.4.2.3)
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 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 SER Section 3.4.2.2.5)
Steel heat exchanger components exposed to lubricating oil (Item 3.4.1-12)	Loss of material due to general, pitting, crevice, and microbiologically-influenced 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 OCGS. (See SER Section 3.4.2.2.5)
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 SER Section 3.4.2.2.6)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER 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 SER Section 3.4.2.2.7)
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 SER Section 3.4.2.2.7)
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 SER Section 3.4.2.2.7)
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 OCGS. (See SER Section 3.4.2.2.7)
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 microbiologically-infl uenced 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. (See SER Section 3.4.2.2.8)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER 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 line item not used in the 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 SER 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 line item not used in the 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 SER Section 3.4.2.1)
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (Item 3.4.1-25)	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 SER Section 3.4.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 OCGS.
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 OCGS.
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 SER Section 3.3.2.1.3)
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 SER Section 3.4.2.1)
Steel piping, piping components, and piping elements exposed to air outdoor (internal) or condensation (internal) (Item 3.4.1-30)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Periodic Inspection (B.2.5)	Acceptable - the OCGS periodic inspection program is consistent with the GALL inspection of internal surfaces in miscellaneous piping and ducting components program for this component group/ aging effect combination. (See SER Section 3.3.2.1.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel heat exchanger components exposed to raw water (Item 3.4.1-31)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced 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 OCGS.
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 microbiologically-influenced 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 OCGS Consistent with GALL.
Stainless steel heat exchanger components exposed to raw water (Item 3.4.1-33)	Loss of material due to pitting, crevice, and microbiologically-influenced 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 OCGS.
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 OCGS.
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 OCGS.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER 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 SER 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 SER Section 3.4.2.1)
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 SER Section 3.4.2.1)
Steel piping, piping components, and piping elements exposed to air - indoor controlled (external) (Item 3.4.1-42)	None	None	Not Applicable	Not Applicable Controlled air environments are not credited at OCGS. Components are evaluated as part of the uncontrolled indoor air environment.
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 OCGS.

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 3.4.1-44)	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 OCGS.

The staff's review of the steam and power conversion system component groups followed one of several approaches. One approach, documented in SER Section 3.4.2.1, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.4.2.2, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.4.2.3, discusses the staff's review of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.4.2.1, the applicant identified the materials, environments, AERMs, and the following programs that manage the effects of aging related to the steam and power conversion system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
- Water Chemistry (B.1.2)
- Flow-Accelerated Corrosion (B.1.11)
- Bolting Integrity (B.1.12)
- Closed-Cycle Cooling Water System (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)

Staff Evaluation. In LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant provided a summary of AMRs for the steam and power conversion system components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. 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 has the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. In SER Section 3.0, the staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments, (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report, and (c) identified those aging effects for the steam and power conversion system components subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.4.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.4.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.4.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report, for the steam and power conversion system components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion, and fouling
- reduction of heat transfer due to fouling
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- cracking due to stress corrosion cracking
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, and galvanic corrosion
- quality assurance for aging management of nonsafety-related components

Staff Evaluation. For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.4.2.2. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

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). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.4.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2.

In LRA Section 3.4.2.2.2.1, the applicant addressed 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.

SRP-LR Section 3.4.2.2.2.1 states that loss of material due to general, pitting, and crevice corrosion can occur in 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 AMP relies on monitoring and controlling 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 Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.2.1 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program 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, ESW system, RBCCW system, and heating and process steam system. Observed conditions with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it includes activities for monitoring and controlling water chemistry to manage the effects of loss of material due to general, pitting, and crevice corrosion. In addition, the staff verified that the One-Time Inspection Program verifies the effectiveness of the Water Chemistry Program in managing loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. The staff concludes 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 staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.2.1 for further evaluation.

In 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.

SRP-LR Section 3.4.2.2.2.2 states that loss of material due to general, pitting, and crevice corrosion can occur in steel piping, piping components, and piping elements exposed to lubricating oil. The existing AMP relies on periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. 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 does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.2.2 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Lubricating Oil Monitoring Activities Program to manage the loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to a lubricating oil internal environment in the condensate system, condensate transfer system, feedwater system, main steam system, main turbine and auxiliary system, ESW system, RBCCW 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Lubricating Oil Monitoring Activities Program and determined that it includes appropriate activities to manage the loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to a lubricating oil internal environment. The staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.2.2 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.4.2.2.2. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion (MIC), and Fouling

In LRA Section 3.4.2.2.3, the applicant stated that loss of material due to general, pitting, and crevice corrosion and MIC, and fouling of steel components exposed to raw water in a PWR auxiliary feedwater system, with reference to the further evaluation in SRP-LR Section 3.4.2.2.3, is applicable to PWRs only. The staff finds acceptable the applicant's evaluation of this aging effect as not applicable to OCGS because it is a BWR plant.

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff 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, with reference to the further evaluation in SRP-LR Section 3.4.2.2.4.1.

The staff reviewed LRA Tables 3.4.2.1.1 through 3.4.2.1.7 and noted that this component group and environment combination was not identified as within the scope of license renewal. Therefore, the staff finds acceptable the applicant's assessment and concludes that this further evaluation is not applicable.

The staff 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, with reference to the further evaluation in SRP-LR. This new AMR was not in the January 2005 draft GALL Report.

The staff reviewed LRA Tables 3.3.2.1.13, 3.3.2.1.15, and 3.3.2.1.29 and noted that the applicant identified copper alloy components exposed to lubricating oil for which the Lubricating Oil Monitoring Activities Program was credited to manage reduction of heat transfer. Generic Note G was cited, indicating that the environment was not in the GALL Report for that component and material; therefore, these AMR line items were identified as not consistent with the GALL Report and are addressed in SER Section 3.4.2.3.

3.4.2.2.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.5.2 against the criteria in SRP-LR Section 3.4.2.2.5.

In LRA Section 3.4.2.2.5.2, the applicant addressed loss of material due to general, pitting, and crevice corrosion and MIC in steel components exposed to soil.

SRP-LR Section 3.4.2.2.5.1 states that loss of material due to general, pitting, and crevice corrosion and MIC can occur in steel (with or without coating or wrapping) piping, piping components, piping elements, and tanks exposed to soil. The Buried Piping 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 does not occur.

LRA Section 3.4.2.2.5.2 states that a Buried Piping Inspection Program will be implemented 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Buried Piping Inspection Program and verified that it includes inspections to detect loss of material in steel piping, piping components, and piping elements due to general, pitting, and crevice corrosion and MIC. The staff confirmed that, for each of the material and 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 the period of extended operation, and a focused inspection will be performed within the first 10 years of the period of extended operation. The staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.5.1 for further evaluation.

The staff 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, with reference to the further evaluation in SRP-LR Section 3.4.2.2.5.2. The staff reviewed LRA Tables 3.4.2.1.1 through 3.4.2.1.7 and noted that other GALL Report AMR line items that address the same material and environment combinations are appropriately credited. Therefore, the staff concludes that this further evaluation is not applicable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.4.2.2.5. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.6 Cracking Due to Stress Corrosion Cracking (SCC)

The staff reviewed LRA Section 3.4.2.2.6.1 against the criteria in SRP-LR Section 3.4.2.2.6.

In LRA Section 3.4.2.2.6.1, the applicant addressed cracking due to SCC for stainless steel components exposed to treated water or steam.

SRP-LR Section 3.4.2.2.6 states that cracking due to SCC can 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 AMP monitors and controls water chemistry to manage the effects of cracking due to SCC. However, high concentrations of impurities at crevices and locations of stagnant flow conditions can cause SCC. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program be verified to ensure that SCC does not occur. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that SCC does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.6.1 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage SCC 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 and process steam system, main steam system, isolation condenser system, shutdown cooling system, and main turbine auxiliary system. Observed conditions with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it includes activities that will mitigate cracking due to SCC. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections of the stainless steel steam and power conversion system components to detect cracking and verify the effectiveness of the Water Chemistry Program. The staff finds that these AMPs will adequately manage cracking due to SCC for stainless steel heat exchanger components in the steam and power conversion systems.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.4.2.2.6. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Sections 3.4.2.2.7 and 3.4.2.2.9 against the criteria in SRP-LR Section 3.4.2.2.7.

In LRA Section 3.4.2.2.7.1, the applicant addressed loss of material due to pitting and crevice corrosion 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.

SRP-LR Section 3.4.2.2.7.1 states that loss of material due to pitting and crevice corrosion can occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements and in stainless steel tanks and heat exchanger components exposed to treated water. The existing AMP monitors and controls 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 be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.7.1 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program 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 RWCU system. Observed conditions with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it will mitigate cracking due to SCC. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that this AMP includes inspections of the stainless steel, aluminum, and copper alloy steam and power conversion system components to detect cracking and verify the effectiveness of the Water Chemistry Program. The staff 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 staff concludes that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.7.1 for further evaluation.

In LRA Section 3.4.2.2.7.2, the applicant addressed loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to soil.

SRP-LR Section 3.4.2.2.7.2 states that loss of material due to pitting and crevice corrosion can occur in stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of this aging effect.

LRA Section 3.4.2.2.7.2 states that a Buried Piping Inspection Program will be implemented 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Buried Piping Inspection Program and verified that it includes inspections to detect loss of material of stainless steel piping due to pitting and crevice corrosion. The staff confirmed that, for each of the material and 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 the period of extended operation, and a focused inspection will be performed within the first 10 years of the period of extended operation. The staff concludes that, based on the program identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.7.2 for further evaluation.

In LRA Section 3.4.2.2.9, the applicant addressed loss of material due to pitting and crevice corrosion for copper alloy components exposed to lubricating oil.

SRP-LR Section 3.4.2.2.7.3 states that loss of material due to pitting and crevice corrosion can occur in copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Monitoring Activities Program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.9 states that this line item is not used, that 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 staff reviewed LRA Tables 3.4.2.1.1 through 3.4.2.1.7 and verified that no copper alloy piping, piping components, or piping elements are within the scope of license renewal.

Therefore, the staff finds acceptable the applicant's conclusion that this further evaluation is not applicable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.4.2.2.7. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.8 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.8 against the criteria in SRP-LR Section 3.4.2.2.8.

In LRA Section 3.4.2.2.8, the applicant addressed loss of material due to pitting and crevice corrosion and MIC in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil.

SRP-LR Section 3.4.2.2.8 states that loss of material due to pitting and crevice corrosion and MIC can occur in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil. The existing AMP relies on periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Monitoring Activities Program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.8 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Lubricating Oil Monitoring Activities Program to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Lubricating Oil Monitoring Activities Program and determined that it includes sampling, testing, and trending activities adequate to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil internal environment. The staff finds this program adequate to manage the aging effect for which it is credited.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.4.2.2.8. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

The staff reviewed LRA Section 3.4.2.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.9.

In LRA Section 3.4.2.2.2.1, the applicant addressed loss of material due to general, pitting, and crevice corrosion of steel and aluminum piping, piping components, and piping elements exposed to treated water.

SRP-LR Section 3.4.2.2.9 states that loss of material due to general, pitting, crevice, and galvanic corrosion can occur in steel heat exchanger components exposed to treated water. The existing AMP monitors and controls 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 Program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

LRA Section 3.4.2.2.2.1 states that the One-Time Inspection Program will be implemented for susceptible locations to verify the effectiveness of the Water Chemistry Program 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, ESW system, RBCCW 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff reviewed the applicant's Water Chemistry Program and verified that it will manage loss of material due to general, pitting, crevice, and galvanic corrosion of steel heat exchanger components. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections to detect cracking and verify the effectiveness of the Water Chemistry Program. The staff concludes 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.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.4.2.2.9. For those LRA line items that apply to this SRP-LR section, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by

10 CFR 54.21(a)(3).

3.4.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program for safety-related and nonsafety-related components. The staff concluded that the program descriptions of the "corrective action," "confirmation process," and "administrative controls" attributes are acceptable.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report, for which the applicant had claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff concludes that the applicant has adequately addressed the issues that required further evaluation. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is discussed in the following sections.

3.4.2.3.1 Condensate System – LRA Table 3.4.2.1.1

The staff reviewed LRA Table 3.4.2.1.1, which summarizes the results of AMR evaluations for the condensate system component groups.

LRA Table 3.4.2.1.1 states that the AMRs for the condensate system either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.4.2.1 and 3.4.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the condensate system components 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).

3.4.2.3.2 Condensate Transfer System – LRA Table 3.4.2.1.2

The staff reviewed LRA Table 3.4.2.1.2, which summarizes the results of AMR evaluations for the condensate transfer system component groups.

LRA Table 3.4.2.1.2 states that loss of material of buried aluminum piping and fittings in an external soil environment will be managed by the Buried Piping Inspection Program.

The staff's review of LRA Table 3.4.2.1.2 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.4-1 dated March 30, 2006, the staff requested that the applicant provide the following additional information about the management of the aging effects:

(a) the type of loss of material expected (pitting, cracking, general corrosion etc.)

(b) operating experience with this material in this environment

(c) type of external coatings and wrappings used and preventive measures to keep them in place

In its response dated April 28, 2006, the applicant stated:

(a) Buried aluminum piping at Oyster Creek is coated to preclude loss of material. Deterioration of the protective coating of aluminum piping at Oyster Creek resulted in loss of material due to pitting and galvanic corrosion.

(b) Operating experience for the buried Condensate Transfer aluminum piping adjacent to the Condensate Transfer pump house has shown previous loss of material subsequent to protective coatings failure. The loss of material was attributed to galvanic corrosion and resulted in leakage of the piping. The galvanic mechanism was primarily due to interaction between aluminum pipe and a large copper grounding grid at the same location. A significant portion of the underground piping is no longer in contact with soil. Piping was relocated aboveground or routed in precast concrete trenches. The remaining run of buried pipe was replaced and coated with the Polykin coating system. Also, a short run of aluminum pipe between the turbine building and reactor building is buried. This piping is located at a different location on site not near the grounding grid. Operating experience and soil samples at this piping location did not identify any leakage.

(c) Replaced piping is coated with Polykin 1029 pipeline primer then 3 layers of Polykin 910 Oil Field utility tape with 50% overlap are applied. Preventive measures to keep them in place include tape termination points sealed with a double wrap of tape around the pipe. The short run of pipe between the turbine building and reactor building is protected by a coal tar enamel. It has a felt wrap and waterproof exterior finish system.

The staff finds the applicant's response acceptable because it identified the type of loss of material expected and the coating specifications.

LRA Table 3.4.2.1.2 states that loss of material of aluminum tanks in an air (internal and external) and external soil environments will be managed by the Aboveground Outdoor Tanks Program. The staff determined that the LRA had insufficient information on the adequacy of the aging management of the tanks.

In RAI 3.4-2 dated March 30, 2006, the staff requested that the applicant provide the following information regarding the tanks:

(1) specific alloy composition of the tank material

(2) description of the tank supports

(3) aging management of the sealant or coatings on the tank bottom, if any

(4) operating experience

(5) purpose of the tanks (including a description of the services performed) and any other material in contact with its internal and external surfaces like expansion joints, piping connections, etc.

(6) specific tests, wall thickness measurements, and inspections to assure that the leak tightness is maintained in the internal and external outdoor air and soil environments

In its response dated April 28, 2006, the applicant stated that the one aluminum tank included in the Aboveground Outdoor Tanks Program, B.1.21 is the Condensate Storage Tank (CST).

(1) The tank shell plates are made from type 5086-H34 aluminum. The bottom plates are constructed from type 5086-H1116 aluminum. The materials are identified in the tank specification and drawings.

(2) The tank is supported by a concrete ring and soil foundation. The tank is connected to the pad by 12 anchor brackets as specified in the tank specification and drawings.

(3) Caulking is applied to tank/concrete seam on the exterior of the tank base to prevent water intrusion underneath the tank. Caulking will be inspected on the external surfaces of the tank.

(4) The tank bottom was inspected in 1980 and localized patch plate repairs were made. Water seepage was discovered during the refueling outage in March 1991. Subsequent inspection found through wall corrosion and thinning of the bottom plates. The tank bottom was then replaced. A layer of clean, washed "low iron" silica sand was installed under the bottom of the new tank plates to inhibit corrosion as detailed in the tank repair specification.

(5) The in scope aluminum tank is the site Condensate Storage Tank. The purpose of the Condensate Storage Tank as discussed in LRA section 2.3.4.2 is to provide for bulk storage of condensate, surge volume capability for the Condensate system and condensate supply for the Condensate Transfer system. Aluminum supply and return piping connect to the aluminum tank. Additionally, overflow and instrument lines and a vent, containing component materials other than aluminum, are connected to the tank. As specified in the Oyster Creek Line List and Specifications, aluminum piping systems are insulated and electrically isolated from ferrous materials.

(6) Aging management of external tank surfaces exposed to air will be performed by visual inspections every five years. The internal surfaces exposed to outdoor air are subcomponents of the tank vent and will be inspected along with the external tank inspection. The external tank surface in contact with soil is inspected by UT measurements of the bottom plates prior to the period of extended operation. A corrosion rate of the bottom plates is determined from thickness measurements and original plate thickness. The results of these inspections are monitored and trended and the tank bottom inspection frequency set such that component intended function is ensured. Note, the internal surfaces of the tank are managed by the Water Chemistry and One-Time Inspection aging management programs.

The staff finds the applicant's response acceptable because it provided the inspection methods for both the internal and external surfaces as well as other pertinent information as to the tank as requested. The staff's concerns described in RAI 3.4-2 are resolved.

In RAI 3.4-3 dated March 30, 2006, the staff noted that LRA Table 3.4.2.1.2 states that loss of material in stainless steel tanks in internal and external environments is managed by the Aboveground Outdoor Tanks Program. The staff requested that the applicant provide the following information:

(1) description of the tanks including supports and other connecting piping

(2) specific tests and inspections (including wall thickness measurements) in the Aboveground Outdoor Tanks Program, which are performed relative to these tanks to assure structural integrity

(3) operating history

In its response dated April 28, 2006, the applicant clarified that there are no stainless steel tanks in the Aboveground Outdoor Tanks Program. The stainless steel listed in LRA Table 3.4.2.1.2 is a screen frame sub-component of the aluminum condensate storage tank roof vent. Recurring visual inspections of this stainless steel subcomponent are included in this program. Operating history of this tank was included in the above response to RAI 3.4-2. The staff's concern described in RAI 3.4-3 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the condensate transfer system components 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).

3.4.2.3.3 Feedwater System – LRA Table 3.4.2.1.3

The staff reviewed LRA Table 3.4.2.1.3, which summarizes the results of AMR evaluations for the feedwater system component groups.

LRA Table 3.4.2.1.3 states that carbon and low alloy steel piping and fittings in containment atmosphere (external) have no aging effects. According to the applicant the aging effect in the GALL Report for this component, material, and environment combination is not applicable (Note I). The applicant cited a previous evaluation in which the staff concludes that loss of material is not an 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.

The staff's review of LRA Table 3.4.2.1.3 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

The staff believes that due to the leakage of moisture and the presence of oxygen during plant shutdown the potential for degradation of carbon steel components cannot be ruled out over an extended period of time. Therefore, there is a need for a one-time inspection prior to the period of extended operation unless the applicant can provide additional assurance in support of its position (e.g., monitored data from the containment nitrogen environment to indicate that free oxygen levels have been and would continue to be continuously maintained below threshold levels during the period of extended operation).

In RAI 3.4-4 dated March 30, 2006, the staff requested that the applicant justify its position or, alternately, commit to a one-time inspection of these components prior to the period of extended operation.

In its response dated April 28, 2006, the applicant committed (Commitment No. 31) to perform a one-time inspection of carbon steel feedwater system piping located inside containment. The one-time inspection will be a visual inspection of the carbon steel piping external surface for loss of material due to corrosion. This inspection will be prior to period of extended operation.

The applicant further stated:

> This one-time inspection is intended to confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the feedwater system located inside containment. If aging degradation is identified, the condition will be documented on an Issue Report and evaluated for corrective actions including additional feedwater system piping and component inspection locations.

The staff finds the applicant's response acceptable because the applicant agreed to the one-time inspection as suggested. The staff's concern described in RAI 3.4-4 is resolved.

LRA Table 3.4.2.1.3 states that there are no AERMs for carbon and low alloy steel valve bodies in external containment air and treated water environments.

In RAI 3.4-5 dated March 30, 2006, the staff requested that the applicant address the same issues previously discussed under RAI 3.4-4 as they are also applicable to carbon and low alloy steel valve bodies. The staff also requested that the applicant justify and provide the basis for its response.

In its response dated April 28, 2006, the applicant stated:

> As stated in the response to RAI 3.4-4, AmerGen will perform a one-time inspection of carbon steel feedwater system piping located inside containment. The one-time inspection will be a visual inspection of the carbon steel piping external surface for loss of material due to corrosion. This inspection will be performed prior to entering the period of extended operation. This one-time

inspection is intended to confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the feedwater system located inside containment. Since the piping and valves are carbon steel, and the environment is the same, results of the one-time inspection of the piping surface will also be applicable to the carbon steel valve external surfaces. If aging degradation is identified, the condition will be documented on an Issue Report and evaluated for corrective actions including additional feedwater system piping and component inspection locations.

The staff finds the applicant's response acceptable because the applicant agreed to a one-time inspection with adequate remedial measures. The staff's concerns described in RAI 3.4-5 are resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the feedwater system components 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).

3.4.2.3.4 Main Condenser Summary of Aging Management Evaluation – LRA Table 3.4.2.1.4

The staff reviewed LRA Table 3.4.2.1.4, which summarizes the results of AMR evaluations for the main condenser component groups.

LRA Table 3.4.2.1.4 states that there are no AERMs for the following main condenser subcomponents:

- carbon and low alloy steel main condenser shell in indoor air (external) and steam (internal) environments
- titanium main condenser tubes in a raw salt water (internal) and steam (external) environment
- aluminum/bronze tubesheet in a raw salt water (internal) and steam (external) environment

The applicant further stated that aging management of the main condenser is not based on analysis of materials, environments and aging effects. Condenser integrity required for the post-accident intended function (holdup and plate out of MSIV leakage) is continuously confirmed by normal plant operation. Therefore, the applicant stated that no traditional AMR or aging management is required.

The staff's review of LRA Table 3.4.2.1.4 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.4-6 dated March 30, 2006, the staff requested that the applicant provide the following information about the main condenser or justify why this information does not apply:

(1) Operational and maintenance history of the main condenser, summarizing the significant abnormal conditions or events which may have occurred in the past. This summary should include a brief discussion of the root cause determination and evaluation of these

events, if available. The staff is particularly interested in events related to fouling, insulation failure, tube ruptures or major leaks, expansion joint failures, condenser air in-leakage, and condenser tube MIC.

(2) Any concerns related to condenser capacity under power uprate conditions.

In its response dated April 28, 2006, the applicant stated:

(1) The main condenser is a critical balance-of-plant component for power generation. The main condenser is required to continuously maintain vacuum pressure integrity to support normal power operation of the station. Condenser tubes can become fouled or corroded as a result of normal plant operation, and these issues are addressed by tube cleaning or tube plugging during refueling and maintenance outages. Tube corrosion, tube fouling or insulation failure does not immediately prevent continued plant operation, and does not prevent the main condenser from performing its intended function of post accident holdup and plateout of main steam isolation valve (MSIV) bypass leakage. Significant condenser air in-leakage would prevent the main condenser from maintaining normal vacuum and would require immediate corrective action or plant shutdown for repair. Air in-leakage does not prevent the main condenser from performing its intended function of post-accident holdup and plateout of MSIV bypass leakage. Under post accident conditions, condenser vacuum is lost and the condenser is at atmospheric pressure.

Major leaks including tube leaks and expansion joint failure would result in immediate shutdown for repair. Such failures would not be expected when the condenser is performing its post-accident intended function because the condenser is not under vacuum conditions and is at atmospheric pressure. The intended function of the main condenser is to provide a post-accident holdup and plateout volume for MSIV bypass leakage. This intended function is not a pressure boundary function. The approach for aging management of the Main Condenser is to demonstrate adequate post-accident structural integrity of the Main Condenser, based on the fact that the condenser is operating prior to the accident and that the conditions, for the condenser are more severe during power operations than they are post-accident, when the MSIVs will be closed and vacuum will be lost. The structural integrity of the main condenser components during power operation will not immediately change post accident, and no aging effects will cause a loss of intended function in the short time that the main condenser is credited following the accident. Since no aging effects can cause a loss of intended function, no aging management is required. Assurance that the main condenser will be available to perform its post-accident intended function is continuously demonstrated by its ability to support normal plant operation. This demonstration is not dependent on the operational and maintenance history of the main condenser. Although the Oyster Creek main condenser has performed well, as demonstrated by reliable plant operation, it is not necessary to consider the detailed operation and maintenance history to support the license renewal conclusion that an aging management program is not required.

(2) AmerGen has no plans to implement power uprate at Oyster Creek. Therefore, the main condenser will not be subject to power uprate conditions.

The staff finds the applicant's response acceptable because the applicant provided an adequate justification demonstrating that the condenser's intended function of post-accident holdup and plateout of MSIV bypass leakage would be maintained. The staff's concerns described in RAI 3.4-6 are resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the main condenser components 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).

3.4.2.3.5 Main Generator and Auxiliary System – LRA Table 3.4.2.1.5

The staff reviewed LRA Table 3.4.2.1.5, which summarizes the results of AMR evaluations for the main generator and auxiliary system component groups.

LRA Table 3.4.2.1.5 states that the AMRs for the main generator and auxiliary system are either consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.4.2.1 and 3.4.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the main generator and auxiliary system components 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).

3.4.2.3.6 Main Steam System – LRA Table 3.4.2.1.6

The staff reviewed LRA Table 3.4.2.1.6, which summarizes the results of AMR evaluations for the main steam system component groups.

The staff's review of LRA Table 3.4.2.1.6 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAIs as discussed below.

LRA Table 3.4.2.1.6 states that there are no AERMs for carbon and low alloy steel expansion joints, flow element and thermowells in an internal and external containment atmosphere environment. As discussed in RAI 3.4-4, the staff considers a one-time inspection prior to the period of extended operation appropriate for these components.

In RAI 3.4-7 dated March 30, 2006, the staff requested that the applicant respond to these concerns about the main steam system and justify its position.

In its response dated April 28, 2006, the applicant stated:

> As stated in the response to RAI 3.4-8, AmerGen will perform a one-time inspection of carbon steel main steam system piping located inside containment. The one-time inspection will be a visual inspection of the carbon steel piping external surface for loss of material due to corrosion. This inspection will be performed prior to entering the period of extended operation. This one-time inspection is intended to confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the main steam system located inside containment. Since the piping, valves, expansion joints, flow elements and thermowells are carbon steel, and the environment is the same, results of the one-time inspection of the piping surface will also be applicable to these other carbon steel component external surfaces. If aging

> degradation is identified, the condition will be documented on an Issue Report and evaluated for corrective actions including additional main steam system piping and component inspection locations.

The staff finds the applicant's response acceptable because the applicant agreed to a one-time inspection of the carbon steel main steam system piping external surface for loss of material due to corrosion. The staff's concern described in RAI 3.4-7 is resolved.

LRA Table 3.4.2.1.6 states that no AERMs were identified for carbon and low alloy steel piping and fittings and valve bodies in internal and external containment air and internal treated water environments. As discussed in RAI 3.4-4, the staff considers a one-time inspection prior to the period of extended operation appropriate for these components.

In RAI 3.4-8 dated March 30, 2006, the staff requested that the applicant respond to its concerns about the main steam system and justify its position.

In its response dated April 28, 2006, the applicant stated:

> AmerGen will perform a one-time inspection of carbon steel main steam system piping located inside containment. The one-time inspection will be a visual inspection of the carbon steel piping external surface for loss of material due to corrosion. This inspection will be performed prior to entering the period of extended operation. This one-time inspection is intended to confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the main steam system located inside containment. Since the piping and valves are carbon steel, and the environment is the same, results of the one-time inspection of the piping surface will also be applicable to the carbon steel valve external surfaces. If aging degradation is identified, the condition will be documented on an Issue Report and evaluated for corrective actions including additional main steam system piping and component inspection locations.

The staff finds the applicant's response acceptable because the applicant agreed to one-time inspection of carbon steel main steam system piping located inside containment in accordance with the staff position. The staff's concern described in RAI 3.4-8 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam system components 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).

3.4.2.3.7 Main Turbine and Auxiliary System – LRA Table 3.4.2.1.7

The staff reviewed LRA Table 3.4.2.1.7, which summarizes the results of AMR evaluations for the main turbine and auxiliary system component groups.

LRA Table 3.4.2.1.7 states that the AMRs for the main turbine and auxiliary system either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.4.2.1 and 3.4.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the main turbine and auxiliary system components 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).

Conclusion. On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results involving material, environment, AERMs, and AMP combinations that are not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.4.3 Conclusion

The staff concludes that the applicant had 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).

3.5 Aging Management of Containment, Structures, Component Supports, and Piping and Component Insulation

This section of the SER documents the staff's review of the applicant's AMR results for the *containment, structures, component supports, and piping and component insulation components* and component groups of the following structures, and commodity groups:

- 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

3.5.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant provided AMR results for the containment, structures, component supports, and piping and component insulation components and component groups.

In LRA Table 3.5.1, "Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports," the applicant provided a summary comparison of its AMRs with those evaluated in the GALL Report for the containment, structures, component supports, and piping and component insulation components and component groups.

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.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the containment, structures, component supports, and piping and component insulation components 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 staff conducted an onsite audit of AMRs during the weeks of October 3-7, 2005, January 23-27, 2006, February 13-17, 2006, and April 19-20, 2006, to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and summarized in SER Section 3.5.2.1.

In the onsite audit, the staff also selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.5.2.2. The staff's audit evaluations are documented in the Audit and Review Report and summarized in SER Section 3.5.2.2.

The staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The technical review 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 staff's evaluations are documented in SER Section 3.5.2.3.

For AMRs that the applicant identified as not applicable or not requiring aging management, the staff conducted a review of the AMR line items and the plant's operating experience, to verify the applicant's claims. Details of these reviews are documented in the Audit and Review Report.

Finally, the staff 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 containment, structures, component supports, and piping and component insulation components.

Table 3.5-1, provided below, includes a summary of the staff's evaluation of components, aging effects and mechanisms, and AMPs listed in LRA Section 3.5 and addressed in the GALL Report.

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 SER Section 3.5.2.2.1)
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 the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Not Applicable	Not Applicable; Steel containment (See SER Section 3.5.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Not Applicable	Not Applicable; Steel containment (See SER Section 3.5.2.2.1)
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 aging management program is to be evaluated	Not Applicable	Not Applicable; Steel containment (See SER Section 3.5.2.2.1)
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, suppression chamber (as applicable) (Item 3.5.1-5)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	ASME Section XI, Subsection 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 SER Section 3.5.2.2.1)
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	Not Applicable	Not Applicable; Steel containment (See SER Section 3.5.2.2.1)
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 SER Section 3.5.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	This TLAA is evaluated in Section 4.3. (See SER Section 3.5.2.2.1)
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	This TLAA is evaluated in Section 4.3. (See SER Section 3.5.2.2.1)
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.	ASME Section XI, Subsection IWE (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.1)
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 welds.	ASME Section XI, Subsection IWE (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.1)
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	This TLAA is evaluated in Section 4.3. (See SER Section 3.5.2.2.1)
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	This TLAA is evaluated in Section 4.3. (See SER Section 3.5.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.5.2.2.1)
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 SER Section 3.5.2.2.1)
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	ASME Section XI, Subsection IWE (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL (See SER Section 3.5.2.1)
Personnel airlock, equipment hatch and CRD hatch locks, hinges, and closure mechanisms (Item 3.5.1-17)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanisms	10 CFR Part 50, Appendix J and Plant Technical Specifications	10 CFR Part 50, Appendix J (B.1.29) and Plant Technical Specifications	Consistent with GALL (See SER Section 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	ASME Section XI, Subsection IWE (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL (See SER 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.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel elements: drywell head and downcomer pipes (Item 3.5.1-21)	Fretting or lock up due to mechanical wear	ISI (IWE)	ASME Section XI, Subsection IWE (B.1.27)	Consistent with GALL. (See SER 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 SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)
Groups 1-3, 5-9: foundation (Item 3.5.1-29)	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 for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Not applicable	Not applicable; no porous concrete subfoundation or de-watering system (See SER Section 3.5.2.2.2)
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 SER Section 3.5.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 when excavated for any reason or if observed conditions in accessible areas exposed to the same environment show significant concrete degradation has occurred, and periodic monitoring of groundwater (non-aggressive environment).	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)
Groups 1-5: concrete (Item 3.5.1-33)	Reduction of strength and modulus due to elevated temperature	A plant-specific aging management program is to be evaluated	Structures Monitoring Program (B.1.31) with a frequency of every refueling outage and a quantitative criterion for crack width	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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.	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.2)
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).	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.2)
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 and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the *recommendations in* ACI 201.2R-77.	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 the recommendations in ACI 201.2R-77.	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with GALL, which recommends further evaluation (See SER Section 3.5.2.2.2)
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 aging management program is to be evaluated	Not Applicable	Not applicable; The only stainless steel lined concrete tank at OCGS is the spent fuel pool skimmer surge tank. Aging effects of the stainless steel tank liner are evaluated with the mechanical auxiliary systems. (See SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)
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 mechanisms	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See SER Section 3.5.2.2.2)
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 SER Section 3.5.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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)	TLAA for Group B1.3 supports; CLB fatigue analysis exists. Not applicable to B1.1 and B1.2; no CLB fatigue analysis	TLAA for Group B1.3 supports; CLB fatigue analysis exists. Not applicable to B1.1 and B1.2; no CLB fatigue analysis (See SER Section 3.5.2.2.2)
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 SER 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 SER Section 3.5.2.1)
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	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with GALL. (See SER 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 SER 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 manage aging, protective coating monitoring and maintenance provisions should be included.	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)	Consistent with GALL. (See SER Section 3.5.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.31)	Consistent with GALL. (See SER 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 (B.1.2) and ASME Section XI, Subsection (IWF) (B.1.28) for Treated Water Environment	Consistent with GALL. (See SER 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 (B.1.31)	Consistent with GALL. (See SER 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	Not Applicable	Not applicable; Lubrite graphitic tool steel is not used for Group B2 and B4 supports sliding surfaces
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)	ASME Section XI, Subsection (IWF) (B.1.28)	Consistent with GALL. (See SER Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: Constant and variable load spring hangers; guides; stops; (Item 3.5.1-54)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	ASME Section XI, Subsection (IWF) (B.1.28)	Consistent with GALL. (See SER Section 3.5.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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)	ASME Section XI, Subsection (IWF) (B.1.28)	Consistent with GALL. (See SER 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)	ASME Section XI, Subsection (IWF) (B.1.28)	Consistent with GALL. (See SER 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 SER 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 SER Section 3.5.2.1)

The staff's review of the containment, structures, component supports, and piping and component insulation component groups followed one of several approaches. One approach, documented in SER Section 3.5.2.1, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.5.2.2, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.5.2.3, discusses the staff's review of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the containment, structures, component supports, and piping and component insulation components is documented in SER Section 3.0.3.

3.5.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.5.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the effects of aging related to the containment, structures, component supports, and piping and component insulation components:

- Water Chemistry (B.1.2)
- One-Time Inspection (B.1.24)
- ASME Section XI, Subsection IWE (B.1.27)
- ASME Section XI, Subsection IWF (B.1.28)
- 10 CFR Part 50, Appendix J (B.1.29)
- Masonry Wall Program (B.1.30)
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.1.32)
- Structures Monitoring Program (B.1.31)
- Protective Coating Monitoring and Maintenance Program (B.1.33)

Staff Evaluation. In LRA Tables 3.5.2.1.1 through 3.5.2.1.19, the applicant provided a summary of AMRs for the containment, structures, component supports, and piping and component insulation components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. 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 has the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant (a) provided a brief description of the system, components, materials, and environments, (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report, and (c) identified those aging effects for the containment, structures, component supports, and piping and component insulation components subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.5.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.5.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report, for the containment, structures, component supports, and piping and component insulation components. The applicant provided information about how it will manage the following aging effects:

PWR and BWR Containment:

- aging of inaccessible concrete areas
- 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
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to stress corrosion cracking
- cracking due to cyclic loading
- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide

Safety-Related and Other Structures and Component Supports:

- aging of structures not covered by structures monitoring program
- aging management of inaccessible areas
- reduction of strength and modulus of concrete structures due to elevated temperature
- aging management of inaccessible areas for Group 6 structures
- cracking due to stress corrosion cracking and loss of material due to pitting and crevice corrosion
- aging of supports not covered by structures monitoring program
- cumulative fatigue damage due to cyclic loading

Quality Assurance for Aging Management of Nonsafety-Related Components

Staff Evaluation. For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.5.2.2. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

3.5.2.2.1 PWR and BWR Containments

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which addresses several areas discussed below.

Aging of Inaccessible Concrete Areas. In LRA Section 3.5.2.2.1.1, the applicant stated that aging of inaccessible areas of concrete containments, with reference to the further evaluation in SRP-LR Section 3.5.2.2.1.1, is not applicable because OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable.

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 LRA Section 3.5.2.2.1.2, the applicant stated that cracks and distortion of concrete subfoundations, with reference to the further evaluation in SRP-LR Section 3.5.2.2.1.2, are not applicable because OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable.

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3.

In LRA Section 3.5.2.2.1.3, the applicant addressed reduction of strength and modulus of concrete due to elevated temperatures.

SRP-LR Section 3.5.2.2.1.3 states 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 Code 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 Code 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 AMP 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)).

LRA Section 3.5.2.2.1.3 states that the normal operating temperature inside the primary containment drywell varies from 139 °F (at elevation 55') to 256 °F (at elevation 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 elevation 55' and are not exposed to the elevated temperature. The biological shield wall extends from elevation 37' 3" to 82' 2" and is exposed to a temperature range of 139 °F to 184 °F. The wall is a composite steel-concrete cylinder surrounding the reactor vessel framed with 27 inches 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 SER Section 3.5.2.2.2.

The staff finds acceptable 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.

Based on the above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.3. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Loss of Material Due to General, Pitting and Crevice Corrosion. The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4.

In LRA Section 3.5.2.2.1.4, the applicant addressed loss of material due to general, pitting, and crevice corrosion in steel elements of accessible and inaccessible areas for BWR containment.

SRP-LR Section 3.5.2.2.1.4 states 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 the ASME Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J Programs, 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.

LRA Section 3.5.2.2.1.4 states 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 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 of exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. In 1987, a corrosion monitoring process was established 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 Program and provide the following:

- 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
- demonstration that the minimum required shell thickness is in accordance with ASME Code

Additionally, the staff was notified of this potential generic issue that later became the subject of 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

Grade 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. The applicant performed a series of investigations to identify the source of the water and its leak path and concluded that the source of water was from the reactor cavity, which is flooded during refueling outages.

With the presence of water in the sand bed region, the applicant took extensive UT thickness measurements of the drywell shell to determine whether degradation had occurred. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.

With reduced thickness readings, the applicant obtained additional thickness measurements to determine the vertical profile of the thinning. In 1986, the applicant excavated two trenches in the drywell concrete floor in bays #5 and #17 where thinning was most severe because the sand bed region was inaccessible at that time. 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 with no floor level thinning showed no significant thinning in the embedded shell. Aside from UT thickness measurements by plant staff, an independent analysis by the EPRI NDE Center, and the GE Ultra Image III "C" scan topographical mapping system 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) the applicant obtained core samples of the drywell shell at seven locations in 1986. The core samples validated the UT measurements and confirmed that the corrosion of the drywell exterior was due to the presence of oxygenated wet sand and exacerbated by chloride and sulfate in the sand bed region. Contaminate concentration due to alternate wetting and drying of the sand also may have contributed to the corrosion. Therefore, the applicant concluded that the optimum method to mitigate the corrosion was by removal of the sand to break up the galvanic cell, removal of the corrosion product from the shell, and application of a protective coating.

Removal of sand was initiated during 1988 by the removal of 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 cut into the sand bed region through the shield wall. The work was finished in December 1992. After sand removal, the applicant found the concrete surface below the sand 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) removal of the loose debris from the concrete floor followed by rebuilding and reshaping of 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 inspected during refueling outages of 1994, 1996, 2000, and 2004. These inspections showed no coating failure or signs of deterioration. Therefore, the applicant concluded that corrosion in the sand bed region had been arrested and expected no further loss of material. 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.

In a letter dated December 3, 2006, the applicant provided information concerning the drywell inspections and ultrasonic (UT) measurements performed during the 2006 refueling outage. On the basis of visual inspections, which indicated no visible deterioration, the applicant confirmed that no further corrosion of the drywell shell is occurring from the exterior of the epoxy-coated sand bed region. On the basis of UT measurements of the drywell shell in the sand bed region from inside the drywell, the applicant confirmed that corrosion on the exterior surfaces of the drywell shell in the sand bed region has been arrested. On the basis of UT measurements taken in the trenches in drywell bays number #5 and #17, the applicant concluded that wall thinning of approximately 0.038" had taken place in each trench since 1986.

On the basis of 106 UT measurements taken on the outside of the drywell in the sand bed region in 2006, the applicant determined that the measured local thickness is greater that the local acceptance criteria of 0.409" for pressure and 0.536" for local bucking. The applicant decided that, since the 106 UT measurements could not be correlated directly with the corresponding 1992 UT data, it would enhance the ASME Section XI, Subsection IWE Program (B.1.27) to require UT measurements of the locally thinned areas in 2008 and periodically during the period of extended operation.

The staff reviewed the applicant's operating experience and proposed aging management activities to address degradation of the primary containment drywell area in the former sand bed region as part of its evaluation of the ASME Subsection IWE Program. The staff previously identified, in the SER, dated August 18, 2006, five OIs and found that the applicant had not provided sufficient information to conclude that the effects of aging for the primary containment would be adequately managed during the period of extended operation. The applicant provided additional information in the letters dated December 3 and 15, 2006, and February 15, 2007, including additional commitments (Commitment No.27), to the staff for review. Upon further evaluation, the staff concludes 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). The staff's resolution of the open items is documented in Section 4.7.2 of this SER.

<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 provided a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the OCGS 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 completely around the inside of the drywell at several elevations. At each elevation, a belt-line sweep took readings on as little as 1-inch centers wherever thickness changed between successive nominal 6-inch centers. 6" by 6" grids that exhibited the worst metal loss around each elevation were established by 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 of the adequacy of this inspection plan was obtained by a completely randomized inspection of 49 grids showing that all inspection locations satisfied ASME Code requirements. Evaluation of UT measurements taken through 2000 concluded that corrosion no longer occurs at two (2) elevations, the third elevation undergoes a corrosion rate of 0.6 mils per year, and the fourth 1.2 mils per year. The recent UT measurements (2004) confirmed that the corrosion rate continues to decline. The 2 elevations that previously exhibited no increase in corrosion continue the trend to no corrosion increase. The rate of corrosion for the third elevation decreased from 0.6 to 0.4 mils per year. The rate of corrosion for the fourth elevation decreased from 1.2 to 0.75 mils per year. After each UT examination campaign, an engineering analysis is performed to ensure the required minimum thickness through the period of extended operation. Thus, corrosion of the drywell shell is considered a TLAA further described in SER Section 4.7.2.

In a letter dated December 3, 2006, the applicant provided information concerning the drywell inspections and ultrasonic (UT) measurements performed during the 2006 refueling outage. On the basis of UT measurements taken at four elevation of the drywell, the applicant determined that:

- No observable corrosion is occurring at elevations 51' 10" and 60' 10".
- A single location at elevation 50' 2" continues to experience minor corrosion at a rate of 0.66 mils/year.
- The corrosion at elevation 87' 5" is statistically insignificant.

The applicant performed UT measurements at two locations at the circumferential weld that joins the bottom spherical plates and the middle spherical plates at elevation 23' 6". The applicant determined that the loss of material in the thinner plates is insignificant and is bounded by corrosion experience at other areas of the drywell above the sand bed region. The applicant determined that the thicker plates have not experienced any observable corrosion.

The applicant performed UT measurements at two locations at the circumferential weld that joins the transition plates, which are referred to as the knuckle plates, between the cylinder and the sphere at elevation 71' 6". The applicant determined that the loss of material in the thinner plates is insignificant and is bounded by corrosion experienced in other areas of the drywell above the sand bed region. Through its inspections, the applicant identified some reduced thickness in the thicker plate that could be attributed to several factors, including variations in original plate thickness, removal of material during original joint preparation, and corrosion. The applicant stated that even if the loss of material is attributed entirely to corrosion, the available thickness margin is adequate to ensure that the intended function of the drywell is not impacted before the next inspection planned for 2010.

The applicant committed to take UT measurements in 2010 at elevations 23' 6" and 71' 6" to confirm that corrosion is bounded by areas of the upper drywell that are monitored periodically. If corrosion in these locations is greater than areas monitored in the upper drywell, the applicant will perform UT inspection on a frequency of every other refueling outage (Commitment 27 Item numbers 10 and 11 in AmerGen Letter No. 2130-06-20358 dated July 7, 2006).

The applicant concluded that the corrective actions taken and continued monitoring of the drywell for loss material through the ASME Section XI, Subsection IWE, Protective Coating Monitoring and Maintenance, and 10 CFR Part 50, Appendix J Programs 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 with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE, Protective Coating Monitoring and Maintenance, and 10 CFR Part 50, Appendix J Programs are evaluated in SER Section 3.0.

The staff noted that the applicant had not addressed aging management of the portion of the drywell shell embedded in the drywell concrete floor. This area is inaccessible for inspection but potentially subject to wetting on both inside and outside surfaces. During the audit, the staff requested that the applicant submit its AMR for this inaccessible portion of the drywell shell.

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 the GALL Report.

The applicant identified that the GALL Report, Volume 2, item II.B1.1-2, AMP 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 use of the guidance of 201.2R for containment shell or liner
- concrete monitoring to ensure that it is free of cracks providing paths for water seepage to the surface of the containment shell or liner
- aging management of the moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management in accordance with ASME Section XI, Subsection IWE requirements
- prompt clean-up of water ponding on the containment concrete floor when detected

If any of these conditions cannot be satisfied, a plant-specific AMP for corrosion is necessary.

The applicant indicated that its AMR results satisfy these requirements and that a plant-specific AMP is not required for corrosion of the embedded drywell shell. The concrete meets the recommendations of ACI 318 and the guidance of ACI 201.2R. The drywell concrete floor will be monitored for cracks under the Structures Monitoring Program. OCGS design does not include a moisture barrier; however, the design provides a 9-inch high curb (minimum) around the entire drywell floor (except at two trenches) to prevent any contact between water accumulated on the floor and the drywell shell. The curb is considered part of the drywell concrete floor and inspected for cracking under the Structures Monitoring Program. 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 that technical specifications limits are not violated. If the sump fills and the overflow leak rate cannot be monitored, a plant shutdown will be required to regain leak rate monitoring capability and to determine the source of the leak.

The applicant further stated that during the investigation 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 to expose the embedded drywell shell so that UT thickness measurements could 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 the period of extended operation a one-time visual inspection of the embedded drywell shell within the two trenches will be performed by removal of the sealant and exposure of 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 for continued protection of the embedded shell. In addition, one-time UT measurements will be taken and corrective actions 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 (Commitment No. 27) 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 Program, or they will be restored to the original design configuration with concrete or other suitable material to prevent moisture collection in these areas.

In addition to its 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, in its letter dated May 1, 2006, the applicant committed (Commitment No. 27) to taking one-time UT measurements to confirm the adequacy of the shell thickness in these areas, providing further assurance that the drywell will remain capable of performing its intended function. This commitment will be performed prior to the period of extended operation.

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 indicating corrosion in the embedded portion of the shell.

In a letter dated December 3, 2006, the applicant provided information concerning the drywell inspections and ultrasonic (UT) measurements performed during the 2006 refueling outage. During the outage, the applicant removed filler material from the two trenches to allow inspection of the embedded shell and found water in one of the trenches. The applicant concluded that the likely source of water was a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough, or condensation within the drywell that either fell to the floor or washed down the Inside of the drywell shell to the concrete floor.

The applicant drew water from the trench and determined the water to be non-aggressive with pH (8.40 - 10.21), chlorides (13.6- 14.6ppm), and sulfates (228 - 230 ppm). The applicant found that the joint between the concrete floor and the drywell shell had not been sealed to prevent water from coming in contact with the inner drywell shell. The applicant first discovered the degraded trough drainage system and the unsealed gap between the concrete slab curb and the interior surface of the drywell shell during the 2006 refueling outage. The following corrective actions were taken during the refueling outage.

- Walkdowns, drawing reviews, tracer testing, and chemistry samples were performed to identify the potential sources of water in the trenches.
- Standing water was removed from trench to allow visual inspection and UT examination of the drywell shell.
- An engineering evaluation was performed to determine the impact of the as-found water on the continued Integrity of the drywell.
- Field repairs and modifications were implemented to mitigate and minimize future water intrusion into the area between the shell and the concrete floor. These repairs and modifications consisted of:
    - Repair of the trough concrete In the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell rather than reaching the drywell sump.
    - Caulking the interface between the drywell shell and the drywell concrete floor and curb to prevent water from reaching the embedded shell.
    - Grouting and caulking the concrete/drywell shell interfaces in the trench areas.
- The trench was excavated to uncover an additional 6" of the internal drywell shell surface for inspection and allow UT thickness measurements to be taken in an area of the shell that was embedded by concrete.
- Visual inspection of the drywell shell within the trenches was performed.
- A total of 584 UT thickness measurements were taken within the two trenches. Forty-two (42) additional UT measurements were taken in the newly exposed area in bay #5.

The applicant determined that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact. The applicant concluded that significant corrosion of the drywell shell would not be expected as long as the benign environment is maintained.

The applicant stated that it will further enhance the Oyster Creek ASME Section XI, Subsection IWE aging management program to require periodic inspection of the drywell shell subject to concrete (with water) environment in the internal embedded shell area and water environment within the trench area. Specific enhancements are:

- UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

- Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified.

- Perform visual inspection of the drywell shell inside the trench in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

- Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor/curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.

After each inspection, the applicant will evaluate UT thickness measurements results and compare them with previous UT thickness measurements. If unsatisfactory results are identified, then applicant will initiate, as necessary, additional corrective actions to ensure the drywell shell integrity is maintained throughout the period of extended operation.

In its letter dated December 3, 2006, the applicant stated that LRA Table 3.5.1 will be revised to add the following Plant Specific Notes to Table 3.5.2.1.1:

10. Water environment for the drywell shell and the reinforced concrete slab (fill slab) was identified during 2006 in two trenches inside the drywell concrete floor. The source of water is most likely from leakage of treated water from plant equipment inside the drywell. Chemical tests of water samples in contact with concrete and the drywell shell indicate that the water is not aggressive (pH = 8.40 -10.21), (Chloride =13.6 - 14.6 ppm), and (Sulfate = 228 - 230 ppm).

11. The moisture barrier was added in 2006 to seal the junction of the embedded drywell shell and the concrete curb inside the drywell. The absence of the moisture barrier was identified as a potential path of water found in contact with the inner drywell shell embedded in the concrete drywell floor (fill slab).

12. 10 CFR Part 50, Appendix J, is not a credited aging management program because the moisture barrier is not the primary containment pressure boundary.

13. Oyster Creek operating experience identified that the reinforced concrete (fill slab) is

subject to ponding of water on the floor and water intrusion into the subsurface of fill slab. The source of water is most likely from leakage of treated water from plant equipment inside the drywell. Chemical tests of water samples in contact with the concrete indicate that the water is not aggressive (pH = 8.40 - 10.21, Chloride =13.6 - 14.6 ppm, and Sulfate = 228 - 230 ppm). The reinforced concrete (fill slab) is monitored for loss of material (spelling, scaling), change in material properties (loss of bond) and cracking due to corrosion of embedded steel. The aging effects and the aging management program are consistent with NUREG-1801, line item III.A1-4, for non-aggressive groundwater environment.

The staff concludes that the applicant will determine, based on the results of the inspection of the two trenches, the condition of the inaccessible portion of the drywell shell embedded in the drywell concrete floor prior to the period of extended operation, and that corrective actions will be taken as necessary if degradation is found. The staff finds the applicant's approach to aging management of the inaccessible portion of the drywell shell embedded in the drywell concrete floor acceptable.

In its evaluation of the applicant's ASME Section XI, Subsection IWE Program the staff evaluated the degradation history of the applicant's containment and the adequacy of its aging management commitments for the period of extended operation. Five open items and their resolutions are discussed in detail in SER Section 4.7.2. Based on the applicant's proposed aging management activities for the period of extended operation, the staff finds that the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.4 for further evaluation and 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).

Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature. LRA Section 3.5.2.2.1.5 states that loss of prestress of concrete containments is not applicable since OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable since OCGS has a Mark I steel containment.

Cumulative Fatigue Damage. LRA Section 3.5.2.2.1.6 states 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). SER Section 4.6 documents the staff's review of the applicant's evaluation of this TLAA.

Cracking Due to Stress Corrosion Cracking (SCC). The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7.

In 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 SCC.

SRP-LR Section 3.5.2.2.1.7 states that cracking due to SCC 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 also could occur in stainless steel vent line bellows for BWR containments. The existing program relies on the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs to manage this aging effect. The GALL Report recommends further evaluation of additional appropriate examinations and evaluations to detect these aging effects for stainless steel penetration sleeves, penetration bellows and dissimilar metal welds, and stainless steel vent line bellows.

LRA Section 3.5.2.2.1.7 states that cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading is considered metal fatigue and addressed as a TLAA in LRA Section 4.6. SCC 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 eliminates 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 a 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 percent 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 to 40 percent. The reactor building normal operating temperature range is 65 °F to 92 °F except in the trunnion room where the temperature can reach 140 °F. The relative humidity is 100 percent maximum. Both the containment atmosphere and indoor air environments are noncorrosive (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 identified no cracking of the components and primary containment leakage has not been identified as a concern. Therefore, the existing 10 CFR Part 50, Appendix J Program leak tests and the ASME Section XI, Subsection IWE Program are adequate to detect cracking. Observed conditions with potential impact on 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 SER Section 3.0.

The staff requested that the applicant address whether the problems encountered at Dresden and Quad Cities Power Plants with cracking of expansion bellows apply to OCGS. The applicant stated that the problems were unique to the Dresden and Quad Cities Power Plant and do not apply to OCGS. On the basis that the environment conducive to SCC does not exist at OCGS, the staff finds the applicant's further evaluation for cracking due to SCC acceptable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.7. For those line items that apply to LRA Section 3.5.2.2.1.7, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracking Due to Cyclic Loading</u>. In LRA Section 3.5.2.2.1.7, the applicant stated that cracking due to cyclic loading is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.6 documents the staff's review of the applicant's evaluation of this TLAA.

<u>Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw</u>. In LRA Section 3.5.2.2.1.8, the applicant stated that loss of material due to freeze-thaw of concrete containments is not applicable since OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable since OCGS has a Mark I steel containment.

<u>Cracking Due to Expansion and Reaction with Aggregate, and Increase in Porosity and</u>

Permeability Due to Leaching of Calcium Hydroxide. In LRA Section 3.5.2.2.1.8, the applicant stated that cracking due to expansion and reaction with aggregates of concrete containments is not applicable since OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable since OCGS has a Mark I steel containment.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2, which addresses several areas discussed below.

Aging of Structures Not Covered by Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.1.

In LRA Section 3.5.2.2.2.1, the applicant addressed further evaluations in accordance with the January 2005 draft SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 SRP-LR in Attachment 3, items T-04, T-06, and T-11 of its reconciliation document. The staff reviewed the reconciliation document against the criteria in the September 2005 SRP-LR Section 3.5.2.2.2.1, for items (1), (2), and (3). Based on its review of LRA Section 3.5.2.2.2.1, the staff determined that the applicant's reconciliation also applies to items (4), (5), and (6) in SRP-LR Section 3.5.2.2.2.1. Item (7) is not applicable to OCGS.

SRP-LR Section 3.5.2.2.2.1 states that the GALL Report recommends further evaluation of certain structure and aging effect combinations not covered by the Structures Monitoring Program, including (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, and 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 and aging effect combinations not within the Structures Monitoring Program.

The SRP-LR further states 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 or ASME Section XI, Subsection IWF Programs to manage this aging effect. The GALL Report recommends further evaluation only for structure/aging effect combinations not within the ASME Section XI, Subsection IWF or Structures Monitoring Programs.

In Attachment 3, item T-04, of its reconciliation document, the applicant stated that this item change requires no change the LRA. 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 the Structures Monitoring Program; therefore, no further evaluation is required.

In Attachment 3, item T-06, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. 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 the Structures Monitoring Program; therefore, no further evaluation is required.

In Attachment 3, item T-11, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. 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 Structures Monitoring Program; therefore, no further evaluation is required.

The staff finds acceptable the applicant's determination that no further evaluation is required on the basis that the Structures Monitoring Program is credited for aging management.

Based on the program above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.1. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas. The staff reviewed LRA Section 3.5.2.2.2.2 and Attachment 3 of the applicant's reconciliation document against the criteria in SRP-LR Section 3.5.2.2.2.2.

In Attachment 3, item T-01, of its reconciliation document, the applicant addressed cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures (T-01). The staff reviewed the reconciliation document against the criteria in SRP-LR Section 3.5.2.2.2.2.1

SRP-LR Section 3.5.2.2.2.2.1 states 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 this item change requires no change to the LRA. For inaccessible areas, as described in UFSAR Section 3.8.4.6, "Materials, Quality Control and Special Construction Techniques," concrete is designed consistent with ACI 318 recommendations to be workable with homogeneous structure which, when hardened, will have durability, impermeability, and the specified strength. Testing of concrete was in accordance with ASTM standards specified in ACI 318 to ensure that the desired quality of concrete was furnished. The strength quality of the concrete was established by tests by a maximum slump of 4 inches in advance of the beginning of operations. Specimens were tested and cured in accordance with ASTM C39.

Review of design and construction documents indicated that the specified air content is 4 to 6 percent. The water-to-cement ratio was based on the strength required by the design considering the maximum slump of 4 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 representing 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. 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 concluded that the loss of material and cracking had no significant impact on the intended function of the affected structure. From this evaluation, the applicant concluded that loss of material and cracking due to freeze-thaw is not significant for inaccessible areas. Thus, no plant-specific AMP is required.

In Attachment 3, item T-03, of its reconciliation document, the applicant addressed cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas for Groups 1-5 and 7-9 structures (T-03). The staff reviewed the reconciliation document against the criteria in SRP-LR Section 3.5.2.2.2.2.2.

SRP-LR Section 3.5.2.2.2.2.2 states 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 ACI 201.2R-77 recommendations.

In Attachment 3, item T-03, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. 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 the Structures Monitoring Program; therefore, no further evaluation is required. The staff finds this acceptable because the item has been included within the scope of the program.

In Attachment 3, item T-08, of its reconciliation document, the applicant addressed 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 in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures (T-08).

SRP-LR Section 3.5.2.2.2.2.3 states 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 the 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 within the scope of the applicant's Structures Monitoring Program.

In Attachment 3, item T-08, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. OCGS 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 the Structures Monitoring Program; therefore, no further evaluation is required. The staff finds this acceptable because the item has been included within the scope of the program.

In LRA Section 3.5.2.2.2.2, the applicant addressed 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 in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures.

SRP-LR Section 3.5.2.2.2.2.4 states 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 their environment is aggressive.

LRA Section 3.5.2.2.2.2 states that recent groundwater analysis results (pH: 5.6 to 6.4, chlorides: 3 to 138 ppm, and sulfates: 7 to 73 ppm) show that the groundwater 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 environments except for fire water pump-houses (fresh water pump-house only), so further evaluation of Group 3 structures other than the fresh water pump-house is not required. The fresh water pump-house 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 exposed to the same environment show that significant concrete degradation has occurred. The Structures Monitoring Program will be enhanced to include periodic groundwater monitoring in order to demonstrate that the below grade environment remains nonaggressive. (Commitment No. 31). Observed conditions with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process.

The staff determined that the applicant's approach to aging management for the freshwater pump-house and the service water seal well is appropriate. The applicant will perform a baseline inspection prior to the period of extended operation and evaluate the results of the inspections to determine if there is a need to inspect the structures more frequently than every 4 years.

The staff concludes that for inaccessible areas the recommendations of SRP-LR Section 3.5.2.2.2.2.4 is achieved by performing: (1) opportunistic inspection of normally inaccessible areas if exposed for any reason, and (2) inspection of inaccessible areas of structures if observed conditions in accessible areas exposed to the same environment show that significant concrete degradation has occurred. The need for periodic inspection of inaccessible areas of the fresh water pump-house will be determined prior to the period of extended operation based on inspection results of the accessible areas with the same environment. The staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.4 for further evaluation.

In Attachment 3, item T-02, of its reconciliation document, the applicant addressed increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures.

SRP-LR Section 3.5.2.2.2.2.5 states 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 ACI 201.2R-77 recommendations.

In Attachment 3, item T-02, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. Further evaluation is required only for inaccessible areas with concrete not constructed as stated (in accordance with ACI 201.2R-77 recommendations). In the LRA, the use of this line item is not for inaccessible areas. Accessible areas inspections are performed in accordance with the Structures Monitoring Program.

The staff concludes that for inaccessible areas the recommendations of SRP-LR Section 3.5.2.2.2.2.5 can be achieved perform: (1) opportunistic inspection of normally inaccessible areas if exposed for any reason and (2) inspection of inaccessible areas of structures if observed conditions in accessible areas exposed to the same environment show that significant concrete degradation has occurred. The staff finds that, based on the information identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.5 for further evaluation.

The staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.3.

In LRA Section 3.5.2.2.2.1, item (8), the applicant addressed reduction of strength and modulus of concrete due to elevated temperatures in BWR Groups 1-5 concrete structures.

SRP-LR Section 3.5.2.2.2.3 states that reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR Groups 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 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 (SRP-LR Appendix A.1).

LRA Section 3.5.2.2.2.1, states that for loss of strength and modulus of concrete structures due to elevated temperatures in Groups 2-5, the GALL Report recommends a plant-specific AMP and further evaluation if the general temperature is greater than 150 °F or if the local temperature is greater than 200 °F. For OCGS, the Structures Monitoring Program manages cracking of concrete structures exposed to elevated temperatures. 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-feet thick concrete wall could be in the range of 180 to 215 °F with a worst case thermal environment inside the containment of 340 °F. As a result, an investigation evaluated 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 subject to high temperature. A map of the cracked area including crack length and width was developed for future monitoring.

Subsequently, the applicant conducted an engineering evaluation to assess the impact of the elevated temperature on the drywell shield wall. For this purpose, a finite element model was created based on the geometry of the shield wall and connecting structural elements. 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. In the May 1994 SER, the staff 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 intended function.

During the audit, the staff noted that the wall has been included within the scope of the Structures Monitoring Program and inspected periodically to ensure its continued intended function. Observed conditions with potential impact on intended function are evaluated or corrected in accordance with the corrective action process.

In order to facilitate its AMR review, the staff asked the applicant for additional information related to the elevated temperature condition in the reactor building drywell shield wall. In its response, the applicant stated that the drywell shield wall elevated temperature became a concern in the early to mid-1980s. 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 CLB 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 stated that the condition of the wall was monitored once 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 by the applicant. 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 documented in a 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 inch. Staff evaluation of information submitted by GPUN on the drywell shield wall elevated temperature began in 1986. In its SER dated October 24, 1986

(Letter, J. Zwolinsky, NRC, to P. Fiedler, GPUN, with 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. GPUN transmitted the requested information in several correspondences between 1990 through 1993. The staff completed its review of the submitted information and concluded in an SER 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, GPUN, "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, SER did not specify that the conclusion was based on the remaining OCGS operating life.

As recommended by the staff in its SER dated May 11, 1994, the applicant implemented a periodic crack monitoring program consisting of visual inspection of the 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 in which it assessed the condition of the drywell shield wall with the reactor cavity flooded with water. No changes to the cracks or water stain were observed. In similar inspections during the 1996 and 1998 refueling outages the structural engineer who performed them concluded that the drywell shield walls are 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, that cracks observed were minor, and that the walls were adequate for their intended functions. The 2005 inspection report noted that the shield walls were in good and 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 evident from 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 but not considered so significant as to impact the intended function of the drywell shield wall. A reanalysis for GPUN by ABB Impell Corporation (Report #0037-00196-0) was 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 (Commitment No. 31) under the Structures Monitoring Program is equal to the condition monitoring activities conducted under the current term to satisfy staff recommendations.

As a followup to the applicant's response, the staff reviewed the May 11, 1994, letter from A. Dromerick and the November 19, 1993, letter from R. Keaton along with ABB Impell Corporation Report #03-0370-1341, "Oyster Creek Nuclear Generating Station Structural Evaluation of the Spent Fuel Pool," Revision 0, June 29, 1992.

The staff reviewed the applicant's responses and concludes that the applicant's program to manage concrete cracking in the drywell shield wall and the spent fuel pool supporting structural elements is adequate based on an inspection frequency of every refueling outage, the inclusion of a quantitative acceptance criterion for crack width consistent with the staff recommendations, and the apparent stability of the existing crack patterns and crack widths.

Based on the information identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.3. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Aging Management of Inaccessible Areas for Group 6 Structures</u>. The staff reviewed LRA Section 3.5.2.2.2.4, and Attachment 3 of the applicant's reconciliation document against the criteria in SRP-LR Section 3.5.2.2.2.4.

In Attachment 3, items T-18 and T-19, of its reconciliation document, the applicant addressed 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 in below-grade inaccessible concrete areas of Group 6 structures (T-18, T-19).

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 their environment is aggressive. The acceptance criteria are described in Branch Technical Position RLSB-1 (SRP-LR Appendix A.1).

In Attachment 3, item T-18, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. The LRA states that inaccessible areas of structures in the scope of license renewal exposed by excavation for any reason will be inspected and groundwater sampled and tested periodically during the period of extended operation. This line item has been invoked for water control structures. The applicant has committed (Commitment No. 31) to a baseline inspection of submerged water control structures prior to the period of extended operation with a second inspection 6 years after the baseline inspection and a third 8 years after the second. Following each inspection, the identified degradations will be evaluated to determine whether more frequent inspections are warranted or there is a need for corrective actions to ensure adequate management of age-related degradations. Inspections will be conducted in accordance with the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. 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 4 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 representing 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 in accordance with the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program 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 these aging effects concluded that they are not so significant as to impact the intended function of the affected structure, and the applicant concluded that they are not significant for accessible and inaccessible areas and that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will adequately manage them. Thus, no plant-specific AMP is required.

The staff finds acceptable the applicant's assessment that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will adequately manage aging effects caused by corrosion of embedded steel and that no plant-specific program is necessary.

In Attachment 3, item T-19, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. The applicant stated that it will inspect inaccessible areas of structures within the scope of license renewal 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. The applicant has committed (Commitment No. 31) to a baseline inspection of submerged water control structures prior to the period of extended operation with a second inspection 6 years after the baseline inspection and a third 8 years after the second. Following each inspection, the identified degradations will be evaluated to determine whether more frequent inspections are warranted or there is a need for corrective actions to ensure adequate management of age-related degradations. Inspections will be conducted in accordance with the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The inspections conducted in accordance with the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program 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 that they are not so significant as to impact the intended function of the affected structure. Based on this evaluation, 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 the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will adequately manage these aging effects. Thus, no plant-specific AMP is required.

The staff finds acceptable the applicant's assessment that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will adequately manage aging effects that may be caused by aggressive chemical attack and that no plant-specific program is necessary.

The staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4.1 for further evaluation.

In Attachment 3, item T-15, of its reconciliation document, the applicant addressed loss of material (spalling, scaling) and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Group 6 structures (T-15).

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 this item change requires no change to the LRA. The applicant stated that for inaccessible areas, as described in UFSAR Section 3.8.4.6, "Materials, Quality Control and Special Construction Techniques," concrete is designed consistent with ACI 318 requirements to be workable with 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 that the desired quality of concrete was furnished. The strength quality of the concrete was established by tests by a maximum slump of four inches made in advance of the beginning of operations. Specimens were tested and cured in accordance with ASTM C39.

The applicant further stated that inspections conducted in accordance with the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program 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 so significant as to impact the intended function of the affected structure. Therefore, loss of material and cracking due to freeze-thaw is not significant in inaccessible concrete areas of Group 6 structures, and no plant-specific AMP is required.

The staff noted that the applicant credited the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program 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 caused by freeze-thaw will be identified. The staff finds acceptable the applicant's conclusion that a plant-specific program is not needed. The staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4.2 for further evaluation.

In Attachment 3, items T-16 and T-17, of its reconciliation document, the applicant addressed cracking due to expansion and reaction with aggregates, as well as increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible reinforced concrete areas of Group 6 structures (T-16, T-17).

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 ACI 201.2R-77 recommendations.

In Attachment 3, items T-16 and T-17, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. The LRA commitment (Commitment No. 31) to perform inspections in accordance with RG 1.127 does not change. As described in UFSAR

Section 3.8.4.6, "Materials, Quality Control and Special Construction Techniques," the cement used 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 in accordance with ASTM C295 and C227 demonstrated no potential alkali reactivity for all aggregates proposed for use, providing reasonable assurance that aggregates will not react with reinforced concrete. 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 requirements.

The staff finds acceptable the applicant's assessment of cracking due to expansion and reaction to with aggregates. The staff 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 staff finds that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4.3 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion</u>. The staff noted that the applicant had not provided a further evaluation for cracking of stainless steel tank liners, with reference to the further evaluation in SRP-LR Section 3.5.2.2.2.5; however, LRA Table 3.5.1, item number 3.5.1-30, addresses this aging effect.

SRP-LR Section 3.5.2.2.2.5 states that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur for Group 7 and 8 stainless steel tank liners exposed to standing water. The GALL Report recommends further evaluation of plant-specific programs to manage these aging effects.

LRA Table 3.5.1, item number 3.5.1-30, states that cracking due to SCC or loss of material due to pitting and crevice corrosion for Group 7 and 8 stainless steel tank liners is not applicable. The only stainless steel lined concrete tank is the spent fuel pool surge tank. Aging effects of the stainless steel tank liner are evaluated with the mechanical auxiliary systems.

The staff reviewed LRA Tables 3.5.2.1.1 through 3.5.2.1.19 and noted that the only stainless steel tank liner listed is the fuel pool skimmer surge tank liner, in LRA Table 3.5.2.1.2. The AMR for this tank references GALL Report 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 staff concludes that the applicant's AMP for the stainless steel tank liner is acceptable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.5. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging of Supports Not Covered by Structures Monitoring Program. The staff reviewed Attachment 3 of the applicant's reconciliation document against the criteria in SRP-LR Section 3.5.2.2.2.6.

In Attachment 3, items T-29, T-30, and T-31, of its reconciliation document, the applicant addressed aging management of component supports and aging effect combinations not covered by the Structures Monitoring Program.

SRP-LR Section 3.5.2.2.2.6 states that the GALL Report recommends further evaluation of certain component support and aging effect combinations not covered by the Structures Monitoring Program, including (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 and aging effect combinations not covered by the Structures Monitoring Program.

In Attachment 3, item T-29, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. 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 the applicant's Structures Monitoring Program; therefore, no further evaluation is required.

The staff verified that this item is within the scope of the Structures Monitoring Program; therefore, no further evaluation is required. The staff finds this assessment acceptable.

In Attachment 3, item T-30, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. 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 the Structures Monitoring Program; therefore, no further evaluation is required.

The staff verified that this item is within the scope of the Structures Monitoring Program; therefore, no further evaluation is required. The staff finds this assessment acceptable.

Attachment 3, item T-31, of its reconciliation document, the applicant stated that this item change requires no change to the LRA. 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 the Structures Monitoring Program, therefore, no further evaluation is required.

The staff verified that this item is within the scope of the Structures Monitoring Program; therefore, no further evaluation is required. The staff finds this assessment acceptable.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.6. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cumulative Fatigue Damage Due to Cyclic Loading. 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 OCGS, 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 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 evaluated in accordance with 10 CFR 54.21(c) in LRA Section 4.6.1.

The evaluation of this TLAA is documented in SER Section 4.6.

3.5.2.2.3 QA for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program for safety-related and nonsafety-related components. The staff concluded that the program descriptions of the “corrective action,” “confirmation process,” and “administrative controls” attributes are acceptable.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report, for which the applicant had claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff concludes that the applicant has adequately addressed the issues that were further evaluated. Five open items were identified and resolved, as documented in SER Section 4.7.2. Based upon this review and evaluation of the containment corrosion history and the applicant's proposed aging management activities for the period of extended operation, the staff finds 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).

3.5.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.5.2.1.1 through 3.5.2.1.19, the staff reviewed additional details concerning the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.5.2.1.1 through 3.5.2.1.19, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is discussed in the following sections.

3.5.2.3.1 Primary Containment – LRA Table 3.5.2.1.1

The staff reviewed LRA Table 3.5.2.1.1, which summarizes the results of AMR evaluations for the primary containment component groups.

The staff's review of LRA Table 3.5.2.1.1 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.5-1 dated March 20, 2006, the staff identified that LRA Table 3.5.2.1.1 indicates that fretting and lockup of suppression pool downcomers will be managed by the ASME Section XI, Subsection IWE Program. Directly, the downcomers are not parts of the pressure boundary. Subsection IWE does not provide examination requirements and acceptance criteria for downcomers; however, as a convenience, the examinations of downcomers can be included in Subsection IWE requirements with special provisions for examining the downcomers for fretting or lockups in the plant-specific procedures. The staff requested that the applicant provide (1) the operating experience with downcomers fretting or lockups and (2) the ISI provisions incorporated in the plant-specific ASME Section XI, Subsection IWE Program.

In its response dated April 18, 2006, the applicant stated as to item (1) that OCGS operating experience has not identified fretting or lockups of the downcomers. Visual inspections in accordance with ASME Section XI, Subsection IWE have been limited to downcomer surfaces above water level in the torus. Areas potentially susceptible to fretting or lockup are submerged in torus water and scheduled for inspection at the end of the current 10-year interval in accordance with Table IWE-2500-1. Consequently, OCGS has no operating experience with fretting or lockups of the downcomers. As to item (2), the applicant explained that the ASME Section XI, Subsection IWE Program includes examination of downcomers with the vent system, examination category E-A, item number E1.20 in accordance with Table IWE-2500-1. The examination method is visual, VT-3, in accordance with IWE. Parameters monitored are loss of material due to corrosion and fretting or lockup at clamps that connect adjacent downcomers. The inspection frequency is every 10 years with 100 percent inspection at the end of the interval in accordance with Table IWE-2500-1.

The staff agreed with the applicant that the examination of downcomers for fretting and lock-ups is part of implementation of the ASME Section XI, Subsection IWE Program and that these types of degradation will be managed by the applicant during the period of extended operation. The staff's concerns described in RAI 3.5-1 are resolved.

In RAI 3.5-2 dated March 20, 2006, the staff noted that LRA Table 3.5.2.1.1 credits the 10 CFR Part 50, Appendix J Program for management of loss of material in downcomers. It is not apparent how the leak testing requirement of Appendix J will detect loss of material in downcomers. The staff requested that the applicant discuss the use of the10 CFR Part 50, Appendix J Program for managing loss of material in downcomers.

In its response dated April 18, 2006, the applicant explained that the primary containment leakage rate testing program is performed in accordance with 10 CFR Part 50, Appendix J, Option B, RG 1.163, NEI 94-01, ANSI/ANS 56.8, and approved plant program documents and procedures. Appendix J of 10 CFR Part 50, paragraph III.A, Type A pretest requirements, requires a general inspection of the accessible interior and exterior surfaces of the containment structure and component prior to any Type A test to uncover any evidence of deterioration which may affect the containment structural integrity or leak-tightness. The general inspection detects loss of material due to corrosion on accessible surfaces of the containment including downcomers. However, the ASME Section XI, Subsection IWE Program is the primary AMP credited for managing loss of material of the downcomers.

The staff finds the applicant's procedure acceptable because it incorporates the examination of downcomers as part of its Appendix J, Type A test pre-service examination requirements. The staff's concern described in RAI 3.5-2 is resolved.

In RAI 3.5-3 dated March 20, 2006, the staff noted under component types "Reactor Pedestal" and "R.C. Floor Slab" a reference to GALL Report Table 1, item 3.5.1-29, where the discussion indicates that the concrete temperatures in the upper part of the drywell could be as high as 259 °F. As a result, the reactor building drywell shield concrete experienced significant cracking. However, the cause of the high temperature is not indicated. In light of that discussion, the staff requested that the applicant provide the following information:

(a) type and adequacy of the cooling system used to control the temperatures in the drywell

(b) operating experience with the reliability of the cooling system

(c) actions taken to reduce the high temperatures in the upper part of the drywell

(d) a summary of the results of the last inspection of the reactor pedestal, R.C. floor slabs, drywell lateral supports, and sacrificial shield wall, including the date of the inspection and frequency of inspection during the period of extended operation

In its response dated April 18, 2006, the applicant explained that the GALL Report Table 1, item 3.5.1-29 discussion paragraph states that the temperatures limits of 150 °F and 200 °F are exceeded only in the upper elevation of the drywell. The reactor pedestal and the reinforced concrete floor slab are not subject to elevated temperature inside the drywell. These structures are located below elevation 55' where the maximum drywell temperature during plant operation is 139 °F. For this reason LRA Table 3.5.2.1.1 indicates "none" for the aging effect associated with GALL Report Table 2, item III.A4-1 (T-10), which rolls up to GALL Report Table 1, item 3.5.1-29. A plant-specific Note 7 was added to LRA Table 3.5.2.1.1 for these components for a technical basis for the aging, "none." The plant-specific note states "Reduction of strength and modulus due to elevated temperature is not an aging effect requiring management." Furthermore, the applicant points to the additional evaluation in LRA Section 3.5.2.2.1.3, which essentially states "Concrete for the reactor pedestal, and the drywell floor slab (fill slab) are located below elevation 55' and are not exposed to the elevated temperature." Additionally, the applicant explained that, as discussed in LRA Section 3.5.2.2.1, item 3, the temperature inside the drywell during plant operation varies from 139 °F at elevation 55' to more than 256 °F in the upper elevations of the drywell, above elevation 95'. Thus, the temperature in the upper elevations of the drywell exceeds local and general limits for concrete in accordance with ACI 349. The affected concrete structure is the drywell shield walls above elevation 95'. The effect of elevated temperature on the drywell shield wall is discussed in detail in LRA Section 3.5.2.2.2, item 8. The applicant provided the following additional information as requested by the staff:

(a) *The drywell cooling system, consisting of the drywell recirculating fan cooler units and the* drywell temperature detection system, is a ventilation system designed to maintain temperature, humidity, and mixing in the drywell to control drywell pressure and protect the drywell and equipment inside from excessive heat by circulating the drywell atmosphere (inerted nitrogen environment) through the drywell fan cooler units cooling coils and transferring heat from the drywell fan cooler units cooling coils to the reactor building closed cooling water system.

The drywell cooling system is comprised of five recirculation fan cooler units including supply fans, demisters, supply and return ductwork, dampers, registers, instrumentation, and controls. In normal operation, four fans (20,000 cfm each) are sufficient for cooling. From the fans, cooled nitrogen is fed to a supply/distribution ring header at elevation 54' and delivered to the air space within the drywell:

- 52,800 cfm is distributed through 5 supply air ducts to Zone I toward the lower part of the drywell for cooling of the recirculation pump motors.
- 16,800 cfm is distributed through 9 supply registers to the remaining portions of Zone I.
- 8,800 cfm is distributed through 5 supply air ducts to Zone II for cooling of the RPV surface and biological shield.
- 1,600 cfm is distributed through a single supply air duct to Zone III for cooling the RPV bottom cavity.

The supply/distribution ring header at elevation 54' does not directly provide cooling to the space above the reactor vessel head. A total of 1,600 cfm is transferred through 8 ventilation hatches from Zone II to the space above the reactor vessel head. Return nitrogen is collected by a return duct ring header at elevation 91' 7":

- 54,400 cfm is returned to the return duct ring header through 5 return ducts in the lower part of the drywell.
- 24,000 cfm is returned to the return duct ring header through 5 return ducts located directly on the return duct ring header.
- 1,600 cfm is returned from the space above the reactor vessel head to the return duct ring header through 3 return ducts.

The return duct ring header at elevation 91' 7" does not directly collect flow from the Zone III RPV bottom cavity area. Nitrogen in this area exits Zone III through access openings and is collected by the return ducts in the lower part of the drywell (Zone I).

The drywell temperature detection system provides information to the operators in the control room to monitor and record the drywell atmosphere temperature at various locations and to determine the drywell bulk temperature during normal plant operation. The drywell temperature detection system is comprised of local drywell temperature instrumentation and includes duct-mounted temperature elements located in the supply and return portions of the recirculation fan ducts. The drywell temperatures are monitored by the plant computer system and recorded on control room and local panel recorders in the reactor building. The drywell cooling system is designed to maintain the drywell bulk temperature below 150 °F as discussed in paragraph (c). The system performs this function adequately.

(b) The cooling system is maintained to maximize reliability. Drywell fan motors on 4 fans were replaced in the mid-'90s with direct drive motors. This change eliminated the possibility of belt breakage or slippage. The fifth fan, which has the original belt-driven motor, is maintained as a spare and used during periods of peak drywell temperature. During refueling outages, maintenance is performed on all fans and motors. Cooling coils are cleaned, bearings greased, and vibration data obtained on all bearings. Belts are replaced on the one belt-driven fan. In recent years there have been no significant component failures that have rendered one train inoperable.

(c) There have been no actions to reduce temperature in the upper elevations. The drywell cooling system has functioned within design bases to cool the drywell adequately. Drywell bulk temperature is maintained under the 150 ° limit even during the highest heat periods. The drywell bulk temperature value is calculated from a weighted average of all the thermocouples. It is the single value used for such action levels as EOP entry, plant shutdown, etc.

(d) Structures inside the drywell were last inspected October 16, 2002, under the Structures Monitoring Program. The reactor pedestal, drywell R.C. floor slab, and liner plate for the sacrificial shield wall were found structurally sound and able to perform their intended functions. Inspection of the drywell lateral supports is included in the ASME Section XI, Subsection IWE Program as nonmandatory augmented inspections during the current term. The last inspection was during the refueling outage in 2004. The inspection report identified no degradations that would impact the intended function of the supports. The reactor pedestal and the R.C. floor slab will be monitored on a frequency of every refueling outage during the period of extended operation under the Structures Monitoring Program. The sacrificial (biological) shield wall carbon steel liner has previously experienced cracking. The cracking was evaluated and determined not to impact the intended function of the wall. This carbon steel liner is monitored under the CLB every refueling outage consistent with an existing NRC commitment and will continue to be monitored every refueling outage during the period of extended operation as part of the Structures Monitoring Program.

The drywell lateral supports are included in Class MC component supports and will be monitored under the ASME Section XI, Subsection IWF Program during the period of extended operation. Inspection frequency is every 10 years in accordance with ASME Code Section XI, Subsection IWF as required by 10 CFR 50.55a.

The staff finds that with the operation of the cooling system as described in responses to paragraphs (a) and (b) and the inspection of structural components as described in response to paragraph (d) there is reasonable assurance that the structures affected by high temperatures will be adequately managed during the period of extended operation. The staff's concerns described in RAI 3.5-3 are resolved.

In RAI 3.5-4 dated March 20, 2006, the staff noted that component type "Shielding Blocks and Plates" uses patented material "Permali," for which no aging effects are indicated in LRA Table 3.5.2.1.1. The staff requested that the applicant briefly describe the material and the AMR results that justified no need for aging management during the period of extended operation.

In its response dated April 18, 2006, the applicant explained that Permali consists of vacuum-impregnated material based on wood veneers (rosewood) and phenolic resin. The material was provided in the OCGS original design in combination with steel blocks to provide neutron shielding around recirculation piping nozzles at biological shield wall penetrations. The material is designed for its operating environment and aging management reviews identified no AERMs during the period of extended operation.

The hydrogen content in wood veneers would make the material susceptible to neutron radiation, and high temperatures around the penetration could affect the stability of phenolic resin. The staff requested from the applicant a detailed justification in its AMR for this material concluding that no aging management is required for this material.

In its supplemental response dated July 10, 2006, the applicant stated:

> AmerGen stated during the conference call that the material was provided in the original plant design specifically for shielding purposes around penetrations in the biological shield wall. Industry and plant specific operating experience have not identified any aging effects requiring management. Also, available vendor data, not specific to Oyster Creek, shows that the material is designed for neutron attenuation in a high temperature environment. But it is unlikely that Oyster Creek will be able to produce specific material test reports for the original material.
>
> AmerGen therefore has elected to monitor the "Permali" material associated with the penetration shielding blocks for potential aging effects that could impact their intended function. The blocks will be monitored for loss of material and cracking through the Structures Monitoring aging management program. The inspection frequency will coincide with the ASME Section XI inspection of reactor vessel nozzles, where the material is applied.

In addition, the applicant revised the Structures Monitoring Program to include inspection and degradation monitoring of Permali. The staff finds this acceptable because it ensures aging management of this material. The staff's concern described in RAI 3.5-4 is resolved.

In RAI 3.5-5 dated March 20, 2006, the staff noted that for all component types described in Table 3.5.2.1.1, the Water Chemistry Program is vital, in addition to the programs noted in the individual component types, for components fully or partially submerged in water. The staff requested that the applicant provide reasons for not including a Water Chemistry Program to manage the aging degradation of these components.

In its response dated April 18, 2006, the applicant recognized that water chemistry is vital for mitigating loss of material due to corrosion of carbon and stainless steel components and cracking of stainless steel components exposed to treated water environments. Torus water chemistry is monitored in accordance with industry guidelines (BWRVIP-130) as described in the Water Chemistry Program. The Water Chemistry Program was not credited for managing the effects of aging of the torus and structural components subject to torus water because the ASME Section XI, Subsection IWE, the 10 CFR Part 50, Appendix J, and the Protective Coating Monitoring and Maintenance Programs are deemed adequate to manage their aging effects. The applicant stated that this position is consistent with the January 2005 draft GALL Report which credits only the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs. However, the applicant recognized that the September 2005 GALL Report added treated water environment to steel elements of the containment (II.B1.1-2 (C-19), but that this line item does not credit water chemistry aging management for any of the components subject to treated water. Based on this discussion, the applicant concluded that, while torus water chemistry is vital and maintained in accordance with BWRVIP-130, the Water Chemistry Program need not be credited to provide reasonable assurance that aging effects of structural components exposed to treated water are adequately managed, that the credited ASME Section XI, Subsection IWE, 10 CFR Part 50, Appendix J, and Protective Coating Monitoring and Maintenance Programs are adequate.

The staff recognized that maintaining the protective coating would eliminate any need for a water chemistry program. However, because the torus coatings and the protected steel of a number of Mark 1 containments degrade, it is essential that the torus water be periodically checked and maintained in accordance with BWRVIP-130 as stated in the UFSAR supplement. Although the applicant does not credit a Water Chemistry Program explicitly, it recognizes a need to maintain the water quality in accordance with the recommendations in the BWRVIP report. The staff's concern described RAI 3.5-5 is resolved.

In RAI 3.5-6 dated March 20, 2006, the staff stated that the through-wall cracking of the Fitzpatrick Nuclear Power Plant torus indicates a need for closer examination of the highly restrained and structurally discontinuous areas subject to operational cyclic loads. The prime AMP for managing degradation of the primary containment structure is the ASME Section XI, Subsection IWE Program. The program is focused towards detecting loss of material. The staff requested that the applicant discuss how the program would detect initiation of such cracking in the primary containment.

In its response dated April 18, 2006, the applicant explained that the ASME Section XI, Subsection IWE Program is not credited for managing crack initiation and growth. The program is based on visual examinations that may not detect cracking experienced at Fitzpatrick. However, the applicant noted that the crack initiation and growth mechanism experienced at Fitzpatrick is not applicable to OCGS:

> The initial review (2005) of the Fitzpatrick torus leak operating experience determined that the crack was related to design and operating conditions that are not applicable to Oyster Creek. Analysis performed by Fitzpatrick indicated that the most likely cause for the initiation and propagation of the crack was the hydrodynamic loads of the turbine exhaust pipe during HPCI operation coupled with the highly restrained condition of the torus shell at the torus column support. The cracking occurred in the heat-affected zone of the lower gusset plate of the ring girder at the torus column support. Fitzpatrick concluded that the crack was

initiated by cyclic loading due to condensation oscillation during HPCI operation. The condensation oscillations induced on the torus shell may have been excessive due to lack of a HPCI pipe sparger. The combined operation of the HPCI system and safety relief valve (SRV) discharges during the northeast grid blackout disturbance of August 2003 may have initiated the crack. The HPCI system operated approximately 14.5 hours and SRVs lifted five times over a period of 28 hours following the grid disturbance.

The applicant had explained that OCGS does not have a high-pressure coolant injection (HPCI) system and was not subject to such events. Furthermore, the applicant recognized that since the initial review the NRC had issued IN 2006-01, "Torus Cracking in BWR Mark I Containment," on January 12, 2006, to alert licensees of the Fitzpatrick condition. After reviewing the impact of the Fitzpatrick experience on OCGS, the applicant will initiate corrective actions if it determines that the condition described in the IN applies to OCGS.

The staff recognized that the major cause of the torus cracking at Fitzpatrick was the condensation oscillation loads generated during the HPCI operation. However, such loads are also generated during SRV discharges in Mark I containments. The staff requested from the applicant the results of its evaluation of the event.

In its supplemental response dated July 10, 2006, the applicant stated:

> AmerGen's final review of the NRC Information Notice 2006-01, "Torus Cracking in BWR Mark I Containment," issued on January 12, 2006 concluded that the torus crack identified by the Fitzpatrick Operating Experience is not applicable to Oyster Creek. The crack was considered event driven, caused by design configuration of the HPCI discharge line into the torus with no spargers. Oyster Creek does not have a HPCI system or a steam discharge line to the torus with the same design configuration as the Fitzpatrick HPCI system.
>
> The SRV discharges won't be a concern for Oyster Creek because unlike the Fitzpatrick event driven HPCI discharges, Mark I containment SRV discharges into the torus are design basis events evaluated in accordance with the Oyster Creek Plant Unique Analysis Report (PUAR). Oyster Creek has five-safety relief valves (EMRVs) installed in the main steam system. When opened, steam discharge from each EMRV is through piping routed inside the vent lines that enter the torus from penetrations in the vent header. The steam lines are then routed to a Y-quencher that discharges underwater. The SRV discharge pipes do not penetrate the torus shell directly.
>
> The Y-Quenchers were provided as a part of the Mark I containment hydrodynamics loads assessment to minimize the consequences of loads that result from blowdown of SRV lines into the torus. Components of the torus that are affected by the cyclic loads, due to blowdowns, were analyzed as described in Oyster Creek PUAR for the current term. The analysis was determined to be a TLAA for the period of extended operation and evaluated as described in LRA Section 4.6.1. Thus, the concern with SRV discharge cycles and their impact on the torus have been addressed in the LRA.

Based on operating experience and the review of Mark I containment information, the staff believes that OCGS is not likely to have the type of the event described in IN 2006-01. The staff's concern described in RAI 3.5-6 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the primary containment components 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).

3.5.2.3.2 Reactor Building – LRA Table 3.5.2.1.2

The staff reviewed LRA Table 3.5.2.1.2, which summarizes the results of AMR evaluations for the reactor building component groups.

The applicant stated that the Structures Monitoring Program manages the aging effect of loss of material for carbon and low alloy steel liners for sumps subject to raw water. The program description states that steel components are inspected for loss of material due to corrosion every 4 years. The staff agreed that the Structures Monitoring Program is an acceptable AMP because it can detect the corrosion of steel liners for sumps and that the inspection frequency of every 4 years is adequate.

The applicant stated that the Structures Monitoring Program manages the aging effect of cracking of concrete grout. The program description states that concrete structures are inspected for cracking every 4 years. The staff agreed that the Structures Monitoring Program is an acceptable AMP because it can detect the cracking of grout and that the inspection frequency of every 4 years is adequate.

The applicant stated that this program is also used to manage the aging effect of change in material properties for the roofing material. The staff agrees with the applicant that periodic visual inspections for roofing material degradation by qualified personnel is a proper way to manage aging effects of the roofing material.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor building components 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).

3.5.2.3.3 Chlorination Facility – LRA Table 3.5.2.1.3

The staff reviewed LRA Table 3.5.2.1.3, which summarizes the results of AMR evaluations for the chlorination facility component groups.

LRA Table 3.5.2.1.3 states that the AMRs for the chlorination facility either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the chlorination facility components 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).

3.5.2.3.4 Condensate Transfer Building – LRA Table 3.5.2.1.4

The staff reviewed LRA Table 3.5.2.1.4, which summarizes the results of AMR evaluations for the condensate transfer building component groups.

LRA Table 3.5.2.1.4 states that the AMRs for the condensate transfer building either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the condensate transfer building components 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).

3.5.2.3.5 Dilution Structure – LRA Table 3.5.2.1.5

The staff reviewed LRA Table 3.5.2.1.5, which summarizes the results of AMR evaluations for the dilution structure component groups.

LRA Table 3.5.2.1.5 states that the AMRs for the dilution structure either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the dilution structure components 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).

3.5.2.3.6 Emergency Diesel Generator Building – LRA Table 3.5.2.1.6

The staff reviewed LRA Table 3.5.2.1.6, which summarizes the results of AMR evaluations for the EDG building component groups.

The staff's review of LRA Table 3.5.2.1.6 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.5-8 dated March 20, 2006, the staff stated that LRA Tables 3.5.2.1.6, 3.5.2.1.15, 3.5.2.1.16, and 3.5.2.1.17 identify loss of preload as the AERM for structural bolts and the Structures Monitoring Program as its AMP. The Structures Monitoring Program states that exposed surfaces of bolting are monitored for indications of loss of preload and that 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 GALL Report AMP XI.M18. LRA Section B.1.12 states that the Bolting Integrity Program takes exception to the GALL Report and that the aging management of structural bolting is addressed by the Structures Monitoring Program. The staff requested that the applicant:

(a) Resolve the apparent inconsistencies that the Structures Monitoring Program states that the proper torque for bolts is applied consistent with the GALL Report bolting integrity program while the Bolting Integrity Program takes exception to the GALL Report and refers the aging management of structural bolting back to the Structures Monitoring Program.

(b) Clarify whether the loss of preload of structural bolts is identified by visual inspection or by application of a torque wrench and if by visual inspection how the loss of preload can be estimated.

(c) Explain how the Structures Monitoring Program relies on bolt procurement controls and installation practices. LRA Section B.1.31 states that the Structures Monitoring Program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied. The staff believes that bolt procurement controls and installation practices supposedly were used before, during, or immediately after installation of the bolts.

(d) Clarify whether there are any structural bolts or fasteners with a yield strength equal to or greater than 150 ksi managed by the Structures Monitoring Program and, if so, justify not using the Bolting Integrity Program as the AMP for structural bolts.

In its response dated April 18, 2006, the applicant stated:

(a) The exception to the GALL Report referred to in the Bolting Integrity Program is that coverage of NSSS component support and structural bolting in the GALL Report is by the Bolting Integrity Program but that instead coverage is by the Structures Monitoring Program for structural bolting, ASME Section XI, Subsection IWE Program for primary containment pressure bolting, and ASME Section XI, Subsection IWF Program for ASME Code Section XI Classes 1, 2, and 3 and Class MC support members. The same procurement and installation procedures credited in the Bolting Integrity Program are also applicable to the structural bolting.

(b) Structural bolting applications at OCGS do not require any specific predetermined bolting preload to assure that structural intended functions are maintained. Structural bolting is assembled by approved bolting materials and lubricants. Bolted connections are assembled by vendor-recommended methods, turn-of-the-nut methods, or standard torque values for the applicable bolt size and material. For structural bolting, loss of preload will not impact the bolted connection intended function unless the bolts become so loose that they affect the integrity and geometry of the bolted connection. This aging effect is managed by visual inspection for loose or missing nuts and bolts.

(c) The same procurement and installation procedures credited in the Bolting Integrity Program are also applicable to the structural bolting. The Structures Monitoring Program is credited because it provides for visual inspections of the structural bolted connections.

(d) Structural bolts with yield strength greater than or equal to 150 ksi are used in limited structural applications, but those bolts are not subject to significant preload stress; therefore, cracking would not be expected. The Structures Monitoring Program includes structural bolting inspections for loss of material due to corrosion and visual inspections for loose nuts, missing bolts, or other indications of loss of preload.

The applicant clarified that the aging effect of structural bolts in managed by visual inspection for loose or missing bolts as specified in the Structures Monitoring Program and that there is no physical check on the preload loss in the bolts or bolt connections. The issue of structural bolts that have yield strength greater than or equal to 150 ksi was resolved in the Audit and Review Report. The staff's concern described in RAI 3.5-8 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the EDG building components 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).

3.5.2.3.7 Exhaust Tunnel – LRA Table 3.5.2.1.7

The staff reviewed LRA Table 3.5.2.1.7, which summarizes the results of AMR evaluations for the exhaust tunnel component groups.

The applicant stated that the Structures Monitoring Program manages the aging effect of cracking for concrete grout. The program description states that concrete structures are inspected for cracking every 4 years. The staff agreed that the Structures Monitoring Program is an acceptable AMP because it can detect the cracking of grout and that the inspection frequency of every 4 years is adequate.

The staff's review of LRA Table 3.5.2.1.7 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant stated that aluminum embedded in concrete has no aging effect. In RAI 3.5-10 dated March 20, 2005, the staff noted that the ACI Building Code prohibits the use of aluminum in structural concrete unless coated or covered to prevent aluminum-concrete reaction or electrolytic action between aluminum and steel. The staff requested that the applicant justify the use of aluminum material in concrete and explain why there is no aging effect and why no AMP is required.

In its response dated April 18, 2006, the applicant stated that, as required by ACI, the concrete is not in direct contact with aluminum. The OCGS specification for placement of concrete requires that where aluminum will contact concrete the contact surface of the metal shall have not less than one coat of zinc chromate primer and one heavy coat of aluminum-pigmented asphalt paint. The applicant's response indicated that it complied with the ACI Code requirement that aluminum not be in direct contact with concrete. The staff's concern described in RAI 3.5-10 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the exhaust tunnel components 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).

3.5.2.3.8 Fire Pond Dam – LRA Table 3.5.2.1.8

The staff reviewed LRA Table 3.5.2.1.8, which summarizes the results of AMR evaluations for the fire pond dam component groups.

LRA Table 3.5.2.1.8 states that the AMRs for the fire pond dam either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire pond dam components 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).

3.5.2.3.9 Fire Pumphouses – LRA Table 3.5.2.1.9

The staff reviewed LRA Table 3.5.2.1.9, which summarizes the results of AMR evaluations for the fire pumphouses component groups.

LRA Table 3.5.2.1.9 states that the AMRs for the fire pumphouses either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire pumphouses components 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).

3.5.2.3.10 Heating Boiler House – LRA Table 3.5.2.1.10

The staff reviewed LRA Table 3.5.2.1.10, which summarizes the results of AMR evaluations for the heating boiler house component groups.

LRA Table 3.5.2.1.10 states that the AMRs for the heating boiler house either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the heating boiler house components 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).

3.5.2.3.11 Intake Structure and Canal (Ultimate Heat Sink) – LRA Table 3.5.2.1.11

The staff reviewed LRA Table 3.5.2.1.11, which summarizes the results of AMR evaluations for the intake structure and canal component groups.

LRA Table 3.5.2.1.11 states that the AMRs for the intake structure and canal either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the intake structure and canal components 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).

3.5.2.3.12 Miscellaneous Yard Structures – LRA Table 3.5.2.1.12

The staff reviewed LRA Table 3.5.2.1.12, which summarizes the results of AMR evaluations for the miscellaneous yard structures component groups.

The applicant stated that no aging effects are considered applicable to polyvinyl chloride (PVC) conduits embedded in concrete. Based on the available information, the staff finds that PVC conduits embedded in concrete will not have aging effects of concern during the period of extended operation. Therefore, the staff concludes that there are no applicable AERMs for PVC conduits embedded in concrete.

The applicant stated that no aging effects are considered applicable to gravel and sand under tank foundations. Based on the available information, the staff agrees that the gravel and sand under tank foundations have no aging effects.

On the basis of its review, as discussed above, *the staff* concludes that the applicant has demonstrated that the aging effects associated with the miscellaneous yard structures components 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).

3.5.2.3.13 New Radwaste Building – LRA Table 3.5.2.1.13

The staff reviewed LRA Table 3.5.2.1.13, which summarizes the results of AMR evaluations for the new radwaste building component groups.

LRA Table 3.5.2.1.13 states that the AMRs for the new radwaste building either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the new radwaste building components 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).

3.5.2.3.14 Office Building – LRA Table 3.5.2.1.14

The staff reviewed LRA Table 3.5.2.1.14, which summarizes the results of AMR evaluations for the office building component groups.

LRA Table 3.5.2.1.14 states that the AMRs for the office building either are consistent with the GALL Report or have no AERM. The staff confirmed that the AMR results presented in this table are consistent with the GALL Report. The staff's evaluation for AMR items that are consistent with the GALL Report is documented in SER Sections 3.5.2.1 and 3.5.2.2.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the office building components 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).

3.5.2.3.15 Oyster Creek Substation – LRA Table 3.5.2.1.15

The staff reviewed LRA Table 3.5.2.1.15, which summarizes the results of AMR evaluations for the OCGS substation component groups.

The applicant stated that the Structures Monitoring Program manages the aging effect of loss of preload for structural bolts. The staff evaluation of loss of preload is documented in SER Section 3.5.2.3.6.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the OCGS substation components 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).

3.5.2.3.16 Turbine Building – LRA Table 3.5.2.1.16

The staff reviewed LRA Table 3.5.2.1.16, which summarizes the results of AMR evaluations for the turbine building component groups.

The applicant stated that the Structures Monitoring Program manages the aging effect of change in material properties for the roofing material. The staff agreed with the applicant that periodic visual inspections for roofing material degradation by qualified personnel properly manage aging effects of roofing material.

The applicant stated that the Structures Monitoring Program manages the aging effect of loss of preload for structural bolts. The staff evaluation of loss of preload is documented in SER Section 3.5.2.3.6.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the turbine building components 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).

3.5.2.3.17 Ventilation Stack – LRA Table 3.5.2.1.17

The staff reviewed LRA Table 3.5.2.1.17, which summarizes the results of AMR evaluations for the ventilation stack component groups.

The applicant stated that the Structures Monitoring Program manages the aging effect of cracking for concrete grout. The program description states that concrete structures are inspected for cracking every 4 years. The staff agreed that the Structures Monitoring Program is an acceptable AMP because it can detect the cracking of grout and that the inspection frequency of every 4 years is adequate.

The staff's review of LRA Table 3.5.2.1.17 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant stated that aluminum embedded in concrete has no aging effect. In RAI 3.5-10 dated March 20, 2005, the staff noted that the ACI Building Code prohibits the use of aluminum in structural concrete unless coated or covered to prevent aluminum-concrete reaction or electrolytic action between aluminum and steel. The staff requested that the applicant justify the use of aluminum material in concrete and explain why there is no aging effect and why no AMP is required.

In its response dated April 18, 2006, the applicant stated that, as required by ACI, the concrete is not in direct contact with aluminum. The OCGS specification for placement of concrete requires that where aluminum will contact concrete the contact surface of the metal shall have not less than one coat of zinc chromate primer and one heavy coat of aluminum-pigmented asphalt paint. The applicant's response indicated that it complied with the ACI Code requirement that aluminum not be in direct contact with concrete. The staff's concern described in RAI 3.5-10 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the ventilation stack components 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).

3.5.2.3.18 Component Supports Commodity Group – LRA Table 3.5.2.1.18

The staff reviewed LRA Table 3.5.2.1.18, which summarizes the results of AMR evaluations for the component supports commodity group component groups.

The staff's review of LRA Table 3.5.2.1.18 identified an areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.5-7 dated March 20, 2006, the staff noted that LRA Table 3.5.3.1.18 indicates that the aging of Class MC component supports is managed by ASME Section XI, Subsection IWF Program during the CLB. However, review of the enhancements in LRA Section B.1.28 indicated that the program will be enhanced during the period of extended operation to include additional MC supports and underwater structures in the torus. The staff requested from the applicant clarification of the inspection of Class MC supports during the CLB and the period of extended operation.

In its response dated April 18, 2006, the applicant noted that the reference to LRA Table 3.5.3.1.18 is a typographical error and should read "LRA Table 3.5.2.1.18." LRA Table 3.5.2.1.18 is for AMR of Class MC component supports during the period of extended operation, not during the CLB. The table reflects enhancements described in the ASME Section XI, Subsection IWF Program.

For the current period, the applicant explained that inspection of some Class MC component supports is conducted under the ASME Section XI, Subsection IWF Program, and others are under the ASME Section XI, Subsection IWE Program. Those included under nonmandatory IWE augmented inspections are vent header supports, downcomer bracing, and drywell stabilizers. Other supports are within the scope of IWF. Supports submerged in torus water are treated as inaccessible under the current term and not included in the inspection plan for either IWF or IWE.

For license renewal, all Class MC component supports are included within the scope of IWF. Submerged supports inside the torus will be monitored under IWF and inspected by divers when the torus shell is submerged or when the torus is dewatered.

The staff finds the applicant's AMP enhancement to include the examinations of all Class MC component supports within the scope of IWF during the period of extended of operation acceptable. The staff's concern described in RAI 3.5-7 is resolved.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the component supports commodity group components 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).

3.5.2.3.19 Piping and Component Insulation Commodity Group – LRA Table 3.5.2.1.19

The staff reviewed LRA Table 3.5.2.1.19, which summarizes the results of AMR evaluations for the piping and component insulation commodity group component groups.

The applicant stated that no aging effects are considered applicable to insulations fabricated from asbestos, calcium silicate, fiberglass, and NUKON. Based on the available information, the staff agreed that these insulations will not cause aging of concern during the period of extended operation. Therefore, the staff concludes that there are no applicable AERMs for these insulations.

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the aging effects associated with the piping and component insulation commodity group components 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).

Conclusion. On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results involving material, environment, AERMs, and AMP combinations that are not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.5.3 Conclusion

The staff concludes that, the applicant has provided sufficient information to demonstrate that the effects of aging for the 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.

3.6 Aging Management of Electrical Components

This section of the SER documents the staff's review of the applicant's AMR results for the electrical components and commodity groups of the following:

- insulated cables and connections
- electrical penetrations
- high voltage insulators
- transmission conductors and connections
- fuse holders
- wooden utility poles
- cable connections (metallic parts)
- uninsulated ground conductors

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant provided AMR results for the electrical components and component groups. In LRA Table 3.6.1, "Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the electrical components and commodity groups.

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 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the electrical components 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 staff conducted an onsite audit of AMRs, during the weeks of October 3-5, 2005, January 23-27, February 13-17, and April 19-20, 2006, to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and summarized in SER Section 3.6.2.1.

In the onsite audit, the staff also selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.6.2.2. The staff's audit evaluations are documented in the Audit and Review Report and summarized in SER

Section 3.6.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review included evaluating whether all plausible aging effects had been identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's evaluations are documented in SER Section 3.6.2.3.

For AMRs that the applicant identified as not applicable, or not requiring aging management, the staff conducted a review of the AMR line items, and the plant's operating experience, to verify the applicant's claims. Details of these reviews are documented in the Audit and Review Report.

Finally, the staff 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, provided below, includes a summary of the staff's evaluation of components, aging effects and mechanisms, and AMPs listed in LRA Section 3.6 and addressed in the GALL Report.

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 Electrical Components	TLAA Environmental Qualification (B.3.2)	Consistent with GALL, which recommends further evaluation (See SER Sections 3.6.2.2 and 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 SER 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 SER Section 3.6.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER 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	Not Applicable	Not Applicable- GALL Report aging effect is not applicable to OCGS. (See SER Section 3.6.2.3)
Metal enclosed bus - Bus/connections (Item 3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus	Not Applicable	Not Applicable. OCGS has no phase buses in the scope of license renewal.
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	Not Applicable	Not Applicable. OCGS has no phase buses in the scope of license renewal.
Metal enclosed bus - Enclosure assemblies (Item 3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	Not Applicable	Not Applicable. OCGS has no phase buses in the scope of license renewal.
Metal enclosed bus - Enclosure assemblies (Item 3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	Not Applicable	Not Applicable. OCGS has no phase bus in the scope of license renewal.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	Periodic Monitoring of Combustion Turbine Power Plant Electrical Program (B.1.37)	Consistent with GALL which recommends further evaluation (See SER Section 3.6.2.2.2)
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	Not Applicable	Not Applicable- GALL Report aging effect is not applicable to OCGS. (See SER Section 3.6.2.2.3)
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	Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program (B.1.40)	Not Applicable- GALL Report aging effect is not applicable to OCGS. (See SER Section 3.6.2.3)
Fuse Holders (Not Part of a Larger Assembly) Insulation material (Item 3.6.1-14)	None	None	None	Consistent with GALL. (See SER Section 3.6.2.1)

The staff's review of the electrical components and component groups followed one of several approaches. One approach, documented in SER Section 3.6.2.1, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.6.2.2, discusses the staff's review of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, discusses the staff's review of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the electrical components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.6.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the effects of aging related to the electrical components:

- 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)
- Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)
- Wooden Utility Pole Program (B.2.6)
- Periodic Monitoring of Combustion Turbine Power Plant (B.2.7)

In its 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 SBO system combustion turbine power plant. As a result, the Periodic Monitoring of Combustion Turbine Power Plant Program was deleted. Therefore, the staff did not review this program.

Staff Evaluation. In LRA Tables 3.6.2.1.1 and 3.6.2.1.2, the applicant provided a summary of AMRs for the electrical components and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. 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 has the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant (a) provided a brief description of the system, components, materials, and environments, (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report, and (c) identified those aging effects for the electrical components subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.6.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report, for the electrical components. The applicant provided information about how it will manage the following aging effects:

- electrical equipment subject to environmental qualification
- degradation of insulator quality due to presence of any salt deposits and surface contamination, and loss of material due to mechanical wear
- loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of pre-load
- quality assurance for aging management of nonsafety-related components

Staff Evaluation. For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.6.2.2. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

3.6.2.2.1 Electrical Equipment Subject to EQ

In LRA Section 3.6.2.2.1, the applicant stated that environmental qualification is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA.

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

The staff reviewed LRA Section 3.6.2.2.5 against the criteria in SRP-LR Section 3.6.2.2.2.

In LRA Section 3.6.2.2.5, the applicant addressed degradation of insulator quality due to presence of any salt deposits and surface contamination, and loss of material due to mechanical wear.

SRP-LR Section 3.6.2.2.2 states that degradation of insulator quality due to presence of any salt deposits and surface contamination could occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP where the potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material due to mechanical wear caused by wind blowing on transmission conductors could occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of this aging effect. Acceptance criteria are described in Branch Technical Position RLSB-1 (SRP-LR Appendix A.1)

Aging Effects. LRA Section 3.6.2.1.3 lists the materials of construction for the high-voltage insulators as:

- aluminum
- cement
- galvanized steel
- malleable iron
- porcelain

The applicant stated that high-voltage insulator components are exposed to an outdoor air environment. The applicant also stated that the high-voltage insulators have no AERMs. LRA Table 3.6.1 identifies degradation of insulation quality due to the presence of any salt deposit, surface contamination, and loss of material caused by mechanical wear due to wind blowing on transmission conductors as the aging effects and mechanisms.

Salt Deposits. The applicant stated that on September 18, 2003, arcing was observed on 230 kV insulators in the OCGS switchyard. The arcing was not severe enough to cause ground faults. No protective relaying was actuated (CAP No. 02003-1925). The observations made in the switchyard are consistent with salt spray on the insulators and resulted from the unusual weather conditions during the passing of Hurricane Isabel. The high winds and waves deposited wind blown salty spray on the insulators. The electrical conductivity of the salty moisture on the insulators caused the observed flashing.

The subsequent rains washed the salt from the insulators and eliminated the problem.)CGS has not experienced any arcing leading to loss of offsite power attributable to salt contamination. Salt spray deposits on high-voltage insulators are a temporary condition and not an aging effect. They are external to the insulator and do not degrade the electrical or mechanical properties of the porcelain insulating material or its support structure. Therefore, no aging management for salt deposits is required for the period of extended operation.

The staff's review of LRA Section 3.6.2.2.5 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.6.2.2.5 dated April 20, 2006, the staff requested that the applicant provide an AMP to manage the aging effects of insulator surface contamination due to salt deposit or further justify not having an AMP.

In its response dated May 9, 2006, the applicant stated that it will implement visual inspections of high-voltage insulators to manage the aging effects of salt build-ups. These inspections will be incorporated as a revision to the Periodic Monitoring of Combustion Turbine Power Plant Electrical Program. Inspections will be by binoculars to a determined threshold for implementing corrective actions. Corrective actions include subsequent cleaning (i.e., washing) of a contaminated insulator. The visual inspections will be twice per year beginning prior to the period of extended operation. The staff finds that the applicant had adequately addressed the staff's concern. The staff identified this response as a revision to Commitment No. 43.

The applicant stated that this inspection will be incorporated as a revision to the Periodic Monitoring of Combustion Turbine Power Plant Electrical Program. The purpose of this AMP will be to demonstrate, for high-voltage insulators subject to an AMR, that the aging effects of insulator surface contamination caused by salt deposit will be adequately managed for reasonable assurance that high-voltage insulators will perform their intended function(s) consistent with the CLB during the period of extended operation.

In its May 9, 2006, letter the applicant modified the Periodic Monitoring of Combustion Turbine Power Plant Electrical Program. In order to determine whether the applicant's AMP was still adequate to manage the effect of aging to maintain the intended function consistent with the CLB for the period of extended operation, the staff reevaluated the following seven program elements: (1) "scope of program," (2) "preventive actions," (3) "parameter monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," and (10) "operating experience." The staff's evaluation of the applicant's "corrective action," "confirmation process," and "administrative controls" is provided separately SER Section 3.0.4.

(1) Scope of Program - The scope of this program includes in-scope high-voltage insulators above 34.5 kV. This scope is acceptable to the staff because the program will include all high-voltage (greater than 35 kV) insulators within the scope of license renewal.

(2) Preventive Actions - The inspection and washing of in-scope high-voltage insulators above 34.5 kV under this AMP assist in preventing faults on high-voltage circuits. These preventive actions are acceptable to the staff because the inspection and washing will provide assurance that the insulators are free from contamination and thus prevent faults on high-voltage circuits.

(3) Parameters Monitored and Inspected - Visual inspection of the in-scope high-voltage insulators above 34.5 kV will be performed by the applicant for signs of salt build-ups. The first inspection will be prior to the period of extended operations with an inspection frequency of at least twice per year. The staff finds that the visual inspection of insulators will indicate salt build-ups and that inspection frequency of at least twice per year is adequate.

(4) Detection of Aging Effects - In-scope high-voltage insulators above 34.5 kV will be checked for salt build-ups by visual inspections. If contamination is identified, the inspections will distinguish between slight, medium, and heavy levels of contamination based on the lack of a shiny surface appearance (slight), build-ups of contamination at the base of the insulators or indications of dripping (medium), or an audible noise or visible corona (heavy). Inspections will begin prior to the period of extended operation and occur twice per year thereafter. The staff finds that inspection frequency of twice per year is adequate to preclude salt deposit on high-voltage insulators.

(5) Monitoring and Trending - Monitoring of electrical commodities involves visual inspection by qualified individuals at specified intervals to determine whether there are salt build-ups on the insulators. The staff finds this monitoring acceptable because it will be performed by qualified individuals at specified intervals.

(6) Acceptance Criteria - High-voltage insulators are to be free from salt build-ups. If contamination is identified, the inspections will distinguish between slight, medium, and heavy levels of contamination based on the lack of a shiny surface appearance (slight), build-ups of contamination at the base of the insulators or indications of dripping (medium), or an audible noise or visible corona (heavy). Subsequent corrective actions will be aligned with the level of contamination. The staff finds the acceptance criterion

(insulators to be free from salt build-ups) acceptable.

(10) Operating Experience - On September 18, 2003, arcing was observed on 230 kV insulators in the OCGS switchyard. This event was entered and evaluated in the corrective action process (CAP No. 02003-1925). The arcing was not severe enough to cause ground faults. No protective relaying was actuated. There was no associated loss of offsite power to OCGS. The observations made in the switchyard are consistent with salt spray on the insulators. This occurrence was the result of unusual weather conditions during the passing of Hurricane Isabel. The high winds and waves deposited wind-blown salt spray on the insulators. The electrical conductivity of the salty moisture on the insulators caused the observed flashing. OCGS has not experienced any arcing leading to loss of offsite power events attributable to salt contamination. The staff finds that the proposed program will provide reasonable assurance that the high-voltage insulators will be free from salt build-ups.

Contamination. The applicant stated that other external substances, including dust or animal contamination, could temporarily contaminate an insulator and cause an electrical path to be formed. Such deposits are temporary and not an aging effect because they are external to the insulator and do not degrade the electrical or mechanical properties of the porcelain insulating material or its support structure. The buildup of surface contamination is gradual. This contamination is washed away by rain or snow; the glazed insulator surface aids this contamination removal. Surface contamination can be a problem in areas with great concentrations of airborne particles as near facilities that discharge soot. OCGS is located in an area where industrial airborne particle concentrations are comparatively low, not in a heavily industrialized area. Minor contamination is washed away by rainfall or snow, and cumulative buildup has not been experienced and is not expected to occur. Therefore, no aging management activities for surface contamination are required for the period of extended operation.

On the basis of its review, the staff finds that surface contamination is not a problem for OCGS because it is not located in a heavily industrialized area. Therefore, the staff determined that no aging management activities for surface contamination are required for the period of extended operation.

Wear. The applicant stated that mechanical wear applies to strain and suspension type insulators if they are subject to significant movement. Movement of the insulators can be caused by wind blowing on the supported transmission conductor, causing it to swing from side to side. If frequent enough, this swinging could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, experience has shown that the transmission conductors do not normally swing significantly. When they do swing due to a substantial wind, they do not continue to swing for very long after the wind has subsided. Wind loading that can cause a transmission line and insulators to sway is considered in the design and installation. Therefore, the loss of material due to wear is not considered an aging effect that will cause a loss of intended function of the insulators. Therefore, loss of material due to wear is not an applicable aging effect for insulators.

On the basis of its review, the staff finds that the high-voltage insulators are not subject to significant movement and concludes that loss of material due to wear is not an applicable aging effect for insulators.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.6.2.2.2. For those line items that apply to LRA Section 3.6.2.2.5, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained, consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Pre-Load

The staff reviewed LRA Section 3.6.2.2.6 against the criteria in SRP-LR Section 3.6.2.2.3.

In LRA Section 3.6.2.2.6, the applicant addressed loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of pre-load.

SRP-LR Section 3.6.2.2.3 states that loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of pre-load could occur in transmission conductors and connections and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of this aging effect.

Aging Effects. LRA Section 3.6.2.1.4 lists the materials of construction for transmission conductors and connections as aluminum and steel.

The applicant stated that transmission conductors and connections are exposed to an outdoor air environment and that the transmission conductors and connections have no AERMs. LRA Table 3.6.1 identifies loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of pre-load as the aging effects and mechanisms.

Loss of Conductor Strength and Wind-Induced Abrasion and Fatigue. The applicant stated that tests by Ontario Hydroelectric showed a 30-percent loss of composite conductor strength of an 80-year old aluminum conductor-steel reinforced (ACSR) conductor due to corrosion. Using the example of a 4/0 ACSR conductor, EPRI 1003057 shows the ultimate strength and the National Electrical Safety Code (NESC) heavy load tension requirements of 4/0 ACSR as 8350 and 2761 pounds, respectively. The margin between the NESC heavy load and the ultimate strength is 5589 pounds (67 percent of ultimate strength margin). The Ontario Hydroelectric study showed a 30-percent loss of composite conductor strength in an 80-year old conductor. In the case of the 4/0 ACSR transmission conductor, a 30-percent loss of ultimate strength would mean that there still would be a 37 percent ultimate strength margin between what is required by the NESC and the actual conductor's strength.

There is a set percentage of composite conductor strength established at which a transmission conductor is replaced. NESC recommends that tension on installed conductors be limited to a maximum of 60 percent of the ultimate conductor's strength. The NESC also sets the maximum tension a conductor must be designed to withstand under various load requirements considering ice, wind, and temperature. Therefore, for a typical transmission conductor, there is an ample design margin to offset the loss of strength due to corrosion and maintain the transmission conductor's intended function through the period of extended operation.

The staff's review of LRA Section 3.6.2.2.6 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAIs as discussed below.

In RAI 3.6.2.2.6-2 dated April 20, 2006, the staff requested that the applicant explain why the Ontario Hydroelectric study applies to OCGS. In its response dated May 9, 2006, the applicant stated that in-scope transmission conductors have a minimum size of 397.5 ACSR and are specified and installed in accordance with NESC. It is conservative to assume the same 80-year 30-percent loss of composite conductor strength for the transmission conductors because the Ontario Hydroelectric tests were for a conservative heavy loading zone. A 397.5 ACSR conductor has a minimum ultimate strength of 9900 pounds. Applying NESC requirements for maximum design line loading accounting for wind and ice (< 60 percent) and initial unloaded tension limits (< 35 percent) the 397.5 ACSR conductors have a minimum heavy load tension ratio of 65 percent. If the conservatively assumed 30-percent loss of composite conductor strength is deducted, the bounding ultimate resulting strength margin is 35 percent. This minimum strength margin for the transmission conductors is sufficient and wind loading and fatigue are not applicable aging mechanisms affecting the intended function of transmission conductors. Based on its review, the staff's concern described in RAI 3.6.2.2.6-2 is resolved.

Corrosion of a steel core caused by loss of zinc coating or aluminum strand pitting corrosion is a very slow-acting aging effect even slower for areas with fewer suspended particles and sulphur dioxide concentrations in the air than in urban or industrial areas. OCGS transmission conductors do not have air particulate or contaminants as in urban or heavy industrial areas. Therefore, corrosion is not an aging mechanism for their intended function. EPRI 1003057 discusses the aging of high-voltage transmission conductors and concludes that the potential aging mechanism of vibration has no significant effects of concern for their intended function. Wind-loading induced vibration is considered in the design and installation. Aging effects of loss of material and fatigue from transmission conductor vibrations or sways would cause no loss of intended function for the period of extended operation. Experience shows that the transmission conductors do not normally swing significantly. When they do swing due to a substantial wind, they do not continue to swing for very long after the wind has subsided. Wind loading that can cause a transmission line to sway is considered in the design and installation. Therefore, wind-loading induced vibration and fatigues are not credible aging mechanisms, and will not cause a loss of intended function of the conductors.

On the basis of its review, the staff finds that outdoor air on aluminum and steel will not result in aging of concern during the period of extended operation. Corrosion is a slow process. Operating experience has found no failure of transmission conductors due to vibration. Therefore, the staff concludes that there are no applicable AERMs for transmission conductors.

Loss of pre-load. The applicant stated that pre-load of bolted connections is maintained by the appropriate design and the use of lock and Belleville washers that absorb vibration and prevent loss of pre-load.

The staff's review found that torque relaxation for bolted connections is a concern for transmission conductor connections. An electrical connection must be designed to remain tight and maintain good conductivity through a wide temperature range. This design requirement is difficult to meet if the materials specified for the bolt and conductor differ and therefore have different rates of thermal expansion. For example, copper or aluminum bus/conductor materials expand faster than most bolting materials. If thermal stress is added to stresses inherent at assembly, the joint members or fasteners can yield. If plastic deformation occurs during thermal loading (i.e., heat up) the joint will be loose when the connection cools.

EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," recommends inspection of bolted joints for evidence of overheating, signs of burning or discoloration, and indications of loose bolts.

In RAI 3.6.2.2.6-1 dated April 20, 2006, the staff requested that the applicant discuss why torque relaxation for bolted connection was not a concern. In its response on May 9, 2006, the applicant stated that the connections at switchyard equipment, transformers (including the in-scope startup and SBO transformers), the startup transformer regulators, and disconnect switches are also periodically evaluated via thermography as preventive maintenance. From the design in accordance with EPRI-104213, periodic monitoring through existing preventive maintenance, and no adverse operating experience, the applicant concluded that there are no additional evaluations or actions required to address the aging mechanism of torque relaxation for bolted connections for transmission conductors. On June 2, 2006, the applicant clarified "periodic" as at least twice per year. The staff's concern described in RAI 3.6.2.2.6-1 is resolved.

Based on the Preventive Maintenance Program identified above to verify the bolted connections, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.6.2.2.3. For those line items that apply to LRA Section 3.6.2.2.3, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained, consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.4 QA for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program for safety-related and nonsafety-related components. The staff concluded that the program descriptions of the "corrective action," "confirmation process," and "administrative controls" attributes are acceptable.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report, for which the applicant had claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff concludes that the applicant has adequately addressed the issues that required further evaluation. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.6.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.6.2.1.1 and 3.6.2.1.2, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.6.2.1.1 and 3.6.2.1.2, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is discussed in the following sections.

Electrical Commodity Groups – LRA Table 3.6.2.1.1

The staff reviewed LRA Table 3.6.2.1.1, which summarizes the results of AMR evaluations for the electrical component and commodity groups.

Cable Connections - Metallic Parts. In LRA Section 3.6.2.3.3, the applicant stated that an evaluation of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation stressors for the metallic parts of electrical cable connections identified none that require aging management.

Aging Effects. LRA Section 3.6.2.1.7 lists the materials of construction for cable connections as various metals used for electrical connections. The applicant stated that cable connections are exposed to containment atmosphere, indoor air, and outdoor air environments and that cable connections have no AERMs. The applicant identified thermal cycling, ohmic heating and electrical transients, vibration, chemical contamination, oxidation, and corrosion as the aging mechanisms and stated why these stressors are not applicable.

The staff reviewed the aging mechanisms identified by the applicant and found them acceptable as consistent with those listed in GALL Report Table 3.6-1.

The applicant stated that the only metallic parts of its electrical cable connections that could potentially be exposed to thermal cycling and ohmic heating are those that carry significant current in power supply circuits. Power supply cables are typically installed in a continuous run from the supply (e.g., switchgear) to the load (e.g., motor). The metallic parts of connections to the supply and load are therefore parts of, or internal to, active components (e.g., switchgear and motor) and therefore not subject to aging management.

The staff found that GALL AMP XI.E6, "Electrical Cable Connections not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specifies that connections to cables within the scope of license renewal are parts of this program regardless of active or passive components.

The staff's review of LRA Table 3.6.2.1.1 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.6.2.3.3 dated April 20, 2006, the staff requested that the applicant provide an AMP with the 10 elements to manage the aging effects for the period of extended operation or additional justification for not requiring an AMP.

In its response dated May 9, 2006, the applicant stated that, before the period of extended operation, it will develop and implement an AMP to manage the aging effects (i.e., loosening of metallic connections) of electrical connections, including those with active components and that this new AMP will manage the aging effects of metallic parts of non-EQ electrical cable connections within the scope of license renewal. The purpose of this AMP will be to demonstrate, for electrical cable connections subject to AMR, that the aging effects caused by thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation of the metallic parts will be adequately managed so that there is reasonable assurance that electrical cable connections will perform their intended function in accordance with CLB during the period of extended operation. The staff's concern described in RAI 3.6.2.3.3 is resolved. The staff identified this commitment as Commitment No. 64.

In its May 9, 2006, letter the applicant created a new AMP, the Electrical Cable Connecting - Metallic Parts - Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, that will manage the aging effects of electrical connections. In order to determine whether the applicant's AMP adequately manages the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven 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," and (10) "operating experience." The staff's evaluation of this AMP is documented in SER Section 3.0.3.1.10. The staff's evaluation of the applicant's "corrective action," "confirmation process," and "administrative controls" is documented separately in SER Section 3.0.4.

Based on the programs identified above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.6.2.3. For those line items that apply to LRA Section 3.6.2.3.3, the staff determined that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained, consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). On the basis of its review of the UFSAR supplement for this program, the staff finds that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

Fuse Holder. In LRA Section 3.6.2.3.1, the applicant stated that the only in-scope fuse holders not parts of a large assembly are the scram solenoid fuse holders located in panels ER7A through ER7H in the reactor building at elevation 23' 6". An evaluation of moisture, chemical contamination, oxidation and corrosion, mechanical stresses, electrical transients, thermal cycling, and fatigue stressors for these fuse holders identified none that require aging management.

Aging Effects. LRA Section 3.6.2.1.5 lists the materials of construction for fuse holders as:

- copper alloy (metallic clamps)
- insulation materials - Bakelite, phenolic, melamine or ceramic, molded polycarbonate,

and other

The applicant stated that fuse holders are exposed to indoor air environments and that they have no AERMs. The applicant identified moisture, chemical contamination, oxidation and corrosion, mechanical stresses, electrical transients, thermal cycling, and fatigue as the aging mechanisms and stated why these stressors are not applicable. The staff reviewed the aging mechanisms identified by the applicant and found them acceptable as consistent with those listed in GALL Report Table 3.6-1. The staff reviewed the applicant's evaluation as discussed below.

Moisture. The applicant stated that the fuse holders requiring an AMR are protected from external sources of moisture by two barriers. The first is the reactor building itself. Panels ER7A through ER7H inside the reactor building at elevation 23' 6" during normal conditions are not in adverse localized areas of high temperature or humidity. They are protected from weather variations and not subject to significant temperature variations. The second barrier is the closed panels in which the fuse holders are mounted. As to internal moisture (i.e., formation of condensation), a walk down revealed no signs of moisture or humidity in the area or within the enclosures.

The staff's review of LRA Section 3.6.2.3.1 identified areas in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAIs as discussed below.

In RAI 3.6.2.3.1-1 dated April 20, 2006, the staff requested that the applicant explain how the rooms containing fuse holders are protected from weather variations. In its response dated May 9, 2006, the applicant stated that fuse panels ER7A through ER7H are located inside the power block, in the reactor building, on elevation 23' 6". The environment in the reactor building is controlled within the design limits by the reactor building heating and ventilation system and is not subject to significant temperature variations. The staff's concern described in RAI 3.6.2.3.1-1 is resolved.

In RAI 3.6.2.3.1-2 dated April 20, 2006, the staff requested that the applicant provide details about the walk down (number and condition of fuse holders inspected, etc.). In its response dated May 9, 2006, the applicant stated that in a walk down of the eight fuse panels within the scope of license renewal there were no signs of moisture or humidity in the areas of the fuse panels or signs of moisture or corrosion on the exterior or interior of the enclosures. All of the fuse holders within each of the eight in-scope fuse panels were visually inspected (roughly 300 fuses holders). There were no observable signs of fuse holder fatigue or strain. Two chipped fuse blocks (Bakelite dielectric material) were identified, entered into the corrective action process, and evaluated as insignificant and nonimpacting for the fuse block function in that the Bakelite still provides adequate separation so there is no immediate concern about a dielectric breakdown. The staff's concern described in RAI 3.6.2.3.1-2 is resolved.

Chemical Contamination. The applicant stated that the fuse holders are protected from chemical contamination by their location and design. There are no sources of chemicals in the vicinity of the fuse panels.

On the basis of its review, the staff finds that fuse holders are protected from chemical contamination and, therefore, there are no applicable AERMs for fuse holder metallic parts.

Oxidation and Corrosion. The applicant stated that fuse holders are made of copper or copper alloy plated with a corrosion-resistant material to protect the base metal from oxidation and provide for low electrical resistance. The fuse holders experience no appreciable change in operating conditions and are not exposed to a heavy industrial or oceanic environment because they are protected. The fuse holders evaluated are not near any humid areas, and therefore this stressor is not applicable.

On the basis of its review, the staff finds that oxidation and corrosion on copper or copper alloy plated with a corrosion-resistant material will not result in aging of concern during the period of extended operation. Therefore, the staff concludes that there are no appreciable AERMs for a fuse holder exposed to oxidation and corrosion.

Mechanical Stresses, Electrical Transients, Thermal Cycling, Fatigue. The applicant stated that mechanical stresses, electrical transients, thermal cycling, and fatigue do not cause AERMs for the following reasons:

(1) Mechanical stress due to forces from electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered an aging mechanism because such faults are infrequent and random. The corrective action process documents adverse conditions and provides corrective actions for electrical faults and transients that actuate the circuit protective devices.

(2) The scram discharge solenoid fuses stay energized during normal operation and do not experience frequent cycling. The loading on these fuses is below 60 percent of rated capacity. NUREG-1760, "Aging Assessment of Safety-related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants," identifies 60 percent loading as a critical value for fuses because at this value enough heat is generated to damage the fuse blocks and connections. The scram solenoids draw only about 10.5 watts, and the fuses are rated for 3 amps. Therefore, these fuses are lightly loaded. Inspection of sample fuses revealed no age-related degradation, and the fuse clips exhibited no any signs of degradation.

(3) Vibration is induced in fuse holders by the operation of such external equipment as compressors, fans, and pumps and is not an applicable aging mechanism because panels ER7A through ER7H are mounted on concrete walls with no such attached sources.

(4) By design and location, the fuse holders are not subject to aging effects of thermal cycling except during testing or a scram. The scram solenoid fuses are continuously and lightly loaded and experience an insignificant temperature rise.

(5) Wear and fatigue are caused by repeated insertion and removal of fuses. The scram solenoid fuses are not subject to frequent manipulations. When these circuits need to be de-energized, power is removed at the safety-related power supplies. When manipulated an inspection would identify any abnormal indication like loose or corroded fuse clips. Fatigue also may be caused by frequent cycling of fuses when subject to significant loading which could cause the clips to expand and contract and result in fatigue failure. By design, the subject fuses do not experience operational cycling during normal service and are lightly loaded. Therefore, fatigue is not an aging concern.

The staff's review of LRA Section 3.6.2.3.1 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.6.2.3.1-3 dated April 20, 2006, the staff requested that the applicant discuss the disconnection means at the SR power supplies and how often the fuses are manipulated and the reasons for manipulation.

In its response dated May 9, 2006, the applicant stated that these circuits are powered by the reactor protection system power supplies. The reactor protection system power is supplied through two independent buses. Each panel supplies power to one logic channel and its pilot and backup scram valve solenoids, one half of the in-core flux amplifiers, one half of the steam line radiation monitors, and one half of the flux amplifiers. A single breaker on each panel powers the scram solenoids and logic system. Routine reactor protection system testing does not include de-energization of scram solenoid circuits. Isolation is accomplished via the valve air supply. The scram solenoid fuses are removed only when corrective maintenance is required (estimated at once in a 15-year span). Manipulation of these fuses would occur only during required corrective maintenance or replacement of a blown fuse. Fuse Control Procedure CC-AA-206 provides instruction for fuse replacements to ensure continuity, tightness and condition (no cracks) of end caps, no corrosion, proper installation, tightness of clips, and firm contact with fuse end caps.

On the basis of its review, the staff finds that mechanical stresses, electrical transients, vibration, thermal cycling, and fatigue do not cause AERMs for a fuse holder metallic parts. The staff's concern described in RAI 3.6.2.3.1-3 is resolved.

On the basis of its review, the staff finds that the applicant has demonstrated that the effects of aging for fuse holders 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).

<u>Non-Class 1E Electrical Penetration</u>. The electrical penetration assemblies are comprised of insulated electrical conductors and seals for the passage of the conductors through a sleeve in the primary containment to provide a pressure barrier between the containment and outside areas. The penetrations are pressurized with nitrogen during normal plant operation. Epoxy potting provides sealing and various insulating materials provide electrical insulation. As demonstrated by the applicant's environmental qualification files, all components of the electrical penetration assemblies have been evaluated for the effects of heat, radiation, moisture, and oxygen and determined to have a qualified life greater than or equal to 60 years.

The applicant concluded that because the non-EQ electrical penetrations are the same as the EQ electrical penetrations, and the EQ penetrations have been shown to have a qualified life of 60 years, the non-EQ electrical penetrations are also qualified for a 60-year life. Consequently, there are no AERMs for the non-EQ electrical penetrations. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be applied to cables entering electrical penetrations (pigtails) because they could experience adverse localized environments.

<u>*Aging Effects*</u>. LRA Section 3.6.2.1.2 lists the materials of construction for electrical penetrations as:

- epoxy potting

- various organic polymers (e.g., XLPE, EPR, PVC, ETFE)

The applicant stated that electrical penetrations are exposed to adverse localized and containment atmosphere environments. The applicant also stated that the following aging effects of the electrical cable insulation external to the penetrations require management: embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance; electrical failure due to thermal/thermoxidative degradation of organics; radiolysis and photolysis (ultraviolet sensitive materials only) of organics; radiation-induced oxidation; and moisture intrusion.

The staff reviewed the aging mechanisms stated by the applicant and found them acceptable as consistent with those listed in GALL Report Table 3.6-1. The staff agreed that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program will adequately manage non-Class 1E penetrations pigtails for the period of extended operation.

The applicant stated that because the environments of the non-EQ electrical penetrations are the same as those of the EQ electrical penetrations, and the EQ penetrations have been shown to have a qualified life of 60 years, non-EQ electrical penetrations are also qualified for a 60-year life.

The staff's review of LRA Section 3.6.2.3.2 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.6.2.3.2 dated April 20, 2006, the staff requested that the applicant confirm that non-EQ electrical penetrations will be exposed to same environments as those of the EQ penetrations. On May 9, 2006, the applicant stated that EQ electrical penetration is bounding in that it encompasses all of the environmental limits to which both EQ and non-EQ electrical penetrations are exposed. With this statement, the staff's concern described in RAI 3.6.2.3.2 is resolved.

On the basis of its review, the staff finds that the applicant has demonstrated that the effects of aging for non-Class 1E electrical penetration 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).

Uninsulated Ground Conductors. The plant grounding and lightning protection system is designed to provide a low-impedance path to ground for fault currents and lightning strokes. The applicant stated that based on industry and plant-specific experiences, no AERMs were identified for uninsulated ground conductors.

Aging Effects. LRA Section 3.6.2.1.8 lists the material of construction for uninsulated ground conductors as copper.

The applicant stated that uninsulated ground conductors are exposed to containment atmosphere, indoor air, and outdoor air environments. The applicant also stated that the uninsulated ground conductors have no AERMs. Copper is a good choice for this application because of its high electrical conductivity, high fusing temperature, and high corrosion resistance. Copper is also relatively strong and easy to join by welding, compression, or clamping. Ground connections are commonly made with welds or mechanical-type connectors, including compression-, bolted-, and wedge-type devices.

Review of available industry technical information on material aging revealed no AERMs for copper grounding materials. In addition, a review of industry and plant operating experiences identified no failures of copper ground systems due to aging effects. A complete survey of OCGS grounding systems in 1988 in accordance with IEEE STD 81-1983 showed adequate grounding and routine inspections of the lightning protection system have identified no degradation due to aging effects.

The staff's review of LRA Section 3.6.2.3.4 identified an area in which additional information was necessary to complete the review of the applicant's AMR results. The applicant responded to the staff's RAI as discussed below.

The staff found that torque relaxation for bolted connections is a concern for ground connections. An electrical connection must be designed to remain tight and maintain good conductivity through a wide temperature range. This design requirement is difficult to meet if the materials specified for the bolt and conductor differ and therefore have different rates of thermal expansion. For example, copper or aluminum conductor materials expand faster than most bolting materials. If thermal stress is added to stresses inherent at assembly, the joint members or fasteners can yield. If plastic deformation occurs during thermal loading (i.e., heatup) the joint will be loose when the connection cools. EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," recommends inspection of bolted joints for evidence of overheating, signs of burning or discoloration, and indications of loose bolts.

In RAI 3.6.2.3.4 dated April 20, 2006, the staff requested that the applicant discuss why torque relaxation for bolted connection was not a concern. In its response dated May 9, 2006, the applicant stated that its ground connections do not experience thermal stresses from the environment or operating conditions. Extremely gradual environmental temperature changes experienced by ground conductors and connections reflect gradual weather or environmentally-induced temperature changes. Ground conductors and connections normally see no current. Under fault conditions, current would flow for a brief period of time and would not cause ohmic heating or related current-induced thermal stresses. As such, these connections do not experience thermal stresses necessary to affect the bolted ground connections. The material for ground conductors is copper, which has high resistance to corrosion. With this discussion, the staff's concern described in RAI 3.6.2.3.4 is resolved.

On the basis of its review, the staff finds that the applicant has demonstrated that the effects of aging for uninsulated ground conductors 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).

Conclusion. On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results involving material, environment, AERMs, and AMP combinations that are not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.6.3 Conclusion

The staff concludes that the applicant had 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).

3.7 Aging Management of Forked River Combustion Turbines (FRCT), Radio Communications System, and Meteorological Tower (Met Tower) Electrical, Mechanical, and Structural Systems and Components

This section of the SER documents the staff's review and evaluation of the SBO FRCT, radio communications system, and Met Tower AMR results for the aging management of the electrical, mechanical, and structural components and component groups associated with these systems.

3.7.1 Summary of Technical Information in the Application

3.7.1.1 Electrical Components

In Appendix C of its response to RAI 2.5.1.19-1 dated October 12, 2005, the applicant provided the results of its AMRs for the FRCT electrical system components and component groups.

In Table 3.6.1A of the October letter, the applicant provided a summary comparison of its AMR line items with the AMR line items evaluated in the GALL Report for the FRCT electrical system components and component groups. For each component type in Table 3.6.1A, the applicant also identified those AMRs consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those not addressed in the GALL Report together with the bases for their exclusion.

In Table 3.6.2.1.2A of the letter, the applicant provided the AMR results for electrical component types of the FRCT electrical components and systems. Specifically, the information for each component type included the intended function, material, environment, AERM, AMPs, the GALL Report Volume 2 item cross-referenced to Table 3.6.1A (Table 1), and generic and plant-specific notes on consistency with the GALL Report.

3.7.1.2 Mechanical Components

In Appendix C of its supplemental response to RAI 2.5.1.19-1 dated November 11, 2005, and its response to RAI 2.5.1.15-1 dated December 9, 2005, the applicant provided the results of its AMRs for the FRCT and radio communications mechanical system components and component groups, respectively.

In Table 3.6.1B of the November letter and Table 3.6.1D of the December letter, the applicant provided a summary comparison of its AMR line-items with those evaluated in the GALL Report for the mechanical system components and component groups. The applicant also identified, for each component type, AMRs consistent with the GALL Report and those for which the GALL Report recommends further evaluation.

In Tables 3.6.2.1.2B of the November letter and 3.6.2.1.3 of the December letter, the applicant provided the AMR results for mechanical component types of the FRCT and the radio communications system, respectively. Specifically, the information for each component type included the intended function, material, environment, AERM, AMPs, the GALL Report Volume 2 item cross-referenced to Table 3.6.1B or 3.6.1D (Table 1), and generic and plant-specific notes on consistency with the GALL Report.

3.7.1.3 Structural Components

The applicant provided the results of its AMRs for the structural components of the FRCT in its October letter. 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 Met Tower structural components in its December letter. For the meteorological tower structural components, the applicant included a summary of LRA Section 3.5.2.1.20, "Meteorological Tower Structures," and the following new tables:

- Table 3.6.1D, "Summary of Aging Management Evaluations"
- Table 3.5.2.1.20, "Meteorological Tower Structures"
- Table 3.6.2.1.3, "Radio Communications System"

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.

3.7.2 Staff Evaluation

The staff reviewed the AMRs to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the FRCT, radio communications, and Met Tower systems components 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 staff reviewed certain identified AMR line items to confirm the applicant's claim that these AMR line items were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the response to RAIs 2.5.1.15-1 and 2.5.1.19-1 was applicable and that the applicant had identified the appropriate GALL Report AMR line items. The staff's evaluation is documented in SER Section 3.7.2.1. In addition, the staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed those selected AMR line items for which further evaluation is recommended by the GALL Report. The staff confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in the SRP-LR. The staff's evaluation is documented in SER Section 3.7.2.2.

The staff also reviewed the remaining AMR line items not consistent with or not addressed in the GALL Report. The staff's evaluations are documented in SER Section 3.7.2.3.

Finally, the staff 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 these systems.

Table 3.7-1 below provides a summary of the staff's evaluation of the components, aging effects and mechanisms, and AMPs listed in the applicant's AMRs for the FRCT, radio communications, and Met Tower systems addressed in the GALL Report.

Table 3.7-1 Evaluation for FRCT, Radio Communications, and Met Tower Electrical, Mechanical, and Structural System 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	Not applicable	Not applicable. FRCT has no EQ components
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	Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	Consistent with GALL. (See SER Section 3.7.2.1)
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	Not applicable	Not applicable. FRCT has no instrumentation circuits.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 (B.1.36)	Consistent with GALL. (See SER Section 3.7.2.1)
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	GALL aging effect is not applicable to OCGS. (See SER Section 3.6.2.3)
Metal enclosed bus - Bus/connections (Item 3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus	Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	Consistent with GALL. (See SER Section 3.7.2.1)
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	Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	Consistent with GALL. (See SER Section 3.7.2.1)
Metal enclosed bus - Enclosure assemblies (Item 3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See SER Section 3.7.2.1)
Metal enclosed bus - Enclosure assemblies (Item 3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See SER Section 3.7.2.1)
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 aging management program is to be evaluated	Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	Consistent with GALL. (See SER Section 3.6.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	GALL aging effect is not applicable to OCGS. (See SER Section 3.6.2.2.3)
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	Electrical Cable Connections - Metallic Parts - Not subject to 10 CFR 50.49 Environmental Requirements (B.1.40)	Consistent with GALL. (See SER Section 3.6.2.3.1)
Fuse Holders (Not Part of a Larger Assembly) Insulation material (Item 3.6.1-14)	None	None	None	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.39) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL, which recommends further evaluation. (See SER Section 3.7.2.2.3)
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 (B.1.39) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.4)
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 (B.1.25A)	Consistent with GALL. (See SER Section 3.7.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff 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 SER Section 3.7.2.1)
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 aging management program is to be evaluated.	Periodic Inspection - FRCT (B.2.5A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.5)
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 aging management program is to be evaluated	Periodic Inspection - FRCT (B.2.5A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.6)
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 Analysis - FRCT (B.1.39) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.7)
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 aging management program is to be evaluated	Periodic Inspection - FRCT (B.2.5A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.7)
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 microbiologically influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection - FRCT (B.1.26A) and Aboveground Outdoor Tanks - FRCT (B.1.21A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.8)
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 microbiologically influenced corrosion, and fouling	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry - FRCT (B.1.22A) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.9)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel heat exchanger components exposed to lubricating oil (Item 3.3.1-21)	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis - FRCT (B.1.39) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.9)
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 aging management program is to be evaluated.	Periodic Inspection - FRCT (B.2.5A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.10)
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 microbiologically influenced corrosion	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry - FRCT (B.1.22A) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL (aluminum and copper alloy), which recommends further evaluation (See SER Section 3.7.2.2.11)
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 microbiologically influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis - FRCT (B.1.39) and One-Time Inspection - FRCT (B.1.24A)	Consistent with GALL, which recommends further evaluation (See SER Section 3.7.2.2.11)
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 SER Section 3.7.2.1.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.7.2.1.3)
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 Outdoor Tanks - FRCT (B.1.21A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.12A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 - FRCT (B.1.12A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.14A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.14A)	Consistent with GALL. (See SER Section 3.7.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 (B.1.14A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.14A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.14A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 Program (B.1.31)	Acceptable since the Structures Monitoring Program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See SER Section 3.7.2.1.2)
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 Program (B.1.31)	Acceptable since the Structures Monitoring Program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See SER Section 3.7.2.1.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 Program (B.1.31)	Acceptable since the Structures Monitoring Program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See SER Section 3.7.2.1.2)
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 Program (B.1.31)	Acceptable since the Structures Monitoring Program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See SER Section 3.7.2.1.2)
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	Structures Monitoring Program (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 SER Section 3.7.2.1.1)
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) microbiologically influenced corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.1.38)	Consistent with GALL. (See SER Section 3.7.2.1)
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 SER Section 3.7.2.1)

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 3.3.1-78)	None	None	None	Consistent with GALL. (See SER Section 3.7.2.1)
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 - FRCT (B.1.25A)	Consistent with GALL. (See SER Section 3.7.2.1)
Galvanized steel piping, piping components, and piping elements exposed to air -indoor uncontrolled (Item 3.3.1-92)	None	None	None	Consistent with GALL. (See SER Section 3.7.2.1)
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 SER Section 3.7.2.1)
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 SER Section 3.7.2.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.3.1-96)	None	None	None	Consistent with GALL. (See SER Section 3.7.2.1)

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	Consistent with GALL. (See SER Section 3.7.2.1)
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 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 SER Section 3.7.2.2.8)
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 (B.1.14A)	Consistent with GALL. (See SER Section 3.7.2.1)
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 (B.1.31)	Consistent with GALL. (See SER Section 3.7.2.1)
All Groups except Group 6: accessible and inaccessible interior/exterior concrete, steel and Lubrite components (Item 3.5.1-21)	All types of aging effects	Structures Monitoring	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See SER Section 3.7.2.1)
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 SER Section 3.7.2.1)

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 SER Section 3.7.2.1)
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. (See SER Section 3.7.2.1)
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. (See SER Section 3.7.2.1)
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. (See SER Section 3.7.2.1)
All Groups: support members: anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc. (Item 3.5.1-23)	Aging of component supports	Structures Monitoring	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See SER Section 3.7.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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 SER Section 3.7.2.1)
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 mechanisms	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See SER Section 3.7.2.1)
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 SER Section 3.7.2.1)

3.7.2.1 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 staff conducted its audit and review to determine whether the applicant's reference to the GALL Report in the LRA is acceptable.

In Appendix C of its October letter, the applicant identified the materials, environments, and AERMs for the FRCT electrical systems. 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)

In Appendix C of its November and December letters, the applicant identified the materials, environments, and AERMs for the FRCT and radio communications mechanical components, respectively. The applicant identified the following programs that manage the aging effects related to these mechanical systems:

- Bolting Integrity - FRCT (B.1.12A)
- Closed-Cycle Cooling Water System - FRCT (B.1.14A)
- Aboveground Outdoor 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)
- Buried Piping Inspection-Met Tower (B.1.26B)

In Appendix C of its November and December letters, the applicant identified the materials, environments, and AERMs for the FRCT and Met Tower structural components. The applicant identified the Structures Monitoring Program to manage the aging effects of the FRCT and Met Tower structural components for all the AMR line items consistent with the GALL Report. The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.

Staff Evaluation. The staff reviewed the FRCT, radio communications, and Met Tower AMR line items to determine whether the applicant had (1) provided a brief description of the system, components, materials, and environment, (2) stated that the applicable aging effects had been reviewed and are evaluated in the GALL Report, and (3) identified those aging effects subject to an AMR.

SER Sections 3.7.2.1.1 through 3.7.2.1.3 document the resolution of discrepancies identified by the staff during its audit of those AMRs that the applicant claimed are consistent with the GALL Report and for which no further evaluation is recommended.

3.7.2.1.1 Increased Hardness, Shrinkage, and Loss of Strength Due to Weathering

In the applicant's December letter, Table 3.5.2.1.20 for the Met Tower includes 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 with the Structures Monitoring Program. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report but a different AMP was credited. The GALL Report recommends GALL AMP XI.M26, "Fire Protection Program," to manage this aging effect.

The staff reviewed the applicant's Structures Monitoring Program and verified that it includes visual inspections of component external surfaces to detect aging degradation of elastomer components. The staff concludes that this AMP is consistent with the recommendations in GALL AMP XI.M26 and 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 staff finds that the applicant appropriately addressed hardening and loss of strength due to elastomer degradation for elastomer components in the Met tower systems.

3.7.2.1.2 Loss of Material Due to General Corrosion

In the applicant's November letter, Table 3.6.2.1.2B for the SBO system includes AMR line items for loss of material due to general corrosion of 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 with the Structures Monitoring Program. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report but a different AMP was credited. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to manage this aging effect.

The staff reviewed the applicant's Structures Monitoring Program and verified that it includes activities consistent with GALL AMP XI.M36 to manage the loss of material in components exposed to an indoor air external environment. The staff concludes that the Structures Monitoring Program 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 staff finds that the applicant appropriately addressed loss of material due to general corrosion of the external surfaces of components constructed of carbon and low-alloy steel exposed to indoor air (uncontrolled) in the FRCT systems.

3.7.2.1.3 Loss of Material Due to General, Pitting and Crevice Corrosion and Loss of Preload

In the applicant's October letter, Table 3.6.2.1.2C for the SBO system includes AMR line items for loss of material due to general, pitting, and crevice corrosion and loss of preload for bolting constructed of carbon, low alloy, and galvanized steel exposed to outdoor or indoor air (uncontrolled). The applicant proposed to manage this aging effect with the Structures Monitoring Program. Generic Note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report but a different AMP was credited. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to manage this aging effect.

The staff reviewed the applicant's Structures Monitoring Program and verified that it includes activities 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 staff concludes that the Structures Monitoring Program 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 staff finds 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 staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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).

3.7.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Information in the Application. In its October letter, Table 3.6.1A, the applicant provided further evaluation of aging management as recommended by the GALL Report for the FRCT electrical system components and component groups. The applicant also provided information about how it will manage the related aging effects.

In its November letter, Table 3.6.1B, the applicant supplemented its response and 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 about how it will manage the related aging effects. In its December letter, Table 3.6.1D, the applicant's summary of AMRs for the radio communications system mechanical components and component groups does not include any AMRs for which further evaluation of aging management is recommended by the GALL Report.

In its responses to RAIs 2.5.1.19-1 and 2.5.1.15-1, Tables 3.6.1C and 3.6.1D, the applicant's summary of AMRs for the FRCT and Met Tower structural components and component groups, respectively, does not include any AMRs for which further evaluation of aging management is recommended by the GALL Report.

Staff Evaluation. For some AMR line items, the GALL Report recommends further evaluation. When further evaluation is recommended, the staff reviews these further evaluations against the criteria in the corresponding SRP-LR section. The staff's assessment of these evaluations is documented in this section. These assessments are applicable to each AMR line item citing the item in Tables 3.6.1A, 3.6.1B, 3.6.1C, or 3.6.1D.

3.7.2.2.1 Degradation Due to Various Aging Mechanisms - Electrical Components

The staff reviewed FRCT Table 3.6.1A, item 3.6.1-1, against the criteria in SRP-LR Section 3.6.2.2.1.

In FRCT Table 3.6.1A, item 3.6.1-1, the applicant addressed FRCT electrical equipment EQ.

SRP-LR Section 3.6.2.2.1 states that 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)(1). The evaluation of this TLAA is addressed separately in SRP-LR Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment."

FRCT Table 3.6.1A, item 3.6.1-1 states that EQ is not applicable. FRCT contains no components subject to 10 CFR 50.49 EQ requirements. The staff verified that there are no components subject to 10 CFR 50.49 EQ requirements in the SBO system and found that the applicant has met the criteria of SRP-LR Section 3.3.2.2.5.1 for further evaluation.

3.7.2.2.2 Station Blackout System Summary of Aging Management Evaluation – LRA Table 3.6.2.1.2A

The staff reviewed LRA Table 3.6.2.1.2A, which summarizes the results of AMR evaluations for the SBO system component groups.

The staff's evaluation of the cable connections (metallic parts), high-voltage insulators, transmission conductors and connections, and uninsulated ground conductors is documented in SER Sections 3.6.2.3.1, 3.6.2.2.2, 3.6.2.2.3, and 3.6.2.3.1, respectively.

On the basis of its review the staff concludes that the applicant has demonstrated that the aging effects associated with the SBO system components 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).

3.7.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, item 3.2.1-6 against the criteria in SRP-LR Section 3.2.2.2.3.4.

In FRCT Table 3.6.1B, item 3.2.1-6, the applicant addressed loss of material due to pitting and crevice corrosion for FRCT mechanical components exposed to lubricating oil.

SRP-LR Section 3.2.2.2.3.4 states that loss of material from pitting and crevice corrosion could occur in 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 not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that no corrosion occurs. 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 no corrosion occurs and that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.2.1-6, states that the One-Time Inspection - FRCT Program will verify the effectiveness of the Lubricating Oil Analysis - FRCT Program at managing the loss of material in copper alloy heat exchanger tubes exposed to a lubricating oil environment. The One-Time Inspection – FRCT Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis - FRCT Program and verified that it includes activities consistent with the recommendations in GALL AMP XI.M39 to manage loss of material for components exposed to lubricating oil. In addition, the staff reviewed the applicant's

One-Time Inspection - FRCT Program and verified that it includes inspections to detect loss of material to verify the effectiveness of the Lubricating Oil Analysis - FRCT Program. The staff concludes that these programs together will adequately manage loss of material in copper alloy heat exchanger tubes exposed to a lubricating oil environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.2.2.2.3.4 for further evaluation. The staff finds 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).

3.7.2.2.4 Reduction of Heat Transfer Due to Fouling - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, item 3.2.1-9, against the criteria in SRP-LR Section 3.2.2.2.4.1.

In FRCT Table 3.6.1B, item 3.2.1-9, the applicant addressed reduction of heat transfer due to fouling for FRCT heat exchanger tubes exposed to lubricating oil.

SRP-LR Section 3.2.2.2.4.1 states that reduction of heat transfer due to fouling could occur in 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 be adequate to preclude fouling. Therefore, the effectiveness of lube oil chemistry control should be verified to ensure that fouling does not occur. 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 does not occur or progresses so slowly that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.2.1-9, states that the One-Time Inspection - FRCT Program will verify the effectiveness of the Lubricating Oil Analysis - FRCT Program 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 Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis - FRCT Program and verified that it includes activities 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 staff reviewed the applicant's One-Time Inspection - FRCT Program and verified that it includes inspections to detect fouling to verify the effectiveness of the Lubricating Oil Analysis - FRCT Program. The staff concludes that these programs together will adequately manage the reduction of heat transfer in copper alloy heat exchanger tubes and fins exposed to a lubricating oil environment

The staff finds that the applicant has met the criteria of SRP-LR Section 3.2.2.2.4.1 for further evaluation. The staff finds 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).

3.7.2.2.5 Cracking Due to Stress Corrosion Cracking (SCC) - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, item 3.3.1-6, against the criteria in SRP-LR Section 3.3.2.2.3.3.

In FRCT Table 3.6.1B, item 3.3.1-6, the applicant addressed cracking due to SCC in FRCT stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust.

SRP-LR Section 3.3.2.2.3.3 states 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 recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

FRCT Table 3.6.1B, item 3.3.1-6, states that the Periodic Inspection - FRCT Program will manage cracking in stainless steel combustion turbine exhaust components exposed to a combustion turbine exhaust gas environment. The Periodic Inspection - FRCT Program will address systems within the scope of license renewal that require periodic monitoring of aging effects 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 monitor conditions to assure that existing environmental conditions do not cause degradation that could result in a loss of system intended functions.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and verified its adequacy to manage cracking in stainless steel combustion turbine exhaust components. The staff concludes that this program will adequately manage cracking in stainless steel combustion turbine exhaust components exposed to a combustion turbine exhaust gas environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.3.3 for further evaluation. The staff finds 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).

3.7.2.2.6 Hardening and Loss of Strength Due to Elastomer Degradation - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, item 3.3.1-11, against the criteria in SRP-LR Section 3.3.2.2.5.1.

In FRCT Table 3.6.1B, item 3.3.1-11, the applicant addressed hardening and loss of strength due to elastomer degradation in elastomer seals and components of FRCT heating and ventilation systems exposed to air - indoor uncontrolled (internal/external).

SRP-LR Section 3.3.2.2.5.1 states that hardening and loss of strength due to elastomer degradation can occur in elastomer seals and components of heating and ventilation systems exposed to air - indoor uncontrolled (internal/external). The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

FRCT Table 3.6.1B, item 3.3.1-11, stated that the Periodic Inspection - FRCT Program will manage the change in material properties in elastomer flexible connections exposed to an indoor air (internal) environment. The Periodic Inspection - FRCT Program will address systems within the scope of license renewal that require periodic monitoring of aging effects 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 monitor conditions to assure that existing environmental conditions do not cause degradation that could result in a loss of system intended functions.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and verified its adequacy to manage the change in material properties in elastomer flexible connections. The staff concludes that this program will adequately manage the change in material properties in elastomer flexible connections exposed to an indoor air (internal) environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.5.1 for further evaluation. The staff finds 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).

3.7.2.2.7 Loss of Material Due to General, Pitting, and Crevice Corrosion - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, items 3.3.1-14 and 3.3.1-18, against the criteria in SRP-LR Section 3.3.2.2.7.

In FRCT Table 3.6.1B, item 3.3.1-14, the applicant addressed loss of material due to general, pitting, and crevice corrosion in FRCT steel piping, piping components, and piping elements, including the tubing, valves, and tanks, exposed to lubricating oil.

SRP-LR Section 3.3.2.2.7.1 states that loss of material due to general, pitting, and crevice corrosion can 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 AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that no corrosion occurs. The GALL Report recommends 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 no corrosion occurs and that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.3.1-14, stated that the One-Time Inspection - FRCT Program will verify the effectiveness of the Lubricating Oil Analysis - FRCT Program 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 Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the Lubricating Oil Analysis - FRCT Program and verified that it includes activities consistent with the recommendations in GALL AMP XI.M39 to manage loss of material for components exposed to lubricating oil. In addition, the staff reviewed the applicant's One-Time Inspection - FRCT Program and verified that it includes inspections to detect loss of material to verify the effectiveness of the Lubricating Oil Analysis - FRCT Program. The staff concludes that these programs 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 staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.1 for further evaluation. The staff finds 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).

In FRCT Table 3.6.1B, item 3.3.1-18, the applicant addressed loss of material due to general (steel only) pitting and crevice corrosion for FRCT steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust.

SRP-LR Section 3.3.2.2.7.3 states that loss of material due to general (steel only) pitting and crevice corrosion can occur in steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

FRCT Table 3.6.1B, item 3.3.1-18, stated that the Periodic Inspection - FRCT Program will 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 - FRCT Program will address systems within the scope of license renewal that require periodic monitoring of aging effects 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 monitor conditions to assure that existing environmental conditions do not cause 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 Program will 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 Program 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. The program includes visual inspections to assure that existing environmental conditions do not cause degradation that could result in a loss of component intended functions.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and verified its adequacy to manage the loss of material of carbon steel and stainless steel combustion turbine casing and exhaust components. In addition, the staff reviewed the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT Program and verified its adequacy to manage the loss of material in carbon steel diesel exhaust components. The staff concludes that these programs together will adequately manage the loss of material of carbon steel and stainless steel components exposed to an exhaust gas environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.3 for further evaluation. The staff finds 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).

3.7.2.2.8 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, items 3.3.1-19 and 3.4.1-11, against the criteria in SRP-LR Sections 3.3.2.2.8 and 3.3.2.2.5.1, respectively.

In FRCT Table 3.6.1B, item 3.3.1-19, the applicant addressed loss of material due to general, pitting, and crevice corrosion and MIC in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil.

SRP-LR Section 3.3.2.2.8 states 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, and piping elements buried in soil. The Buried Piping Inspection - FRCT 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 Inspection - FRCT Program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

FRCT Table 3.6.1B, item 3.3.1-19, states that the Buried Piping Inspection - FRCT Program will manage the loss of material in carbon steel piping exposed to a soil environment. The Buried Piping Inspection - FRCT 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 Outdoor Tanks - FRCT Program will manage the loss of material in steel tank bottoms exposed to a soil environment. The Aboveground Outdoor Tanks - FRCT Program includes periodic internal UT inspections on the bottom of the outdoor steel main fuel oil tank supported by earthen/concrete foundations.

The staff reviewed the applicant's Buried Piping Inspection - FRCT Program and verified its adequacy to manage the loss of material of carbon steel piping. The applicant was asked to confirm that, in addition to inspections within the first 10 years of the period of extended operation, for each of the material and environment combinations for which the Buried Piping Inspection - FRCT Program will be credited at least one inspection will be during the 10-year period immediately prior to the period of extended operation.

The applicant stated that inspections will be during the 10-year period immediately prior to the period of extended operation for the buried piping for which this AMP is credited. There have been no inspections completed to date, and there have been no identified failures of this buried piping since the FRCT units went into operation.

The staff reviewed the applicant's response and Commitment No. 57 and determined that, in addition to a focused inspection within the first 10-year period of the period of extended operation, an inspection during the 10-year period immediately prior to the period of extended operation would provide objective evidence that the components were in acceptable condition and that no significant aging was present for them. On this basis, the staff concludes that the applicant's response was acceptable.

In addition, the staff reviewed the applicant's Aboveground Outdoor Tanks - FRCT Program and verified its adequacy to manage the loss of material in steel tank bottoms. The staff concludes that these programs will adequately manage the loss of material of carbon steel piping and steel tank bottoms exposed to a soil environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.8 for further evaluation. The staff finds 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).

In FRCT Table 3.6.1D, item 3.4.1-11, the applicant addressed loss of material due to general, pitting, and crevice corrosion and MIC in FRCT steel (with or without coating or wrapping) piping, piping components, piping elements, and tanks exposed to soil.

SRP-LR Section 3.4.2.2.5.1 states 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 Inspection - FRCT 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 Inspection - FRCT Program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

FRCT Table 3.6.1D, item 3.4.1-11, states that the new Buried Piping Inspection-Met Tower Program will 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 Inspection-Met Tower 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 for any other reason. Within 10 years prior to the period of extended operation, inspection of the buried piping and tank will be performed unless an opportunistic inspection occurs within this 10-year period.

Following commencement of the period of extended operation, inspection of the buried piping and tank will again be performed within the next 10 years unless an opportunistic inspection occurs during this 10-year period. In 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 accordance with standard industry practices for the inspection and maintenance of external coatings and wrappings. Exceptions apply to the GALL Report recommendations for Buried Piping Inspection-Met Tower Program implementation.

The staff reviewed the applicant's Buried Piping Inspection-Met Tower Program and verified that it is 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 staff concludes that the applicant's program will adequately manage the loss of material of copper and carbon steel piping and carbon steel tank bottoms exposed to a soil environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.4.2.2.5.1 for further evaluation. The staff finds 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).

3.7.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, items 3.3.1-20 and 3.3.1-21, against the criteria in SRP-LR Sections 3.3.2.2.9.1 and 3.3.2.2.9.2, respectively.

In FRCT Table 3.6.1B, items 3.3.1-20, the applicant addressed loss of material due to general, pitting, and crevice corrosion and MIC and fouling for FRCT steel piping, piping components, piping elements, and tanks exposed to fuel oil.

SRP-LR Section 3.3.2.2.9.1 states that loss of material due to general, pitting, and crevice corrosion and MIC and fouling could occur in steel piping, piping components, piping elements, and tanks exposed to fuel oil. The existing AMP relies on the Fuel Oil Chemistry Program to monitor and control 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 no corrosion occurs. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion and 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 no corrosion occurs and that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.3.1-20, states that the One-Time Inspection - FRCT Program will verify the effectiveness of the Fuel Oil Chemistry - FRCT Program 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 Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the applicant's Fuel Oil Chemistry - FRCT Program and verified that it will mitigate loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks. In addition, the staff reviewed the applicant's One-Time Inspection - FRCT Program and verified that it includes inspections to detect loss of material due to general, pitting, and crevice corrosion and MIC and fouling to verify the effectiveness of the Fuel Oil Chemistry - FRCT Program. The staff concludes 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 staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.9.1 for further evaluation. The staff finds 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).

In FRCT Table 3.6.1B, item 3.3.1-21, the applicant addressed loss of material due to general, pitting, and crevice corrosion and MIC and fouling for FRCT steel heat exchanger components exposed to lubricating oil.

SRP-LR Section 3.3.2.2.9.2 states that loss of material due to general, pitting, and crevice corrosion and MIC and fouling could occur for steel heat exchanger components exposed to lubricating oil. The existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that no corrosion occurs. The GALL Report recommends 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 no corrosion occurs and that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.3.1-21, states that the One-Time Inspection - FRCT Program will verify the effectiveness of the Lubricating Oil Analysis - FRCT Program at managing the loss of material in carbon steel heat exchanger components exposed to a lubricating oil environment. The One-Time Inspection - FRCT Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the Lubricating Oil Analysis - FRCT Program and verified that it will mitigate loss of material in carbon steel heat exchanger components. In addition, the staff reviewed the applicant's One-Time Inspection Program and verified that it includes inspections to detect loss of material due to general, pitting, and crevice corrosion and MIC and fouling to verify the effectiveness of the Lubricating Oil Analysis - FRCT Program. The staff concludes that these AMPs will adequately manage loss of material in carbon steel heat exchanger components exposed to a lubricating oil environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.9.2 for further evaluation. The staff finds 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).

3.7.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, item 3.3.1-25, against the criteria in SRP-LR Section 3.3.2.2.10.3.

In FRCT Table 3.6.1B, item 3.3.1-25, the applicant addressed loss of material due to pitting and crevice corrosion for FRCT copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external).

SRP-LR Section 3.3.2.2.10.3 states 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 recommends further evaluation of a plant-specific AMP to ensure adequate management of these aging effects.

FRCT Table 3.6.1B, item 3.3.1-25, stated that the Periodic Inspection - FRCT Program will manage the loss of material in copper alloy heat exchanger tubes exposed to a condensation (external) environment. The Periodic Inspection - FRCT will address systems within the scope of license renewal requiring periodic monitoring of aging effects 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 monitor conditions to assure that existing environmental conditions do not cause degradation that could result in a loss of system intended functions.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and verified its adequacy to manage loss of material in copper alloy heat exchanger tubes. The staff concludes that the program will adequately manage loss of material in copper alloy heat exchanger tubes exposed to a condensation (external) environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.3 for further evaluation. The staff finds 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).

3.7.2.2.11 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion - Mechanical Components

The staff reviewed FRCT Table 3.6.1B, items 3.3.1-32 and 3.3.1-33, against the criteria in SRP-LR Section 3.3.2.2.12.1 and 3.3.2.2.12.2, respectively.

In FRCT Table 3.6.1B, items 3.3.1-32, the applicant addressed loss of material due to pitting and crevice corrosion and MIC in FRCT stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil.

SRP-LR Section 3.3.2.2.12.1 states that loss of material due to pitting and crevice corrosion and MIC could occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil. The existing AMP relies on the Fuel Oil Chemistry Program to monitor and control 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 no corrosion occurs. The GALL Report recommends 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 no corrosion occurs and that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.3.1-32, states that the One-Time Inspection - FRCT Program will verify the effectiveness of the Fuel Oil Chemistry - FRCT Program 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 Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the applicant's Fuel Oil Chemistry - FRCT Program and verified that it will mitigate loss of material due to pitting and crevice corrosion and MIC. In addition, the staff reviewed the applicant's One-Time Inspection - FRCT Program and verified that it includes inspections to detect loss of material due to pitting and crevice corrosion and MIC to verify the effectiveness of the Fuel Oil Chemistry - FRCT Program. The staff concludes that these programs will adequately manage loss of material in stainless steel piping, piping components, and piping elements exposed to a fuel oil environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.1 for further evaluation. The staff finds 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).

In FRCT Table 3.6.1B, item 3.3.1-33, the applicant addressed loss of material due to pitting and crevice corrosion and MIC in FRCT stainless steel piping, piping components, and piping elements exposed to lubricating oil.

SRP-LR Section 3.3.2.2.12.2 states that loss of material due to pitting and crevice corrosion 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 not conducive to corrosion. However, control of lube oil contaminants may not always be adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that no corrosion occurs. The GALL Report recommends 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 no corrosion occurs and that the component's intended function will be maintained during the period of extended operation.

FRCT Table 3.6.1B, item 3.3.1-33, states that the One-Time Inspection - FRCT Program will verify the effectiveness of the Lubricating Oil Analysis - FRCT Program 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 Program includes (1) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the aging effect, (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for followup examinations to monitor the progression of aging if age-related degradation could jeopardize an intended function before the end of the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis - FRCT Program and verified that it will manage the loss of material in stainless steel piping, piping components, and piping elements. In addition, the staff reviewed the applicant's One-Time Inspection - FRCT Program and verified that it includes inspections to detect loss of material due to pitting and crevice corrosion and MIC to verify the effectiveness of the Lubricating Oil Analysis - FRCT Program. The staff concludes that these programs will adequately manage loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment.

The staff finds that the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.2 for further evaluation. The staff finds 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).

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommends further evaluation, the staff determined that the applicant adequately addressed the issues that required further evaluation. The staff finds 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).

3.7.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In its November letter, Table 3.6.1B, the applicant provided information about components or material and environment combinations in the GALL Report that it had evaluated as not applicable.

In Tables 3.6.2.1.2B, 3.6.2.1.2C, and 3.5.2.1.20 of this letter, the applicant provided additional details of the results of the AMRs for material, environment, AERM, and AMP combinations not consistent with the GALL Report.

The applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. The staff reviewed the results of the AMRs for material, environment, AERM, and AMP combinations that are not consistent with or not addressed in the GALL Report.

3.7.2.3.1 Mechanical System AMR Line Items That Have No Aging Effect - Table 3.6.2.1.2B

In its November letter, Table 3.6.2.1.2B, the applicant included AMR line items for which no aging effects were identified, specifically 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 staff reviewed the recommendations in the GALL Report for these material and environment combinations and determined that the applicant's evaluations were consistent with the recommendations in the GALL Report. In addition, the staff reviewed the applicant's AMR technical basis document, OC-AMR-2.5.1, "Station Blackout System-Mechanical," Revision 0, which includes an operating experience review for the FRCT, and determined that no significant aging effects had been identified for FRCT mechanical components with these material and environment combinations.

The staff's review of current industry operating experience 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 experience aging during the period of extended operation. Therefore, the staff concludes that there are no applicable AERMs for these material and environment combinations.

On the basis of its review of the applicant's program, the staff finds that the applicant has demonstrated that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7.2.3.2 Loss of Preload for Carbon and Low-Alloy Steel Exposed to Outdoor Air (External) - FRCT Table 3.6.2.1.2B

In its November letter, 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 to manage this aging effect. Generic Note H indicated that the aging effect is not addressed in the GALL Report for this component, material and environment combination. In plant-specific Note 2, the applicant stated that the aging effects for carbon and alloy steel closure bolting in outdoor air (external) environments also include loss of preload.

The staff reviewed the applicant's Bolting Integrity - FRCT Program and determined that it manages loss of preload for closure bolting constructed of carbon and low-alloy steel exposed to outdoor air (external). On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.3 Loss of Preload for Stainless Steel Exposed to Indoor or Outdoor Air (External) - FRCT Table 3.6.2.1.2B

In its November letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination. In a plant-specific note, 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 staff reviewed the applicant's Bolting Integrity - FRCT Program and determined that it manages loss of preload for closure bolting constructed of stainless steel exposed to indoor or outdoor air (external). On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.4 Cracking Initiation and Growth for Carbon and Low-Alloy Steel Exposed to Combustion Turbine Exhaust Gases (Internal) - FRCT Table 3.6.2.1.2B

In its November letter, 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 to manage this aging effect. Generic Note H indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination. In plant-specific Note 9, 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 resulting in leaks, but have not prevented combustion turbine operation. Cracks are repaired prior to reassembly.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and determined that it manages 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 staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.5 Reduction of Heat Transfer for Carbon and Low-Alloy Steel Exposed to Fuel Oil (Internal) - FRCT Table 3.6.2.1.2B

In its November letter, 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 and One-Time Inspection - FRCT Programs to manage this aging effect. Generic Note H indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination. In plant-specific Note 4, the applicant stated that aging effects include reduction of heat transfer between the fuel oil environment and steel-sheathed tubular heating elements.

The staff reviewed the applicant's Fuel Oil Chemistry - FRCT Program and determined that it manages 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 staff reviewed the applicant's One-Time Inspection - FRCT Program and determined that it includes inspections adequate to verify the effectiveness of the Fuel Oil Chemistry - FRCT Program. On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.6 Change in Material Properties for Elastomer Exposed to Fuel Oil or Outdoor Air (External) - FRCT Table 3.6.2.1.2B

In its November letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and determined that it manages 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 staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.7 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 November letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination. In plant-specific Note 8, the applicant stated that visual inspection of tubes and fins by the identified AMP will assure that the heat transfer intended function is maintained.

The staff reviewed the applicant's Periodic Inspection - FRCT Program and determined that it manages 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 staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.8 Loss of Material for Bronze Exposed to Outdoor Air (External) - FRCT Table 3.6.2.1.2B

In its November letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

The staff reviewed the applicant's Structures Monitoring Program and determined that it manages loss of material for valve bodies constructed of bronze exposed to outdoor air (external). On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.9 Loss of Material for Copper Exposed to Soil - Radio Communications Systems Table 3.6.2.1.3

In its December letter, 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 Inspection-Met Tower Program to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

The staff reviewed the applicant's Buried Piping Inspection-Met Tower Program and determined that it manages loss of material for piping and fittings constructed of copper exposed to soil. On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.10 Loss of Material for Copper Exposed to Outdoor Air - Radio Communications Systems Table 3.6.2.1.3

In its December letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

The staff reviewed the applicant's Structures Monitoring Program and determined that it manages loss of material for piping and fittings constructed of copper exposed to outdoor air (external). On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.11 Loss of Material for Brass Exposed to Outdoor Air - Radio Communications Systems Table 3.6.2.1.3

In its December letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

The staff reviewed the applicant's Structures Monitoring Program and determined that it manages loss of material for valve bodies constructed of brass exposed to outdoor air (external). On this basis, the staff concludes that the applicant's AMR is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.12 Structural AMR Line Items That Have No Aging Effect

In its December letter, Tables 3.6.2.1.2C and 3.6.1D, the applicant included AMR line items for which no aging effects were identified. The staff reviewed these AMR line items to determine their acceptability, including the following:

- 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 staff reviewed the GALL Report recommendations for these material and environment combinations and determined that the applicant's evaluations are consistent with the recommendations. In addition, the staff reviewed the applicant's AMR technical basis documents, OC-AMR-2.5.1, "Station Blackout System-Structural," Revision 0, and OC-AMR-2.5.1.15, "Radio Communication System," Revision 0, which include operating experience reviews for the FRCT and Met Tower, respectively, and determined that no significant aging effects had been identified for structural components with these material and environment combinations.

On the basis of its review of current industry and plant-specific operating experience, the staff finds 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 experience aging of concern during the period of extended operation. Therefore, the staff concludes that there are no applicable AERMs for these material and environment combinations.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.13 Change in Material Properties and Loss of Material for Wood Exposed to Soil - FRCT Table 3.6.2.1.2C

In its November letter, 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 to manage these aging effects. Generic Note J indicates that neither component nor the material and environment combination is evaluated in the GALL Report. In plant-specific Note 2, the applicant stated that the foundation piles are inaccessible and will not be inspected directly. Instead the foundation will be inspected visually for cracking and distortion due to increased stress levels from settlement that may result from degradation of the piles.

The staff 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 that the turbine support foundation has shown no signs of cracking or distortion due to increased stress levels from settlement that could result from degradation of the wooden piles. Therefore, the staff concludes that monitoring the foundation for settlement damage is an acceptable method to manage aging of the wood piles indirectly.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.14 Loss of Preload for Galvanized Steel Bolts Exposed to Outdoor Air - FRCT Table 3.6.2.1.2C

In its November letter, 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 to manage this aging effect. Generic Note H indicates that the aging effect is not addressed in the GALL Report for this component, material and environment combination. In plant-specific Note 3, the applicant stated that the Structures Monitoring Program is applicable to this component.

Based on its review of the Structures Monitoring Program the staff finds acceptable the applicant's AMR for structural bolts constructed of galvanized steel exposed to outdoor air.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.15 Loss of Material for Carbon and Low-Alloy Steel Exposed to Closed Cooling Water - FRCT Table 3.6.2.1.2C

In its November letter, 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, the applicant stated that the combustion turbine support legs have 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 AMP.

The staff asked the applicant for information about operating experience with the water-jacketed combustion turbine support legs, for a description of the AMP credited for the interior (wetted) surfaces of the support legs because Note 1 states that the AMP will be provided later, and whether the scope of the selected AMP had been enhanced for the FRCT support legs.

In its 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 submitted in the November letter. This table indicates that the Closed-Cycle Cooling Water System - FRCT Program is credited for managing the reduction of heat transfer and loss of material aging effects on the internal wetted surfaces. These components are included in this AMP and in AMP-PBD-B.1.14A.

The staff confirmed that this component had been included in the Closed-Cycle Cooling Water System - FRCT Program and that the program is appropriate for managing this aging effect.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.16 Change in Material Properties for Polyvinyl Chloride Exposed to Outdoor Air (Met Tower Table 3.5.2.1.20)

In its December letter, 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 to manage these aging effects. Generic Note J indicates that neither the component nor the material and environment combination is evaluated in the GALL Report.

Based on its review of the Structures Monitoring Program the staff finds acceptable the applicant's AMR for conduits constructed of polyvinyl chloride exposed to outdoor air.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.17 No Aging Effect for Polyvinyl Chloride Exposed to Soil (Met Tower Table 3.5.2.1.20)

In its December letter, 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 AMP. Generic Note J indicates that neither component nor the material and environment combination is evaluated in the GALL Report.

The staff noted that there has been extensive industry operating experience with polyvinyl chloride exposed to soil. This material is typically nonreactive with organic constituents in soil and has had wide use in buried applications. Therefore, the staff determined that the applicant's AMR for conduits constructed of polyvinyl chloride exposed to soil is acceptable.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.18 Loss of Material for Galvanized Steel Exposed to Soil (Met Tower Table 3.5.2.1.20)

In its December letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

The staff determined that the use of the Structures Monitoring Program is appropriate and finds acceptable the applicant's AMR for conduits constructed of galvanized steel exposed to soil.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.2.3.19 Loss of Preload for Carbon and Low-Alloy Steel Bolts Exposed to Outdoor Air (Met Tower Table 3.5.2.1.20)

In its December letter, 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 to manage this aging effect. Generic Note G indicates that the environment is not addressed in the GALL Report for this component and material combination.

Based on its review of the Structures Monitoring Program the staff finds acceptable the applicant's AMR for structural bolts constructed of carbon and low-alloy steel exposed to outdoor air.

On the basis of its review of the applicant's program, the staff finds 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).

3.7.3 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the FRCT, radio communications system, and Met Tower components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.8 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, "Aging Management Review Results," and LRA Appendix B, "Aging Management Programs." On the basis of its review of the AMR results and AMPs, the staff concludes that the applicant has demonstrated that the aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concludes that the supplement adequately describes the AMPs credited for managing aging, as required by 10 CFR 54.21(d).

With regard to these matters, the staff concludes that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section of the safety evaluation report (SER) discusses the identification of time-limited aging analyses (TLAAs). In license renewal application (LRA) Sections 4.2 through 4.7, AmerGen Energy Company, LLC (AmerGen or the applicant) discussed the TLAAs for Oyster Creek Generating Station (OCGS). SER Sections 4.2 through 4.7 document the review of the TLAAs, as conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), the applicant must provide a list of TLAAs, as defined in 10 CFR 54.3, "Interpretations."

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant must provide a list of plant-specific exemptions, granted under 10 CFR 50.12, "Specific Exemptions," that are based on TLAAs. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for OCGS against the six criteria specified in 10 CFR 54.3. The applicant indicated that it had identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), engineering calculations, technical reports, engineering work requests, licensing correspondence, and applicable vendor reports. In LRA Table 4.1-1, "Time-Limited Aging Analyses Applicable to Oyster Creek," the applicant listed the applicable TLAAs:

- neutron embrittlement of reactor vessel and internals
- metal fatigue of the reactor vessel, internals, and reactor coolant pressure boundary (RCPB) piping and components
- environmental qualification (EQ) of electrical equipment
- fatigue analysis of primary containment, attached piping, and components
- reactor building crane, turbine building crane, heater bay crane load cycles
- drywell corrosion
- equipment pool and reactor cavity walls rebar corrosion
- reactor vessel weld flaw evaluations
- control rod drive (CRD) stub tube flaw analysis

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that it did not identify any exemptions granted under 10 CFR 50.12 that were based on a TLAA, as defined in 10 CFR 54.3.

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to OCGS. The staff reviewed the information to determine whether the applicant had provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and (2).

As defined in 10 CFR 54.3, TLAAs meet the following six criteria:

(1) involve systems, structures, and components that are within the scope of license renewal, as described in 10 CFR 54.4(a),

(2) consider the effects of aging,

(3) involve time-limited assumptions defined by the current operating term (40 years),

(4) are determined to be relevant by the applicant in making a safety determination,

(5) involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, as described in 10 CFR 54.4(b), and

(6) are contained or incorporated by reference in the CLB

The applicant provided a list of common TLAAs from NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated September 2005. The applicant listed those TLAAs that are applicable to OCGS in LRA Table 4.1-1.

As required by 10 CFR 54.21(c)(2), the applicant must provide a list of all the exemptions granted under 10 CFR 50.12 that are based on TLAAs and evaluated and justified for continuation through the period of extended operation. In the LRA, the applicant stated that each active exemption was reviewed to determine whether the exemption was based on a TLAA. The applicant did not identify any TLAA-based exemptions. On the basis of the information provided by the applicant with regard to the process used to identify TLAA-based exemptions, as well as the results of the applicant's search, the staff finds that the applicant identified no TLAA-based exemptions that are justified for continuation through the period of extended operation, in accordance with 10 CFR 54.21(c)(2).

4.1.3 Conclusion

On the basis of its review, the staff finds that the applicant provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff confirmed, consistent with 10 CFR 54.21(c)(2), that no exemptions granted pursuant to 10 CFR 50.12 (and in effect) are based on a TLAA.

4.2 <u>Neutron Embrittlement of the Reactor Vessel and Internals</u>

During plant service, neutron irradiation reduces the fracture toughness of ferritic steel in the beltline region of the reactor vessel for light-water nuclear power reactors. Areas of review to ensure that the reactor vessel and reactor vessel internals have adequate fracture toughness to prevent brittle failure during normal and off-normal operating conditions include the following:

- reactor vessel materials upper-shelf energy (USE) reduction due to neutron embrittlement,
- adjusted reference temperature (ART) for reactor vessel materials due to neutron embrittlement,
- operating pressure-temperature (P-T) limits for heatup and cooldown operations, as well as hydrostatic and leak-testing conditions,
- reactor vessel circumferential weld examination relief,
- reactor vessel axial weld examination relief,
- core reflood thermal shock analysis, and
- reactor internals components

The adequacy of the analyses for these seven review areas is evaluated for the period of extended operation.

The ART is defined as the sum of the initial (unirradiated) reference temperature nil ductility (RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin term (m). Delta RT_{NDT} is the product of a chemistry factor and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," dated May 1988, or from surveillance data. The fluence factor depends on the neutron fluence. The margin term depends on whether the initial RT_{NDT} is a plant-specific value or a generic value and whether the chemistry factor was determined using the tables in RG 1.99, Revision 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence, and the calculation methods. Revision 2 of RG 1.99 describes the methodology to be used in calculating the margin term. The mean RT_{NDT} is the sum of the initial RT_{NDT} and ΔRT_{NDT}, without the margin term. The ΔRT_{NDT} and ART calculations meet the criterion of 10 CFR 54.3(a). Therefore, these calculations are considered TLAAs. The ART values for the reactor vessel materials are used for the P-T limits analysis. The mean RT_{NDT} values are used in the analysis of the circumferential weld examination relief and the axial weld examination relief.

Appendix G of 10 CFR Part 50, provides the staff's criteria for maintaining acceptable levels of USE for the reactor vessel beltline materials of operating reactors throughout the licensed lives of the facilities. The rule requires reactor vessel beltline materials to have a minimum USE value of 75 foot-pounds in the unirradiated condition and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless analysis demonstrates that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G to Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant reactor vessel surveillance capsule data that are reported through implementation of a plant's reactor vessel material surveillance program (Appendix H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50).

Revision 2 of RG 1.99 provides an expanded discussion regarding the calculation of Charpy USE values and describes two methods for determining Charpy USE values for reactor vessel beltline materials, depending on whether a given reactor vessel beltline material is represented in the plant's reactor vessel material surveillance program. If surveillance data are not available, the Charpy USE value is determined in accordance with position 1.2 in RG 1.99, Revision 2. If surveillance data are available, the Charpy USE should be determined in accordance with position 2.2 in RG 1.99, Revision 2. These methods refer to Figure 2 in RG 1.99, Revision 2, which indicates that the percentage drop in Charpy USE depends on the amount of copper in the material and the neutron fluence. Since the analyses performed in accordance with 10 CFR Part 50, Appendix G, are based on a flaw with a depth equal to one-quarter of the vessel wall thickness (1/4T), the neutron fluence used in the Charpy USE analysis is the neutron fluence at the 1/4T-depth location.

The applicant described its evaluation of this TLAA in LRA Section 4.2. To demonstrate that neutron embrittlement does not significantly impact the integrity of boiling-water reactor (BWR) vessel and reactor vessel internals during the license renewal term, the applicant included a discussion of the following topics related to neutron embrittlement in LRA Section 4.2:

- reactor vessel materials USE reduction due to neutron embrittlement
- ART for the reactor vessel materials due to neutron embrittlement
- reactor vessel thermal limit analysis, operating P-T limits
- reactor vessel circumferential weld examination relief
- reactor vessel axial weld examination relief
- core reflood thermal shock analysis
- reactor vessel internals components

Neutron Fluence Analysis. The maximum core average exposure projected from the current value to the end of the period of extended operation (60 years) is less than 50 effective full-power years (EFPYs). This value was obtained by assuming operation at 100 percent power from the current cycle to the end of the period of extended operation. Since a 100 percent capacity factor cannot be achieved, OCGS is not likely to exceed 48 EFPYs by the end of the period of extended operation. Therefore, the staff finds that 50 EFPYs bounds the actual exposure that will be accrued over the 60-year life of the plant.

Fluence was calculated for the OCGS reactor vessel for the extended 60-year (50 EFPY) licensed operating period, using the methodology of the RAMA Fluence Methodology software package. The Electric Power Research Institute (EPRI) developed the RAMA methodology which follows the guidance of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," dated March 2001. The NRC previously reviewed the RAMA methodology and issued an SER approving its use. OCGS will comply with the conditions of the SER. As part of the fluence analysis for the reactor vessel, the fluence measurement results from one surveillance capsule and six special surveillance capsules, tested as part of the Boiling Water Reactor Owners Group (BWROG) Supplemental Surveillance Program, were evaluated to develop a plant-specific uncertainty analysis for the application of the RAMA methodology to OCGS. The uncertainty analysis is consistent with the provisions of RG 1.190.

4.2.1 Reactor Vessel Materials Upper-Shelf Energy Reduction Due to Neutron Embrittlement

4.2.1.1 Summary of Technical Information in the Application

In LRA Section 4.2.1, the applicant summarized the evaluation of reactor vessel materials USE reduction due to neutron embrittlement for the period of extended operation. USE is the standard industry parameter used to indicate the maximum toughness of a material at high temperature. Appendix G of 10 CFR Part 50 requires the predicted end-of-life Charpy impact test USE for reactor vessel materials to be at least 50 ft-lb (absorbed energy), unless an approved analysis supports a lower value. Initial unirradiated test data are not available for the reactor vessel to demonstrate a minimum 50 ft-lb USE by standard methods. End-of-life fracture energy was evaluated by using an equivalent margin analysis (EMA) methodology approved by the NRC in NEDO-32205-A, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper-Shelf Energy in BWR-2 through BWR-6 Vessels." The applicant concluded that this analysis confirmed that an adequate margin of safety against fracture, equivalent to the requirements 10 CFR Part 50, Appendix G, does exist.

The reactor vessel was originally licensed for 40 years with an assumed neutron exposure of less than 10^{19} n/cm^2 (E > 1.0 MeV). The CLB calculations use calculated fluences that are lower than this limiting value. The applicant stated that the design-basis value of 10^{19} n/cm^2 (E > 1.0 MeV) bounds calculated fluences for the original 40-year license term. The tests performed on reactor vessel materials provided limited Charpy impact data. It was not possible to develop original Charpy impact test USE values using the methods of 10 CFR Part 50, Appendix H and American Society for Testing and Materials (ASTM) E23, "Methods for Notched Bar Impact Testing of Metallic Materials," invoked by 10 CFR Part 50, Appendix G. Therefore, the alternative NRC-approved methods in NEDO-32205-A were used to demonstrate compliance with the USE requirement in 10 CFR Part 50, Appendix G.

The applicant stated that peak fluence was calculated at the reactor vessel inner surface (inner diameter) for the purpose of evaluating the USE. The value of neutron fluence was also calculated for the 1/4T location into the reactor vessel wall base material, measured radially from the inside diameter (ID) at the clad-base metal interface, using equation 3 from paragraph 1.1 of RG 1.99, Revision 2. This 1/4T depth is specified in ASME Code, Section XI, Appendix G, 1998 Edition through 2000 Addenda, Article G-2120, as the maximum postulated defect depth. The maximum 1/4T fluence value calculated at 50 EFPYs is 4.39 $\times 10^{18}$ n/cm^2 in the lower intermediate shell. LRA Tables 4.2.1-1, 4.2.1-2, and 4.2.1-3 provide the 1/4T fluence.

The 60-year USE was evaluated by an EMA using the 50-EFPY calculated fluence and surveillance capsule results. Valid data are available for only one surveillance capsule. EPRI TR-113596, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," dated September 1999, (also referred to as the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-74-A report), performed a generic analysis and determined that the percent reduction in Charpy USE for the limiting BWR-2 plates and BWR-2 through BWR-6 welds are 29.5 percent and 39 percent, respectively. LRA Tables 4.2.1-1 through 4.2.1-3 provide the results of the EMA for the limiting welds and plates in the OCGS reactor vessel. The applicant stated that the results demonstrated that the percent USE reduction for the reactor vessel materials is less than the BWRVIP-74 EMA percent reduction acceptance criterion in all cases.

4.2.1.2 Staff Evaluation

Section IV.A.1.a of 10 CFR Part 50, Appendix G, requires, in part, that the reactor pressure vessel (RPV) beltline materials have Charpy USE values in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb, unless it is demonstrated, in a manner approved by the NRC, that lower values of Charpy USE will ensure margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code.

By letter dated April 30, 1993, the BWROG submitted NEDO-32205-A to demonstrate that BWR RPVs could meet margins of safety against fracture equivalent to those required by Appendix G of the ASME Code Section XI for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the staff concludes that the topical report demonstrated that the evaluated materials have the margins of safety against fracture equivalent to Appendix G of the ASME Code, Section XI, in accordance with 10 CFR Part 50, Appendix G. In that report, the BWROG derived, through statistical analysis, the unirradiated USE values for materials that originally did not have documented unirradiated Charpy USE values. Using these statistically derived Charpy USE values, the BWROG predicted the USE values through 40 years of operation, in accordance with RG 1.99, Revision 2. According to this RG, the decrease in USE depends on the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE value in the transverse direction for the base metal and along the weld for the weld material was 35 ft-lb.

General Electric (GE) performed an update to the USE EMA, which is documented in EPRI TR-113596. The staff documented its review and approval of EPRI TR-113596 in a letter dated October 18, 2001. The analysis in EPRI TR-113596 determined the reduction in the Charpy USE resulting from neutron irradiation using the methodology in RG 1.99, Revision 2. Using this methodology and a correction factor of 65 percent for conversion of the longitudinal properties to transverse properties, the lowest Charpy USE at 50 EFPYs of facility operation for all BWR-2 plates was projected to be 35 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical Position MTEB 5-2. The EMA acceptance criteria specified in the staff-approved report for BWRVIP-74 are based on the percentage reduction in the Charpy USE values resulting from neutron irradiation using the methodology in RG 1.99, Revision 2. The acceptance criteria that are specified in the BWRVIP-74 report indicate that the maximum allowable percentage reduction in USE value is 29.5 percent for the BWR-2 plates and 39 percent for the BWR-2 through BWR-6 welds.

The staff's review of LRA Section 4.2.1 identified an area in which additional information was necessary to complete the review of the reactor vessel materials USE reduction due to neutron embrittlement. The applicant responded to the staff's request for additional information (RAI) as discussed below.

Since the analysis in the BWRVIP-74 report is a generic analysis, the applicant submitted plant-specific information in LRA Tables 4.2.1-1 through 4.2.1-3 to demonstrate that the limiting beltline materials for the reactor vessel will meet the criteria in the BWRVIP-74 report at the end of the license renewal period. The information provided in the LRA demonstrates that the percent reduction in USE for the limiting reactor vessel beltline materials at OCGS is less than the acceptance criteria specified in BWRVIP-74.

In RAI 4.2.2-1 dated March 30, 2006, the staff requested that the applicant provide the values for the percentage reduction in USE at the end of the extended period of operation for all the plates and weld metals in the beltline region of the reactor vessel.

In its response dated May 15, 2006, the applicant provided the results of the calculation of the USE EMA for all the remaining (nonlimiting) reactor vessel beltline materials for the extended period of operation. These supplemental calculations demonstrate that the percent reduction in USE for the nonlimiting reactor vessel beltline materials is less than the acceptance criteria specified in BWRVIP-74. The staff determined that the above information satisfied this RAI. The staff's concern described in RAI 4.2.2-1 is resolved.

Table 4.2.1 Upper Shelf Energy Calculations

OCGS Reactor Vessel Material	Percent USE Reduction of OCGS Reactor Vessel Material	Percent USE Reduction Acceptance Criterion*	Evaluation Result
Limiting Plate 564-03D, E, F	29%	USE drop must be < 29.5%	Acceptable pursuant to 10 CFR 54.21(c)(1)(ii)
Limiting Weld 86054B & 1248	32%	USE drop must be < 39%	Acceptable pursuant to 10 CFR 54.21(c)(1)(ii)

As noted in text, acceptance criteria established per BWRVIP-74.

The staff verified the reduction in the unirradiated USE values resulting from neutron radiation using the methodology in RG 1.99, Revision 2, and finds that all the beltline materials meet the acceptance criteria specified in the staff-approved BWRVIP-74 report, and 10 CFR Part 50, Appendix G.

4.2.1.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of reactor vessel materials USE reduction due to neutron embrittlement in LRA Section A.4.1.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor vessel materials USE reduction due to neutron embrittlement is adequate.

4.2.1.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel materials USE reduction due to neutron embrittlement TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Adjusted Reference Temperature for Reactor Vessel Materials due to Neutron Embrittlement

4.2.2.1 Summary of Technical Information in the Application

In LRA Section 4.2.2, the applicant summarized the ART determination for the vessel materials due to neutron embrittlement. The ART is defined as the sum of the initial (unirradiated) RT_{NDT}, the mean value of the adjustment in RT_{NDT} caused by irradiation (ΔRT_{NDT}), and a margin (m) term. The margin is defined in RG 1.99, Revision 2. As addressed in RG 1.99, Revision 2, ΔRT_{NDT} is a function of neutron fluence. Since neutron fluence changes with time, the determination of ΔRT_{NDT} (and, therefore, ART) meets the criteria of 10 CFR 54.3(a) for being a TLAA.

The OCGS reactor vessel was licensed for 40 years with an assumed neutron exposure of less than 10^{19} n/cm^2 (E > 1.0 MeV). The applicant stated that the CLB calculations use calculated fluences that are lower than this limiting value. Therefore, the design-basis value of 10^{19} n/cm^2 bounds calculated fluences for the original 40-year license term for the reactor vessel. The ART values were determined using the embrittlement correlations defined in RG 1.99, Revision 2.

The applicant calculated fluences for the reactor vessel for the extended 60-year licensed operating period using the RAMA Fluence Methodology software package. Peak fluences were calculated at the vessel inner surface (inner diameter) for the purpose of evaluating the USE and ART values. The neutron fluence values were also calculated for the 1/4T location in the vessel wall, measured radially from the ID using equation 3 from paragraph 1.1 of RG 1.99, Revision 2. This 1/4T depth is given in ASME Code, Section XI, Appendix G, Subarticle G-2120, as the maximum postulated defect depth. The applicant calculated ART values for the reactor vessel beltline materials based on the embrittlement correlation found in RG 1.99, Revision 2. LRA Table 4.2.2-1 presents the peak fluence and ART values for the 60-year licensed operating period. The applicant claimed that the limiting ARTs allow P-T limits that will provide reasonable operational flexibility.

4.2.2.2 Staff Evaluation

The applicant calculated the 50-EFPY fluences for the reactor vessel using the RAMA Fluence Methodology software package. Since this is an NRC-approved methodology, the calculated fluences provided in the LRA are acceptable. The applicant determined that the peak surface fluence is 6.97 x 10^{18} n/cm^2 (E > 1.0 MeV) and the peak 1/4T fluence is 4.39 x 10^{18} n/cm^2 (E > 1.0 MeV) for the OCGS reactor vessel. LRA Table 4.2.2-1 shows the bounding fluence values for the period of extended operation.

The staff's review of LRA Section 4.2.2 identified an area in which additional information was necessary to complete the review of the ART for reactor vessel materials due to neutron embrittlement. The applicant responded to the staff's RAI as discussed below.
In reviewing the chemistry data (percent copper and percent nickel) and chemistry factor values for the lower-to-lower intermediate shell circumferential weld 3-564; lower shell axial welds 2-564A, B, and C; and lower intermediate shell axial welds 2-564D, E, and F provided by the applicant in LRA Table 4.2.2-1, the staff determined that these percent copper, percent nickel, and chemistry factor values are less conservative than the corresponding chemistry data and chemistry factor values that were established in the staff's reactor vessel integrity database for these welds.

In RAI 4.2.2-2 dated March 30, 2006, the staff requested that the applicant provide the following supplemental information, (1) verification of whether the chemistry data contained in LRA Table 4.2.2-1 are valid for these welds, and (2) justification for the use of these chemistry data for the above welds, including the source of the data and a specific reference for the documentation and analysis demonstrating that these chemistry data represent the best available estimate of the weld chemistries.

In its response dated April 26, 2006, the applicant stated that the material properties presented in LRA Table 4.2.2-1 are valid for use in the TLAAs for the ART and USE. The applicant indicated that these materials properties (specifically the copper and nickel chemistry data) were taken from the data that were submitted to the NRC as part of a 1996 license amendment application to revise the P-T limit curves in the plant technical specifications. This information was subsequently approved by the NRC in its 1998 issuance of the license amendment to update the P-T limit curves for OCGS. These data reflected new reactor vessel beltline weld chemistry information that became available as a result of a Combustion Engineering (CE) Reactor Vessel Owners Group study that led to the publication of topical report CE NPSD-1039, Revision 2, "Best Estimate Copper and Nickel Values in CE Fabricated Reactor Vessel Welds," dated June 1997. The NRC staff approved the use of these data for OCGS by letter dated August 6, 1999, which closed out an open RAI concerning Generic Letter (GL) 92-01, "Reactor Vessel Structural Integrity," dated February 28, 1992. Therefore, the reactor vessel beltline weld chemistry information from LRA Table 4.2.2-1 is valid in that it represents the latest and most accurate assessment of the weld chemistries, based on the analyses documented in CE NPSD-1039, Revision 2. Given this assessment, the staff determined that the above information satisfied this RAI. The staff's concerns described in RAI 4.2.2-2 are resolved.

The staff independently reviewed all ART calculations in LRA Table 4.2.2-1 based on the approved chemistry and fluence data and determined that the applicant appropriately followed the guidance of RG 1.99, Revision 2, in determining the ART values for the reactor vessel beltline materials. Therefore, these values are acceptable.

4.2.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of ART for reactor vessel materials due to neutron embrittlement in LRA Section A.4.1.2. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address ART for reactor vessel materials due to neutron embrittlement is adequate.

4.2.2.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the ART for reactor vessel materials due to neutron embrittlement TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.3 Reactor Vessel Thermal Limit Analyses: Operating Pressure - Temperature Limits

4.2.3.1 Summary of Technical Information in the Application

In LRA Section 4.2.3, the applicant summarized the evaluation of reactor vessel thermal limit analyses and associated operating P-T limits for the period of extended operation. The ART is a key material property for developing operating P-T limits and is used to establish the minimum temperature at which the reactor vessel can be pressurized. ART is the sum of the initial RT_{NDT}, ΔRT_{NDT}, and margin (m) for uncertainties at a specific reactor vessel location and material. Neutron embrittlement increases the ART. Thus, the minimum temperature at which the reactor vessel can be pressurized increases with increased fluence. The ART of the limiting beltline material is used to adjust the beltline P-T limits to account for irradiation effects. Appendix G to 10 CFR Part 50 requires reactor vessel thermal limit analyses to determine operating P-T limits for bolt up, hydro-test, pressure tests, and normal operating and anticipated operational occurrences. Operating limits for pressure and temperature are required for three categories of operation (1) hydrostatic pressure tests and leak tests, referred to as Curve A, (2) nonnuclear heatup/cooldown and low-level physics tests, referred to as Curve B, and (3) core critical operation, referred to as Curve C. P-T limits are developed for three bounding vessel regions (1) the upper vessel region (non-beltline, including the head flange region), (2) the core beltline region, and (3) the vessel bottom head region.

The applicant stated that the OCGS technical specifications contain P-T limit curves for heatup and cooldown operations, core critical operations, and inservice leakage and hydrostatic testing. According to the applicant, limits are also imposed on the maximum rate of change of reactor coolant temperature. The technical specifications P-T limit curves for the current 40-year licensed operating period are calculated for 32 EFPYs. The applicant stated that new P-T limits have been calculated and that they will be submitted for approval prior to entering the period of extended operation.

4.2.3.2 Staff Evaluation

The applicant calculated revised P-T limits using an approved fluence methodology and 50-EFPY fluence values that are valid for the period of extended operation. The revised P-T limit curves will be submitted to the NRC for approval prior to entering the extended period of operation (Commitment No. 46). The applicant's CLB allows the development of P-T limit curves consistent with the 2000 Edition through 2001 Addenda of the ASME Code, Section XI. The applicant stated that it will manage the P-T limits using approved fluence calculations when there are changes in power of core design in conjunction with surveillance capsule results from the BWRVIP integrated surveillance program. The staff finds that the applicant's plan to manage the P-T limits is acceptable because changes to the P-T limit curves will be implemented by the license amendment process (i.e., through revisions of the plant technical specifications) and will meet the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

4.2.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel thermal limit analyses: operating P-T limits in LRA Section A.4.1.3. On the basis of its review of the UFSAR supplement and Commitment No. 46, the staff concludes that the summary description of the applicant's actions to address reactor vessel thermal limit analyses: operating P-T limits is adequate.

4.2.3.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel thermal limit analyses operating P-T limits TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement and Commitment No. 46 contain an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Reactor Vessel Circumferential Weld Examination Relief

4.2.4.1 Summary of Technical Information in the Application

In LRA Section 4.2.4, the applicant summarized the evaluation of reactor vessel circumferential weld examination relief for the period of extended operation. Relief from reactor vessel circumferential weld examination requirements under GL 98-05, "Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Shell Welds,"dated November 10, 1998, is based on probabilistic assessments that predict an acceptable probability of failure per reactor operating year. The analysis is based on reactor vessel metallurgical conditions as well as flaw indication sizes and frequencies of occurrence that are expected at the end of a licensed operating period. OCGS has received this relief for the remainder of its 40-year licensed operating period. OCGS received NRC approval for a technical alternative, which eliminated the reactor vessel circumferential shell weld inspections for the current license term. The basis for this relief request was an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license, based on BWRVIP-05 and the extent of neutron embrittlement. The applicant stated that anticipated changes in metallurgical conditions expected over the extended licensed operating period require an analysis for 50 EFPYs and approval by the NRC to extend this relief request.

The NRC evaluation of BWRVIP-05 used the FAVOR code to perform a probabilistic fracture mechanics (PFM) analysis to estimate the reactor vessel shell weld failure probabilities.

The following are the three key assumptions of the PFM analysis:

(1) the neutron fluence was the estimated end-of-license mean fluence
(2) the chemistry values were mean values based on vessel types, and
(3) the potential for beyond-design-basis events was considered.

LRA Table 4.2.4-1 compares the reactor vessel limiting circumferential weld parameters to those used in the NRC evaluation of BWRVIP-05 for the first two key assumptions. Table 4.4 of BWRVIP-05 and Table 2.6-5 of the final SER of the BWRVIP-05 report supplied the data in LRA Table 4.2.4-1.

The OCGS 50-EFPY fluence is slightly lower and the chemistry factor is considerably lower than the limits of the NRC analysis. As a result, the shift in reference temperature, ΔRT_{NDT}, and the unirradiated reference temperature, initial RT_{NDT}, are lower compared to the NRC analysis. This combination of initial RT_{NDT} and ΔRT_{NDT} yields an ART that is considerably lower than the NRC mean analysis value. Therefore, the reactor vessel shell weld embrittlement due to neutron fluence has a negligible effect on the probabilities of reactor vessel shell weld failure. The mean RT_{NDT} value at 50 EFPYs is bounded by the 64-EFPY mean RT_{NDT} provided by the NRC. Based on this analysis, the applicant concludes that the OCGS reactor vessel conditional failure probability is bounded by the NRC analysis. The applicant claimed that the procedures and training used to limit cold overpressure events will be the same as those approved by the NRC when OCGS requested relief for the current license term.

4.2.4.2 Staff Evaluation

The staff's final SER concerning the BWRVIP-05 report, dated July 28, 1998, discusses the technical basis for relief. In this letter, the staff concludes that, since the failure frequency for circumferential welds in BWR plants is significantly below the criterion specified in RG 1.154, "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," dated January 1987, and below the core damage frequency (CDF) of any BWR plant, the continued inspection would result in a negligible decrease in an already acceptably low reactor vessel failure probability. Therefore, elimination of the inservice inspection (ISI) requirements for reactor vessel circumferential welds is justified. The staff's letter indicated that BWR applicants may request relief from the ISI requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RPV welds by demonstrating that:

- at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the SER dated July 28, 1998, and
- the applicants have implemented operator training and established procedures that limit the frequency of cold overpressure events to the frequency specified in the staff's SER.

The letter indicated that the requirements for inspection of circumferential reactor vessel welds during an additional 20-year license renewal period would be reassessed, on a plant-specific basis, as part of any BWR LRA. Therefore, the applicant must request relief from inspection of circumferential welds during the license renewal period, pursuant to 10 CFR 50.55a.

Section A.4.5 of the BWRVIP-74 report indicates that the staff's SER of the BWRVIP-05 report conservatively evaluated the BWR reactor vessels to 64 EFPYs, which is 10 EFPYs greater than what is realistically expected for the end of the license renewal period. The NRC staff used the mean RT_{NDT} value for materials to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPYs in the staff SER dated July 28, 1998. The neutron fluence used in this evaluation was the neutron fluence at the clad-weld (inner) interface.

Since the staff analysis discussed in the BWRVIP-74 report is a generic analysis, the applicant submitted plant-specific information to demonstrate that the OCGS beltline materials meet the criteria specified in the report. To demonstrate that the reactor vessel has not become embrittled beyond the basis for the relief, LRA Table 4.2.4-1 compares the 50-EFPY material data for the limiting circumferential welds with the 64-EFPY reference case in Appendix E to the staff's SER of the BWRVIP-05 report. The material data included amounts of copper and nickel, chemistry factor, the neutron fluence, ΔRT_{NDT}, initial RT_{NDT}, and mean RT_{NDT} for the limiting circumferential weld at the end of the period of extended operation. The staff verified the validity of the data for the copper and nickel contents and the initial RT_{NDT} values for the reactor vessel beltline materials based on the evaluation in SER Section 4.2.2. The 50-EFPY mean RT_{NDT} value is 9.8 °F. The staff reviewed the applicant's calculations for the 50-EFPY mean RT_{NDT} values for the circumferential welds using the data presented in LRA Table 4.2.4-1 and found them to be accurate. These 50-EFPY mean RT_{NDT} values are bounded by the 64-EFPY mean RT_{NDT} value of 128.5 °F used by the NRC for determining the conditional failure probability of a circumferential weld. The 64-EFPY mean RT_{NDT} value from the staff SER dated July 28, 1998, is representative of a CE weld because CE fabricated the circumferential welds in the OCGS reactor vessel. Since the OCGS 50-EFPY mean RT_{NDT} value is less than the 64-EFPY value used in the staff SER dated July 28, 1998, the staff concludes that the reactor vessel conditional failure probability is bounded by the NRC analysis.

The applicant stated that the procedures and training used to limit cold overpressure events will be the same as those approved by the NRC when OCGS requested the relief for the current license period. The applicant stated that the procedures and training requirements identified in the request to use the BWRVIP-05 report are provided in the document, "USNRC Safety Evaluation by the Office of Nuclear Reactor Regulation, Inservice Inspection Program, Relief Request R17, Revision 1, Oyster Creek Nuclear Generating Station, Amergen Energy Company, LLC, Docket No. 50-219," dated July 11, 2002. The applicant stated that it will submit an extension of this relief request for the extended period of operation to the NRC for approval prior to entering the period of extended operation.

The staff finds that the applicant's evaluation for this TLAA is acceptable because the OCGS 50-EFPY conditional failure probability for the reactor vessel circumferential welds is bounded by the NRC analysis in the staff SER dated July 28, 1998, and the applicant will be using procedures and training to limit cold overpressure events during the period of extended operation. This analysis satisfies the evaluation requirements of the staff SER dated July 28, 1998; however, the applicant is still required to request relief for the circumferential weld examination for the extended period of operation, in accordance with 10 CFR 50.55a.

4.2.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel circumferential weld examination relief in LRA Section A.4.1.4. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor vessel circumferential weld examination relief is adequate.

4.2.4.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel circumferential weld examination relief TLAA, the analyses have been projected to the end of the period of extended operation. However, even though the analyses have been projected to the end of the period of extended operation, the applicant will still have to request an extension of the relief for circumferential welds examination for the renewal period. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 Reactor Vessel Axial Weld Examination Relief

4.2.5.1 Summary of Technical Information in the Application

In LRA Section 4.2.5, the applicant summarized the evaluation of reactor vessel axial weld examination relief for the period of extended operation. The BWRVIP recommendations for inspection of reactor vessel shell welds (BWRVIP-05) contain generic analyses supporting an NRC safety evaluation conclusion that the generic plant axial weld failure rate is no more than 5×10^{-6} per reactor-year. BWRVIP-05 showed that the axial weld failure rate of 5×10^{-6} per reactor-year is orders of magnitude greater than the 40-year end-of-life circumferential weld failure probability and used this analysis to justify relief from inspection of the circumferential welds, as described in LRA Section 4.2.4.

This generic BWR axial weld failure rate depends on given assumptions regarding flaw density, distribution, and location. The failure rate also assumes that "essentially 100 percent" of the reactor vessel axial welds will be inspected. The applicant stated that because of various obstructions within the reactor vessel, OCGS was not able to meet the "essentially 100 percent" axial weld inspection requirement. An analysis was performed to assess the effect the limited scope inspections on the axial weld failure probability. This analysis included an estimate and comparison of the failure probability for axial welds that had undergone an "essentially 100 percent" inspection and the failure probability for axial welds that had undergone the limited scope inspections. The analysis concluded that the conditional failure probability due to a low-temperature overpressurization event is very small, taking into consideration the limited scope axial weld inspection coverage. The NRC approved a relief request for the limited axial weld inspection coverage for the current 40-year licensed operating period. The staff's SER dated July 11, 2002, documents the technical basis for granting this relief. The anticipated changes in metallurgical conditions expected over the extended licensed operating period require an additional analysis for 50 EFPYs and NRC approval to extend the reactor vessel axial weld inspection relief request through the extended licensed operating period.

The applicant compared the limiting axial weld properties at 50 EFPYs with the limiting axial weld properties provided in the March 7, 2000, supplement to the SER for BWRVIP-05, which resulted in an NRC-calculated axial weld failure probability of 5×10^{-6} per reactor-year. The OCGS limiting axial weld chemistry, chemistry factor, and 50-EFPY mean RT_{NDT} values are within the limits of the values assumed in the staff's analysis. These limiting axial weld parameters also fall well within the 64-EFPY values reported in BWRVIP-05 and the 64-EFPY values reported in Table 2.6-5 of the staff's original SER on BWRVIP-05. Based on the above comparisons, the applicant concluded that the probability of failure for the axial welds is bounded by the NRC evaluation.

The applicant acknowledged that the axial weld failure probability of 5×10^{-6} per reactor-year calculated by the NRC in the supplement to the SER on BWRVIP-05 depends on the assumption that "essentially 100 percent" examination coverage of all reactor vessel axial welds can be achieved, in accordance with ASME Code, Section XI, requirements. At OCGS, less than 90 percent of the axial weld length can be examined. Therefore, the applicant performed an analysis for 50 EFPYs to assess the effect of the limited scope axial weld inspection on the axial weld failure probability. This analysis also determined whether the limited scope axial weld inspection provided sufficient coverage of regions contributing to the majority of the failure risk. As with the previous analysis that determined the conditional failure probability for the limited scope axial weld inspection coverage for the original 40-year licensed operating period, the 50-EFPY analysis included an estimate and comparison of the failure probability for axial welds that had undergone an "essentially 100 percent" inspection and the failure probability for axial welds that had undergone the limited scope inspections. The analysis determined that the conditional probability of failure due to a low-temperature overpressurization event was only 5.8×10^{-8} per reactor-year for the actual inspection coverage. This unit-specific axial weld conditional failure probability at 50 EFPYs is significantly lower than the 5×10^{-6} axial weld failure probability calculated by the NRC staff. The applicant concluded that this value provides a sufficient margin of safety to support relief from the requirement for an "essentially 100 percent" examination coverage of all axial welds, applicable to 50 EFPYs. The applicant will request an extension out to 50 EFPYs of this relief from the requirement for "essentially 100 percent" examination coverage of all reactor vessel axial welds prior to entering the period of extended operation (Commitment No. 47).

4.2.5.2 Staff Evaluation

In its July 28, 1998, letter, the staff identified a concern regarding the failure frequency of axial welds in BWR reactor vessels. In response to this concern, the BWRVIP supplied evaluations of axial weld failure frequency in letters dated December 15, 1998, and November 12, 1999. The staff's SER on these analyses is documented in a letter dated March 7, 2000. The staff performed a generic analysis using Pilgrim Nuclear Power Station as a model for BWR reactor vessels that were fabricated with electroslag welds and demonstrated that a mean RT_{NDT} of 114 °F resulted in a failure frequency of 5×10^{-6} per reactor-year of operation. The applicant calculated, and the staff confirmed, that the limiting axial weld mean RT_{NDT} value for OCGS at 50 EFPYs is 50.3 °F, which supports the conclusion that the failure frequencies will be less than 5×10^{-6} per reactor-year of operation at the end of the period of extended operation. Therefore, this analysis is acceptable.

The applicant is currently operating under an ISI program relief granted by the NRC that authorizes limited scope examination coverage for specified reactor vessel axial welds. The SER dated July 11, 2002, documents the technical basis for granting this relief from the ASME Code, Section XI, requirements mandating 100-percent examination coverage of all axial welds. This relief is effective through the end of the current 40-year licensed operating period and does not authorize reduced examination coverage for the applicable reactor vessel axial welds beyond the end of the current 40-year licensed operating period. The anticipated changes in metallurgical conditions expected over the extended licensed operating period require an additional analysis for 50 EFPYs and NRC approval to extend the reactor vessel axial weld inspection relief through the end of the extended licensed operating period. The applicant must submit, on an interval-by-interval basis, either a request for approval of an alternative to ASME Code, Section XI, requirements, pursuant to 10 CFR 50.55a(a)(3), or a request for relief from ASME Code, Section XI, requirements, pursuant to 10 CFR 50.55a(g)(6)(i), to address future axial weld examinations if less than "essentially 100 percent" coverage is, or will be, obtained.

4.2.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel axial weld examination relief in LRA Section A.4.1.5. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor vessel axial weld examination relief is adequate.

4.2.5.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel axial weld examination relief TLAA, the analyses have been projected to the end of the period of extended operation. However, even though the analyses have been projected to the end of the period of extended operation, the applicant will still have to submit, on an interval-by-interval basis, either a request for an alternative to ASME Code, Section XI, requirements, pursuant to 10 CFR 50.55a(a)(3), or a request for relief from ASME Code, Section XI, requirements, pursuant to 10 CFR 50.55a(g)(6)(i), to address future axial weld examinations if less than "essentially 100 percent" coverage is, or will be, obtained during the renewal period. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.6 Core Reflood Thermal Shock Analysis

4.2.6.1 Summary of Technical Information in the Application

In LRA Section 4.2.6, the applicant stated that OCGS, as a BWR-2, does not have jet pumps and therefore postdesign-basis analysis (DBA) loss-of-coolant accident (LOCA) reflood of the core does not occur. No reflood analysis has been performed for OCGS; therefore, reflood thermal shock analysis is not applicable.

4.2.6.2 Staff Evaluation

OCGS is a BWR-2 and does not have jet pumps. Therefore, post-DBA LOCA reflood of the core does not occur. No reflood analysis has been performed for OCGS. Therefore, the staff concludes that a core reflood thermal shock analysis is not required.

4.2.6.3 UFSAR Supplement

OCGS is a BWR-2 and does not have jet pumps. Therefore, post-DBA LOCA reflood of the core does not occur. No reflood analysis has been performed for OCGS. Therefore, a UFSAR supplement summary description of its TLAA evaluation is not required.

4.2.6.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that a core reflood thermal shock analysis is not required.

4.2.7 Reactor Internals Components

4.2.7.1 Summary of Technical Information in the Application

In LRA Section 4.2.7, the applicant summarized the evaluation of reactor internals components for the period of extended operation. A number of the reactor internals components are subject to high fluence because of their proximity to the core. This high fluence can lead to stress relaxation for bolting or irradiation assisted stress corrosion cracking (IASCC) for other components. Because the fluence experienced by components is a function of the life of the plant, the NRC safety evaluations for BWRVIP-25 and BWRVIP-26 have identified that neutron aging of these components is a TLAA issue. BWRVIP-25 also identifies stress relaxation of the core plate rim holddown bolts as a TLAA issue.

OCGS has installed core plate wedges, which structurally replace the lateral load resistance provided by the rim holddown bolts. Therefore, failure of the bolts due to stress relaxation is not a concern. Because core plate wedges have been installed, a calculation of stress relaxation of the rim holddown bolts has not been performed. Furthermore, BWRVIP-25 does not recommend inspection of the rim holddown bolts if wedges are installed. Thus, the applicant concluded that a TLAA is not applicable for the OCGS core plate holddown bolts.

The applicant stated that fluence calculations have been performed for the reactor vessel internals. The core shroud, incore instrumentation dry tubes, and top guide have experienced fluence greater than 5×10^{20} n/cm^2 (E > 1.0 MeV) and are considered susceptible to IASCC. No TLAA associated with IASCC exists for the core shroud, incore dry tubes, or top guide.

4.2.7.2 Staff Evaluation

The staff's review of LRA Section 4.2.7 identified an area in which additional information was necessary to complete the review of the reactor internals components. The applicant responded to the staff's RAI as discussed below.

The staff reviewed the information provided in the LRA and determined that the austenitic stainless steel materials in the core shroud, incore instrumentation dry tubes, and the top guide are exposed to neutron fluence greater than 5×10^{20} n/cm^2 (E > 1.0 MeV) and are considered susceptible to IASCC in the BWR environment.

In RAI 4.2.2-3 dated March 30, 2006, the staff requested that the applicant clarify why there is no TLAA associated with IASCC for the core shroud, incore instrumentation dry tubes, and top guide, given that these components have been exposed to a fluence exceeding 5×10^{20} n/cm^2 (E > 1.0 MeV) and are considered susceptible to IASCC.

In its response dated April 26, 2006, the applicant stated that portions of the core shroud, incore instrumentation dry tubes, and top guide have already been exposed to a fluence exceeding 5×10^{20} n/cm^2 (E > 1.0 MeV) and are therefore already considered susceptible to IASCC. As a result, the applicant stated that the aging effects of intergranular stress corrosion cracking (IGSCC) and IASCC for the core shroud, incore instrumentation dry tubes, and top guide is being managed by performing inspections as part of its BWR Vessel Internals Program, using the appropriate BWRVIP guidelines as follows:

> Core Shroud Aging Management. In 1994 Oyster Creek performed a comprehensive examination of the core shroud and discovered significant cracking in one of the core shroud's circumferential welds. During the same refueling outage core shroud repair hardware was installed to ensure the core shroud would continue to perform its intended function. The repair consisted of 10 tie rods anchored at the top and bottom of the core shroud. The core shroud repair system structurally replaces all horizontal welds. Therefore, as discussed in BWRVIP-76, no further inspection of the horizontal welds is required. Subsequent inspections focus on the vertical welds.
>
> For the period of extended operation, the vertical weld 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 visual examination of locking devices, critical gap or contact areas, bolting, and the overall component. The repair anchorage inspections include and EVT-1 inspection of the most highly stressed accessible load bearing weld every ten years. If indications are identified, they will be evaluated and appropriate corrective actions will be taken. This program provides reasonable assurance that the core shroud will perform its intended function during the period of extended operation.
>
> Incore Instrumentation Dry Tubes Aging Management. The inspection plan requires inspections to be conducted on the incore dry tubes in accordance with the requirements of GE SIL-409, Revision 2, and BWRVIP-47. Inspections at Oyster Creek have revealed cracking or crack indications for a number of the incore dry tubes. These cracks or indications have been observed in the top portion of the dry tube assembly and are attributed to the high fluence in this region.

GE incorporated design improvements into the upper portion of the replacement dry tube assemblies in 1986. The improvements consist of the elimination of crevices exposed to reactor water and a change to a more IASCC-resistant material in the region of the cracks. There have been no confirmed reports of cracking in dry tubes manufactured after 1986. The improved dry tube assemblies are direct replacements and have [a] minimum expected life of 20 years.

Oyster Creek plans to replace all currently installed incore instrumentation dry tubes by the end of 2008, starting in 2006. Oyster Creek will inspect the condition of the dry tubes during the first ten years of operation of the replacement incore dry tubes. Future inspection and replacement requirements will be based on the results of these inspections and other industry operating experience. Additional information can be found in the response to the NRC audit question AMR-348.

Top Guide Aging Management. The inspections of the top guide will be performed in accordance with BWRVIP-26-A. As a minimum, ten (10) percent of the top guide locations will be inspected using enhanced visual inspection technique, EVT-1, within 12 years, with one-half of the inspections (5 percent of locations) to be completed within 6 years. Since cracking has already been detected in portions of the top guide, Oyster Creek has an aggressive program to perform detailed [inspections] using UT methods during the current licensed operating period. In addition, all identified flaws are evaluated in accordance with BWRVIP guidelines. Corrective actions will be taken, including repair or replacement of the top guide if required. Additional information on the top guide can be found in the response to NRC audit question AMR-331.

Based on the above information, the staff concludes that the applicant had adequately demonstrated how the effects of aging will be managed for the core shroud, incore instrumentation dry tubes, and top guide. This management of aging effects will ensure that these reactor internals components will retain their integrity while in service. The applicant will take the appropriate corrective actions, including repair or replacement of these components, as warranted, based on the results of ISIs. The staff's concern described in RAI 4.2.2-3 is resolved.

4.2.7.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor internals components in LRA Section A.4.1.6. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor internals components is adequate.

4.2.7.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the reactor internals components TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue of the Reactor Vessel, Internals, and Reactor Coolant Pressure Boundary Piping and Components

A cyclically loaded metal component may fail because of fatigue even though the cyclic stresses are considerably less than the static design limit. Some design codes therefore contain explicit metal fatigue calculations or design limits, such as the ASME Code and the United States of America Standards (USAS) piping codes. Cyclic or fatigue design of other components may not be designed to these codes, but may use similar methods. The analyses, calculations, and designs tied to cycle count limits or to fatigue usage factor limits may be TLAAs.

4.3.1 Reactor Vessel Fatigue Analyses

4.3.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.1, the applicant summarized the evaluation of reactor vessel fatigue analyses for the period of extended operation. Reactor vessel fatigue analyses of the vessel, including the vessel support skirt, shell, upper and lower heads, closure flanges, nozzles and penetrations, nozzle safe ends, basin seal skirt support, and closure studs, depend on the assumed numbers and the severity of normal and upset-event pressure and thermal operating cycles to predict end-of-life fatigue usage factors. The assumed cycle counts used to determine fatigue usage factors are based on the 40-year life of the plant.

4.3.1.2 Staff Evaluation

The OCGS RPV was designed in accordance with ASME Code, Sections I and VIII. These codes do not require explicit fatigue analysis of the components. However, the applicant also evaluated the reactor vessel components using fatigue criteria similar to that contained in ASME Code, Section III.

The specific design criterion for fatigue analysis of the RPV components involves calculating the cumulative usage factor (CUF). The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The applicant's original design criteria required that the fatigue usage be less than 0.8, which is more conservative than the current ASME Code, Section III, requirement that the fatigue usage be less than 1.0.

The staff's review of LRA Section 4.3.1 identified areas in which additional information was necessary to complete the review of the reactor vessel fatigue analyses. The applicant responded to the staff's RAI as discussed below.

The LRA indicated that the fatigue usage (based on the use of projected cycles for 60 years) for the reactor vessel closure studs, support skirt, and the basin seal skirt to vessel flange junction was predicted to exceed the original OCGS acceptance limit of 0.8. The application also indicated that the fatigue usage of these components was shown to be acceptable by using more refined analysis methods.

In RAI 4.3-1 dated March 30, 2006, the staff requested that the applicant describe the more refined analyses that it performed for these components.

In its response dated May 1, 2006, the applicant described the analyses used to demonstrate that these components met the design allowable limit. The applicant indicated that revised analyses of the RPV closure studs and support skirt were performed using methodology from the 1995 Edition through 1996 Addenda of Section III of the ASME Code. The 1995 edition through 1996 Addenda of Section III of the ASME Code contains design criteria that are acceptable to the staff for performing a fatigue analysis of RPV components because they are referenced in 10 CFR 50.55a. The applicant's projected fatigue usage for these components is less than 0.8 for 60 years of plant operation.

The applicant also indicated that the RPV basin seal skirt was evaluated using a finite element model to obtain a more accurate stress. The applicant stated that the original stress and fatigue evaluations were updated using the stresses obtained from the finite element analysis. The applicant indicated that the resulting fatigue usage factors were all less than the original OCGS acceptance limit of 0.8.

The staff finds the use of a finite element model to be an acceptable method to evaluate the stresses in the RPV basin seal. The staff's concern described in RAI 4.3-1 is resolved.

The LRA indicated that the reactor vessel feedwater nozzles were reanalyzed to account for the effects of rapid thermal cycling. The application also indicated that the analysis satisfied the original reactor vessel design limits. However, LRA Table 4.3.1-2 indicates that the 40-year fatigue usage of the feedwater nozzle is projected to be 0.952.

In RAI 4.3-2 dated March 30, 2006, the staff requested that the applicant clarify whether the reanalysis of the feedwater nozzle for the rapid thermal cycling satisfied the original OCGS reactor vessel design fatigue limit of 0.8. The staff also requested that the applicant indicate when the analysis that calculated the fatigue usage of 0.952 was performed and provide the basis for its acceptance.

In its response dated May 1, 2006, the applicant indicated that the original RPV stress report predicted a fatigue usage of 0.1 for the feedwater nozzle blend radius region. The applicant also stated that the feedwater nozzles were reanalyzed as a result of crack indications found in 1977. The applicant indicated that the analysis used a conservative number of cycles for on/off feedwater flow at low power conditions. The reanalysis used a fatigue usage factor limit of 1.0 as the acceptance criterion. The applicant indicated that it had recently changed the RPV fatigue usage factor acceptance criterion from 0.8 to 1.0 using the process described in 10 CFR 50.59 making it consistent with the ASME Code, Section III, fatigue acceptance limit.

The applicant indicated a recent detailed stress analysis of the feedwater nozzle using the 1995 Edition through 1996 Addenda of Section III of the ASME Code predicted a fatigue usage factor of 0.389 for 60 years of plant operation. As discussed previously, the 1995 Edition through 1996 Addenda of Section III of the ASME Code contains design criteria that are acceptable to the staff for performing a fatigue analysis of RPV components.

LRA Table 4.3.1-1 provides the RPV design transients. These include the RPV design transients specified in the FSAR Update, Table 5.2-2, plus additional transients that were not included in the original RPV design. LRA Table 4.3.1-1 indicates that the number of design plant heatup/cooldown and scram cycles may be exceeded during the period of extended operation. The applicant will use its Metal Fatigue of Reactor Coolant Pressure Boundary Program to monitor the fatigue usage of the bounding RPV locations to assure that the fatigue usage design limits are not exceeded. The applicant indicated that the program will monitor the RPV locations listed in LRA Table 4.3.1-2.

The staff finds that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program is acceptable for managing the fatigue usage of RPV components during the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii). The staff's concern described in RAI 4.3-2 is resolved.

4.3.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel fatigue analyses in LRA Section A.4.2.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor vessel fatigue analyses is adequate.

4.3.1.4 Conclusion

On the basis of its review and the RAI responses, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the reactor vessel fatigue analyses TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2 Fatigue Analysis of Reactor Vessel Internals

The design codes described in LRA Section 4.3.1 did not require a fatigue analysis to be performed for nonpressure boundary components of the RPV. However, the OCGS license renewal process reviewed the existing licensing basis analyses for additional analyses that may contain fatigue analyses. The review of the CLB found no fatigue analysis on the reactor vessel internals with the exception of one associated with the shroud repairs.

4.3.2.1 Low-Cycle Thermal and Flow-Induced Vibration Fatigue Analysis of the Core Shroud and Repair Hardware

4.3.2.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.2.1, the applicant summarized the evaluation of low-cycle thermal and flow-induced vibration fatigue analysis of the core shroud and repair hardware for the period of extended operation. Only one analysis of low-cycle fatigue of reactor vessel internals was identified for OCGS, which includes an evaluation of the core shroud and core shroud repair hardware. The core shroud repair safety evaluation for OCGS states that the limiting upset loading condition is the cold feedwater transient. The design analysis for the repair determined this event to be the most significant contributor to fatigue usage.

A review of licensing-basis documents found no evidence of analyses of pressure or thermal cycle fatigue for the core plate, top guide, fuel supports, incore instrumentation tubes, or CRD assemblies. Low-cycle mechanical fatigue was mentioned only for the tie rod stabilizers in the core shroud repair evaluations.

The currently predicted 40-year CUF for the core shroud and core shroud repair hardware is less than 0.04. In 60 years, this would translate to 0.06. These usage values are small compared to the acceptance limit of 1.0. Moreover, the repair hardware was designed for a 40-year life. Since the shroud repairs were installed in 1994, the design of the core shroud repair hardware for fatigue effects will remain valid for the extended licensed operating period.

4.3.2.1.2 Staff Evaluation

The applicant indicated that the only fatigue analysis of the OCGS reactor vessel internals involved the core shroud repair. The applicant further indicated that the maximum fatigue usage for the limiting thermal transient was 0.04. The applicant estimated the maximum fatigue usage of 0.06 for 60 years of operation, which is well within the ASME Code allowable limit of 1.0. The staff finds acceptable the applicant's conclusion that the projected fatigue usage is small compared to the ASME Code allowable limit of 1.0. Therefore, the staff finds that the applicant's evaluation provides an acceptable basis to demonstrate that the fatigue usage of the core shroud repair will remain within the ASME Code limit.

4.3.2.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of low-cycle thermal and flow-induced vibration fatigue analysis of the core shroud and repair hardware in LRA Section A.4.2.2.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address low-cycle thermal and flow-induced vibration fatigue analysis of the core shroud and repair hardware is adequate.

4.3.2.1.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the low-cycle thermal and flow-induced vibration fatigue analysis of the core shroud and repair hardware TLAA, the analyses will remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3 Reactor Coolant Pressure Boundary Piping and Component Fatigue Analysis

4.3.3.1 Reactor Coolant Pressure Boundary Piping and Components

4.3.3.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.3.1, the applicant summarized the evaluation of RCPB piping and components for the period of extended operation. The RCPB piping was designed to ASME Code, Section I, as stated in UFSAR Section 3.1.26. ASME Code, Section I, refers to American Standards Association (ASA) B31.1 of 1955 for design requirements except for materials. In addition, the reactor recirculation pumps were designed to ASA B31.1 (1955) and ASME Code, Section VIII. All remaining non-RCPB piping was analyzed based on ASA B31.1 (1955) or the ASME Code. In a few instances, piping was designed to ASME Code, Section II, Class 2 or 3. In addition, all 11 Class I (seismic) piping systems were evaluated based on USAS B31.1 of 1983, Winter 1984 Addenda.

The thermal cycles used in the reactor vessel fatigue analysis conservatively approximate the assumed thermal cycle count for the analyses used in the codes associated with piping and components. UFSAR Table 5.2-2 lists some of these thermal cycles. Based on a detailed review of components and assessments performed as a part of the Metal Fatigue of Reactor Coolant Pressure Boundary Program, the applicant identified additional thermal cycles. When combined, the total count of the thermal cycles in LRA Table 4.3.1-1 is less than 2,700 for a 40-year plant operating period. For the 60-year extended operating period, the number of thermal cycles for piping analyses would be proportionally increased to less than 3,500, a fraction of the 7,000-cycle threshold. Therefore, the applicant determined that the existing piping analyses within the scope of license renewal containing assumed thermal cycle counts are valid for the period of extended operation.

4.3.3.1.2 Staff Evaluation

The applicant indicated that RCPB piping was originally designed in accordance with ASA B31.1, which did not require explicit fatigue analyses of piping components. Instead, ASA B31.1 contained a limit of 7,000 for equivalent full-range thermal cycles. The same 7,000 cycle limit applies to B31.1 and ASME Code, Class 2 and 3 piping. The applicant used the total number of design thermal cycles listed in LRA Table 4.3.1-1 to estimate the maximum number of thermal cycles for 40 years of plant operation. The applicant then multiplied the 40-year number by 1.5 to estimate the maximum number of cycles for 60 years of plant operation. The applicant's evaluation applied to both the RCPB piping and the non-RCPB piping. The staff concludes that the applicant performed a conservative estimate of the maximum number of full-range thermal cycles because most of the transients listed in LRA Table 4.3.1-1 do not result in full-range thermal bending stresses at the maximum allowable ASA B31.1 thermal expansion stress range. Therefore, the staff finds that the applicant performed an acceptable evaluation to demonstrate that the piping analyses remain valid for the period of extended operation.

4.3.3.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of RCPB piping and components in LRA Section A.4.2.3.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address RCPB piping and components is adequate.

4.3.3.1.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the RCPB piping and components TLAA, the analyses will remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3.2 Fatigue Analysis of the Isolation Condenser

4.3.3.2.1 Summary of Technical Information in the Application

In LRA Section 4.3.3.2, the applicant summarized the evaluation of fatigue analysis of the isolation condenser for the period of extended operation. The OCGS isolation condenser provides core cooling when the reactor vessel becomes isolated from the turbine and the main condenser. The UFSAR indicates that the isolation condenser was designed for 1,500 cycles of operation. Fatigue evaluation of the OCGS isolation condenser was not performed as a part of original component design. However, subsequent stress and fatigue evaluations were performed for portions of the isolation condenser system. The isolation condenser piping outside of the containment was evaluated for fatigue as a part of a leak-before-break (LBB) analysis completed in 1991. In addition, a transient stress analysis was performed for the isolation condenser tubes as a part of tube bundle replacement in 1998. A plant-specific stress analysis performed for the replacement tube bundles states that the design life of the tube bundle is 1500 cycles. Further, a comparison between the Nine Mile Point Unit 1 and OCGS isolation condensers determined that the two condensers are similar enough for the Nine Mile Point Unit 1 stress and fatigue results to be considered bounding when applied to OCGS. The applicant determined that these stress and fatigue analyses, when applied to the OCGS associated with the isolation condenser, demonstrate that the 40-year CUFs for the critical components of the isolation condenser are below the ASME Code, Section III, allowable value of 1.0.

4.3.3.2.2 Staff Evaluation

The staff's review of LRA Section 4.3.3 identified areas in which additional information was necessary to complete the review of the fatigue analysis of the isolation condenser. The applicant responded to the staff's RAI as discussed below.

The applicant indicated that a fatigue evaluation of the OCGS isolation condenser was not performed as part of the original component design. However, the applicant also indicated that the design life of the replacement tube bundle is 1500 cycles.

In RAI 4.3-3 dated March 30, 2006, the staff requested that the applicant provide the following information regarding the evaluation of the isolation condenser:

(a) The application indicates that a fatigue analysis was not performed as part of the original component design. The application also indicates that a later evaluation was performed for the tube bundle replacement in 1998 and that the design life of the tube bundle replacement is 1500 cycles. Explain how the design life of 1500 cycles was determined. Provide the fatigue usage based on the peak stresses calculated for the OCGS tube bundle replacement.

(b) The application references the fatigue analysis of the Nine Mile Point Unit 1 isolation condenser. It indicates that the Nine Mile Unit 1 isolation condenser stress and fatigue results are considered bounding for OCGS. Provide a detailed discussion of how it was determined that the Nine Mile Point Unit 1 analysis was bounding for OCGS. The discussion should include a comparison of the isolation condenser sizes and the sub-component materials, geometries and thicknesses and should address the tube and shell thermal transients and flow rates.

(c) The application indicates that the isolation condenser piping outside of the containment was evaluated for fatigue as part of a leak-before-break (LBB) analysis completed in 1991. It indicates that the piping outside the drywell was replaced in 1992. Provide the design criteria that was used to evaluate the replacement piping, including the number and types of thermal transients analyzed. Provide the maximum calculated fatigue usage for the replacement piping.

In its response dated May 1, 2006, the applicant indicated that the design life of 1500 cycles was obtained using the bounding value of the stress intensity for the six cross sections evaluated in the 1998 Holtec stress report of the OCGS emergency condenser tube bundle replacement. The applicant indicated that, considering the number of projected cycles listed in LRA Table 4.3.1-1, the maximum fatigue usage of the isolation condensers would be 0.347 for the period of extended operation. The applicant further indicated that, at the time the LRA was prepared, a plant-specific stress analysis had not been located for the OCGS isolation condensers. As a consequence, the applicant referenced the Nine Mile Point Unit 1 analysis. The applicant indicated that the Holtec stress report was subsequently located. The applicant stated that the 1500-cycle allowable limit was based on the number of allowable cycles obtained from the fatigue curve, considering the maximum alternating stress intensity reported in the Holtec stress report. The applicant projected that the number of cycles of emergency isolation condenser actuation will be below the 1500-cycle design limit through the period of extended operation. Therefore, the staff concludes that the applicant has performed an adequate evaluation to demonstrate that the fatigue usage of the isolation condensers will remain within acceptable limits during the period of extended operation.

The applicant's response indicated that MPR Associates, Inc., conducted an ASME Code, Section III, fatigue evaluation of the isolation condenser piping outside the drywell. The fatigue evaluation was performed on the piping replaced in 1992. The applicant indicated that the piping was evaluated for 400 cycles using a conservative step change in temperature transient. The maximum calculated usage factor was 0.174. The applicant also indicated that the calculated fatigue usage was less than the screening criteria of 0.4, therefore, the piping was not included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff finds that using a step change in temperature to represent the temperature transient is conservative. The applicant's estimated number of design cycles for 60 years of plant operation for the "B" condenser is 520, which exceeds the 400 cycles used for the piping fatigue evaluation. The applicant stated that the actual number of thermal cycles for the piping is not expected to exceed 400 because the piping was replaced in 1992. Considering that the maximum calculated fatigue usage for 400 cycles is only 0.174, the staff concludes that the fatigue usage of the isolation condenser piping outside the drywell should remain within the ASME Code allowable limit of 1.0 during the period of extended operation and is acceptable.

The applicant indicated that the isolation condenser piping inside the drywell was evaluated as part of the reactor recirculation piping described in LRA Section 4.3.4. The staff reviewed Metal Fatigue of Reactor Coolant Pressure Boundary Program in SER Section 3.0.3.2.27, and determined that the program will provide an acceptable method to assure that the fatigue usage of these components will remain within acceptable limits during the period of extended operation.

Based on the above discussion, the staff's concerns described in RAI 4.3-3 are resolved.

4.3.3.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of fatigue analysis of the isolation condenser in LRA Section A.4.2.3.3. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address fatigue analysis of the isolation condenser is adequate.

4.3.3.2.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the fatigue analysis of the isolation condenser TLAA, the analyses will remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.4 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)

4.3.4.1 Summary of Technical Information in the Application

In LRA Section 4.3.4, the applicant summarized the evaluation of the effects of the reactor coolant environment on fatigue life of components and piping, Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," for the period of extended operation. ASME Code, Section III, uses stress versus allowable cycle curves (S-N curves) based on tests in air to determine a fatigue usage factor. GSI-190 addresses the effects of the reactor coolant environment on fatigue life of components and piping. The environment of a stressed component can affect fatigue life. Although GSI-190 is resolved, SRP-LR Section 4.3.1.2 states that, "The applicant's consideration of the effects of coolant environment on component fatigue life for license renewal is an area of review." The GSI-190 review requirements are therefore imposed by the SRP-LR and do not depend on the individual plant licensing basis.

The applicant further stated that the staff assessed the impact of reactor water environment on fatigue life at high-fatigue usage locations and presented the results in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," dated March 1995. To comply with the requirements of GSI-190, OCGS would be required to perform plant-specific calculations for the locations identified in NUREG/CR-6260 for the older vintage BWR plants. For license renewal, plant-specific calculations have been performed for the following locations identified in NUREG/CR 6260 for older vintage BWR:

- reactor vessel (lower head to shell transition),
- feedwater nozzle
- recirculation system (residual heat removal (RHR) return line tee, or the shutdown cooling return line tee at OCGS, and the RPV inlet and outlet nozzles),
- core spray system (nozzle and safe end),
- RHR line (tapered transition); OCGS does not have an RHR system (location is bounded by the isolation condenser return line tee), and
- limiting Class 1 location in a feedwater line

For each location, detailed environmental fatigue calculations were performed using the appropriate environmental factor (F_{en}) relationships from NUREG/CR 6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steel," dated February 1998, for carbon and low-alloy steels and from NUREG/CR 5704, "Effects of LWR

Coolant Environment on Fatigue Design Curves of Austenitic Stainless Steels," dated April 1999, for stainless steels, as appropriate for the material at each of the above locations.

4.3.4.2 Staff Evaluation

The applicant indicated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced before the period of extended operation to assure that the design cycle limits are not exceeded. The applicant's program will track transients and cycles of critical reactor coolant system components that have explicit design transient cycles to assure that these components remain within their design basis. GSI-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190 to address license renewal. The staff closed GSI-190 in December, 1999, and concluded the following:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe leaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant evaluated the effects of the reactor coolant environment on the fatigue life of locations equivalent to those identified in NUREG/CR-6260. LRA Table 4.3.4-1 provides the overall environmental fatigue multipliers for the components analyzed. The staff compared the usage factors provided by the applicant with the usage factors presented in NUREG/CR-6260 for the older vintage BWR. NUREG/CR-6260 identified several locations for which the environmental usage factor was projected to exceed 1.0, including the core spray nozzle safe end, the feedwater nozzle, the feedwater line reactor core isolation coolant (RCIC) tee connection, and the RHR return line tee.

OCGS is a BWR-2, whereas the locations selected in NUREG/CR-6260 are based on a BWR-4. Consequently, some of the NUREG/CR-6260 locations are not directly applicable to OCGS. The applicant selected the isolation condenser return line tee into the shutdown cooling line as an alternative to the RHR return line tee for the evaluation. In addition, the applicant selected the limiting Class 1 location on the feedwater line as an alternative to the RCIC connection because OCGS does not have an RCIC system. The applicant indicated that the RHR tapered transition is bounded by the isolation condenser return line tee. The applicant also added the recirculation inlet and outlet nozzles to the evaluation. The staff finds the applicant's alternative selections reasonable and acceptable.

The applicant also indicated that OCGS uses hydrogen water chemistry. The NUREG/CR-6260 components were evaluated for a high oxygen environment without hydrogen water chemistry.

Oxygen concentration has a significant impact on the fatigue life of carbon and low-alloy steel components. Hydrogen water chemistry is used to lower the oxygen concentration in BWRs in order to reduce the potential for stress corrosion cracking (SCC) of stainless steel components. The reduced oxygen concentration also results in a significant reduction in the impact of the environment on the fatigue life of the OCGS carbon and low-alloy steel components compared to the equivalent NUREG/CR-6260 carbon and low-alloy steel components.

The staff's review of LRA Section 4.3.4 identified an area in which additional information was necessary to complete the review of the effects of the reactor coolant environment on the fatigue life of components and piping. The applicant responded to the staff's RAI as discussed below.

In RAI 4.3-4 dated March 30, 2006, the staff requested that the applicant provide the calculation of the F_{en} for the RPV inlet and outlet nozzles and the feedwater nozzle and explain how each parameter used in the calculation was determined.

In its response dated May 1, 2006, the applicant described the basis for the calculated F_{en} factors. The applicant indicated that the usage factor for the recirculation inlet nozzle was based on an overall environmental factor that considered the amount of time normal water chemistry was used before the implementation of hydrogen water chemistry at OCGS. The applicant assumed a saturated strain rate and the maximum transient temperature for the calculation. These assumptions are conservative because they maximize the calculated F_{en} factor and resulting fatigue usage. The resulting usage factor is well within the allowable limit of 1.0. The staff finds this evaluation acceptable.

The applicant indicated the that the fatigue usage at the recirculation outlet nozzle is greater than the inlet nozzle, primarily because the outlet nozzle experiences added thermal transients associated with operation of the isolation condenser. The applicant calculated specific F_{en} factors for each load-pair based on the maximum temperature and average strain rate for the load-pair. The staff considers the use of the average strain rate acceptable for calculating the F_{en} factor. The evaluation also considered the amount of time normal water chemistry was used before the implementation of hydrogen water chemistry at OCGS. This explains the differences in reported F_{en} factors between the recirculation inlet and outlet nozzles. The staff finds the applicant's evaluation of the recirculation outlet nozzle acceptable.

The applicant indicated that the fatigue usage of the feedwater nozzle was calculated using a similar method to that used for the recirculation outlet nozzle. The applicant calculated specific F_{en} factors for each load-pair considering the amount of time the nozzle was subject to hydrogen water chemistry. The staff questioned whether the F_{en} factor value of 2.17 for the low-alloy steel feedwater nozzle was correct. The minimum value of F_{en} for low-alloy steel using the equations in NUREG/CR-6583 should be 2.45.

In a supplemental response to RAI 4.3-4 dated June 12, 2006, the applicant explained the basis for the F_{en} factor. The applicant indicated that the initial fatigue usage (without environmental considerations) was calculated assuming the number of transient cycles for 60 years of plant operation. However, since the feedwater nozzle was replaced after 7 years of plant operation, the applicant used the number of transient cycles for 53 years of plant operation to calculate the environmental fatigue usage. The applicant calculated an average F_{en} factor based on the ratio of the environmental fatigue usage to the fatigue usage without environmental considerations. The staff finds the applicant's explanation of its basis for the reported F_{en} factor acceptable.

The applicant used the same environmental factor for the RPV and core spray nozzle that was used for the recirculation inlet nozzle. The resulting environmental fatigue usage was well within the allowable limit of 1.0 for the period of extended operation. The applicant reported a F_{en} factor for the stainless steel isolation condenser return line tee that is consistent with a thermal transient with a relatively high strain rate. As discussed in the previous section of this SER, the applicant stated that the isolation condenser return line piping was evaluated using a conservative step change in temperature. A step change in temperature will cause a relatively high strain rate in the piping. The applicant's evaluation of the isolation condenser return line tee connection indicated that the environmental fatigue usage was well within the allowable limit of 1.0 for the period of extended operation. The staff finds the evaluations of the reactor vessel, core spray nozzle, and isolation condenser return line tee acceptable.

The applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program, which is evaluated in SER Section 3.0.3.2.29, will monitor these locations. The applicant indicated that the program will track the fatigue usage of these locations using either stress-based or cycle-based monitoring. The staff finds that the applicant's program will provide an acceptable method to assure that the fatigue usage of these components will remain within acceptable limits during the period of extended operation. The staff's concern described in RAI 4.3-4 is resolved.

4.3.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the effects of GSI-190 in LRA Section A.4.2.4. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address GSI-190 is adequate.

4.3.4.4 Conclusion

On the basis of its review and the RAI responses, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the effects of the reactor coolant environment on fatigue life of components and piping TLAA, the analyses have been projected to the end of the period of extended operation. The applicant also demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the effects of the reactor coolant environment on fatigue life of components and piping TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification of Electrical Equipment

The 10 CFR 50.49 Environmental Qualification Program has been identified as a TLAA for the purposes of license renewal. The TLAA of EQ electrical components includes all long-lived, passive, and active electrical components and instrumentation and controls (I&C) components that are important to safety and located in a harsh environment. The harsh environments of the plant are those areas that are subjected to environmental effects by a LOCA or a high-energy line break. The EQ equipment comprises safety-related and Q-list equipment, nonsafety-related equipment the failure of which could prevent satisfactory accomplishment of any safety-related function, and necessary postaccident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of EQ TLAAs in the LRA. The applicant shall demonstrate that, for each type of EQ equipment, one of the following is true: (1) the analyses will remain valid for the period of extended operation, (2) the analyses have been projected to the end of the period of extended operation, or (3) the effect of aging on the intended functions will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

In LRA Section 4.4, the applicant summarized the evaluation of EQ of electrical equipment for the period of extended operation. Certain provisions in 10 CFR 50.49(e)(5) regarding aging require, in part, consideration of all significant types of aging degradation that can affect component functional capability. This section also requires component replacement or maintenance before the end of designated life, unless additional life is established through ongoing qualification. Different qualification criteria, pursuant to 10 CFR 50.49(k) and (l), apply based on plant vintage. RG 1.89, Revision 1, "Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants," dated June 1984, the Division of Operating Reactors (DOR) Guidelines, and NUREG-0588 provide supplemental EQ regulatory guidance for compliance with these different qualification criteria. The Environmental Qualification Program was established to demonstrate that certain electrical components are qualified to perform their safety function in harsh plant environments after the effects of inservice aging. The program complies with the requirements of 10 CFR 50.49, or DOR guidelines for that equipment presently qualified to DOR guidelines. The EQ-related equipment is identified in controlled equipment databases and equipment qualification binders. The Environmental Qualification Program manages component thermal, radiation, and cyclic aging as applicable, through the aging evaluations based on 10 CFR 50.49 or DOR guidelines for those components presently qualified with DOR guidelines.

With regard to GSI-168, the applicant stated that it is performing an analysis for all EQ-related equipment and will qualify all low-voltage I&C cables for 60 years of service without lowering the original environmental service conditions. Cables that cannot be shown to have a qualified life of 60 years will be replaced or reanalyzed before the end of their qualified life. In some cases, actual cable loads will be determined and provided as a basis for reanalysis. For OCGS, the EQ TLAA ensures that the effects of aging will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). Therefore, with respect to GSI-168, adherence to the Environmental Qualification Program and use of current EQ process will provide reasonable assurance through the extended period of operation that the equipment qualification will be maintained in compliance with the applicable NRC requirements. EQ cables will be inclusive of a new inspection program, described in LRA Section B.1.34, that will visually inspect a sample of cables and connections located in adverse localized environments for indications of accelerated age-related degradation. The scope of this program includes inspections of power, I&C cables, and connections. These inspections will be performed before the period of extended operation, with an inspection frequency of at least once every 10 years.

Aging evaluations of electrical components in the Environmental Qualification Program that specify qualification of at least 40 years are TLAAs. As such, a reanalysis will be applied to EQ components now qualified for the current operating term of 40 years. Reanalysis of an aging evaluation to extend the qualification of a component is performed by reducing margin or excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component may be performed as part of the Environmental Qualification Program. While a component life-limiting condition may result from thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, unrealistically low activation energy, or application of a component (deenergized versus energized). The important attributes of reanalysis will include analytical methods, data collection and conservative reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

4.4.2 Staff Evaluation

The staff reviewed LRA Section 4.4 to determine whether the applicant had submitted adequate information to meet the requirement of 10 CFR 54.21(c)(1). For the electrical equipment identified in LRA Table 4.1-1, the applicant used 10 CFR 54.21(c)(1)(iii) to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. The staff reviewed the Environmental Qualification Program to determine whether it will ensure that the electrical and I&C components covered under this program will continue to perform their intended functions consistent with the CLB for the period of extended operation. The staff's evaluation of the components' qualification focused on how the Environmental Qualification Program manages the aging effects to meet the requirements delineated in 10 CFR 50.49.

The staff conducted an audit of the information provided in LRA Section B3.2 and program bases documents. On the basis of its audit, the staff finds that the Environmental Qualification Program, which the applicant claimed to be consistent with the GALL AMP X.E1, "Environment Qualification of Electrical Components," is consistent with the GALL Report. Therefore, the staff finds that the program is capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the Environmental Qualification Program provides reasonable assurance that the aging effects will be managed and that components within the scope of the program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Environmental Qualification of Electrical Equipment in LRA Section A.4.3. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address EQ is adequate.

4.4.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the Environmental Qualification of Electrical Equipment TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.5 Loss of Prestress in Concrete Containment Tendons

4.5.1 Summary of Technical Information in the Application

In LRA Section 4.5, the applicant stated that the containment does not have prestressed tendons. Thus, this topic is not a TLAA at OCGS.

4.5.2 Staff Evaluation

OCGS containment does not have prestressed tendons; therefore, the staff finds that this TLAA is not required.

4.5.3 UFSAR Supplement

OCGS containment does not have prestressed tendons; therefore, a UFSAR supplement is not required.

4.5.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that this TLAA is not required for OCGS.

4.6 Fatigue of Primary Containment, Attached Piping, and Components

The primary containment was designed in accordance with ASME Code, Sections VIII and IX (the latest edition at the time of the design and all applicable addenda), and Nuclear Case Interpretations 1270-N-5, 1271-N, and 1272-N-5. Subsequent to design completion and start of commercial operation, new suppression chamber (or torus) hydrodynamic loads were identified during industry performance of large-scale testing for the Mark III containment system and in-plant testing for Mark I primary containment systems. The "new loads" are related to the postulated LOCA and electromagnetic relief valve (EMRV) operation (also referred to as a safety relief valve in some parts of the UFSAR). Therefore, subsequent to the original OCGS containment design, the containment was reanalyzed in response to the "new loads" discoveries by GE and others of unevaluated loads resulting from design-basis events and EMRV discharge. The load definitions included assumed pressure and temperature cycles resulting from EMRV discharge and design-basis LOCA events. This reevaluation was performed in two parts, generic analyses applicable to each of the several classes of BWR containments and Mark I containment program plant unique analyses. The scope of the analyses included the pressure suppression chamber (shells and welds), the drywell-to-pressure suppression chamber vents (header and downcomers), EMRV discharge piping, other piping attached to the pressure suppression chamber, penetrations, and vent bellows. In addition, the suppression chamber and suppression chamber vents, including the vent headers and downcomers, were modified at OCGS over a number of years, commencing in 1975, in order to reestablish the original design safety margins when new loads were considered. The modification work was performed in accordance with several codes, including ASME Code Section III, Subsection NE, "Class MC Components," 1977 Edition through Summer 1977 Addenda. Finally, the plant unique analysis for OCGS was updated in 1994 to accommodate an increased EMRV setpoint pressure.

4.6.1 Fatigue Analysis of the Primary Containment System (Includes Suppression Chamber, Vents, Vent Headers, and Downcomers, EMRV Discharge Piping inside the Suppression Chamber, External Suppression Chamber Attached Piping, Associated Penetrations, and Drywell-To-Suppression Chamber Vent Line Bellows)

4.6.1.1 Summary of Technical Information in the Application

In LRA Section 4.6.1, the applicant summarized the evaluation of fatigue analysis of the primary containment system (including the suppression chamber, vents, vent headers, and downcomers; EMRV discharge piping inside the suppression chamber; external suppression chamber attached piping and associated penetrations; and drywell-to-suppression chamber vent line bellows) for the period of extended operation. There are 5 SRVs (EMRVs) installed in the main steam system. When opened, steam discharges from each EMRV through piping routed through the drywell to the suppression chamber. The EMRV discharge piping enters the suppression chamber through penetrations on the suppression chamber vent header where the steam is discharged to the suppression chamber water through a quencher attached to the suppression chamber. There are also a number of external piping systems attached to the suppression chamber shell. Mark I containment designs include a drywell-to-suppression chamber vent line. A bellows assembly is provided at the penetration of the vent line to the suppression chamber. The bellows allows differential movement of the vent system and suppression chamber to occur without developing significant interaction loads. New hydrodynamic loads were identified subsequent to the original design for the containment suppression chamber vents. These additional loads result from blowdown into the suppression chamber during a postulated LOCA and during EMRV operation during plant transients. The latest OCGS plant unique analysis report presents the results of analyses of these effects. This report describes the fatigue analyses of EMRV discharge lines, Y-quenchers, the EMRV discharge line penetrations through the vent lines, suppression chamber shell (torus) attached piping systems, and the associated penetrations. These analyses assume a limited number of EMRV actuations throughout the 40-year life of the plant and are therefore TLAAs.

Regarding its analysis, the applicant stated that the current design-basis analyses assumed 450 EMRV actuations of all 5 EMRVs simultaneously during the normal operating condition, plus 20 cycles for an intermediate-break accident or 20 cycles for a small-break accident or 1 cycle for a DBA, whichever was more bounding. In addition, it was assumed that each EMRV actuation results in one thermal, one pressure, and five dynamic load cycles. The design basis also included an operating-basis earthquake, which was assumed to be equivalent to 10 EMRV cycles. LRA Table 4.6.1-1 summarizes the design-basis fatigue CUF values from the analyses described above. For all primary containment system components the majority of the CUF is caused by accident loading, which is not expected to occur. The contribution to CUF by EMRV actuations is small and will remain small for the number of events anticipated for the 60-year life of the plant. Because the projected number of actual events for 60 years of operation is less than the number assumed in the design-basis (40-year) analysis, this analysis remains bounding for the period of extended operation. Therefore, CUFs for these locations are expected to remain below the allowable value of 1.0 for the 60-year life of the plant. Monitoring of these locations in the Metal Fatigue of Reactor Coolant Pressure Boundary Program will verify this assumption.

4.6.1.2 Staff Evaluation

The staff's review of LRA Section 4.7.1.1 identified an area in which additional information was necessary to complete the review of the reactor building crane. The applicant responded to the staff's RAI as discussed below.

In LRA Section 4.6.1, the applicant indicated that primary containment was designed in accordance with ASME Code, Sections VIII and IX (the latest edition at the time of the design and all applicable addenda) and Nuclear Case Interpretations 1270-N-5, 1271-N, and 1272-N-5. The applicant further indicated that the modification work associated with the Mark 1 containment long-term program was performed in accordance with several codes, including ASME Code, Section III, Subsection NE, 1977 Edition through Summer 1977 Addenda. Finally, the OCGS analysis was updated in 1994 to accommodate an increased EMRV setpoint pressure. In addition, the applicant indicated that it performed a structural evaluation of drywell thinning at various locations in 1986 and 1987.

In RAI 4.6-1 dated March 30, 2006, the staff requested that the applicant describe the structural evaluation that was performed and indicate whether the evaluation involved any TLAAs.

In its response dated May 1, 2006, the applicant stated that the drywell shell plates were not evaluated for fatigue. The applicant indicated that updated information regarding the evaluation of the drywell thinning was provided in response to RAI 4.7.2-1.

On the basis of the applicant's statement that the drywell shell plates had not been evaluated for fatigue, this RAI response is considered to be acceptable. SER Section 4.7 documents further discussion of the applicant's evaluation of drywell thinning. The staff's concern described in RAI 4.6-1 is resolved.

As stated in the previous section, the applicant indicated that the majority of the fatigue usage of the critical components associated with primary containment system suppression chamber is caused by the DBA and operating-basis earthquake loading combination. This load combination is not expected to occur during the plant lifetime and; therefore, the number of these postulated load combinations do not increase for the period of extended operation. The remaining load combination relevant to the fatigue usage involves EMRV actuations during normal operating conditions. The applicant indicated that the number of expected EMRV actuations is 188 through the period of extended operation. The number of expected actuations is within the 450 EMRV actuations assumed for the fatigue evaluation of primary containment components.

On this basis, the staff concludes that the fatigue analyses of the primary containment components will remain valid for the period of extended operation. In addition, the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor the number of EMRV actuations. The staff concludes that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program will provide assurance that the fatigue usage of the primary containment components will remain within the allowable limit of 1.0 during the period of extended operation.

4.6.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of fatigue analysis of the primary containment system in LRA Section A.4.4.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address fatigue analysis of the primary containment system is adequate.

4.6.1.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the fatigue analysis of the primary containment system TLAA, the analyses will remain valid for the period of extended operation. The applicant has also demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the fatigue analysis of the primary containment system TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.2 Primary Containment Process Penetrations and Bellows Fatigue Analysis

4.6.2.1 Summary of Technical Information in the Application

In LRA Section 4.6.2, the applicant summarized the evaluation of primary containment process penetrations and bellows fatigue analysis for the period of extended operation. Containment pipe penetrations must accommodate thermal movement during normal plant operation and transients. Some of the piping penetrations have bellows to help accommodate expansion from differential thermal growth. The penetrations and bellows are designed for a minimum number of operating thermal cycles over the design life of the plant at normal, test, and limiting design containment pressures. These analyses also assume a limited number of thermal cycles throughout the 40-year life for the plant and are therefore TLAAs.

Evaluation of the containment penetrations was performed in accordance with the cyclic exclusion criteria of ASME Code, Section III, Subsection NE-3221.5(d). The applicant evaluated the limiting containment penetrations for thermal cycles as summarized in LRA Table 4.6.2-1. Two of the containment penetrations (main steam and feedwater) also have bellows to help accommodate thermal expansion. The containment process line bellows are designed for 7000 cycles. LRA Table 4.6.2-1 also summarizes the evaluation of the process line bellows for thermal cycles.

The governing fatigue analyses have been reviewed to establish a comprehensive and bounding set of penetration results for evaluation of fatigue effects in the license renewal period. LRA Table 4.6.2-1 summarizes the results of the penetration analyses. This table shows the expected number of relevant thermal cycles for each penetration for the 60-year extended operating period. For all of the penetrations, the 60-year number of cycles is projected to be less than the number of cycles evaluated in the design-basis fatigue exemption analyses. Thus, the 60-year cycle counts continue to permit the fatigue exemption requirements of ASME Code Section III, Subsection NE, to be met for a 60-year operating period. LRA Table 4.6.2-1 also includes the feedwater and main steam penetrations bellows. The number of relevant cycles anticipated for the 60-year extended period of operation is considerably less than the 7000 allowed cycles for each penetration. As additional assurance that these requirements will continue to be met, the Metal Fatigue of Reactor Coolant Pressure Program will include the bounding (isolation condenser) penetration.

4.6.2.2 Staff Evaluation

In LRA Section 4.6.2, the applicant indicated that it performed the evaluation of the containment penetrations in accordance with the criteria of ASME Code, Section III, Subsection NE-3221.5(d). In addition, the main steam and feedwater line bellows were designed for 7000 cycles. LRA Table 4.6.2-1 provides a comparison of the number of expected cycles for the period of extended operation with the number of allowable cycles for the limiting containment penetrations and for the main steam and feedwater line bellows. The comparison shows that the projected number of cycles will be within allowable limits for the period of extended operation. The staff finds that the applicant has demonstrated that the containment process penetration and bellows analyses will remain valid for the period of extended operation.

The applicant also committed to monitor the thermal transient cycles for the bounding (isolation condenser) penetration using the Metal Fatigue of Reactor Coolant Pressure Boundary Program. This program provides additional assurance that the number of thermal transient cycles for the isolation condenser penetration will not exceed the number assumed in the design during the period of extended operation.

4.6.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of primary containment process penetrations and bellows fatigue analysis in LRA Section A.4.4.2. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address primary containment process penetrations and bellows fatigue analysis is adequate.

4.6.2.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the primary containment process penetrations and bellows fatigue analysis TLAA, the analyses will remain valid for the period of extended operation. The applicant had also demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the primary containment process penetrations and bellows fatigue analysis TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific Time-Limited Aging Analyses

In LRA Section 4.7, the applicant provided its evaluation of plant-specific TLAAs. The TLAAs evaluated include the following:

- crane load cycle limit
- drywell corrosion
- equipment pool and reactor cavity walls rebar corrosion
- reactor vessel weld flaw evaluations
- CRD stub tube flaw analysis

4.7.1 Crane Load Cycle Limit

The load cycle limits for cranes was identified as a potential TLAA. The following OCGS cranes are within the scope of license renewal and have been identified as having a TLAA, which requires evaluation for 60 years:

- reactor building crane
- turbine crane
- heater bay crane

The method of review applicable to the crane cyclic load limit TLAA involves: (1) reviewing the existing 40-year design basis to determine the number of load cycles considered in the design of each of the cranes in the scope of license renewal and (2) developing 60-year projections for load cycles for each of the cranes in the scope of license renewal and comparing them with the number of design cycles for 40 years.

4.7.1.1 Reactor Building Crane

4.7.1.1.1 Summary of Technical Information in the Application

In LRA Section 4.7.1.1, the applicant summarized the evaluation of the reactor building crane for the period of extended operation. This evaluation of cycles over the 40-year life is the basis of a safety determination and is therefore a TLAA. The 105-ton reactor building crane is designed to meet or exceed the design fatigue requirements of the Crane Manufacturers Association of America (CMAA) Specification 70, Class A1. The crane was therefore designed for 20,000 to 100,000 load cycles. A review of reactor building crane operation during the current life of the plant indicates that the total number of lifts above 25 tons to date is less than 1200. The total number of lifts has been conservatively estimated to be less than 2800 for the total life of plant, including the extended period of operation associated with license renewal and removal of spent fuel for the spent fuel storage pool. This is considerably less than the allowable design value of 20,000 to 100,000 cycles and is therefore acceptable. Thus, the applicant successfully projected the reactor building crane load cycle fatigue analysis for 60 years of plant operation.

4.7.1.1.2 Staff Evaluation

The reactor building crane was originally designed for 20,000 to 100,000 load cycles. The applicant estimated the total number of lifts to be less than 2800 for the total life of the plant, including the extended period of operation associated with license renewal and removal of spent fuel for the spent fuel storage pool. The staff reviewed the basis for this determination and finds this estimate reasonable. This is considerably less than the allowable design value of 20,000 to 100,000 cycles and is therefore acceptable.

The staff's review of LRA Section 4.7.1.1 identified areas in which additional information was necessary to complete the review of the reactor building crane. The applicant responded to the staff's RAI as discussed below.

In RAI 4.7.1-1 dated March 30, 2006, the staff requested that the applicant discuss any major repairs, modifications, or replacements done in the past which affected the original design basis of the reactor building, turbine, and heater bay cranes at OCGS. The staff also requested the applicant to identify any lifts in excess of the capacity of these cranes which have occurred in the past.

In its response dated April 28, 2006, the applicant stated:

> Operating experience review indicates that there were no major repairs of passive components made to the reactor building, turbine building, and heater bay cranes. However modifications were made to both the reactor building and the turbine building crane. The only major modification is the replacement of the original reactor building crane trolley with a new upgraded single failure-proof trolley that satisfies the guidelines of NUREG 0612, Section 5.1.6 "Single Failure Proof Handling Systems." As described in the UFSAR Section 9.1.4.2.3, the new trolley main hoist is rated for 105 tons and the auxiliary hoist is rated for 10 tons. The design is in accordance with NUREG 0612, NUREG 0554 and specification CMAA-70. Other modifications and replacements done in the three cranes, in the past, consist of replacement of active components with state-of-art components to improve operational performance and instrument reliability. For example a modification was initiated in 1995 to retrofit the entire existing reactor building crane control system.
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> The cranes are predominantly used for lifts that are significantly less than their rated capacity. On occasion, the cranes are used for lifts near their capacity. Only the turbine building crane is used every 5 outages (10 years) for lifts that exceed its rated capacity of 150 Tons. The lifts consist of removing the main generator for inspection and repairs and reinstalling it. Engineering evaluation was conducted to determine if the crane is capable of handling the lift, which is approximately 165 Tons. The evaluation concluded that the crane bridge, trolley, and supporting structure are capable of supporting the lift. However the capacity of a reduction g Bar and reduction pinion are exceeded. As a result Oyster Creek initiated a modification to upgrade the crane from 150 Ton rated capacity to 165 Tons. The modification consists of replacing existing motors and other active components, and replacing existing bolts and studs with SA-325 high strength material.

In RAI 4.7.1-2 dated March 30, 2006, the staff requested that the applicant discuss the operational history of the three cranes within the scope of license renewal. In its response dated April 28, 2006, the applicant stated:

> A review of the site operating and maintenance experience found no history of age-related degradation that adversely impacts the structural support intended function of the reactor building crane, turbine building crane, and the heater bay crane. Minor degradations that are not aged related, such as a bent support angle for the main walkway handrail of the reactor building crane, and overstressed bolts on the same walkway, were identified during the recent crane inspection. The support angle and the bolts were replaced. NDE examinations identified weld indications that were subsequently determined to be acceptable as-is. Other identified crane problems were due to degradation of active components that do not impact the license renewal intended function.

Based on a review of the estimated number of lifts, the original design basis, as well as the major repairs, modifications, or replacements and operational history of the reactor building crane as discussed above, the staff concludes that the applicant's projection of the reactor building crane load cycle fatigue analysis for 60 years of plant operation is acceptable. The staff's concerns described in RAIs 4.7.1-1 and 4.7.1-2 are resolved.

4.7.1.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor building crane in LRA Section A.4.5.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor building crane is adequate.

4.7.1.1.4 Conclusion

On the basis of its review and the RAI responses, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor building crane TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.1.2 Turbine Building Crane

4.7.1.2.1 Summary of Technical Information in the Application

In LRA Section 4.7.1.2, the applicant summarized the evaluation of the turbine building crane for the period of extended operation. The 150-ton turbine building crane purchasing specification required that the crane conform to the latest edition of CMAA, Specification 70, for electric overhead traveling cranes, Service Class A. The crane was therefore designed for 20,000 to 100,000 load cycles. The number of lifts originally projected for 40 years is less than 1250. This can be multiplied by a factor of 1.5 to determine the number of cycles for 60-year life. Therefore, the number of load cycles projected for a 60-year plant life is less than 2000. This is less than the 20,000 to 100,000 permissible cycles and is therefore acceptable. Thus, the applicant successfully projected the turbine building crane load cycle fatigue analysis for 60 years of plant operation.

4.7.1.2.2 Staff Evaluation

The turbine building crane was originally designed for 20,000 to 100,000 load cycles. The applicant estimated the total number of lifts to be less than 2000 for the total life of the plant, including the extended period of operation associated with license renewal. The staff reviewed the basis for this determination and concurs finds this estimate reasonable. This is considerably less than the allowable design value of 20,000 to 100,000 cycles and is therefore acceptable.

Based on a review of the estimated number of lifts, the original design basis, as well as the major repairs, modifications, or replacements which may have affected the design basis and operational history of the turbine building crane, as discussed in the responses to RAIs 4.7.1-1 and 4.7.2-2 in SER Section 4.7.1.1, the staff concludes that the applicant's projection of the turbine building crane load cycle fatigue analysis for 60 years of plant operation is acceptable.

4.7.1.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of turbine building crane in LRA Section A.4.5.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address turbine building crane is adequate.

4.7.1.2.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the turbine building crane TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.1.3 Heater Bay Crane

4.7.1.3.1 Summary of Technical Information in the Application

In LRA Section 4.7.1.3, the applicant summarized the evaluation of the heater bay crane for the period of extended operation. The 25-ton heater bay crane purchasing specifications required that the crane conform to the latest edition of the Electric Overhead Crane Institute's Specification 61. The crane was therefore designed for 20,000 to 100,000 load cycles. The number of lifts originally projected for 40 years is less than 400. This can be multiplied by a factor of 1.5 to determine the number of cycles for a 60-year plant life. Therefore, the number of load cycles projected for a 60-year period is less than 600. This is less than the 20,000 to 100,000 permissible cycles and is therefore acceptable. Therefore, the applicant successfully projected the heater bay crane fatigue analysis for 60 years of plant operation.

4.7.1.3.2 Staff Evaluation

The heater bay crane was originally designed for 20,000 to 100,000 load cycles. The applicant estimated the total number of lifts to be less than 600 for the total life of the plant, including the extended period of operation associated with license renewal. The staff reviewed the basis for this determination and finds this estimate reasonable. This is considerably less than the allowable design value of 20,000 to 100,000 cycles and is therefore acceptable.

Based on a review of the estimated number of lifts, the original design basis, as well as the major repairs, modifications, or replacements that may have affected the design basis and operational history of the heater bay crane, as discussed in the responses to RAIs 4.7.1-1 and 4.7.2-2 in SER Section 4.7.1.1, the staff concludes that the applicant successfully projection of the heater bay crane load cycle fatigue analysis for 60 years of plant operation.

4.7.1.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of heater bay crane in LRA Section A.4.5.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address heater bay crane is adequate.

4.7.1.3.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the heater bay crane TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.2 Drywell Corrosion

4.7.2.1 Summary of Technical Information in the Application

In LRA Section 4.7.2, the applicant summarized the evaluation of drywell corrosion for the period of extended operation. The Mark I containment design includes an annulus (expansion gap) between the containment and the primary containment shield wall. The potential for degradation of the containment results from conditions that allow the introduction of water into the annulus. This potential for corrosion was first recognized when water was noticed coming from the sand bed drains in 1980. Corrosion was later confirmed by ultrasonic thickness measurements taken in 1986. Corrective action included establishing a minimum shell thickness. This was accomplished by demonstrating through analysis that the original drywell design pressure was conservative. The plant technical specifications were amended to reduce the drywell design pressure from 62 to 44 psig. The new design pressure, coupled with the measures to prevent water intrusion in the gap between the containment vessel and the shield wall concrete, allow the drywell vessel to meet ASME Code requirements for the remaining 40-year plant life. Analysis of the minimum wall thickness of the containment vessel satisfies the criteria of 10 CFR 54.3(a) and is thus a TLAA.

Regarding its analysis, the applicant stated that several corrective actions have been taken to ensure minimum wall thicknesses are maintained, including removal of sand from the sand bed region to break up galvanic action, removal of the corrosion product from the containment vessel, and application of a protective coating. In addition, OCGS performs a monitoring program to ensure that corrosion mitigation measures are effective and the required minimum wall thickness is maintained. The ASME Section XI, Subsection IWE Program ensures that the reduction in vessel thickness will not adversely affect the ability of the drywell to perform its safety function. 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. Coated drywell surfaces do not show signs of or deterioration. Drywell vessel wall thickness measurements indicate a substantial margin to the minimum wall thickness, even when projected to the year 2029 using conservative estimates of the corrosion rates. 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 ASME Section XI, Subsection IWE Program assures that the drywell vessel thickness will not be reduced to less than the minimum required value in any future operation. Therefore, the effects of loss of material on the intended function of the drywell will be adequately managed in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation.

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effects of loss of material on the intended function of the drywell will be adequately managed in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation.

4.7.2.2 Staff Evaluation

The staff's review of LRA Section 4.7.2 identified areas in which additional information was necessary to complete the review of drywell corrosion. The applicant responded to the staff's RAI as discussed below.

4.7.2.2.1 Drywell Corrosion Sampling

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide information concerning the drywell corrosion existing during the late 1980s, and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done for identifying the areas of corrosion has been adequate.

In its response dated April 7, 2006, the applicant emphasized that it employs a robust process of establishing confidence that the nature and locations of sampling done and the areas considered for identifying the areas of corrosion have been adequate. The applicant stated that the elements of process were developed over several years and were defined in several technical documents submitted to the NRC in the 1990s. The applicant summarized the process as follows:

> Inspections using UT thickness measurements were conducted during refueling outages and outages of opportunity between 1986 and 1989 to establish and characterize the extent of corrosion of the drywell shell. The initial UT measurements were not based on a sampling process. Instead, the measurements were taken in areas that correspond to locations where water leakage was observed from the sand bed region drains. The UT measurements were then expanded around the drywell perimeter and vertically to establish locations affected by corrosion. Approximately 1000 UT thickness measurements were taken to identify thinnest areas. In addition, core samples of the drywell shell were taken at seven locations, believed to be representative of general wastage, to confirm UT results.
>
> Based on the results of these inspections, elevations 11'-3", 50'-2", and 87'-5" were identified for monitoring. Elevation 11'-3", which corresponds to the sand bed region, showed the highest corrosion rate in 1987 (up to 39.1 +/- 3.4 mils per year) based on 1986, and 1987 UT measurements. The high rate of corrosion in the sand bed region prompted corrective action of a physical nature that involved removal of the sand. As a result, corrosion of the drywell shell in the sand bed region was addressed differently than the upper region of the drywell.

The most critical region affected by the corrosion-related metal loss was the sand bed region of the drywell shell. The applicant provided a brief history of the UT measurements taken and actions taken to prevent or mitigate corrosion in this area as follows:

> The high rate of corrosion in the sand bed region was attributed to galvanic corrosion of the drywell shell caused by water retained in the sand because of lack of proper drainage. To reduce the corrosion rate, Oyster Creek initiated several corrective actions as described in the response to item (c) below.

Evaluation of these corrective actions concluded that the most effective action to reduce the corrosion rate is to remove the sand from the sand bed region and protect the drywell shell from additional corrosion by applying a protective coating.

Location of the UT measurements was not based on a sampling process. Instead, the locations were based on UT measurements taken at all accessible locations that correspond to the sand bed region from inside the drywell to establish the thinnest area. After the sand was removed in 1992, and prior to coating the shell, thickness measurements were taken in each of the 10 bays, from outside the drywell, to establish the minimum general and local thickness of the thinned shell. The measurements from inside the drywell showed that the minimum general thickness of the sand bed region is 0.800 inches, and the minimum local thickness is 0.618 inches. The measurements from outside the drywell in the sand bed region showed that the minimum thickness is generally greater than 0.800 inches. There were local areas where the thickness is less than 0.800 inches. However, the minimum average thickness in these areas is greater than 0.736 inches, which is required for satisfying ASME Code requirements. The minimum local thickness measured from outside the sand bed region is 0.603 inches. Considering measurement and instrument accuracies, it is concluded that locations examined from inside the drywell represent the condition of the sand bed region.

The results of these measurements and subsequent analysis, which considered all design basis loads and load combinations, confirmed that the "as found" condition of the drywell shell thickness satisfies ASME Section III minimum thickness requirements. Additional thickness measurements taken at all accessible locations (total of 19) from inside the drywell in 1992, 1994, and 1996 show no corrosion, or no significant corrosion (see Table-2). In addition, inspection of the protective coating on exterior surfaces of the drywell shell in the sand bed region, every other refueling outage, shows no degradation of the coating or the underlying shell."

A general trend of the average corrosion found in the sand-pocket area as provided by the applicant is shown in Figure 3 of the response. Figure 3 shows the growth of corrosion for the location of thinnest wall thickness. It shows an average thickness of 0.87 inch in December 1986 and approximately 0.8 inch in December 1992. After 1992 (i.e., after the application of an epoxy coating to the shell in the sand pocket area), the average thickness appears to have stabilized at 0.8 inch based on the readings taken in 1994 and 1996. After 1996, the applicant extrapolated the thickness to remain as 0.8 inch during the current licensing period and during the period of extended operation.

The applicant provided a status of corrosion of the upper region, above the sand bed region, and noted that based on the results of approximately 1000 UT measurements, the applicant continued to monitor elevations 50' 2" and 87' 5" in the regions above the sand bed region. A third elevation, 51' 10", was added to the scope of inspection after it was determined that the supplied plate thickness is slightly less than the adjacent 50' 2". For each elevation, UT measurements spaced approximately 1 inch within a 6-inch by 6-inch array were taken from inside the drywell around the entire perimeter of each elevation. Engineering evaluation of the UT results concluded that monitoring of 12 locations would represent the drywell shell condition and provide reasonable assurance that significant corrosion would be detected before a loss of an intended function. The applicant concluded that this is because the 12 locations, as described below, were selected considering the degree of drywell shell thinning and the minimum required thickness to satisfy ASME stress requirements:

- seven locations at 50' 2",
- three locations at elevation 87' 5", and
- two locations at elevation 51' 10".

These locations are inspected from the inside of the drywell shell on a frequency of every other refueling outage.

In response to an earlier concern from the staff regarding whether the inspected locations represent the condition of the entire drywell, in 1990, General Public Utilities Corporation (GPU) prepared a new random UT inspection plan (also known as augmented inspection) designed to address the concern. The plan was based on a nonparametric statistical approach using attribute sampling that assumes no prior knowledge of the distribution of corrosion above the sand bed region. It consisted of random UT testing of 57 plates using the 6-inch by 6-inch grid. The applicant-established acceptance criteria were that the mean and local thickness of the shell equals or exceeds the required minimum thickness, plus a corrosion allowance necessary to reach the next inspection.

The applicant noted that the inspection results using the new random inspection plan confirmed that previously monitored locations bound the condition of the drywell above the sand bed region, except one location at elevation 60' 10". This elevation was added to elevations 50' 2", 51' 10", and 87' 5" and has been monitored every other refueling outage since identified in 1992.

After describing the basis for the earlier staff acceptance of the applicant's program the applicant provided the results of further inspections:

> During a recent walkdown of the torus by the system engineer, water was found in three 5-gallon containers that were installed to collect water leakage from the sand bed drains. Two of the 3 containers were found nearly full. The third container was approximately half full. Inspection of the drain lines showed that the lines were dry and that water in the containers was not due to a water leakage. The containers were closed such that their overflow was unlikely as confirmed by no water ponding on the floor.

Thus, the applicant concluded with reasonable assurance that the volume of water was limited to what is contained in the containers, and attempted to justify that the small amount of water was not expected to have significant impact on the drywell shell and on the coating of the shell, since the coating is designed for a submerged environment. The applicant noted that further inspection of the sand bed region coating conducted in 2004 did not indicate coating degradation or indications of drywell shell corrosion. Similarly, UT examinations on the upper region of the drywell showed a decrease in the corrosion rate since the previous inspection in 2000. Thus, the applicant concluded that the small volume of water found in the bottles should not have created an environment that would result in significant corrosion to the drywell shell.

OCGS Issue Report No. 00470325 was issued, in accordance with the corrective action process, to investigate the source of water and evaluate its impact on the drywell shell. Based on the discussion above, and as indicated in the tables supplied in response to item (d) below, the applicant concluded that drywell corrosion is effectively managed both during the current and proposed renewed terms of plant operation. The monitored locations under the current term were subjected to extensive UT measurements conducted over several years. The staff finds the sampling methodology to identify these locations, and the results of inspections, acceptable for the current term. The applicant stated that the same locations will be inspected during the extended period of operation.

In summary, the applicant emphasized that OCGS has conducted extensive examinations to identify the cause of drywell corrosion, employed a robust sampling process, quantified with reasonable assurance the extent of drywell shell thinning due to corrosion, and assessed its impact on the drywell's structural integrity.

In addition, the applicant stated that water intrusion into the gap between the drywell shell and the drywell shield wall was identified as the cause for corrosion. Corrective actions have been taken to mitigate corrosion in the sand bed region and in the upper region of the drywell. Corrosion of the drywell shell in the sand bed region has been arrested. These actions also have effectively reduced the rate of corrosion to a negligible amount in the upper region, as demonstrated by UT thickness measurements. OCGS and its consultants performed stress and buckling analyses considering all design-basis loads and load combinations. The results of these analyses indicated that buckling controls the minimum drywell shell thicknesses in the sand bed region, while areas above the sand bed region are controlled by accident pressure membrane stresses. In both cases, the minimum measured drywell shell thickness satisfied ASME Code Section III requirements.

Open Item 4.7.2-1.1: Location of UT Measurements

The staff's review of the applicant's response, including Figure 3 and Tables 1 and 2, determined that UT measurements taken in the spherical portion of the drywell shell adequately represent the upper spherical area. However, there were no measurements taken in the lower portion of the spherical area above the sand-pocket area. To ensure that the spherical portion of the drywell shell is properly represented in the database, additional UT measurements taken approximately at or above the junction of the 0.722 inch and 1.154 inch thick plates would be desirable. Likewise, additional UT measurements should be taken on the cylindrical portion of the drywell shell at about 71' 6" (i.e. at the junction of the 0.640 inch plate and the thickened plate in the knuckle area). The staff requested that the applicant clarify its UT sampling plan in context of the entire drywell shell assessment.

In its response dated June 20, 2006, the applicant stated:

> A review of the drywell fabrication and installation details show that the welds that attach the 0.770 inches (the correct thickness is 0.770 inches, not 0.722 inch as indicated in the meeting notes) nominal plates to the 1.154 inch nominal plates at elevation 23 ft 6 7/8 inch are double bevel full penetration welds. The external edge of the 1.154 inches plates is tapered to 3 to 12 minimum as required by ASME Section VIII, Subsection UW-35, while the internal edge of the 1.154 inch plates are flush with the 0.770 inch plates. Thus there are no ledges that could retain water leakage and result in more severe corrosion than in areas included in the inspection program. Also, this joint is located below the equatorial center of the sphere. Therefore, in the event that water may run down the gap between the drywell shell and the concrete wall it would not collect on this joint.

In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing inspections were conducted at 19 locations on either the 1.154 inch thick plates or on the 0.770 inch thick plates. The UT measurements were taken on a 6 inch x 6 inch grid (49 UTs) at each location. The UT measurement results show that thinning of the plates at these locations is less severe than the areas that are included in the corrosion-monitoring program. For this reason, the transition area was not added to the corrosion-monitoring program. Based on the above, AmerGen concludes that areas monitored under the drywell corrosion monitoring program bound the transition (from 1.154 inches to 0.770 inch thick plates) area of the drywell shell. Nevertheless, UT measurements will be taken on the 0.770 inch thick plate, just above the weld, prior to entering the period of extended operation.

The measurements will be conducted at one location using the 6 inch x 6 inch grid. A second set of UT measurements will be taken two refueling outages later at the same location. The results of the measurements will be analyzed and evaluated to confirm that the rate of corrosion in the transition is bounded by the rate of corrosion of the monitored areas in the upper region of the drywell. If corrosion in the transition area is found to be greater than areas monitored in the upper region of the drywell, UT inspections in the transition area will be performed on the same frequency as those performed on the upper region of the drywell (every other refueling outage).

Similarly, a review of fabrication and installation details of the containment drywell shell shows that the weld that connects the 2.625" knuckle plates to the 0.640"cylinder plates at elevation 71 ft 6 inch is a double bevel full penetration weld. The edges of the 2.625 inch plates were fabricated with a 3 to 12 taper to provide a smooth transition from the thicker to the thinner plate as required by ASME Section VIII, Subsection UE-35. Thus there are no ledges that could retain water leakage and result in more severe corrosion than the areas included in the inspection program.

In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing (UT) inspections were conducted at 18 locations on the 2.625 inch thick knuckle plate and at four (4) locations on the 0.640 inch thick cylinder plate. The UT measurements were taken on a 6 inch x 6 inch grid (49 UTs) at each location. The UT measurement results showed that thinning of the plates at these locations was less severe than the areas that are included in the corrosion monitoring program. For this reason the knuckle area was not added to the corrosion monitoring program. Based on the above, AmerGen concludes that areas monitored under the drywell corrosion monitoring program bound the knuckle area of the drywell shell. However, UT measurements will be taken above the 2.625 inch knuckle plate in the 0.640 inch thick plate prior to entering the period of extended operation.

The staff views random sampling of UT measurement as being valuable if the likelihood of corrosion is almost equal at every place in the region considered for UT measurements. If the geometry of the region and water flow in the air gap is such that suggest itself that one area is more likely to have corrosion than the other, then the sampling plan has to consider those areas which are more likely to have corrosion in addition to the randomly selected areas. If the water flow in the air gap is high, the applicant's argument that the weld transition will not allow water accumulation will be accurate. However, if the water flow is slow, this may not hold true. During the forthcoming outage, the applicant plans to perform UT measurements at one location on each of the transition areas.

The staff believes that examination of 4 locations in each transition area is needed. The locations along the thickness transition should be consistent with the areas that have large water accumulation and corrosion in the sand bed region. This was identified as open item (OI) 4.7.2-1.1 in the SER, dated August 18, 2006.

The applicant updated the IWE Program commitments in its December 3, 2006, submission (pages 73 and 74, items 10 and 11) with four separate sets of UT thickness measurements of the drywell shell at two areas of transition between shell plate thicknesses using a 6"x6" grid (*i.e.*, four separate 49-point UT sets at the transition at elevation 23' 6 7/8" and four sets of UTs at elevation 71'-6"). The specific locations selected will be based on previous operational experience (*i.e.*, biased toward areas that have experienced corrosion or exposure to water leakage). These measurements will be at the same locations prior to the period of extended operation and at the second refueling outage after the initial inspection. If corrosion in these transition areas is greater than in areas monitored in the upper drywell, UT inspections in the transition areas will be on the same frequency as those in the upper drywell (every other refueling outage). Of these four locations there were UT measurements at two for each transition area during 2006 outage. These first-time readings show that the mean and individual thicknesses meet acceptance criteria with adequate margin. There will be UT measurements in the remaining two locations at each transition area during the next outage prior to the period of extended operation.

The applicant's actions to include in the program UT measurement of shell areas that may experience increased rates of corrosion resolve the staff concern. The basis for the staffs conclusion is that the UT measurements as described should provide an adequate data base to confirm whether the random sampling program for UT measurements is reasonably representative.

The staff, however, noted an inconsistency in license renewal Commitment 27, "ASME Section XI, Subsection IWE," items 10 and 11, where it states that the UT measurements will be at one location. In discussions on December 13, 2006, the applicant indicated that this statement was an editorial error. In a subsequent letter dated December 15, 2006, AmerGen corrected the error in the license renewal commitment list. Open Item 4.7.1-1.1 is closed.

In its letter dated February 15, 2007, the applicant revised a commitment (Commitment No. 27) by adding Item 21, which states that the performance of the full scope of drywell sand bed region inspections will be conducted every other refueling outage. The staff identified this commitment item as a license condition.

Open Item 4.7.2-1.2: Drywell Shell Embedded Concrete

In the sand pocket region of the drywell shell, the most susceptible bays are incorporated in the sampling. However, the staff believes that readings should be taken vulnerable locations and that UT techniques are reliable. The first issue is addressed below and the second issue is addressed as part of UT Measurement Issues.

The first item is that it is not clear if the junction between the 1.154- and the 0.676-inch plate at the elevation 6' 10.25" is represented in the sampling. Though this point is below the bottom of the sand-pocket area in contact with the alkaline environment of concrete, in the past (before sealing of the junction between the steel and the concrete), this area would have been subjected to the same type of contaminated water as the drywell in the sand-pocket area and is considered as a suspect area for corrosion. The staff requested that the applicant justify why this area should not be included in the sampling plan.

In its response dated June 20, 2006, the applicant noted that a review of the drywell construction and fabrication details shows that the drywell skirt is welded to the 1.154 inch thick plate below the sand bed floor. This thick plate is welded to the 0.676 inch plate at elevation 6' 10.25". The purpose of the skirt, which is also embedded in concrete, was to support the drywell during construction. The presence of the skirt prevents moisture intrusion into the 0.676 inch plate. Quoting the provisions of GALL Report the applicant noted:

- Concrete meeting the specifications of ACI 318 or 349 and the guidance of 201.2R was used for the containment shell or liner.

- The concrete is monitored to ensure that it is free of cracks that provide a 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 Code Section XI, Subsection IWE requirements.

- Water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

Additionally, AmerGen contracted with Structural Integrity Associates, Inc. (SI) to provide an assessment of corrosion of the embedded drywell shell in the sand bed region. The applicant asked SI to address corrosion of the drywell shell prior to 1992, when the shell was potentially exposed to moisture retained by the sand, and post 1992 after the sand was removed and other mitigative actions were taken to prevent water intrusion into the embedded shell. The assessment results can be summarized as follows:

- Corrosion of the Embedded Drywell Shell prior to 1992: The corrosion of the drywell shell in the sand bed region was caused by the moisture trapped in the sand bed due to water leakage into the region. The source of leakage was determined to be the reactor cavity, which is filled with demineralized water during refueling outages. The water passed over the Firebar-D coating that was applied to the drywell shell to allow for formation of the required seismic gap between the drywell shell and the encircling concrete shield wall. The Firebar-D material is a magnesium oxychloride compound. The drywell was erected onsite and exposed to salt air environment during construction, which could also introduce contaminants to the sand bed environment. Chemistry test results on wet sand conducted in 1986 indicated that the leachate from the moist sand had a pH of 8.46 and contained only 45 ppb chlorides and <17 ppb sulfates.

- As noted in EPRI Report 1002950, this water is not aggressive to concrete since the pH is greater than 5.5, the chlorides are less than 500 ppm and sulfates are less than1500 ppm. This means that the wetted concrete environment will provide a high pH environment that will protect the embedded shell from corrosion. Additionally, the corrosion rates calculated for the carbon steel plugs removed from the drywell shell in the sand bed region were comparable to carbon steel exposed to typical waters over a similar temperature range. While an increase in the salinity and impurity of the water will increase the kinetics of the corrosion reaction by increasing the electrolyte conductivity and can alter the form of corrosion experienced by steel (e.g., from general corrosion to pitting corrosion), impurities such as chloride and sulfate are not fundamentally involved in the corrosion anodic and cathodic reactions. In fact, increasing the salinity of the water decreases the dissolved oxygen content of the water and, thus, reduces the concentration of cathodic reactant present for the corrosion reaction.

The applicant stated that it is reasonable to assume that the corrosion rate of the embedded shell is significantly less than the shell in contact with the sand bed for two primary reasons:

- The carbon steel in the embedded region is in contact with high pH concrete that allows the creation of a passive film on the steel surface. That is, the presence of abundant amounts of calcium hydroxide and relatively small amounts of alkali elements, such as sodium and potassium, gives concrete a very high alkalinity (e.g., pH of 12 to 13). In fact thermodynamic calculations reveal no corrosion of iron (steel) above pH 10 at room temperature.

- Uniform corrosion will tend to occur when some surface regions become anodic for a short period, but their location and that of the cathodic regions constantly change. For example, general corrosion/rusting of mild steel will occur when there is a uniform supply of oxygen available across the surface of the steel and there is a uniform distribution of defects in the oxide film as is usually the case in the non-protective films formed on unalloyed steel. In the absence of areas of high internal stress (e.g., cold-worked regions) or segregated zones (e.g., non-uniform distributions of sulfide inclusions), a number of anodic regions will develop across the surface. Some areas will become less active while new anodic regions become available. Therefore, overall attack takes place at a number of anodic sites whose positions may change, leading to general rusting across the surface.

  If the supply of oxygen is not uniform across a surface, then any regions that are depleted in oxygen will become anodic as the case of moist sand in contact with the drywell steel. The remainder of the drywell surface including the embedded steel has oxygen available to it and therefore acts as a large cathodic area. When the cathodic area is larger, local attack will occur in the smaller anodic region. This phenomenon is referred to as differential aeration.

  Therefore, due to the creation of a differential aeration cell, the adjacent carbon steel in contact with the moist sand bed acts as an anode that sacrifices itself to the benefit of the steel in the embedded region. That is, the corrosion of the sand cushion steel preferentially corrodes as galvanically coupled to the embedded steel.

The applicant, also discussed potential for corrosion of the embedded drywell shell after 1992. In response to RAI 4.7.2-1(c) AmerGen described several corrective actions taken to mitigate corrosion of the drywell shell. These mitigative actions are designed to minimize water intrusion into the sand bed region, provide for an effective drainage of the region in the event of water leakage and monitor the drains to detect leakage. If water leakage is observed coming from the sand bed region drains, numerous investigative and corrective actions will be taken. In addition, a silicone seal is applied at the junction of drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the embedded drywell shell. These actions mitigate subsequent long term significant corrosion of the embedded shell for the following two reasons:

- The general lack of two of the four necessary fundamental parameters necessary for any form of corrosion to occur, an electrolyte, (i.e., moisture) and the cathodic reactant (i.e., oxygen), while only the lack of one fundamental parameter is sufficient to prevent corrosion. Sealing off the embedded steel will prevent any refreshment of moisture in the embedded region and any residual moisture will not support any subsequent corrosion once all the dissolved oxygen is consumed in the cathodic corrosion reaction. The cessation of the corrosion reaction will occur regardless of the presence of contaminants that may be dissolved in the water (e.g., chloride, sulfate, etc.) since although these impurities can affect the kinetics of the corrosion reaction, they do not participate in the cathodic reduction reaction. Once the cathodic reaction is stopped, corrosion is stopped. Intermittent wetting and aeration of the embedded steel would produce only minimal additional corrosion.

- The presence of concrete in contact with the embedded steel will mitigate corrosion even if sufficient moisture and oxygen are available due to the spontaneous formation of a thin protective oxide passive film on the embedded steel surface in the highly alkaline solution of the concrete. As long as this film is not disturbed, it will keep the steel passive and protected from corrosion.

In summary, the applicant noted that AmerGen has extensively investigated drywell corrosion, including the embedded shell. A review of plant operating and industry experience indicates that corrosion of embedded steel in concrete is not significant because it is protected by the high alkalinity in concrete. Corrosion could only become significant if the concrete environment is aggressive. Also, historical data shows that the environment in the sand bed region is not aggressive, and thus any water in contact with the embedded shell is not aggressive. The data also shows that corrosion of the drywell shell in the sand bed region is due to galvanic corrosion and impurities such as chlorides and sulfates are not fundamentally involved in the corrosion anodic and cathodic reactions. Thus, only limited corrosion would be anticipated for the drywell embedded shell.

AmerGen has also committed to a comprehensive drywell corrosion-monitoring program for the period of extended operation. The program includes mitigative measures to prevent water intrusion into the sand bed region. The sand bed region concrete floor is sealed with epoxy coating. The junction between the sand bed region concrete floor and the drywell shell was sealed in 1992 to prevent moisture from impacting the embedded shell. Thus, additional significant corrosion of the embedded shell is not expected because of lack of moisture and depleted oxygen. AmerGen will also take specific actions if water leakage is detected in the sand bed region drains.

For all of the above reasons, the applicant stated that the corrosion rate for the embedded drywell shell is less than the corrosion rate of the sand bed region of the drywell shell. Also, direct monitoring of the drywell shell in the sand bed region adequately bounds any corrosion in the drywell embedded shell.

AmerGen concluded that corrosion monitoring of the sand bed region of the drywell shell is bounding with respect to corrosion that may have occurred on the drywell embedded shell prior to 1992. After 1992, corrosion of the embedded shell has not been significant because of the mitigative measures implemented and the robust drywell corrosion AMP and the applicant concluded that this trend of no significant corrosion will continue during the period of extended operation.

The staff understands AmerGen's technical reasons to support the applicant's view that the inaccessible portion of the drywell shell (i.e. embedded between the concrete floor inside, and concrete outside) is not likely to be subject to the same type of severe corrosion as experienced in the sand bed area. However, the experience of general corrosion in the liner plates embedded in concrete of a number of PWR and BWR containments suggests that certain irregularities during the construction (i.e. foreign objects or voids in the concrete) could trigger corrosion that is not arrested later by the concrete environment. This is particularly significant for the plates potentially subject to water seepage. The applicant's position that the uniformly reduced thickness used in the GE analysis compensates for any corrosion that may have occurred before the area was sealed in 1992 has some validity. Because the staff was still evaluating, this item was identified as OI 4.7.2-1.2 in the SER, dated August 18, 2006.

During the October 2006 refueling outage, the applicant inspected the embedded drywell shell in the trenches in bays #5 and #17 after removing the filler material in the trenches and observed approximately 5 inches of standing water in the trench located in bay #5, and the trench in bay #17 was damp. Investigations concluded that the likely water sources were a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough or condensation within the drywell that either fell or washed down the inside of the drywell shell to the concrete floor. Water samples taken from the trench in bay #5 were tested and determined to be non-aggressive in pH (8.4 – 10.21), chlorides (13.6 – 14.6 ppm), and sulfates (228 – 230 ppm).

The applicant entered the condition into the corrective action process. Several corrective actions included repair of the trough concrete in the area under the reactor vessel to prevent water from migrating through the concrete and reaching the drywell shell and caulking of the interface between the drywell shell and the drywell concrete floor/curb including the trench areas. The trench bay in bay #5 also was excavated to uncover an additional 6 inches of the internal drywell shell surface for inspection and UT thickness measurement. A total of 584 UT thickness measurements were taken using a 6"x6" template within the two trenches. Forty-two additional UT measurements were taken in the newly exposed area in bay #5.

Visual examination of the drywell shell within the two trenches detected minor surface rust with no recordable corrosion on the inner surface of the shell. The UT measurements indicated that the drywell shell in the trench areas had experienced a 0.038" reduction in average thickness since 1986. Amergen concluded that the wall thinning was a result of corrosion on the exterior surface of the drywell shell in the sand bed region between 1986 and 1992 when the sand was still in place and the corrosion was known.

An engineering evaluation to determine the impact of the as-found water on the continued integrity of the drywell concluded that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact and that significant corrosion of the drywell shell is not expected as long as this benign environment is maintained. More specifically, this engineering evaluation indicates that no significant corrosion of the inner surface of the embedded drywell shell is anticipated for the following reasons:

- The water in contact with the drywell shell has been in contact with the adjacent concrete, which is alkaline, increases the pH of the water, and inhibits corrosion. This high-pH water contains levels of impurities significantly below the EPRI embedded steel guidelines action level recommendations.

- Any new water (*e.g.*, reactor coolant) entering the concrete-to-shell interface (now minimized by repairs) also increases pH by its migration through and contact with concrete, creating a non-aggressive, alkaline environment.

- Minimal corrosion of the wetted inner drywell steel surface in contact with concrete is expected only during outages because the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant as the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also repairs/modifications during the 2006 outage will further minimize exposure of the drywell shell to oxygen.

After the UT thickness measurement during the 2006 outage of the newly-exposed shell area in bay #5, which had not been examined since initial construction, a reduction of average shell thickness of 0.041" was observed. The applicant maintains that, although no continuing corrosion is expected, there is sufficient margin for both the 1.154" thick plate and the 0.676" thick plate even assuming the same reduction until the end of the period of extended operation.

The applicant also has enhanced the AMP to require periodic inspection of the drywell shell subject to concrete (with water) environments in the internal embedded shell area. After each inspection, UT thickness measurements will be evaluated and compared to previous UT thickness measurements. If results are unsatisfactory, additional corrective actions, as necessary, will maintain drywell shell integrity throughout the period of extended operation.

To investigate the feasibility of state-of-the-art non-destructive examination techniques to determine the condition of the embedded region, the applicant contacted EPRI and other utility owners that use these techniques. After discussions and findings, the applicant understood that a "guided wave" technology may be able to provide some qualitative information on whether the embedded shell has undergone corrosion; however, neither this nor any other known non-destructive methods could determine the thickness of the embedded drywell shell or the specific extent of corrosion.

Based on review of the applicant's evaluation of the condition of the inaccessible portion of drywell shell embedded in concrete, the applicant's actions to date to minimize entry of water in the concrete-to-shell interface, and the enhanced inspection program including a detailed UT measurement plan of the embedded shell area committed by the applicant, the staff concludes with reasonable assurance that the environment in the region is sufficiently non-aggressive for no significant progressive corrosion. Therefore, the staff concern is resolved and Open Item 4.7.2-1.2 is closed.

In its letter dated February 15, 2007, the applicant change a commitment (Commitment No. 27) by adding Item 20, which states AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17. AmerGen will monitor the two trenches for the presence of water during each refueling outage. The staff identified this commitment item as a license condition.

Ultrasonic Testing Measurement Issues

In the sand pocket region of the drywell shell, the most susceptible bays are incorporated in the sampling. However, the staff believes that readings should be taken at vulnerable locations and that UT techniques are reliable. The first issue is addressed as part of Open Item 4.7.2-1.2 and the second issue is addressed below.

The second item is that a review of UT data indicates that the UT measurements taken from inside the drywell after 1992 show a general increase in the metal thickness. In some cases, the average increase is as much as 40 mils in a 2-year timeframe. In general, it appears that the UT measurements taken after 1992 require proper calibration, considering the coatings on both sides of the drywell shell. The staff requested that the applicant address this issue during a public meeting held June 1, 2006.

In its response dated June 20, 2006, the applicant provided the following discussion of sensitivities involved with the UT measurement process and how they will be minimized in the future:

> UT Instrumentation Uncertainties. The UT instrumentation, which includes the transducer, cable and ultrasonic unit, will be calibrated to within approximately +/- 0.010 inches. Exelon Procedure (ER-AA-335-004) step 4.1.3 requires that he UT instruments must be checked within 2% of the calibration standard (block) prior to use. For the sand bed region, which is nominally 1" thick, a 1-inch thick calibration standard block is used. This results in checking the UT instrument to within 0.020" inches or +/- 0.010". UT instrumentation accuracy is verified under controlled conditions where UT thickness readings are performed on calibration blocks. The calibration blocks have been precisely machined to prescribed thicknesses, which are then verified by micrometer readings.
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> Actual Drywell Surface Roughness and UT Probe Location Repeatability. Due to the corrosion, the outside surface of the Drywell Vessel is not smooth and uniform. The surface condition is indicative of general corrosion, which is rough with high and low points spaced very closely together. This profile was verified when the sand was removed in 1992. The UT Instrumentation probes are 7/16" in diameter and are dual element transducers (i.e. half transmits sound and the other half receives). The probes emit a focused beam that measures an area significantly smaller than 7/16" diameter and will record the thinnest reading within that area.
>
> Because the surface roughness of the drywell within this 7/16" diameter can vary, the probe must be placed at precisely the same location to precisely repeat a thickness reading. A slight shift of the probe will result in a reading which is correct, but different from a previous reading.
>
> The variability associated with this factor is reduced by the use of the stainless steel template. The template has been manufactured with holes in a 7 by 7 pattern on 1 inch centers. Each of the 49 holes has been machined with a diameter so that the UT probe fits within each hole snugly. The templates are machined with 1/16" wide slits on each

edge of the template at 0, 90, 180, and 270 degrees. During inspections the slits in the template are lined up with permanent marks that were placed on the drywell shell when the location was originally inspected. The UT readings are then taken by placing the probe inside each hole in the template.

Inspection procedures require that NDE personnel performing the inspection place the template precisely on the permanent markings.

Actual Drywell Surface Roughness and UT Probe Rotation. The UT probe sends the signal from one side of the probe and receives the signal on the other side. The probe must be oriented in the same plane in order to measure exactly the same point. Test data taken on a mock up with similar roughness showed that a variance up to 0.016 inch was noted when rotating the probe 360 degrees over the same spot. Therefore, a slight rotation of the probe will result in a reading, which is correct, but different from a previous reading.

Inspection procedures require that NDE personnel performing the inspection place the probe in the same orientation.

Temperature Effects. Significant temperature differences between inspections may result in a shift in the material thickness. Therefore, the inspection specification will require that NDE personnel performing the inspection record the surface temperature of the area that is inspected.

Batteries. Inspection specifications require the installation of new batteries prior to each series of inspections.

NDE Technician. Inspection specifications require that personnel conducting UT examinations be qualified in accordance with Exelon Procedure ER-AA-335-004.

Calibration Block. Exelon Procedure ER-AA-335-004 requires that calibration blocks used during the inspection be inspected to verify that the ultrasonic response equals the physical measurement.

Internal Surface Cleanliness. The inspection areas are covered with a qualified grease to protect the examination surface from rusting between inspection periods. The grease must be removed prior to the inspection and reapplied after the inspection. Tests performed in April and May of 2006 show that the presence of the grease will increase the readings as much as 12 mils. In 1996, the governing specification did not clearly specify the requirement to remove the grease prior to the inspection. Therefore it is possible that the requirement to remove the grease was not communicated to the contractor, and that the contractor who performed the 1996 inspection may have not removed the grease.

The inspection procedures will clearly require that personnel conducting UT examinations remove the grease prior to performing the examination.

UT Unit Settings. It is possible that the ultrasonic unit can be set in a "high gain" setting which may bias the machine into including the external coating as part of the thickness. Future inspections will use modern "state of the art" UT units that do not have gain settings.

Identification of the Physical Inspection Location. There is a potential that inspection locations may be mislabeled on the data sheets. The inspection procedures uniquely and clearly identify each inspection location and provide the specific instruction as to the area's location.

Data Analysis. The above potential variables will be considered in the analysis of the data. The analysis not only determines a mean for each grid or sub-grid, but also the variance of the means. These variances will be compared to past inspections to ensure consistency. The mean and the variance are compared to the acceptance criteria.

In addition, the mean UT thickness values for a current inspection will be computed and compared to the previous inspection prior to restarting from an outage. If data anomalies similar to 1996 are identified corrective actions will be taken, including new UT measurements, as necessary, to ensure accuracy of measurements.

Based on the applicant's discussion of the variables involved in the UT results, the staff finds it reasonable to conclude that the anomalous readings of 1994 and 1996 could be attributed to one or more of the factors enumerated in the discussion. The staff was concerned about systematic corrections to the UT measurements and could not determine the basis for the applicant's use of the anomalous readings nor systematic corrections. The applicant could not isolate the factors that contributed to these anomalous results; therefore, it plans to utilize the lessons learned from the experience for the future UT examinations. On the basis of the applicant's written response, the staff determined that its concerns have been resolved.

4.7.2.2.2 Minimum Drywell Thickness

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide a summary of the factors considered in establishing the minimum required drywell thickness.

In its response dated April 7, 2006, the applicant explained that the factors considered in establishing the minimum required drywell thickness at various elevations of the drywell are described in detail in engineering analyses documented in two GE reports, Index Nos. 9-1, 9-2, and 9-3, 9-4. Report Index No. 9-1, 9-2 was generated for the drywell condition with sand in the sand bed region and Report Index No. 9-3, 9-4 addressed the drywell condition without sand in the sand bed region. The two reports were transmitted to the staff in December 1990 and 1991, respectively. Report Index No. 9-3, 9-4 was revised later to correct errors identified during an internal audit and was resubmitted to the staff in January 1992. The analysis described in Report Index No. 9-3, 9-4 (i.e., without sand) is the current applicable analysis for the drywell.

In its response the applicant also noted that it based the analysis on the original code of record, ASME Code, Section VIII, and Code Cases 1270N-5, 1271-N, and 1272N-5. The ASME Code and its Code Cases do not provide specific guidance in two areas. The first relates to the size of a region of increased membrane stress due to thickness reductions from local or general corrosion effects, and the second pertains to the allowable stresses for Service Level C or post-accident conditions. In the first case, guidance was sought from ASME Code Section III, NE-3213.10. For Service Level C or post-accident conditions, the SRP-LR was used as guidance to develop the allowable stresses. Additionally, the applicant summarized the analysis efforts in the following paragraphs:

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 vent bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis considered drywell geometry and materials, thickness reduction from corrosion, test loads, normal operating loads, design basis accident loads, seismic loads, refueling loads, and design basis load combinations. Pressure and temperature were in accordance with approved Technical Specification Amendment No. 165, which established a revised design bases accident pressure of 44 psig and accident temperature of 292°F. The results of the analysis show that the minimum required ASME Code thickness of the drywell shell above the sand bed region is controlled by membrane stresses and the minimum drywell shell thickness in the sand bed region is controlled by buckling. The minimum required ASME Code thicknesses above the sand bed region are shown in Table 1 (attached to the response). For the sand bed region, 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. This thickness satisfies ASME Code requirements and is considered the minimum required thickness.

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-1 302-1 87-5320-024. The calculation uses a "Local Wall Acceptance Criteria." This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick so 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) shows that there is more than one 12" by 12" area thinner than 0.736" but thicker than 0.536". Also the actual data for two bays shows that there is more than one 2½ in. diameter area thinner than 0.736" but thicker than 0.490". Acceptance is based on the following evaluation. The effect of these very localized 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 the 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 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 Boiler and Pressure Vessel (B&PV) 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 the 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 2½ 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 percent to 0.536" over a one square foot area would only create a 9.5 percent 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 percent reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5 percent over a one square foot area which only reduced the load factor and theoretical buckling stress by 3.5 percent for the whole drywell, resulting in the largest reduction possible. To bring these results into perspective, a review of the nondestructive examination (NDE) reports indicates that there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch 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 percent 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 percent. 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 N284 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.

In summary, the applicant noted that the minimum required drywell shell thickness is based on an analysis conducted in accordance with ASME Code. Factors considered include drywell geometry, material of construction, reduced wall thickness due to corrosion, and applicable design-basis loads and load combinations. Accident pressure and temperature are 44 psig and 292 °F, respectively, in accordance with the approved technical specification amendment No. 165.

In a letter dated April 7, 2006, the applicant responded to RAI 4.7.2-1. In its response the applicant stated that the minimum required thicknesses of the drywell shell above the sand bed region shown in Table-1 of the response are controlled by membrane stresses. The minimum required general drywell shell thickness in the sand bed region of 0.736 inch is controlled by buckling. Localized areas in the sand bed region where the thickness is less than 0.736 inch are evaluated against a local thickness acceptance criteria (0.49 inch) developed 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." Application of these ASME Code sections is justified as discussed above, and specific buckling sensitivity analysis results support the conclusion that, on an average wall thickness basis, buckling of the shell is unaffected by local wall thickness areas as these are distributed over the sand bed region.

The staff reviewed the cited analysis reports to ensure that the parameters used and the assumptions made in the analysis are valid for the period of extended operation. However, based on the review conducted, the staff requested that the applicant provide additional information to address certain gross assumptions.

Attachment 1A of the GPU letter dated November 26, 1990, makes a statistical evaluation of the UT measurement data taken up to 1990. On the cover page of the report, GPU Nuclear Corporation states a disclaimer, "the work is conducted by an individual(s) for use by GPU. Neither GPU nor the authors of the report warrant that the report is complete of accurate ...." In view of this disclaimer, the staff at a public meeting on June 1, 2006, asked the applicant to provide a detailed description of the way the UT measurement data, whether taken as part of the 6-inch by 6-inch grid, or isolated readings, were evaluated and used in performing the analysis.

In its response dated June 20, 2006, the applicant clarified the use of the statistical evaluation as follows:

> The disclaimer noted by the NRC staff is on the cover page of Technical Data Report (TDR) No. 948 Revision 1, "Statistical Analysis of the Drywell Thickness Data." The disclaimer statement is a standard clause that was placed on TDRs developed in accordance with the applicable GPUN procedure at the time. AmerGen points out that TDR No. 1027, which is also a part of Attachment 1A includes the same disclaimer. The disclaimer was intended to reinforce that TDRs are not design basis documents and were not design verified in accordance with the GPUN QA Program. In this case TDR 948 was developed to summarize the initiative that surveyed the drywell and that assessed initial corrosion rates based on data collected from 1986 through December 1988. However this TDR did not serve as the design basis document, which demonstrated the drywell shell met design basis requirements. The TDR in Section 1 (Introduction/Background) explains that the TDR documents the assumptions, methods and results of the statistical analysis used to evaluate the corrosion rates. The section then states that the complete analysis is documented in calculation C-1302-187-5300-005.
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> > Calculation C-1302-187-5300-005, "Statistical Analysis of Drywell Thickness Data Thru 12-31-88" did serve as the design basis document, which demonstrated the drywell shell met design basis requirements. This calculation was developed and design verified in accordance with the GPUN QA Program and is approximately 200 pages long. A review of the information contained in the TDR Section 4.6 (Summary of Conclusion) shows that it is consistent with the information in Section 2 (Summary of Results) in calculation C-1302-0187-5300-005. Thus, the information in the TDR No. 948 represents design quality information.
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> In response to the NRC's question on how the UT measurement data were evaluated and used in the drywell analysis, AmerGen provided a description of how the 49-point array statistical analysis was performed in response to NRC Q&A #AMP-356, item (4). In that response, AmerGen stated that the methodology and acceptance criteria that are 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, "Statistical Analysis of Drywell Thickness Data Thru 4-24-90". This calculation is the more recent version of calculation C-1302-187-5300 and has been submitted by AmerGen to the NRC.

These two 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.

The initial locations identified in 1986 and 1987 where corrosion loss was most severe were selected for repeat inspection over time to measure corrosion rates. 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. If the data was normally distributed, then the mean value of the 49 points was calculated and used to represent the general drywell shell thickness in the tested area. If the 49 points were not normally distributed, then the grid was subdivided into datasets (usually 2, top and bottom) that were normally distributed. The mean value for each dataset was then calculated. The minimum mean value was compared to the minimum required thickness as described below.

The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736 inches. In addition each individual reading was compared to the local minimum required criteria of 0.490 inches. The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to NRC Question #AMP-210. 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, although random variations in the UT measurements as a result of such factors as variables in the inspection process and in environmental conditions may occur. 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 inches.

A process similar to that described above is applied to the thinnest individual reading in each grid. The lowest reading taken is also verified against the local minimum thickness requirement. Then 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 0.490 inches.

The staff finds that the applicant has provided an explanation of the documents used for the design basis calculations. Furthermore, the applicant provided the process used in establishing the minimum thickness of the drywell used in the 1991 GE analysis. Based on the discussion provided above, the staff finds the applicant's historical method of determining the minimum required wall thickness acceptable because these processes use recognized industry standards for performance and evaluation of results. On the basis of the applicant's written response, the staff determined that its concerns related to the disclaimer in the Technical Data Report had been resolved.

Open Item 4.7.2-1.3: ASME Code Case N-284

In the applicant's discussion, a summary of the methods and assumptions used in the buckling analysis of the shell in the sand-pocket area has been given. Though it has not endorsed ASME Code Case N-284 for use, the staff does not take exception to the use of average compressive stress across the metal thickness for buckling analysis of the as-built shell. However, if the corrosion has reduced the strength of the remaining metal through the cross section, this assumption may not be valid. The staff requests the applicant to address this issue.

In its response dated June 20, 2006, the applicant provided the following discussion on the use of ASME Code Case N-284:

> Although Revision 1 of Code Case 284 had not yet been issued when the Reference 2 report (An ASME Section VIII Evaluation of Oyster Creek Drywell for Without Sand Case, Part II – Stability Analysis," GE Report, Index No. 9-4, Revision 0, DRF # 00664) was written, the authors had the benefit of consultation with Dr. Clarence Miller who was the primary author of the revision. Thus, the plasticity correction factors used in the evaluation (in Figure 2-4 of Reference 2) are the same as those in Figure 1610-1 of Code Case N-284 Revision 1.
>
> Paragraph 1500 in both revisions allows higher values of capacity reduction factors due to internal pressure by stating, "The influence of internal pressure on a shell structure may reduce the initial imperfections and therefore higher values of capacity reduction factors α_{ij} may be acceptable. Justification for higher values of α_{ij} must be given in the design report." The technical approach documented and used in the Reference 2 analysis was reviewed and accepted by Dr. Miller in Reference 4 (Miller, C.D., 1991, "Evaluation of Stability Analysis Methods Used for the Oyster Creek Drywell," Docket No. 50-219, September 12, 1991, CBI Technical Services Company Report prepared for GPU Nuclear Corporation). that is also cited as one of the references in Reference 3 report (NUREG/CR-6706 "Capacity of Steel and Concrete Containment Vessels With Corrosion Damage,"February 2001").
>
> Thus, the technical approach used in the stability evaluation of Reference 2 is entirely consistent with the guidelines in Revision 1 of Code Case N-284.
>
> In the Reference 6 report (Miller, C.D., "Applicability of ASME Code Case N-284-1 to Buckling Analysis of Drywell Shell," June 15, 2006), Dr. Miller discussed the applicability of the N-284-1 methods to corroded shells. He indicated that the imperfection limit indicated by a parameter e/t (where 'e' is the eccentricity and 't' is the shell thickness) was assumed as 1.0 in Code Case N-284-1. The imperfections could be from the fabrication process in the case of a new shell or could be from a combination of fabrication and corrosion in the shells already in service. The contribution to e/t parameter from corrosion was defined as follows:

$$(e/t)_{corrosion} = (t_n - t_c)/(2t_c)$$

For the sand bed region, if we assume the minimum general corroded thickness of 0.736 inch and the nominal thickness of 1.154 inches, the $(e/t)_{corrosion}$ works out to be (1.154-0.736)/(2x0.736) or 0.28. However, this does not mean the preceding value of $(e/t)_{corrosion}$ need always be added to the (e/t) value from fabrication. In fact it needs to be subtracted where the fabrication related eccentricity is in the outward radial direction. Since the fabrication related eccentricities are likely randomly distributed and thus are equally like in either direction, the overall net effect of the corrosion-induced eccentricities would be insignificant. Thus, it is concluded that the corrosion on the outside surface of the shell will not introduce eccentricities that would significantly impact the e/t value of 1.0 assumed in Code Case N-284.

As a summary, the applicant stated:

> The stress analysis of Oyster Creek drywell satisfies the local primary stress requirements of NE-3213.10. Conservatism in the allowable primary stress intensity value, the assumed peak pressure during the LOCA condition and the assumption of local corroded thickness in the entire region of the drywell provide additional structural margin.
>
> Since the Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.
>
> The technical approach used in the stability evaluation of the Oyster Creek drywell is consistent with the requirements specified in Code Case N-284, Revision 1. Additional eccentricity produced by shell corrosion in service is expected to be accommodated within the allowable limit for imperfections.
>
> As indicated in Table-1, UT measurements of the drywell shell above the sand bed region show that the measured general thickness contains significant margin. Considering the ongoing corrosion in that region is insignificant, the margin can be applied to offset uncertainties related to surface roughness.
>
> UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736 inch thickness assumed in the buckling analysis by significant margin except in 2 bays, bay #17 and bay #19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074 inch and 0.064 inch respectively. Considering that significant additional corrosion is not expected in the sand bed region, the margin can be applied to offset uncertainties related to the surface roughness.

The staff finds that the applicant has provided a thorough explanation of the factors considered in applying the ASME Code Case N-284-1 for buckling analysis of the corroded shell in the sand bed area of the drywell shell. However, it does not address the staff's concern about whether it is appropriate to assume the same strength across the corroded section of the shell. The incorporation of the "e/t" corrosion concept to arrive at a representative distribution of strength along the corroded section that recognizes the lower strength at the corroded side and full strength at the inside surface could support the claim of conservatism in the analysis. This was identified as OI 4.7.2-1.3 in the SER, dated August 18, 2006.

On further evaluation of the applicant's information, the staff concludes that the stability evaluation was consistent with the guidelines of ASME Code Case N-284-1. The staff's concern about use of the same section strength across the corroded section of the shell is addressed by the Code Case N-284-1, which uses conservative assumptions to determine shell capacity reduction factors (*i.e.*, assumption of imperfection limit indicated by parameter "e/t" to be 1.0 in the code case) expected to compensate reasonably for such use of same section strength. In addition, the applicant conservatively assumed the local corroded thickness for the entire drywell shell region and demonstrated that the code allowable stresses were satisfied consistently with the guidelines of the code case. Thus, this analysis adds a margin of safety for the drywell stability evaluation. On this basis, the staff believes that the stability evaluation method is adequate and acceptable, and the staff's concern is resolved. Open Item 4.7.2-1.3 is closed.

<u>Open Item 4.7.2-1.4: Localized Thin Areas</u>

For the localized thin areas, the applicant is using the provision of NE-3213.10 of Subsection NE of Section III of the ASME Code. This provision, although not directly applicable to the randomly thin areas caused by corrosion, if used with care and adequate conservatism, may provide some idea about the primary stress levels at the junction of the thin and thick areas. The staff requested that the applicant provide a summary of the process used to address this issue.

In its response dated June 20, 2006, the applicant noted that this is the only method available and that this approach was accepted by the staff in the 1990s. Recently, the applicant had contracted GE to review the 1991 analysis for the purpose of identifying conservatism. The applicant summarized the GE report as follows:

> Although the ASME Section III and Section VIII analysis procedures were not developed for randomly thin areas caused by corrosion, GE has concluded that the same analysis procedures are applicable to in-service components as long as the section thickness values used are adjusted to account for the reduction due to corrosion. Table 2-1 of Reference 1 lists the nominal thickness values and the 95% confidence level thickness values in the locally corroded areas. Even though the corroded thickness is present only in a very local area of a region, the reduced value was used for that drywell region in the Section VIII stress analysis.
>
> ASME Section III, Subsection NE-3213.10 states that membrane stress produced by pressure or other mechanical loading and associated with a primary or discontinuity effect produces excessive distortion in the transfer of load to other portions of the structure. Conservatism requires that such stress be classified as a local primary membrane stress even though it has some characteristics of a secondary stress. A stressed region may be considered local if the distance over which the membrane exceeds 1.1 S_{mc} (stress intensity) does not extend in the meridional direction more than 1.0(Rt)½, where S_{mc} is as defined in Subsection NE-3112.4, R is the minimum mid surface radius of curvature and t is the minimum thickness in the region considered. Regions of local primary stress intensity involving axisymmetric membrane distributions which exceed 1.1S_{mc} shall not be closer in the meridional direction than 2.5 (Rt)½, where R is defined as (R1 + R2)/2 and t is defined as (t1 + t2)/2, where t1 and t2 are the minimum thicknesses at each of the regions considered and R1 and R2 are the minimum

midsurface radii of curvature at these regions where the membrane stress intensity exceeds 1.1 S_{mc}. The requirements of ASME Section III, Subsection NE-3213.10 were satisfied by determining the maximum meridional extent of the areas where the local primary membrane stress exceeds 1.1 S_{mc}, but is below the allowable value of 1.5 S_{mc} [Reference 1]. The maximum extent was determined to be 11 inches (using the large displacement solution) and was found to be acceptable [i.e., less than the allowable value of 1.0(Rt)½ or 17.6 inches]. Given that a uniform minimum corroded thickness for a drywell region is used in the evaluation, the preceding analysis is expected to be bounding for the actual corroded condition.

The applicant notes that the above evaluation was based on a peak internal pressure of 62 psi. However, the applicant points out that the Oyster Creek specific calculation with an adder of 15% showed the peak internal pressure as 44 psi, and that this value was approved by the NRC in 1993.

The applicant noted that "although provisions in ASME Code Section III, Subsection NE-3213.10 are not directly applicable to the randomly thin areas caused by corrosion, AmerGen believes that the provisions are applicable to the analysis of Oyster Creek drywell shell based on the following:

- The stress analysis of Oyster Creek drywell presented in Reference 1 satisfies the local primary stress requirements of NE-3213.10. Conservatism in the allowable primary stress intensity value, the assumed peak pressure during the LOCA condition and the assumption of local corroded thickness in the entire region of the drywell provide additional structural margin.

- The Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.

- As indicated in Table-1, UT measurements of the drywell shell above the sand bed region show that the measured general thickness contains significant margin. Considering the ongoing corrosion in that region is insignificant, the margin can be applied to offset uncertainties related to surface roughness.

Table 4.7.2 Drywell Shell Thickness and the Minimum Available Thickness Margin

Drywell Region	Nominal Design Thickness (inches)	Minimum Measured Thickness, (inches)	Minimum Required Thickness (inches)	Minimum Available Thickness Margin (inches)
Cylindrical	0.640	0.604	0.452	0.152
Knuckle	2.625	2.54	2.29	0.25
Upper Sphere	0.722	0.676	0.518	0.158
Middle Sphere	0.770	0.682	0.541	0.141
Lower Sphere[1]	1.154	0.800[1]	0.629	0.171
Sand Bed [2]	1.154	0.800	0.736	0.064

1. The general thickness in the lower sphere is conservatively assumed to be the same as the sand bed region.
2. The minimum required general thickness in the sand bed region is controlled by buckling analysis, governed by load combinations that do not include the 44 psi pressure.

- UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736'" thickness assumed in the buckling analysis by significant margin except in 2 bays, bay 17 and bay 19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074" and 0.064" respectively. Considering that significant additional corrosion is not expected in the sand bed region, the margin can be applied to offset uncertainties related to the surface roughness.

The staff identified this issue as OI 4.7.2-1.4 in the SER, dated August 18, 2006.

After further evaluation of the applicant's justification, the staff concludes that use of the NE-3213.10 provisions of Subsection NE of Section III of the ASME Code is acceptable. The staff's acceptance is based on the applicant's conservative approaches to its determination of the allowable shell capacity. Specifically, the applicant demonstrated acceptable shell capacity based on use of a conservative LOCA peak internal pressure (i.e., peak internal pressure of 62 psi in the evaluation versus the 44 psi peak internal pressure in an Oyster Creek specific calculation approved by the NRC in 1993), use of local corroded thickness for the entire region of the drywell, and compliance with local primary stress code limits in the corroded condition. In addition, the applicant expects its enhanced actions to prevent additional corrosion in the sand bed region. On this basis, the staff's concern is resolved and Open Item 4.7.2-1.4 is closed.

4.7.2.2.3 Mitigating Actions

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide a summary of the actual mitigating actions taken and their effectiveness.

In its response dated April 7, 2006, the applicant listed the following actions:

- cleared the former sand bed region drains to improve drainage,

- replaced reactor cavity steel trough drain gasket, which was found to be leaking,

- removed water from the sand bed region,
- installed a cathodic protection system in bays with greatest wall thinning in early 1989 - subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and was removed from service in 1992,
- removed sand in the sand bed region to break up the galvanic cell,
- removed corrosion products from the external side of the shell in the sand bed region,
- upon sand removal, the sand bed concrete floor was found cratered and unfinished - the concrete floor was repaired, finished and coated to permit proper drainage of the sand bed region,
- applied a silicone seal at the juncture of the drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the embedded drywell shell in concrete,
- applied a multi-layered epoxy protective coating to the exterior surfaces of the drywell shell in the sand bed region (i.e., one pre-primer coat, and two top coats),
- applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner, this limits water intrusion into the gap between the drywell shell and the drywell shield wall, and confirmed that the reactor cavity concrete trough drains are not clogged

The applicant further explained that these mitigating features have been in place since 1992. The most effective feature was the removal of sand in the sand bed region to break up the galvanic cell, which significantly reduced the rate of corrosion in that region. The sand bed region coating is effective because it is protecting the underlying drywell shell from ongoing corrosion, as confirmed by a comparison of UT measurements taken in 1992, 1994, and 1996. The other features, except for cathodic protection, are also effective because their implementation limited water intrusion into the gap between the drywell shell and the drywell shield wall, thus reducing the rate of corrosion in the upper region of the drywell.

A comparison of UT measurements taken in 1992, 1994,1996, 2000, and 2004 on the upper region of the drywell shell shows that either the corrosion is no longer occurring or is negligible considering the accuracy of UT instruments. As stated previously, the cathodic protection system was installed in the bays with the greatest wall thinning in early 1989. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and was removed from service in 1992.

Based on the discussion above, the staff finds the applicant's response to item (c) acceptable, as it describes the mitigating actions taken by the applicant. The staff's concern described in RAI 4.7.2-1(c) is resolved.

4.7.2.2.4 Chart of Ultrasonic Test Measurements

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide a comparative graph (or chart) showing the drywell thickness based on the assumed corrosion rate and that actually found after the mitigating actions were implemented.

In its response dated April 7, 2006, the applicant provided Tables 1 and 2. These tables provide UT thickness measurements for the upper region of the drywell, and for the sand bed region of the drywell shell, respectively.

The staff finds the tables and figures useful in understanding the extent of corrosion. The staff's concern described in RAI 4.7.2-1(d) is resolved.

4.7.2.2.5 Location of Drywell Corrosion

Junction of Drywell Floor and Shell

In RAI 4.7.2-2 dated March 10, 2006, the staff noted that a number of Mark I containments have experienced corrosion inside their drywells at the junction of the bottom concrete floor and the steel shell. The staff requested that the applicant provide information regarding corrosion of the drywell shell at this location or any other location of the drywell inside surfaces.

In its response dated April 16, 2006, the applicant stated that OCGS has not experienced corrosion on the inside surfaces of the drywell shell, including the junction of the bottom concrete floor and the steel shell. The inside of the drywell is coated with Carbo-Zink 11 over an SSPC-SP6/SP5, commercial abrasive blast surface preparation to a dry film thickness of 3-6 mils. Moreover, visual inspections conducted in accordance with ASME Code Section XI, Subsection IWE, have not identified recordable corrosion at the junction of the bottom concrete floor and the steel shell or any other location inside the drywell. Minor surface rust has been noted in some areas where the coating is damaged or removed for UT measurements. The minor surface rust is limited to isolated areas and does not impact the intended function of the drywell.

Based on the above discussion, the staff finds this response acceptable, as the condition would not challenge the intended function of the drywell shell. The staff's concern described in RAI 4.7.2-2 is resolved.

Open Item 4.7.2-3: Leakage From Refueling Seal

In RAI 4.7.2-3 dated March 10, 2006, the staff noted that leakage from the refueling seal has been identified as one of the reasons for accumulation of water and contamination of the sand-pocket area. The refueling water passes through the gap between the shield concrete and the drywell shell in the long length of inaccessible areas. As there is a potential for corrosion in this area, ASME Code Subsection IWE would require augmented inspection of this area. The staff requested that the applicant provide a summary of inspections performed (visual and nondestructive examination (NDE)) and mitigating actions taken to prevent water leaks from the refueling seal components.

In its response dated April 16, 2006, the applicant stated that the refueling seals at OCGS consist of stainless steel bellows. In the mid-to-late 1980s, GPU conducted extensive visual and NDE inspections to determine the source of water intrusion into the seismic gap between the drywell concrete shield wall and the drywell shell and its accumulation in the sand bed region. The inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested using helium (external) and air (internal) without any indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in a concrete trough below the bellows. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the seismic gap. The drain line has been checked before refueling outages to confirm that it is not blocked. The only other seal is the gasket for the reactor cavity steel trough drain line. This gasket was replaced after the tests showed that it was leaking. However, the gasket leak was ruled out as the primary source of water observed in the sand bed drains because there is no clear leakage path to the seismic gap. Minor gasket leaks would be collected in the concrete trough below the gasket and would be removed by the drain line similar to leaks from the refueling bellows.

In addition, the applicant noted that additional visual and NDE (dye penetrant) inspections on the reactor cavity stainless steel liner had identified a significant number of cracks, some of which were throughwall cracks. Engineering analysis concluded that the cracks were most probably caused by mechanical impact or thermal fatigue, and not IGSCC. These cracks were determined to be the source of refueling water that passed through the seismic gap. To prevent leakage through the cracks, GPU installed an adhesive-type stainless steel tape to bridge any observed large cracks and subsequently applied a strippable coating. This repair greatly reduced leakage and was implemented every refueling outage while the reactor cavity was flooded.

The applicant noted that it has committed to monitor the sand bed region drains for water leakage. A review of plant documentation did not provide objective evidence that the commitment has been implemented since 1998. Issue Report No. 348545 was issued in accordance with the OGCS corrective action process to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future, including during the period of extended operation.

The applicant also committed (Commitment No. 27, Item 4) to performing augmented inspections of the drywell in accordance with ASME Code Section XI, Subsection IWE. These inspections consist of UT examinations of the upper region of the drywell and visual examinations of the protective coating on the exterior of the drywell shell in the sand bed region. UT measurements will supplement the visual inspection of the coating measurements from inside the drywell once before entering the period of operation and every 10 years thereafter during the period of extended operation.

The staff's review of the applicant's response determined that the epoxy coating applied in the sand-bed region of the shell has a limited life and water leakage from the air gap has not been prevented. In view of these observations, the staff requested that the applicant provide a systematic program of examination of the coating that would provide confidence that the preventive measure is adequately implemented at all locations in the sand-pocket areas.

In its response dated June 20, 2006, the applicant committed that it will monitor the sand bed region drains on a daily basis during refueling outages and take the following actions if water is detected. The actions will be completed prior to exiting the outage.

- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
- The water will be chemically analyzed to aid in determining the source of leakage.
- A remote inspection will be performed in the trough drain area to determine if the trough drains are operating properly.

- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected.
- If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation will be consistent with the existing program.
- The degraded coating and/or the seal will be repaired in accordance with station procedures.
- UT measurements will be taken in the upper region of the drywell consistent with the existing program.

The applicant, also, committed (Commitment No. 27, Item 3) to monitor the sand bed region drains quarterly during the operating cycle. The applicant stated that if water is detected, actions listed below will be taken. Those that require an outage to be accomplished will be completed during the next scheduled refueling outage.

- The leakage rate will be quantified to determine a representative flow rate. The leakage rate will be trended.
- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
- The water will be chemically analyzed to aid in determining the source of leakage.
- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected during the next refueling outage or an outage of opportunity.
- If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation of the results will be consistent with the existing program.
- UT measurements will be taken in the upper region of the drywell consistent with the existing program.
- The degraded coating and/or the seal will be repaired in accordance with station procedures.

The staff finds that the applicant's program will provide reasonable assurance that any further incidents of water in the sand bed region will be systematically evaluated, and actions will be taken to prevent further degradation of the drywell shell. However, the program was not clear regarding the extent of the coated surfaces examined during each inspection. This was identified as OI 4.7.2-3 in the SER, dated August 18, 2006.

The applicant committed (Commitment No. 27) to monitoring of the coating on the drywell shell exterior in the sand bed region as part of its ASME Section XI, Subsection IWE Program and of its Protective Coating Monitoring and Maintenance Program. The applicant committed to additional visual inspections of the epoxy coating in all 10 drywell bays at least once prior to the period of extended operation. In a letter dated December 3, 2006, the applicant stated that 100 percent of the epoxy coating had been inspected during the October 2006 outage with no evidence of flaking, blistering, peeling, discoloration or other signs of coating distress. These commitments, with the IWE program and the October 2006 inspection which indicated no coating degradation, resolve the staff concern over the extent of coatings inspection. Therefore, the staff's concern is resolved and Open Item 4.7.2-3 is closed.

In its letter dated February 15, 2007, the applicant revised a commitment (Commitment No. 27) by adding Item 19, which states that AmerGen will perform an engineering study prior to the proposed renewal period to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage. The ACRS recommended the license be conditioned to require the study. The staff identified this as a license condition consistent with the applicant's Commitment 27 item 19.

4.7.2.2.6 Ultrasonic Test Measurement Program

In view of the uncertainty regarding the long-term effectiveness of the coating and water leakage, the staff requested that the applicant review the accuracy of the UT measurements and establish a credible program for performing the UT examination of the shell in the sand-bed region during the period of extended operation.

In its response dated June 20, 2006, the applicant stated:

> In a letter dated April 4, 2006, AmerGen committed to perform UT measurements of the sand bed region every 10 years. In view of the uncertainty regarding the long-term effectiveness of the coating and water leakage, the NRC requested the applicant to clarify the commitment for UT measurement frequency in the sand bed region.
>
> AmerGen is confident that the aging management program it committed itself to in the April 4, 2006 letter is adequate to ensure that significant drywell corrosion will be detected and addressed prior to impacting the intended function of the containment. The program requires visual inspection of the coating in the sand bed region on a frequency of every other refueling outage.
>
> The program also requires performing UT inspections in the upper regions of the drywell shell on a frequency of every other refueling outage. The measurements in the upper region of the drywell bound the sand bed region since the environment is the same and the sand bed region is protected with epoxy coating while the upper region is coated only with a Zinc primer. In addition, AmerGen is committed to performing UT examinations of the sand bed region every 10 years. The 10-year frequency for the UT measurements is based on ASME Section XI requirements and is intended to confirm that the coating continues to mitigate corrosion. The initial UT measurements will be taken prior to entering the period of extended operation. The UT measurements are only a part of the overall program designed to provide reasonable assurance that significant corrosion is detected before containment intended function is adversely impacted.
>
> Nevertheless, AmerGen will take a second set of UT measurements in the sand bed region two refueling outages after the measurements taken prior to entering the period of extended operation. The results of the measurements will be

evaluated to determine the appropriate measurement frequency required to provide continued reasonable assurance that corrosion is being effectively monitored and managed during the period of extended operation. The frequency will be established as appropriate, but not to exceed every 10 years. In Item H of the June 20, 2006 response, AmerGen provides additional information on the actions that will be taken if water is detected in the sand bed region drains.

Based on the applicant's commitment (Commitment No. 27), the staff understands that the applicant will take UT measurements in the sand bed region two refueling outages after the measurements taken prior to entering the period of extended operation. The staff's finds this acceptable; therefore, the concern is resolved.

In RAI 4.7.2-4 dated March 10, 2006, the staff noted that industrywide operating experience indicates a number of incidences of torus corrosion in Mark I containments. Neither LRA Table 3.5.2.1.1 nor the ASME Section XI, Subsection IWE Program describes operating experience related to corrosion of the OCGS torus. The staff requested that the applicant provide a summary of the results of IWE inspections performed on the torus and instances of torus corrosion.

In SER Section 3, the staff evaluates the condition of the torus (suppression chamber) and concludes that aging effects will be adequately managed during the period of extended operation.

4.7.2.2.7 Sandia National Laboratories Drywell Structural Analysis

To provide additional assurance that the applicant's AMP (as discussed in Section 3), would provide a framework for insuring that the Oyster Creek drywell shell can withstand the postulated design loads during the renewal period, the NRC staff contracted with Sandia National Laboratories (Sandia) to analyze the drywell with conservatively biased modeling of the degradation. The Sandia analysis is in report SAND2007-0055 (ML070120395), "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station," which was issued on January 12, 2007. As part of the analysis, Sandia developed a detailed three-dimensional (3D) finite element model of the drywell containment vessel using information provided by the NRC and the applicant. The model was used to evaluate the structural integrity of the vessel in terms of the stress limits specified in the ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Division I, Subsection NE, and in terms of buckling (stability) limits specified in ASME B&PV Code Case N-284. The purpose of the Sandia analysis was to examine whether the Oyster Creek degraded drywell shell can withstand the postulated loadings without exceeding the ASME code requirements for stress and stability.

The Sandia analysis did not replace or reproduce the analysis done in the GE study. The baseline (i.e. un-degraded) analysis was performed to isolate the effects of the degradation. The Sandia analysis focused more on the relative reduction in design margin due to the corrosion than on the calculated absolute stresses or stability limits.

The Sandia analysis used a different modeling approach than the GE study and made assumptions regarding general design information when plant specific information was unavailable. Analyst judgment was used in applying the ASME Code requirements. Consequently, the numerical values derived by the Sandia analysis are generic in nature and are not part of the Oyster Creek current licensing basis.

The Sandia study included stress and buckling analyses for both a representation of the containment in its degraded condition and in its original, as-built, condition. The study of the as-built conditions provides base-line analyses to assess the effects of degradation on the stresses and buckling behavior for the containment.

The conclusions resulting from the study included:

- The introduction of degradation does cause a noticeable increase in the stress levels throughout the drywell shell for each load condition.
- In general, the accident condition (accident pressure 44 psig, and temperature 292°F) causes the largest stress increases throughout the drywell when degradation is introduced.
- The buckling evaluation performed using ASME N-284 show that based on the loadings and the Sandia model, both the refueling and post-accident load combinations met buckling requirements.
- ASME allowable stresses are met for all three load cases examined.

The effects of locally thinner regions in bays #1 and #13 were explored. Under the refueling load condition, the buckling initiation was observed as a result of these thin areas. However, the effective safety factor was maintained above the ASME minimum of 2.0 for the load combination containing loadings from the refueling activities, the postulated seismic loads, and a hypothetical external pressure load of 2 pounds per square inch.

The Sandia Report results support and confirm that the drywell will be able to perform its intended functions in its present condition. The report also indicates that the areas of the drywell shell above and below the sand bed region have sufficient thickness to accommodate additional corrosion of the shell before ASME Code safety factors or minimum wall thickness criteria are reached. However, in the sand bed region, UT measurements indicate that wall thickness of some areas of the shell are at or near the wall thickness required to satisfy the ASME Code safety factor or the minimum wall thickness criteria.

Additionally, the NRC staff requested Sandia to perform an analysis of the drywell shell with the existing degradation to assess the minimum thickness required in the sand bed area to maintain the minimum safety factors against bucking. Sandia analyzed the shell using the provisions of ASME Section III Code Case N-284. In considering the capacity reduction factor applicable to the load combination incorporating the refueling load and external pressure, Sandia did not give any credit to the membrane tensile stresses produced in the shell by the meridional compressive load, by not increasing capacity reduction factor. Sandia arrived at a minimum thickness of 0.844".

In the staff's SER dated April 14, 1992, the staff had made an assessment of the GE analysis for the load combination incorporating the refueling load and external pressure. The SER and attached Technical Evaluation Report by Brookhaven National Laboratory documented the staff's review of the increased capacity reduction factor due to the membrane tension, and accepted the process of deriving the increased capacity reduction factor. The GE analysis assumed a uniform minimum thickness in the sand bed region of 0.736". The Staff finds the use of the increased capacity reduction factor described in the GE analysis is reasonable and consistent with ASME Code Case N-284 as well as ASME Section VIII, Code Case 2286.

Based on its review and the applicant's Commitment 27, the staff identified a licensing condition that requires the applicant to monitor the shell degradation in all 10 bays of the sand bed region every other refueling outage throughout the renewal period.

During the Advisory Committee on Reactor Safeguards (ACRS) meeting on February 1, 2007, the applicant committed to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operations. In its letter dated February 15, 2007, the applicant revised a license commitment (Commitment No. 27) by adding Sub-item 18, which states that AmerGen will perform a 3-D finite elemental analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code requirement for buckling. The staff identified this commitment item as a license condition.

4.7.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of drywell corrosion in LRA Section A.4.5.2.

The staff's review of LRA Section A.4.5.2 identified an area in which additional information was necessary to complete the review of drywell corrosion.

In RAI 4.7.2-5 dated March 10, 2006, the staff noted that for this important issue the UFSAR supplement should, at a minimum, briefly describe the quantitative aspect of the drywell corrosion and the applicant's assertions to maintain it above a certain thickness to ensure that the containment can perform its intended function during the period of extended operation. The applicant will use the TLAA and Subsection IWE of the ASME Code to maintain the containment functionality.

In its response dated April 26, 2006, the applicant stated that UFSAR Section 3.8.2.8 provides historical information on drywell corrosion and corrective actions taken to control it. The section also describes aging management activities that are implemented during the current term consistent with the existing commitments to NRC. The section is revised periodically to include, by reference, the results of quantitative engineering analyses, the UT measurements in the upper regions of the drywell, and inspection of the coating of the drywell shell in the sand bed region.

The applicant stated that LRA Section A.1.27, ASME Code Section XI, Subsection IWE, and the license renewal commitment list (Commitment No. 27), which are included in the application, will be incorporated in the UFSAR as a supplement. However, the applicant recognizes that both the LRA Appendix A and the commitment list do not include additional commitments to the NRC staff on drywell corrosion for the period of extended operation. Hence, the applicant stated that it will revise the commitment list to include details of these additional commitments and will use it as the basis for the drywell corrosion aging management program during the period of extended operation. The revised commitment list and LRA Section A.1.27 will be incorporated in the UFSAR. The supplement, therefore, will include elements of the drywell corrosion aging management program in sufficient detail to ensure that program commitments are documented in the UFSAR.

In a letter dated December 3, 2006, the applicant provided additional commitments for enhancing the ASME Section XI, Subsection IWE aging management program. The new commitment 27 items are:

14. UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are Identified.

16. Perform visual inspections of the drywell shell inside the trenches in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

17. Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.

During the Advisory Committee on Reactor Safeguards (ACRS) meeting on February 1, 2007, the applicant committed to perform an engineering study prior to the period of extended operation in order to identify options to eliminate or reduce the leakage in the refueling cavity liner. The applicant also committed to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

In its letter dated February 15, 2007, the applicant confirmed the commitments it made to the ACRS and revised commitment 27) ASME Section XI, Subsection IWE. The applicant also added commitments for inspection of the drywell trenches and full scope of drywell sand bed region inspections. The specific commitment items which the applicant added are:

18. AmerGen will perform a 3-D finite element structural analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements.

19. AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage.

20. AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17 during the Oyster Creek 2008 refueling outage (see item 16 of AmerGen's IWE Program (Commitment 27), made in its letter 2130-06-20426). AmerGen will extend this commitment and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.

21. Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as:

    - UT measurements from inside the drywell (Item 1)
    - Visual inspections of the drywell external shell epoxy coating in all 10 bays (Item4)
    - Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (Item 12)
    - UT measurements at the external locally thinned areas inspected in 2006 (Items 9 and 14)

The staff, consistent with ACRS recommendations, identified these items as license conditions.

The staff finds the applicant's additional commitments for enhancing the ASME Section XI, Subsection IWE aging management program acceptable; therefore, the concern described in RAI 4.7.2-5 is resolved.

On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address drywell corrosion is adequate.

4.7.2.4 Conclusion

On the basis of its review and the license conditions discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the drywell corrosion TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Equipment Pool and Reactor Cavity Walls Rebar Corrosion

4.7.3.1 Summary of Technical Information in the Application

In LRA Section 4.7.3, the applicant summarized the evaluation of equipment pool and reactor cavity walls rebar corrosion for the period of extended operation. A letter to the NRC discussing drywell corrosion reported that leakage was observed in the vicinity of the equipment pool and reactor cavity walls, indicating slight corrosion of the reinforcing bar. Based on a representative concrete core sample, it was conservatively estimated that the diameter of a typical reinforcing rebar in the localized area could be expected to be reduced by 0.002 inch per year. The walls in question are reinforced with No. 8 and No. 11 rebar. Assuming the corrosion continues for the entire 40-year life of the plant, the diameter of the reinforcing bar would be reduced by 8 and 6 percent, respectively. The corrosion was localized and the reduced reinforcing bar diameter was judged to have no impact on the concrete integrity.

Regarding its analysis, the applicant stated that the equipment pool and reactor cavity walls were recently visually inspected. The walls indicated no signs of water intrusion. No indications of further deterioration were observed. Conservatively assuming the above corrosion rates continue through the end of the period of extended operation, the diameter of the No. 8 and No. 11 reinforcing bar are estimated to be reduced by 12 and 9 percent, respectively. Since the corrosion continues to be localized, there is no significant impact on the integrity of the concrete.

The applicant projected the corrosion of the reinforcing bar to the end of the period of extended operation. The integrity of the concrete will be maintained even if the reinforcing bar corrosion continues to the end of the period of extended operation.

4.7.3.2 Staff Evaluation

The staff's review of LRA Section 4.7.3 identified areas in which additional information was necessary to complete the review of the equipment pool and reactor cavity walls rebar corrosion. The applicant responded to the staff's RAI as discussed below.

In RAI 4.7.3-1 dated March 30, 2006, the staff requested that the applicant provide the following information:

- an explanatory figure of the equipment pool area and the reactor cavity wall areas affected by rebar corrosion and leakages,
- the extent of areas of walls affected by the corrosion and leakages,
- the calculated maximum stresses in the rebars during the normal operating and the postulated accident loads or seismic events for which the walls are designed, and
- the effect of the 60-year corrosion on the stresses calculated in (3) above

In its response dated May 1, 2006, the applicant provided the following information.

In response to item (1), the applicant provided a plan view of the reactor building at an elevation of 95' 3". The view shows three areas affected by rebar corrosion and water leakage. The applicant noted that water and rust stains were observed around hairline cracks on the exterior surfaces of these walls in 1986. As a result, these areas were considered suspect for rebar corrosion. The walls are also affected by the elevated temperature in the upper region of the drywell, evaluated under Integrated Plant Assessment Systematic Evaluation Report, Systematic Evaluation Program (SEP) Topic 111-7B.

The staff finds the sketch and explanatory description provided informative and useful in understanding rebar corrosion.

In response to item (2), the applicant explained that the reactor cavity and equipment pool walls affected by rebar corrosion are limited to localized portions of the walls between elevation 95' and 119'. These local areas were documented in a material nonconformace report (MNCR #86-870) in 1986, when a reddish-brown (rust-like) deposit was observed in and around hairline cracks in the walls. Later, it was determined that these deposits were from iron oxide corrosion products from the embedded reinforcement steel and the corrosion was most likely a product of water leakage during refueling outages. It was considered probable that treated water entered the preexisting cracks in the concrete wall, which wetted the surface of the rebar. Based on these determinations, GPU concluded that a corrosion damage assessment was necessary to establish the degree of rebar corrosion.

To accomplish the corrosion assessment, concrete core samples were taken and tested as described in response to item (1) above to determine whether water intrusion into the cracks created an environment that is aggressive to the rebar. Based on the test results, the applicant made a judgment that the environment was not aggressive and only minimal rebar corrosion, if any, should be expected. The applicant's response to RAI 4.7.3-2, below, provides an additional description of the extent of corrosion and established corrosion rate.

In response item (3), the applicant stated that the calculated maximum stress used to evaluate the affected rebar by corrosion was 32.8 kips per square inch (ksi). This maximum stress was based on the GPU comprehensive analysis to assess the impact of observed cracking and elevated temperatures on the spent fuel pool structure and the drywell shield wall. GPU conducted the analysis using a finite element ANSYS model of the north side of the reactor building, which included half of the drywell shield wall and the spent fuel storage pool. ABB Impell Report No. 03-0370-1341 summarized the analysis results, which were transmitted to the NRC by letter dated September 1992. The results of the analysis indicated that for load combinations involving operating and seismic loads (combinations 3.3.2c and 3.3.2d in ABB Impell Report No. 03-0370-1341, page 39), the maximum calculated stress was 32.8 ksi. This maximum stress was only in a few elements in the area of the fuel transfer canal on the south wall of the spent fuel pool. The areas affected by rebar corrosion are in the south side of the reactor building, away from the transfer canal and from the heavily loaded spent fuel pool area. Based on the above calculations, the applicant concluded that using a stress value of 32.8 ksi for areas affected by rebar corrosion is very conservative because loads in the north half of the reactor building are significantly higher than the south half of the building as a result of the fuel pool structure weight and the weight of the high-density spent fuel racks.

Furthermore, the applicant cited a letter from Alexander W. Dromerick (NRC) to John J. Barton (GPU), "Request for Additional Information - SEP Topic 111-76, 'Shield Wall Temperature" dated July 26, 1993, when the NRC requested that GPU provide numerical values of stresses under load combinations 3.3.2c and 3.3.2d in the concrete and reinforcing bars in the drywell shield wall above elevation 95'. The NRC also requested that GPU discuss the measures taken (if any) to prevent the migration of moisture through the cracks to alleviate rebar corrosion. In response, GPU transmitted the ABB Impell Report No. 0037-00196-01 via a letter to the NRC dated November 19, 1993. The report summarized rebar and concrete stresses at locations used to evaluate the capacity of the drywell shield wall above elevation 95' for load combinations 3.3.2c and 3.3.2d. These load combinations included normal operating loads and design-basis seismic loads. The maximum calculated reinforcement stresses in critical locations (worst area) were 32.8 ksi for load combination 3.3.2c and 31.4 ksi for load combination 3.3.2d. The applicant used these stresses to determine the increased rebar stresses due to corrosion.

In response to item (4), the applicant noted that, as discussed in the TLAA 4.7.3 analysis, periodic inspections of the reactor cavity and equipment pool walls conducted since the mid-1990s indicated no signs of water intrusion or indications of further deterioration of the rebar. The TLAA was based on the corrosion rate of 0.001 inch per year reported to the NRC by letter dated December 5, 1990. By letter dated November 19, 1993, GPU informed the NRC that corrosion was not ongoing.

Although there is no evidence of continuing rebar corrosion, AmerGen is conservatively assuming corrosion of 0.010 inch all around the rebar during the period of extended operation, in addition to the assumed corrosion of 0.020 inch all around for the current term. This results in a total assumed corrosion of 0.030 inch, yielding a reduction of cross section area of 13 percent for No. 8 rebar and 8 percent for No. 11 rebar. The maximum tensile stress in rebar affected by corrosion is found to be 37.6 ksi for the reinforcing steel having the minimum yield strength of 40 ksi. Since the corrosion continues to be localized, there is no significant impact on structural integrity of the reinforced concrete walls. The applicant refers to its response for item (2) for additional rationale as to why the corrosion rate is conservative.

In summary, the applicant noted that the estimated reduction in rebar cross section area, in locations affected by this rebar corrosion, through the period of extended operation is 13 percent for No. 8 rebar and 8 percent for No. 11 rebar. This results in a stress increase of 14.5 percent for the No. 8 rebar and 9.1 percent for the No. 11 rebar. Based on the stress increases discussed above and using the maximum calculated stress of 32.8 ksi, the maximum stress in the No. 8 rebar affected by corrosion is 37.6 ksi and 35.8 ksi for the No. 11 rebar. These stresses remain below the American Concrete Institute (ACI) yield stress of 40 ksi. Furthermore, the applicant notes that the calculated 32.8 ksi stress is overly conservative for the drywell shield wall affected by the rebar corrosion, because it is based on the highly loaded spent fuel pool (high-density racks), and for the highly stressed area around the slot in the south wall of the fuel pool.

Based on the detailed responses, the staff finds acceptable the applicant's assessment that areas subjected to localized cracking and rebar corrosion are not as heavily loaded as the walls of the spent fuel pool, and the use of rebar stress values from the analysis of the spent fuel pool is conservative. Considering the capacity reduction factor of 0.9, the ACI would allow up to 36 ksi for grade 40 rebar steel. However, taking into account the conservative estimates of corrosion and the conservative stress calculations, the staff finds that the walls with localized rebar corrosion will be able to perform their intended function during the period of extended operation. The staff's concerns described in RAI 4.7.3-1 are resolved.

In RAI 4.7.3-2 dated March 30, 2006, the staff requested that the applicant provide:

(1) the bases for the corrosion rate established in the analysis,

(2) assertions that these rates will not be exceeded during the period of extended operation, and

(3) the means of monitoring the actual corrosion of the rebar during the period of extended operation

In its response dated May 1, 2006, the applicant stated the following:

> In response to item (1), the applicant stated that it derived the corrosion rate based on chemical analysis of concrete core samples taken on a location that is representative of the drywell shield wall and the equipment pool wall concrete. The samples were analyzed via standard gravimetric, titrimetric, energy dispersive X-ray, and leachate ion chromatography techniques. In addition, a pH determination was derived from the leachate sample. The samples were analyzed for total composition, chlorides, and sulfates. The test results indicated that rebar is exposed to a nonaggressive environment that contains 10 parts per million (ppm) chlorides, 890 ppm sulfates, and a pH of 11.6.

Based on the results of these analyses, the applicant concluded that only a mild corrosion environment would exist because of an absence of aggressive levels of contaminants within an alkaline environment. The applicant also stated that under this type of environment and considering that this rebar is not continuously wetted, the rate of corrosion is estimated to be approximately 0.001 inch per year. Published corrosion data in Uhlig's Corrosion Handbook for carbon steel (not rebar) in an alkaline environment was used as input to establish the corrosion rate of 0.001 inch per year. The applicant considered the corrosion rate appropriate for use in the existing conditions, since the environmental conditions within the crack annulus are pH controlled rather than oxygen controlled.

For the evaluation of the walls, the applicant conservatively estimated that the rebar diameter will be reduced by 0.002 inch per year, as reported to the NRC in a letter dated December 5, 1990.

In 1993, GPU conducted additional evaluations to assess the condition of the rebar using a corrosion rate that is based on plant operating experience. For this evaluation, GPU reviewed the loss of metal in the upper regions of the drywell shell that are based on actual UT measurements. The review indicated that drywell shell thickness in this area was reduced by approximately 0.020 inch. Conservatively assuming the affected No. 8 and No. 11 rebar experienced the 0.020-inch corrosion all around, the rebar diameter would be reduced by 0.040 inch. This represents an approximate 8-percent reduction in cross section area of the No. 8 rebar and a 6-percent reduction in the cross section area of the No. 11 rebar.

Given the minimal amount of time the rebar is exposed to moisture, the fact that concrete provides an alkaloid environment which limits corrosion of reinforcing, and the fact that no indication of corrosion has been observed, GPU believes significant corrosion has not occurred and will not occur in the future. Based on this information and as discussed in item (2) below, AmerGen concurs with the GPU conclusion that significant corrosion has not occurred in the current term. AmerGen evaluated and concluded that significant corrosion will not occur during the period of extended operation. However, because the rebar is inaccessible for direct visual examination, the applicant is conservatively assuming this rebar would be subject to additional corrosion of 0.010 inch all around the rebar during the period of extended operation.

The staff considers the applicant's approach and corrosion rates assumptions reasonable.

In response to item (2), the applicant asserts that the corrosion rate used to evaluate rebar corrosion is conservative and the rebar yield stress of 40 ksi will not be exceeded during the period of extended operation. The applicant stated:

First, the estimated corrosion of 0.020 inches for the current term is based on carbon steel in a slightly corrosive environment. The rebar is not subject to a corrosive environment as shown by concrete test samples. The assumed 0.010 inches for the period of extended operation is also conservative because there is no evidence of ongoing corrosion based on the existing monitoring activities in accordance with the Structures Monitoring Program (B.1.31).

Secondly, rebar embedded in concrete is passivated by the alkalinity of the concrete mix by forming a protective hydrous ferrous oxide on their exposed surfaces. Even when portions of the reinforcements are exposed via cracks in the concrete, which acts as a passageway for environmental contact, the rate of corrosion is generally low due to the barrier effect of the pre-existing oxide film. The limited corrosivity under these conditions within a crack annulus is a product of the alkaline leachant from the concrete and the slow diffusion of oxygen within the annulus and through the protective oxide layer. This type of condition would promote a weak electrochemical corrosion cell, precluding dissolution of the protective film.

Thirdly, the cause of corrosion was attributed to water leakage from the reactor cavity and equipment pool during refueling outages. The source of leakage has been investigated extensively and determined to be due to cracks in the stainless liner of the wall. The cracks are now sealed with a strippable coating prior to filling the reactor cavity and the equipment pool with water. The strippable coating has been found effective in minimizing water leakage. AmerGen has made a commitment (see AmerGen letter to NRC dated April 4, 2006) to continue applying the strippable coating during the period of extended operation.

Fourth, the water used to fill the reactor cavity and the equipment pool is treated in accordance with BWRVIP-130 guidance as described in Oyster Creek Water Chemistry aging management program (B.1.02). The treated water maintains an environment that is non-aggressive consistent with concrete sample test results described in item (1) above. Also as discussed in NUREG-1801 Revision 1, and [Electric Power Research Institute] Report #1002950, corrosion of embedded steel in concrete is not significant if the steel is not exposed to an aggressive environment defined as concrete pH<11.5 or chlorides >500 ppm. Oyster Creek concrete samples test, described in response to RAI 4.7.3-2 (1) above, indicate that concrete pH=11.6, and chlorides=10 ppm. Thus the reinforcement is exposed to a non-aggressive environment and the corrosion is expected to be insignificant.

On the technical basis described above, the applicant asserted that the estimated total corrosion of 0.020 inch all around the rebar diameter and the assumed corrosion of 0.010 inch during the period of extended operation is bounding and will not be exceeded during the period of extended operation.

In response to item (3), the applicant stated that the walls affected by rebar corrosion are in the scope of the Structures Monitoring Program. The walls will be inspected every refueling outage while the reactor cavity and equipment pool are full of water to ensure that water leakage during refueling is detected. The walls will be visually inspected for new cracks, crack growth, water stains, and rust stains. Monitoring these parameters provides reasonable assurance that significant rebar corrosion will be detected before a loss of intended function.

The staff finds this acceptable. The preventive measure described, particularly the one related to the commitment (Commitment No. 27, Item 2) to apply strippable coating before the refueling activities, should reduce further wetting of the rebar. In addition, monitoring the walls during every refueling outage reinforces the applicant's attempts to minimize additional corrosion of the rebars and keep the total corrosion within the established limits. The staff's concerns described in RAI 4.7.3-2 are resolved.

4.7.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of equipment pool and reactor cavity walls rebar corrosion in LRA Section A.4.5.3.
In response to RAI 4.7.3-3, the applicant revised LRA Section A.4.5.3 to read as follows:

> Corrosion of reinforcing bar in localized areas of the reactor cavity and equipment pool walls was suspected as a result of observed rust in and around cracks in the walls between elevation 95' and 119'. To assess the condition of the reinforcing bars, concrete core samples were taken in 1988 and chemically analyzed to determine if water intrusion into concrete cracks created an environment that is aggressive to rebar. These analyses showed that the environment is not aggressive and thus corrosion should not be significant. However, because of the observed rust like substance in and around the cracks, the affected rebar were conservatively assumed to be subject to corrosion of 0.020 inches all around the rebar during the current term. Engineering analysis concluded the corrosion amount of reinforcing bars would not impact structural integrity of the affected walls during the current period of operation.
>
> For the period of extended operation, corrosion of the reinforcing bars and the rate of corrosion is a TLAA. Although there is no evidence of continuing rebar corrosion, AmerGen is conservatively assuming additional corrosion of 0.010 inches all around the rebar during the period of extended operation. Corrosion of the reinforcing bar has been projected to the end of the extended period in accordance with 10 CFR 54.21(c)(1)(ii), and determined that the intended function of the drywell shield wall and the equipment pool wall will be maintained through the period of extended operation.

The staff finds the applicant's revision to the UFSAR supplement acceptable. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address equipment pool and reactor cavity walls rebar corrosion is adequate.

4.7.3.4 Conclusion

On the basis of its review and the RAI responses, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the equipment pool and reactor cavity walls rebar corrosion TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.4 Reactor Vessel Weld Flaw Evaluations

4.7.4.1 Summary of Technical Information in the Application

In LRA Section 4.7.4, the applicant summarized the evaluation of reactor vessel weld flaw evaluations for the period of extended operation. The ISI report for the Section XI inspections performed in 2000 informed the NRC of flaws that were detected in two vertical reactor vessel welds. These flaws were evaluated and found acceptable, in accordance with ASME Code Section XI, IWB-3600. The flaw evaluations were based on conditions valid for the current life of the plant, including fluence at 32 EFPYs, thermal transients, and existing P-T curves. Because the flaw evaluations are only valid for the current 40-year life of the plant, the flaw evaluations satisfy the criteria of 10 CFR 54.3(a) and are TLAAs.

Regarding its analysis, the applicant stated that these flaws have been reevaluated for the conditions at the end of the proposed period of extended operation, including fluence for 50 EFPYs. The existing flaws were found to be acceptable, in accordance with ASME Section XI, IWB-3600, for the period of extended operation.

The flaw evaluations associated with the reactor vessel axial weld have been projected to be acceptable to the end of the period of extended operation.

4.7.4.2 Staff Evaluation

The staff's review of LRA Section 4.7.4 identified an area in which additional information was necessary to complete the review of the reactor vessel weld flaw evaluations. The applicant responded to the staff's RAI as discussed below.

The staff reviewed the information provided in the LRA and determined that the flaws documented in the 2001 ISI report for the specified reactor vessel axial welds must be reevaluated for the conditions at the end of the extended period of operation.

In RAI 4.2.2-4 dated March 30, 2006, the staff requested that the applicant submit the analysis demonstrating that these flaws are acceptable in accordance with the ASME Code, Section XI, Article IWB-3600, for the period of extended operation.

In its response dated April 26, 2006, the applicant provided its evaluation of the flaws detected in the reactor vessel axial welds. This flaw evaluation was provided in a report by Structural Integrity Associates, Inc., entitled "SAI Calculation OC-05Q-319, RPV Flaw Evaluation." This report reevaluated the flaws in the reactor vessel axial welds against the acceptance criteria of ASME Code, Section XI, Article IWB-3600, for the period of extended operation using revised P-T limit curves to accommodate 50-EFPY neutron fluence. The calculations contained in the report reproduced the previous allowable flaw sizes based on a 32-EFPY fluence for the current licensed operating period. The revised allowable flaw sizes for 50 EFPYs were then computed using the 50-EFPY neutron fluence and revised P-T limit curves. These revised allowable flaw sizes were compared to the previously found indications. The 50-EFPY analysis adequately demonstrated that the as-found indications are acceptable compared to the revised allowable flaw sizes. The staff determined that the above information is acceptable. The staff's concern described in RAI 4.2.2-4 is resolved.

Based on the above flaw evaluation, the staff concludes that the applicant had adequately demonstrated that the reactor vessel axial weld flaws are acceptable, in accordance with ASME Code, Section XI, Article IWB-3600, through the period of extended operation.

4.7.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel weld flaw evaluations in LRA Section A.4.5.4. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor vessel weld flaw evaluations is adequate.

4.7.4.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel weld flaw evaluations TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.5 CRD Stub Tube Flaw Analysis

4.7.5.1 Summary of Technical Information in the Application

In LRA Section 4.7.5, the applicant summarized the evaluation of the control rod drive (CRD) stub tube flaw analysis for the period of extended operation. In Amendment 37 to the OCGS provisional operating license application, information was provided to the Atomic Energy Commission regarding repair of cracks that were discovered in the CRD stub tubes during construction. The proposed repair included grinding out of the observed cracks and applying a weld overlay. In support of the proposed repair, an analysis was performed to demonstrate that, if an undetected crack were still to exist after the repairs, it would not grow through the overlay during the life of the plant. According to Amendment 37, the analysis indicated that more than 1000 startup and shutdown cycles would be required for the postulated crack to grow through the clad overlay. At the time the analysis for Amendment 37 was performed, the design number of startups and shutdowns assumed for design analyses was 120. Therefore, it was concluded that any crack not detected by the precladding inspection would not propagate to the surface during the reactor lifetime. The evaluation of the postulated flaw was analyzed for the 40-year life of the plant and meets the criteria of 10 CFR 54.3(a) for a TLAA.

Regarding its analysis, the applicant explained that the postulated undetected flaw described in Amendment 37 states that it would require more than 1000 startup and shutdown cycles to propagate the flaw to the surface, potentially leading to coolant leakage. The projected number of startup and shutdown cycles at the end of the period of extended operation is less than 275. Therefore the flaw evaluation described in Amendment 37 is valid for the period of extended operation.

The number of startup and shutdown cycles to the end of the evaluation period will remain less than the 1000 cycles assumed in the analysis of the postulated flaw, therefore, the evaluation remains valid for license renewal.

4.7.5.2 Staff Evaluation

The staff's review of LRA Section 4.7.5 identified an area in which additional information was necessary to complete the review of the CRD stub tube flaw analysis. The applicant responded to the staff's RAI as discussed below.

The staff reviewed the information in the LRA and determined that the original analysis demonstrating that more than 1000 startup and shutdown cycles would be required to propagate a flaw through the weld overlay on the CRD stub tubes appropriately covered the period of extended operation because the projected number of startup and shutdown cycles at the end of the period of extended operation is less than 275. However, given the extent of operating experience since the time of the original analysis, there is a possibility that other CRD stub tube degradation mechanisms that were not known or considered at the time of the original analysis could potentially compromise the integrity of the CRD stub tube over the period of extended operation.

In RAI 4.7.5-1 dated March 30, 2006, the staff requested that the applicant discuss whether there are any known degradation mechanisms discovered since the time of implementation of the CRD stub tube repair that could potentially invalidate the original analysis discussed above. If any CRD stub tube degradation mechanism is known to exist that was not taken into consideration at the time of the original analysis, thereby potentially invalidating that analysis, the staff requested that the applicant submit a revised TLAA for the CRD stub tubes demonstrating that the integrity of these components would be maintained over the period of extended operation.

In its response dated April 26, 2006, the applicant explained that the original analysis only considered the effects of fatigue. The impact of SCC was not understood at that time and, as such, the original analysis is not currently considered relevant for the evaluation and management of SCC. Therefore, the original analysis is considered to have shortcomings by modern-day standards because it does not fully consider all possible degradation mechanisms. Furthermore, in its response the applicant discussed the leakage effects resulting from SCC in the CRD stub tubes:

> During the 18R refueling outage in 2000, while performing the RPV pressure test, leakage was observed from CRD housing locations 42-43 and 43-39 at the bottom head interface. As a result of detected leakage emanating from the bottom head region, roll expansion repair design was engineered in accordance with BWRVIP-17. UT inspections were performed inside 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 43-39 were roll expansion repaired and the leakage was stopped.

The applicant explained in detail how it will manage the effects of aging for the CRD stub tubes during the period of extended operation:

> As a result of past stub tube leakage at Oyster Creek, as well as more recent BWRVIP guidance associated with stress corrosion cracking concerns, the effects of cracking in the CRD stub tubes are being managed by means of inspections performed as part of the Oyster Creek Reactor Internals Program (B.1.9). The Reactor Internals Program follows the requirements of the ASME

Code, Section XI and the recommendations of the BWRVIP guidelines. BWRVIP-17 *specifies in-service inspection requirements for all roll-expanded* CRD housings. The ASME Code, 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 the ASME Code, Section XI. The examinations are performed at the normal operating pressure of the Class 1 pressure boundary.

Oyster Creek is pursuing publication and approval of ASME Code Case N–730 to make the previously implemented Oyster Creek roll expansion repairs permanent. Once ASME and the NRC approve the Code Case, the Oyster Creek Reactor Internals Program will be revised to be consistent with the requirements of the Code Case. If Code Case N–730 is not approved, the program will be changed to require weld repair for the previously implemented roll expansion repairs prior to the period of extended operation. In either case, analyses will be performed to evaluate the effects of stress, fatigue, and fracture mechanics of the stub tubes for the period of extended operation as a part of the permanent repair implementation.

Based on the above information, the staff concludes that the applicant has adequately demonstrated that the CRD stub tube analysis will ensure that the CRD stub tubes will retain their integrity throughout the period of extended operation. Therefore, the staff determined that the above information, as stated in Commitment No. 9, is acceptable. The staff's concern described in RAI 4.7.5-1 is resolved.

4.7.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of CRD stub tube flaw analysis in LRA Section A.4.5.5. On the basis of its review of the UFSAR supplement and Commitment No. 9, the staff concludes that the summary description of the applicant's actions to address CRD stub tube flaw analysis is adequate.

4.7.5.4 Conclusion

On the basis of its review and the RAI response, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the CRD stub tube flaw analysis will remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement and Commitment No. 9 contain an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.8 Conclusion for Time-Limited Aging Analyses

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concludes that the applicant has demonstrated that (1) the TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i), (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) that the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and found that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, consistent with 10 CFR 54.21(c)(2), the staff concludes that no plant-specific, TLAA-based exemptions are in effect

With regard to these matters, the staff concludes that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.21(c), will be in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NRC staff issued its safety evaluation report (SER) with open items related to the renewal of the operating license for Oyster Creek Generating Station (OCGS) on August 18, 2006. On October 3, 2006, the applicant presented its license renewal application, and the staff presented its findings to the ACRS Plant License Renewal Subcommittee.

The NRC staff issued an updated SER on December 29, 2006. On January 18, 2007, the applicant presented its license renewal application, the staff presented its review findings and the representative for the interveners presented their information, which were associated with drywell shell integrity, to the ACRS Plant License Renewal Subcommittee.

During the 539th meeting of the ACRS on February 1, 2007, the ACRS completed its review of the Oyster Creek license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated February 8, 2007. A copy of this letter and the staff's response is provided on the following pages of this SER Section.

Consistent with ACRS recommendation, the staff added two additional license conditions to the SER.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

RSR-2233

February 8, 2007

The Honorable Dale E. Klein
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Chairman Klein:

During the 539th meeting of the Advisory Committee on Reactor Safeguards, February 1-3, 2007, we completed our review of the license renewal application for the Oyster Creek Generating Station (OCGS) and the updated Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during meetings on October 3, 2006 and January 18, 2007. During these reviews, we had the benefit of discussions with representatives of the NRC staff and its contractor Sandia National Laboratories (SNL), members of the public, and AmerGen Energy Company, LLC (AmerGen) and its contractors. We also had the benefit of the documents referenced. This report fulfills the requirements of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

RECOMMENDATIONS

1. With the incorporation of the conditions described in Recommendations 2, 3, and 4, the application for license renewal for OCGS should be approved.

2. We concur with the staff's proposal to impose license conditions to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

3. The staff should add a license condition to ensure that the applicant fulfills its commitment to perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner.

4. The staff should add a license condition to ensure that the applicant fulfills its commitment to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

DISCUSSION

The Oyster Creek Generating Station is located in Lacey Township, Ocean County, New Jersey, approximately 2 miles south of the community of Forked River, 2 miles inland from the shore of Barnegat Bay, and 9 miles south of Toms River, New Jersey. The NRC issued the provisional operating license for OCGS on April 9, 1969 and the operating license on July 2, 1991. OCGS is a single unit facility with a single cycle, forced circulation boiling water reactor (BWR)-2 with a Mark 1 containment. The nuclear steam supply system was furnished by General Electric and the balance of the plant was originally designed and constructed by Burns & Roe. The licensed power output is 1930 MWt with a design electrical output of approximately 650 MWe. The applicant, AmerGen requested renewal of the OCGS operating license for 20 years beyond the current license term, which expires on April 9, 2009.

During the 1980s, the licensee discovered corrosion on the outside wall of the OCGS drywell shell. Although some corrosion had occurred in the upper shell region, the majority had occurred in a region near the base of the shell where the shell was partially supported by a sand bed. The licensee determined that water had been leaking through flaws in the refueling cavity liner during refueling operations. This water had migrated down the outside of the drywell shell and into the sand bed. As part of the corrective actions, the licensee removed the sand and applied an epoxy coating to the outside of the shell in the sand bed region. In addition, repairs were made to the refueling pool liner and the concrete drain trough under the refueling seal. These repairs reduced the leakage and routed any leakage to a drain line rather than down the outside of the drywell shell. To further reduce leakage, the licensee applied strippable coatings to the liner during all but one of the subsequent refueling outages. The licensee performed ultrasonic testing (UT) to determine the as-found condition of the drywell shell and performed a structural analysis in 1992 to demonstrate acceptability of the containment in the degraded condition.

The 1992 structural analysis was reviewed and approved by the NRC staff. This analysis included a determination of the stresses in the thinned region under the design pressure loads and an evaluation of the potential for buckling during normal operations and postulated accident conditions. The buckling analysis utilized American Society of Mechanical Engineers (ASME) Code Case N-284, Revision 1. The staff accepted the use of this Code Case in the 1992 analysis. In support of the review of the OCGS license renewal application, the staff had SNL perform a confirmatory structural analysis. Both analyses demonstrated that the drywell shell met the minimum ASME Code requirements for buckling. However, the amount of margin above the Code minimum depended on the applicability of the increase in the buckling capacity due to tensile stresses orthogonal to the applied compressive stresses computed according to the Code Case. During the January 18, 2007 meeting, the Subcommittee requested additional justification for using the increased capacity factor. At our February meeting, Dr. C. Miller, the author of the ASME Code Case, described the technical basis for the Code Case and presented test results to demonstrate that the increased capacity factor was applicable to OCGS. The increased capacity factor used in the 1992 analysis provided by the applicant was based on results for metal cylinders. Dr. Miller showed results of tests conducted on metal spheres which demonstrated that the results for cylinders were conservative for spherical shells. The staff reaffirmed its position that the use of the increased capacity factor is appropriate for the analysis of the OCGS drywell shell. We concur with this position.

The 1992 structural analysis was based on the assumption that the shell is uniformly thinned in the sand bed region. The applicant has committed to perform a 3-D finite-element analysis of the

OGCS drywell to determine the margin of the shell in the as-found condition using modern methods. This analysis will provide a more accurate quantification of the margin above the Code required minimum for buckling. The applicant has committed to complete the analysis prior to the period of extended operation. We commend the applicant for this action and would like to be briefed by the staff on the results when they become available. Although it is anticipated that the analysis will demonstrate additional margin above the Code required minimum, the applicant should complete this analysis in a timely manner prior to entering the period of extended operation in order to identify and resolve any unexpected results. The analysis should include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect the Code margins. The staff should impose a license condition to ensure that the applicant completes the analysis prior to entering the period of extended operation.

In 2006, the applicant performed additional UT and visual inspections of the drywell shell. When compared to the previous UT, the 2006 results confirmed that the corrective actions taken in the sand bed region had been effective and that the corrosion had been arrested or at least that the corrosion rates were very low (i.e., within the data scatter). The epoxy coating appeared in very good condition with no evidence of degradation which is also consistent with the conclusion that the corrosion has been effectively arrested. These examinations also demonstrated that the corrosion rate in the upper shell region and the embedded floor regions remained sufficiently low to demonstrate structural integrity during the period of extended operation. The applicant has committed to perform UT and visual inspections of the drywell shell during the period of extended operation. Because of the relatively small margin above the Code minimum against buckling in the sand bed region shown by current analyses, the staff is proposing a license condition to increase the frequency of drywell inspections and UT in the sand bed region to all 10 bays every other refueling outage for the extended period of operation. Increased inspections will result in additional radiation exposure to personnel involved in the inspections. Therefore, the applicant should be allowed to increase the period between inspections if it demonstrates increased margin through analysis or if the ongoing inspections continue to demonstrate that the corrosion has been sufficiently arrested. With this provision, we agree with this license condition.

The 2006 examinations revealed that when the cavity was flooded for refueling, water leakage was still occurring. This leakage of approximately 1 gallon per minute is well within the capacity of the drain as long as the drain system is working properly. The purpose of the drain system is to catch water that may leak past a failed refueling seal or liner and divert the water to sumps, and prevent it from coming into contact with the outside of the drywell shell. Leakage is not expected to occur as part of normal operation with properly maintained equipment and structures. The applicant has committed to continue monitoring for leakage of the refueling cavity liner and other water sources associated with the drywell. The applicant has also committed to complete an engineering study to identify cost-effective repair or replacement options to eliminate the refueling cavity liner leakage. The engineering study will be completed prior to entering the period of extended operation. We agree that efforts should be made to eliminate routine leakage in order to provide increased protection against further degradation. The staff should impose a license condition to ensure the study is completed by the applicant prior to the period of extended operation.

During the 2006 refueling outage, the applicant discovered water in two trenches that had been previously excavated to allow access to and inspection of the inside of the shell in the embedded region. The applicant determined that the water had come from normal operation and maintenance activities. The water had migrated to the trenches due to a blocked drain tube in the sub-pile area and the lack of a seal between the shell and concrete curb. The applicant repaired the drain tube and installed a seal in the gap between the shell and concrete curb. The applicant intends to fill these trenches after two consecutive outages in which no water is observed. Having the trenches open is beneficial for identifying drainage issues, but it increases the risk of additional corrosion because it provides an open area in which water can be trapped against the shell. The staff is proposing a license condition that would require the applicant to leave the trenches open and monitor them during each refueling outage until such time that the applicant can demonstrate that the water sources have been identified and eliminated. We agree with the monitoring of the trenches to ensure the elimination of the sources of water. However, leaving the trenches open longer than necessary increases the risk of future corrosion. Therefore, the applicant should not be unnecessarily delayed in repairing the trenches. With this provision, we agree with the license condition proposed by the staff.

In the updated SER, the staff documents its review of the license renewal application and other information submitted by AmerGen and obtained during an audit and inspections conducted at the plant site. The staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's aging management programs (AMPs); and the identification and assessment of time-limited aging analyses (TLAAs) requiring review.

The OCGS application either demonstrates consistency with the Generic Aging Lessons Learned (GALL) Report or documents deviations from the approaches specified in the GALL Report. The staff reviewed this application in accordance with NUREG-1800, the "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants."

The applicant identified those SSCs that fall within the scope of license renewal. For these SSCs, the applicant performed a comprehensive aging management review. Based on the results of this review, the applicant will implement 57 AMPs for license renewal including existing, enhanced, and new programs. In the SER, the staff concludes that the applicant has appropriately identified SSCs within the scope of license renewal and that the AMPs described by the applicant are appropriate and sufficient to manage aging of long-lived passive components that are within the scope of license renewal. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we agree with this conclusion.

The staff conducted inspections and an audit of the license renewal application. The purpose of the inspections was to verify that the scoping and screening methodologies are consistent with the regulations and are adequately reflected in the application. In addition, the inspectors personally examined selected areas of the sand bed region to verify the condition of the epoxy coating. The audit confirmed the appropriateness of the AMPs and the aging management reviews. Based on the inspections and audit, the staff concluded that these programs are consistent with the descriptions contained in the OCGS license renewal application. The staff also concluded that the existing programs, to be credited as AMPs for license renewal, are generally functioning well and that the applicant has established an implementation plan in its commitment tracking system to ensure timely completion of the license renewal commitments.

The applicant identified those systems and components requiring TLAAs and reevaluated them for 20 more years of operation. Affected TLAAs include those associated with neutron embrittlement, metal fatigue, irradiation-assisted stress corrosion cracking, environmental qualification of electrical equipment, and stress relaxation of hold-down bolts. The staff concluded that the applicant has provided an adequate list of TLAAs. Further, the staff concluded that in all cases the applicant has met the requirements of the license renewal rule by demonstrating that the TLAAs will remain valid for the period of extended operation, or that the TLAAs have been projected to the end of the period of extended operation, or that the aging effects will be adequately managed for the period of extended operation. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we concur with the staff that OCGS TLAAs have been properly identified and that criteria supporting 20 more years of operation have been met.

With the incorporation of the license conditions described in Recommendations 2, 3, and 4, no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) preclude renewal of the operating license for OCGS. The programs established and committed to by AmerGen provide reasonable assurance that OCGS can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public and the NRC should approve the AmerGen application for renewal of the operating license for OCGS.

Sincerely,

/RA/

William J. Shack
Chairman

References:

(4) Updated Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station, December 29, 2006.

(5) Safety Evaluation Report with Open Items Related to the License Renewal of the Oyster Creek Generating Station, August 18, 2006.

(6) Oyster Creek Generating Station- Application for Renewed Operating Licenses, July 22, 2005.

(7) Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application, June 20, 2006.

(8) Audit and Review Report for Plant Aging Management Reviews and Programs- Oyster Creek Generating Station August 18, 2006.

(9) 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, November 11, 2005.

(10) Oyster Creek Generating Station - NRC License Renewal Inspection Report 05000219/2006007, September 21, 2006

(11) Memorandum dated December 14, 2006 from Louise Lund to John Larkins, Subject: Review Background Materials for the Meeting of the License Renewal Subcommittee Scheduled on January 18, 2007, Related to the Interim Review of the License Renewal of the Oyster Creek Generating Station. ML063470557

(12) Memorandum date December 8, 2006 from Michael P. Gallagher to the U.S. Nuclear Regulatory Commission, Subject: Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating License for Oyster Creek Generating Station. ML063470532

(13) Sandia National Laboratories Report "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station," January 2007

(14) ASME Code Case N-284-1, "Metal Containment Shell Buckling Design Methods, Class MC, Section III, Division one, March 14, 1995."

(15) Letter dated January 31, 2007, from Senator Frank Lautenberg, Senator Robert Menendez, Representative Christopher H. Smith, and Representative Jim Saxton to The ACRS.

(16) Letter dated January 31, 2007 from Richard Webster, Rutgers Environmental Law Clinic to the ACRS, regarding the Safety Evaluation Report for Oyster Creek Nuclear Power Plant.

(17) Oyster Creek Generating Station-NRC In-Service Inspection and License Renewal Commitment Followup Inspection Report 0500021/2006013, January 17, 2007.

March 8, 2007

Dr. William J. Shack, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Dr. Shack:

During the 539th meeting of the Advisory Committee on Reactor Safeguards (ACRS or the Committee) held on February 1–3, 2007, the ACRS completed its review of the license renewal application (LRA) for the Oyster Creek Generating Station (OCGS) and the associated final safety evaluation report (SER) prepared by the U.S. Nuclear Regulatory Commission (NRC) staff. In its final report, the Committee recommends renewal of the OCGS operating license in conjunction with the recommendations discussed in your letter dated February 8, 2007. The staff appreciates the Committee's expeditious, objective, and in-depth review of the LRA and the staff's final SER. The staff agrees with the Committee's recommendations:

1. The staff will impose a license condition to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

2. The staff will ensure that the applicant fulfills its commitment to (a) perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner, and (b) perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued support of the license renewal process.

Sincerely,

/RA/

Luis A. Reyes
Executive Director
for Operations

cc: Chairman Klein
Commissioner McGaffigan
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

March 8, 2007

Dr. William J. Shack, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Dr. Shack:

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1. The staff will impose a license condition to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

2. The staff will ensure that the applicant fulfills its commitment to (a) perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner, and (b) perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued support of the license renewal process.

Sincerely,
/RA/
Luis A. Reyes
Executive Director
for Operations

cc: Chairman Klein
Commissioner McGaffigan
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

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Letter to W. Shack, from L. Reyes, dated: March 8, 2007

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR OYSTER CREEK GENERATING STATION

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SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) reviewed the license renewal application (LRA) for Oyster Creek Generating Station in accordance with the NRC regulations and NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated September 2005. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

On the basis of its review, the staff concludes that the applicant adequately identified those systems and components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those systems and components that are subject to an aging management review, as required by 10 CFR 54.21(a)(1). The staff also concludes that the applicant demonstrated that the aging effects will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3). Further, the staff concludes that the applicant demonstrated that (1) the time-limited aging analyses (TLAAs) will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i), (2) the TLAAs had been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) that the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). On the basis of its evaluation of the LRA, the staff finds that the requirements of 10 CFR 54.29(a) have been met, that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 are documented in Supplement 28 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Oyster Creek Nuclear Generating Station Final Report," dated January 2007 (ML070100234).

APPENDIX A

COMMITMENTS FOR LICENSE RENEWAL OF OCGS

During the review of the Oyster Creek Generating Station (OCGS) license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff), AmerGen Energy Company, LLC (the applicant) made commitments related to aging management programs (AMPs) to manage the aging effects of structures and components (SCs) both prior to and during the period of extended operation. The following table lists these commitments along with the implementation schedules and the sources for each commitment.

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing program is credited. For the isolation condensers this program also includes enhancement activities identified in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," 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.	A.1.1	Prior to the period of extended operation.	Section B.1.1
2) Water Chemistry	Existing program is credited.	A.1.2	Ongoing	Section B.1.2
3) Reactor Head Closure Studs	Existing program is credited.	A.1.3	Ongoing	Section B.1.3
4) BWR Vessel ID Attachment Welds	Existing program is credited.	A.1.4	Ongoing	Section B.1.4

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COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
5) BWR Feedwater Nozzle	Existing program is credited. The Oyster Creek Feedwater Nozzle Program will be enhanced to implement the recommendations of the BWR Owners Group Licensing Topical Report General Electric (GE) NE-523-A71-0594-A, Revision 1.	A.1.5	Prior to the period of extended operation.	Section B.1.5 Letter 2130-06-20354
6) BWR Control Rod Drive Return Line Nozzle	Existing program is credited.	A.1.6	Ongoing	Section B.1.6
7) BWR Stress Corrosion Cracking	Existing program is credited. The program will be enhanced to add the following requirement to the Line Specifications for all applicable license renewal systems: "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."	A.1.7	Prior to the period of extended operation	Section B.1.7 Letter 2130-06-20354
8) BWR Penetrations	Existing program is credited.	A.1.8	Ongoing	Section B.1.8
9) BWR Vessel Internals	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	A.1.9	Prior to the period of extended operation	Section B.1.9

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COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	permanent repair, once the NRC approves the ASME code case (Code Case N-730). 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-58-A, which has been approved by the NRC, or an alternate ASME code repair plan that 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, 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. (4) Oyster Creek will revise its Reactor internals program to also manage the aging effect of loss of material due to the			Letter 2130-06-20354

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	aging mechanisms of pitting and crevice corrosion for Reactor Internals. (5) Oyster Creek will comply with all the applicable requirements that will be specified in the staff's final safety evaluations (SEs) of the BWRVIP-76 and BWRVIP-104 reports, and that it will complete all the license renewal action items in the final SE applicable to Oyster Creek, when they are issued. (6) The Reactor Internals program will be enhanced to include inspection for loss of material for the feedwater sparger, steam separator, RPV surveillance capsule holders and baffle plate. (7) The Reactor Internals Program will be enhanced to include and document the condition of the CRD and Feedwater Nozzle thermal sleeves to ensure future inspections look for thermal sleeve bypass flow. (8) AmerGen/Exelon is committed to following BWRVIP guidelines: • Oyster Creek will inform the (NRC) staff of any decision to not fully implement a BWRVIP guidelines approved by the			

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	staff within 45 days of the report • Oyster Creek will notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP report. • Oyster Creek will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP report.			
10) Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	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. At least one year prior to the period of extended operation, the following information will be submitted to the NRC: 1) the type and composition of CASS reactor internal components within the scope of license renewal; and 2) the results of evaluations performed to determine susceptibility to thermal aging and neutron irradiation embrittlement. 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	A.1.10	Prior to the period of extended operation	Section B.1.10 Letter 2130-06-20358

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	the high temperature and neutron fluence present in the reactor environment.			
11) Flow-Accelerated Corrosion	Existing program is credited.	A.1.11	Ongoing	Section B.1.11
12) Bolting Integrity	Existing program is credited. Program site implementing documents will be enhanced to include reference to EPRI TR-104213, Bolted Joint Maintenance & Application Guide, December 1995.	A.1.12	Prior to the period of extended operation	Section B.1.12 Letter 2130-06-20354
13) Open-Cycle Cooling Water System	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 microbiologically influenced corrosion in the RBCCW, TBCCW and Containment Spray preventative maintenance tasks.	A.1.13	Prior to the period of extended operation	Section B.1.13

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COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
14) Closed-Cycle Cooling Water System	Existing program is credited.	A.1.14	Ongoing	Section B.1.14
15) Boraflex Monitoring	Existing program is credited.	A.1.15	Ongoing	Section B.1.15
16) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	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 10 CFR54.4(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.	A.1.16	Prior to the period of extended operation	Section B.1.16
17) Compressed Air Monitoring	Existing program is credited.	A.1.17	Ongoing	Section B.1.17
18) BWR Reactor Water Cleanup System	Existing program is credited. Based on Generic Letter 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 Generic Letter 88-01, all inspection requirements for the portion	A.1.18	Ongoing	Section B.1.18

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	of the RWCU System outboard of the second containment isolation valves have been eliminated.			
19) Fire Protection	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. (4) Clearance inspection of in-scope fire doors every two years.	A.1.19	Prior to the period of extended operation	Section B.1.19 Letter 2130-06-20354

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COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
20) Fire Water System	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.	A.1.20	Prior to the period of extended operation	Section B.1.20
21) Aboveground Outdoor	Program is new. The program will manage the corrosion of outdoor carbon steel and aluminum	A.1.21	Prior to the period of extended operation	Section B.1.21

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COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
Tanks	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 of carbon steel or of the unpainted aluminum tank. Bottom UTs are performed on tank bottoms supported by soil or concrete.			Letter 2130-06-20354
22) Fuel Oil Chemistry	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	A.1.22	Prior to the period of extended operation	Section B.1.22

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	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. (6) One time internal inspection of the Emergency Diesel Generator fuel oil day tanks prior to the period of extended operation to confirm the absence of aging effects.			Letter 2130-06-20354
23) Reactor Vessel Surveillance	Existing program is credited. The program will be enhanced to implement BWRVIP-116 "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal," including the conditions specified by the NRC in its Safety Evaluation Dated February 24, 2006. If the Oyster Creek standby capsule is removed from the reactor pressure vessel (RPV) without the intent to test it, the capsule will be stored in a	A.1.23	Prior to the period of extended operation	Section B.1.23 Letter 2130-06-20358 Letter 2130-06-20354

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COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	manner that maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary.			
24) One-Time Inspection	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 following: (1) 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 four-inch nominal pipe size (NPS) exposed to reactor coolant. Inspections will include UT examination of 10% of the total small bore Class I butt welds and destructive or non- destructive	A.1.24	Prior to the period of extended operation Perform prior to the period of extended operation. Perform prior to the	Section B.1.24 Letter 2130-06-20354

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***COMMITMENT* NUMBER**	***ITEM NUMBER AND COMMITMENT***	***UFSAR* SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	***SOURCE***
	examination of a single small bore Class I socket welded connection. (2) To confirm the effectiveness of the Water Chemistry program to manage the loss of material and crack initiation and growth aging effects. Included in the scope of this activity, a one-time UT inspection of the "B" Isolation Condenser shell below the waterline will be conducted looking for pitting corrosion. (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.		period of extended operation.	

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COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	(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 nonsafety 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 CFR54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities. (8) Two stainless steel pipe sections in a stagnant or low flow area in the Reactor Water Cleanup System, and two stainless steel pipe sections in a stagnant or low flow area in the Isolation Condenser System will be included in the one-time inspection samples for stress		Incorporate into program prior to period of extended operation	

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COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	corrosion cracking.			
25) Selective Leaching of Materials	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.	A.1.25	Prior to the period of extended operation.	Section B.1.25
26) Buried Piping Inspection	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. 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	A.1.26	Prior to the period of extended operation.	Section B.1.26 Letter 2130-06-20354

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COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	pipe or component has not been previously replaced or recoated, if any such locations remain. (2) Fire protection components in the scope of the program. (3) Piping located inside the vault in the scope of the program. The vault is considered a manhole that is located between the reactor building and the exhaust tunnel.			
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: (1) Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed	A.1.27	Prior to the period of extended operation. Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage	Section B.1.27 Letter 2130-06-20354 Letter 2130-06-20358 Letter 2130-07-20464 Letter 2130-06-20358

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	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: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection.			

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	These actions will be completed prior to restart from the associated outage. Note: The frequency for the inspections described in item 1 (above) has been changed to every other refueling outage, in accordance with item 21 of the IWE Inspection Program.			
	(2) 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.		Refueling outages prior to and during the period of extended operation	
	(3) The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage.		Periodically	
	• The sand bed region drains will be monitored daily during refueling outages. If leakage is detected, procedures will be in place to determine the source of leakage and investigate and address the impact of leakage on the drywell		Daily during refueling outages.	

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	shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage. • The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:		Quarterly during non-outage periods.	

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	• Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program. • Any degraded coating or moisture barrier will be repaired. (4) 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		Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage thereafter	

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	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. Note: The scope and frequency for the inspections described in item number4 (above) has been changed to all 10 bays every other refueling outage, in accordance with item 21 of the IWE Inspection Program. (5) A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations,		Prior to the period of extended operation (completed during 2006 refueling outage)	

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	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. Note: Item 5 (above) is supplemented by Item numbers 16 and 20 of the IWE Inspection Program.			
	(6) The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. 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, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to (completed during 2006 refueling outage) and during the period of extended operation.	Letter 2130-06-20426
	(7) AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage		Every other refueling outage prior to (completed during	

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	at the same locations as are currently measured.		2006 refueling outage) and during the period of extended operation	
	(8) The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.			
	(9) 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).		Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage thereafter	

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	Note: Item 9 (above) is supplemented by Items 14 and 21 of the IWE Inspection Program. (10) AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at four locations using the 6"x6" grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later.	

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	(11) AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at four locations using the 6"x6" grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later.	
	(12) When the sand bed region drywell shell coating inspection is performed (Commitment 27, Items 4 and 21), the seal at the junction between the sand bed		Prior to the period of extended operation (completed during 2006 refueling	

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	region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program. Note: The frequency for the inspections described in Item 12 (above) has been changed to every other refueling outage, in accordance with Item 21 of the IWE Inspection Program		outage); then every other refueling outage thereafter.	
	(13) The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.		Once per refueling cycle.	
	(14) UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.		During the 2008 refueling outage and every other refueling outage thereafter	

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	Note: The frequency for the inspections described in Item 14 (above) has been change to every other refueling outage, in accordance with Item 21 of the IWE Inspection Program.			
	(15) Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay # 13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are Identified. Note: The scope and frequency for the inspections described in Item 15 (above) have been changed to all 10 bays every other refueling outage, in accordance with Item 21 of the IWE Inspection Program.		All 10 bays will be inspected during the 2008 refueling outage and every other refueling outage thereafter.	

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	(16) Perform visual inspections of the drywell shell inside the trenches in bay # 5 and bay # 17 and take UT measurements inside these trenches In 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. Note: Item 16 (above) is supplemented by Item 20 of the IWE Inspection Program		During the 2008 refueling outage and subsequent refueling outages until trenches are restored to original configuration.	
	(17) Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.		In accordance with ASME Section XI, Subsection IWE.	
	(18) AmerGen will perform a 3-D finite element structural analysis of the primary		Prior to the period of extended operation	

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	containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements.			
	(19) AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage.		Prior to the period of extended operation	
	(20) AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays 5 and 17 during the Oyster Creek 2008 refueling outage (see item 16 of AmerGen's IWE Program (commitment 27), made in its letter 2130-06-20426). AmerGen will extend this commitment			

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	and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.			
	(21) Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as: • UT measurements from inside the drywell (Item 1) • Visual inspections of the drywell external shell epoxy coating in all 10 bays (Item 4)		During the 2008 refueling outage and every other refueling outage thereafter. If the analysis being performed under Item 18 above establishes increased margin, or if ongoing inspections continue to demonstrate that	

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	• Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (Item 12) • UT measurements at the external areas inspected in 2006 (Items 9 and 14)		drywell corrosion has been sufficiently arrested, the period between inspections may able increased to minimize personnel radiation exposure.	
28) ASME Section XI, Subsection IWF	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.	A.1.28	Prior to the period of extended operation.	Section B.1.28
29) 10 CFR Part 50, Appendix J	Existing program is credited.	A.1.29	Ongoing	Section B.1.29
30) Masonry Wall Program	Existing program is credited. The Masonry Wall Program is part of the Structures Monitoring Program.	A.1.30	Ongoing	Section B.1.30

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31) Structures Monitoring Program	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 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. The scope of this enhancement includes the Reactor Building Closed Cooling Water System carbon steel piping and piping elements located inside the Drywell since operating experience has	A.1.31	Prior to the period of extended operation.	Section B.1.31 Letter 2130-06-20354

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	shown an exposure to an environment conducive to corrosion during outages. Also, to confirm that there is no significant age related degradation occurring on the external carbon steel surfaces of the feedwater and main steam system located inside containment, one-time visual inspections of feedwater and main steam system piping inside the containment for loss of material due to corrosion will be performed. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting. (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			

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	anchorage. (6) Periodic sampling, testing, and analysis of ground water to confirm that the environment remains nonaggressive 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			

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	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 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. (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. (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			

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	of mechanical components. (16) 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). (17) 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 six years after this baseline inspection and a third inspection eight years after the second inspection. After each inspection, an evaluation will be performed to determine if identified degradation warrant more frequent inspections or corrective actions.			
32) RG 1.127, Inspection of Water- Control Structures Associated with Nuclear	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 Program will be enhanced to include:	A.1.32	Prior to the period of extended operation.	Section B.1.32

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Power Plants	(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. (6) Parameters monitored will be enhanced to include change in material properties, due to leaching of calcium hydroxide, and aggressive chemical attack. Submerged water control structures will be inspected under the Structural Monitoring Program as follows: 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 six years after this baseline inspection and a third inspection eight years after the second inspection. After each inspection, an			Letter 2130-06-20354

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	evaluation will be performed to determine if identified degradation warrants more frequent inspection or corrective actions.			
33) Protective Coating Monitoring and Maintenance Program	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. The program will be enhanced to include: (1) 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 sandbed region, will be consistent with ASME Section XI, Subsection IWE requirements. (2) 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 prior to entering the period of extended operation.	A.1.33	Prior to the period of extended operation.	Section B.1.33 Letter 2130-06-20354

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	(3) The inspection of 100% of the sandbed region epoxy coating every 10 years during the period of extended operation. Inspections will be staggered such that at least three bays will be examined every other refueling outage. (4) The inspection of all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the current 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. Note: The scope and frequency for the inspections described in Item 4 (above) has been changed to all 10 bays every other refueling outage, in accordance with Item 21 of the IWE Inspection Program.			
34) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental	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	A.1.34	Prior to the period of extended operation.	Section B.1.34

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Qualification Requirements	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	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.	A.1.35	Prior to the period of extended operation.	Section B.1.35

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COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
36) Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Program is new. The program manages the aging of inaccessible medium-voltage cables (2.4 kV, 4.16 kV, 13.8 kV and 34.5 kV) 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 or partial discharge, 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 an initial frequency of six years, after which the frequency will be evaluated and adjusted, based on test results; the period between tests shall not exceed 10 years. Results of cable tests will be trended. Trending will occur at the same frequency as cable testing. Inclusion of the 13.8 kV system circuits in this program reflects the scope expansion of the Station Blackout System electrical commodities. Inclusion of the 34.5 kV system circuits in this program reflects the scope	A.1.36	Prior to the period of extended operation.	Section B.1.36 Letter 2130-06-20354

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	enhancement for reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.			

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37) Periodic Testing of Containment Spray Nozzles	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.	A.2.1	Ongoing	Section B.2.1
38) Lubricating Oil Monitoring Activities	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 Protection System diesel driven pump gearbox lubricating oil cooler.	A.2.2	Prior to the period of extended operation.	Section B.2.2 Letter 2130-06-20354

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	AmerGen will enhance Oyster Creek Program B.2.2 to include sampling and measurement of flash point of diesel engine lubricating oil to detect contamination of lubricating oil by fuel oil.			
39) Generator Stator Water Chemistry Activities	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.	A.2.3	Ongoing	Section B.2.3
40) Periodic Inspection of Ventilation Systems	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	A.2.4	Prior to the period of extended operation.	Section B.2.4

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	inspection guidance for detection of the applicable aging effects.			
41) Periodic Inspection Program	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.	A.2.5	Prior to the period of extended operation.	Section B.2.5
42) Wooden Utility Pole Program	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	A.2.6	Prior to the period of extended operation.	Section B.2.6

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	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 - Electrical	A new plant specific program is credited. The program will be used in conjunction with the existing Structures Monitoring Program, the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR50.49 Environmental Qualification Requirements program and the new Electrical Cable Connections 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 inaccessible medium voltage cables; and visual inspection of accessible phase bus and connections and phase bus insulators/supports; and visual inspection of high voltage insulators above 34.5 kV for salt build-up. The new program will be performed on a twice per year frequency for high voltage insulator inspections; on a 2- year	A.1.37	Prior to the period of extended operation.	Section B.1.37 Letter 2130-06-20354

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	interval for manhole, pit and trench inspections, on a 5-year frequency for phase bus inspections, and on a 10-year interval for cable and connection inspections.			
44) Metal Fatigue of Reactor Coolant Pressure Boundary	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. AmerGen will revise the Oyster Creek UFSAR to update the current licensing basis to reflect that a cumulative usage factor of 1.0 will be used in fatigue analysis for reactor coolant pressure boundary components, as endorsed by the NRC in 10 CFR 50.55a.	A.3.1	Prior to the period of extended operation. Prior to the period of extended operation. Prior to the period of extended operation.	Section B.3.1 Letter 2130-06-20354

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	Certification by a Professional Engineer of the reactor vessel design specification and design reports prepared for the fatigue activities associated with the Oyster Creek License Renewal Application will be performed.			
45) Environmental Qualification (EQ) Program	Existing program is credited. EQ components that cannot be qualified for 60-years will be replaced before the end of their qualified life.	A.3.2	Ongoing	Section B.3.2
46) New P-T curves	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.	A.4.1.3	Prior to the period of extended operation.	Section 4.2.3
47) Circum-ferential Weld Exam Relief	Apply for extension Reactor Vessel Circumferential Weld Examination Relief for 60-year operation	A.4.1.4	Prior to the period of extended operation.	Section 4.2.4
48) Axial weld Exam Relief	Apply for extension Reactor Vessel Axial Weld Examination Relief for 60-year operation	A.4.1.5	Prior to the period of extended operation.	Section 4.2.5
49) Measure Drywell wall thickness	Drywell wall thickness will be monitored to ensure minimum wall thickness is maintained. The ASME Section XI, Subsection IWE Program,	A.4.5.2	Ongoing	Section 4.7.2

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	will manage the aging effects.			
50) Fluence Methodology	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.	A.4.1.1	Prior to the period of extended operation.	Section 4.2.1
51) Bolting Integrity-FRCT	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. 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.	A.1.12A	Prior to the period of extended operation.	Section B.1.12A Letter 2130-05-20228
52) Closed-Cycle Cooling Water	The Closed-Cycle Cooling Water System – FRCT Program is a new program that manages	A.1.14A	Prior to the period of extended operation.	Section B.1.14A Letter 2130-

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System - FRCT	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 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.			05-20228

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53) Aboveground Steel Tanks - FRCT	The Above ground Steel Tanks - FRCT 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 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	A.1.21A	Prior to the period of extended operation.	Section B.1.21A Letter 2130-05-20228

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	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.			
54) Fuel Oil Chemistry – FRCT	The Fuel Oil Chemistry - FRCT 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	A.1.22A	Prior to the period of extended operation.	Section B.1.22A Letter 2130-05-20228

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	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 -	The One-Time Inspection – FRCT program will provide measures to verify that an aging	A.1.24A	Prior to the period of extended operation.	Section B.1.24A Letter 2130-

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
FRCT	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.			05-20228
56) Selective Leaching of Materials -FRCT	The Selective Leaching of Materials - FRCT 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. Onetime inspections will consist of visual inspections supplemented by hardness tests. If selective leaching is found, the condition will be evaluated to determine the	A.1.25A	This new program will be implemented in the time period after January 2018 and prior to January 2028.	Section B.1.25A Letter 2130-05-20228

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	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	The Buried Piping Inspection - FRCT 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,	A.1.26A	Prior to the period of extended operation.	Section B.1.26A Letter 2130-05-20228

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	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	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components - FRCT 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	A.1.38	Inspection for CT Unit 1 will be performed by May 2014, and inspection for CT Unit 2 will be performed by November 2015.	Section B.1.38 Letter 2130-05-20228

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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 – FRCT	The Lubricating Oil Analysis Program – FRCT 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	A.1.39	Prior to the period of extended operation	Section B.1.39 Letter 2130-05-20228 Letter 2130-

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	buildup. The program will also include the measurement of flash point. 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 new program will be implemented prior to the period of extended operation.			06-20354

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
60) Periodic Inspection Program - FRCT	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	A.2.5A	Inspection for CT Unit 1 will be performed by May 2014, and inspection for CT Unit 2 will be performed by November 2015.	Section B.2.5A Letter 2130-05-20228

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	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	The Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply 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 tanks 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 backup engine generator fuel (propane) supply piping and the associated buried fuel supply tank, located at the 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,	A.1.26B	Prior to the period of extended operation	Section B.1.26B Letter 2130-05-20239

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	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.			
62) Spent Fuel Pool	AmerGen will commit to perform monitoring of any leakage from the spent fuel pool liner via the pool leak chase piping.		Prior to the period of extended operation	GALL Reconciliation Letter 2130-06-20293
63) Buried Piping	AmerGen will replace the previously un-replaced, buried safety-related ESW piping prior to the period of extended operation.		Prior to the period of extended operation	Letter 2130-06-20328
64) Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program that will be used to manage the aging effects of metallic parts of non-EQ electrical cable connections within the scope of license renewal during the period of extended operation. A	A.1.40	Prior to the period of extended operation	Section B.1.40 Letter 2130-06-20354

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
Requirements	representative sample of non-EQ electrical cable connections will be selected for testing considering application (high, medium and low voltage), circuit loading and location, with respect to connection stressors. The type of test to be performed, i.e., thermography, is a proven test for detecting loose connections. A representative sample of non-EQ cable connections will be tested at least once every 10 years. This new program will be implemented prior to the period of extended operation.			
65) Corrective Action, Confirmation and Administrative Controls for Forked River Combustion Turbine Activities	Prior to the period of extended operation, AmerGen will ensure that procedures are established to implement the program elements of Corrective Action, Confirmation, and Administrative Controls, as described in Sections A.0.5 and B.0.3 of Enclosure 1 of AmerGen letter 2130-06-20334, for the Forked River Combustion Turbine aging management activities.	A.0.5	Prior to the period of extended operation	B.0.3 Letter 2130-06-20334

APPENDIX B: CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and AmerGen Energy Company, LLC (AmerGen). This appendix also contains other correspondence regarding the staff's review of Oyster Creek Generating Station (OCGS) (under Docket No. 50-219).

APPENDIX B: CHRONOLOGY	
Date	**Subject**
August 10, 2004	Letter from J.A. Benjamin, AmerGen to the NRC, Requesting Exemption from the Requirements of 10 CFR2.109(b) - Regarding Effect of Timely License Renewal Application (Accession No. ML042250155)
December 22, 2004	Letter from P.S. Tam, NRC to AmerGen, Approving Request for Exemption from the Requirements of Section 109(b) of 10 CFR Part 2, Regarding Effect of Timely License Renewal Application (Accession No. ML042960164)
July 22, 2005	Letter from C.N. Swenson, AmerGen to the NRC, Submitting Application for Renewed Operating License No. DPR-16 (Accession No. ML053050477)
July 22, 2005	Letter from C.N. Swenson, AmerGen to the NRC, Submitting License Renewal Drawings to Support the Review of the Application for Renewed Operation License (Accession No. ML052200523)
July 22, 2005	Letter from C.N. Swenson, AmerGen to the NRC, Submitting License Renewal Drawings to Support the Review of the Application for Renewed Operation License (Accession No. ML052200509)
July 26, 2005	Letter from P.B. Cowan, AmerGen to D.J. Ashley, NRC, Submitting Additional Information to Support the Review of the Application for Renewed Operation License (Accession No. ML052200511)
July 26, 2005	Letter from AmerGen to the NRC, Submitting the Environmental Report - Operating License Renewal Stage, Appendices A-F (Accession No. ML052080193)
July 26, 2005	Letter from AmerGen to the NRC, Submitting the Environmental Report - Operating License Renewal Stage, Cover through Section 9 (Accession No. ML052080189)
July 26, 2005	Letter from AmerGen to the NRC, Submitting the AmerGen Application for License Renewal (Accession No. 052080185)

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Date	**Subject**
July 26, 2005	Letter from AmerGen to the NRC, Transmittal of Application for Renewed Operating License - Reformatted CD-ROM (Accession No. ML052080174)
July 28, 2005	NRC Press Release-05-107: NRC Announces Availability of License Renewal Application for Oyster Creek (Accession No. ML052090318)
July 29, 2005	Letter from S.S. Lee, NRC to C.N. Swenson, AmerGen, Stating the Receipt and Availability of LRA for AmerGen (Accession No. ML052100022)
August 2, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Information for the Scoping Audit (Accession No. ML060740367)
August 3, 2005	Memorandum (signed by J.H. Eads) to S.S. Lee, NRC, A Notice of Public Information Session for NRC to Describe its License Renewal Process was submitted (Accession No. ML052160042)
August 17, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Long Range Planning Question (Accession No. ML060740354)
August 17, 2005	NRC Press Release-I-05-043: Public Meeting August 24 in Lacey Township, NJ On License Renewal Application for Oyster Creek Nuclear Plant (Accession No. ML052290259)
August 18, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Long Range Planning Question (Accession No. ML060740508)
August 24, 2005	NRC Press Release-I-05-043: NRC Updates Public on License Renewal Process at Oyster Creek (Accession No. ML052360494)
September 8, 2005	Letter from AmerGen to the NRC, Transmittal of License Renewal Scoping and Screening Procedures (From CD-Rom) (Accession No. ML060790273)
September 9, 2005	Letter from P.T Kuo, NRC to C.N. Swenson, AmerGen, Regarding the Determination of Acceptability & Sufficiency for Docketing, Proposed Review Schedule, & Opportunity for Hearing regarding the Application from AmerGen for renewal of Operating License for AmerGen (Accession No. ML052520034)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
September 12, 2005	Letter from R. Benson, OCGS to M.T. Masnik, NRC, Communicating Notice of September 13, 2005 Oyster Creek Community Advisory Panel Meeting (Accession No. ML060810075)
September 12, 2005	NRC Press Release-05-128: NRC Announces Opportunity for Hearing on Application to Renew Operating License for AmerGen (Accession No. ML052550182)
September 13, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Communication of Draft RAIs (Accession No. ML060740508)
September 16, 2005	Letter from P.T Kuo, NRC to C.N. Swenson, AmerGen, Communicating Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process for License Renewal for AmerGen (Accession No. ML052590296)
September 20, 2005	Letter from AmerGen to NRC, Transmittal of License Renewal Audit and Inspection Handbook (Accession No. ML060760429)
September 23, 2005	Letter from Brookhaven National Lab to the NRC, Communicating an Outline of the Audit and Review Plan for Plant Aging Management Reviews and Programs at AmerGen (Accession No. ML052690388)
September 28, 2005	Memorandum (Signed by D.J. Ashley) to S.S. Lee, NRC, A Notice of Forthcoming Exit Meeting with AmerGen on License Renewal Scoping and Screening Methodology Audit for AmerGen was communicated (Accession No. ML052720556)
September 28, 2005	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding Request for Additional Information for the review of the AmerGen LRA (Accession No. ML052710157)
October 5, 2005	Memorandum (signed by G V Cranston), to D.J. Ashley, NRC, The Audit and Review Plan for Plant Aging Management Reviews and Programs at AmerGen was forwarded (Accession No. ML052850300)
October 12, 2005	Letter from AmerGen to the NRC, Transmitting the OCGS 6 mile Vicinity Map, and OCGS Site Boundary (Accession No. ML052280187)
October 12, 2005	Letter from P.T Kuo, NRC to B. Obermeyer, Emporia State University, Response to Request for Comments Concerning the OCGS Application for Operating License Renewal (Accession No. ML052870572)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
October 12, 2005	Letter from P.T Kuo, NRC to M. Gould, Nanticoke Lenni-Lenape Indians of New Jersey, Response to Request for Comments Concerning the OCGS Application for Operating License Renewal (Accession No. ML052870563)
October 12, 2005	Letter from P.T. Kuo, NRC to T. Francis, Delaware Tribe of Western OK, Response to Request for Comments Concerning the OCGS Application for Operating License Renewal (Accession No. ML052870571)
October 12, 2005	Letter from P.T Kuo, NRC to J. Brooks, Delaware Tribe of Indians, Response to Request for Comments Concerning the OCGS Application for Operating License Renewal (Accession No. ML052870553)
October 12, 2005	Letter from P.T. Kuo to D.L. Klima, US Advisory Council on Historic Preservation, Regarding Oyster Creek License Renewal Review (Accession No. ML052870543)
October 12, 2005	Letter from P.T. Kuo to D. Guzzo, State of NJ, Historic Preservation Office, regarding Oyster Creek License Renewal Review (Accession No. ML052870531)
October 12, 2005	Letter from P.T. Kuo, NRC to R. Chicks, Stockbridge Munsee Community of Wisconsin, Response to Request for Comments Concerning the AmerGen Application for Operating License Renewal (Accession No. ML052900227)
October 12, 2005	Letter from C.N. Swenson, AmerGen to NRC, Response to NRC Request for Additional Information related to OCGS LRA (Accession No. ML052910091)
October 18, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Forwarding AMR Questions (Accession No. ML060740444)
October 20, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Forwarding More AMR Questions (Accession No. ML060740475)
October 24, 2005	Letter from K.E. LaGory, Argonne National Lab to W. Maher, OCGS, Forwarding OCGS Site Audit Docs 10-24 (Accession No. ML060800457)
October 26, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Forwarding Additional Information from the AMP/AMR Team Leader (Accession No. ML060740455)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
October 31, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Forwarding AMR Questions for OC (Accession No. ML060740441)
October 31, 2005	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, OC Pre-Audit AMR Questions- Structures, LRA3.5 (Accession No. ML060740442)
November 1, 2005	Official Transcript of Proceedings, NRC: Oyster Creek Nuclear Generating Plant Public Meeting: Evening Session, Toms River, NJ, 11/1/05 (Accession No. ML053400371)
November 1, 2005	Official Transcript of Proceedings, NRC: Oyster Creek Nuclear Generating Plant Public Meeting: Afternoon Session, Toms River, NJ, 11/1/05 (Accession No. ML053400361)
November 1, 2005	NRC Press Release-I-05-056: Public Comments on Potential Environmental Impacts are Key Part of AmerGen LRA Review (Accession No. ML053050168)
November 3, 2005	Letter from S. Leta, New Jersey Public Interest Research Group (NJPIRG) to M.T. Masnik, NRC, Questions regarding Oyster Creek Water Intake/Discharge (Accession No. ML060800688)
November 4, 2005	Letter from K.E. LaGory, Argonne National Lab to J.A. Ward, Pacific National Lab, Forwarding Example of NPDES Report (Accession No. ML061070306)
November 9, 2005	Letter from M.T. Masnik, NRC to C.N. Swenson, AmerGen, Forwarding Request for Additional Information for the review of the AmerGen LRA (Accession No. ML053130387)
November 9, 2005	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding Request for Additional Information for the review of the AmerGen LRA (Accession No. ML053140042)
November 11, 2005	Letter from C.N. Swenson, AmerGen, to the NRC Stating AmerGen's Readiness to Resume NRC Audits Associated with the Plant LRA (Accession No. ML053250326)
November 11, 2005	Letter from C.N. Swenson, AmerGen to the NRC, Forwarding Response to NRC Request for Additional Information (Accession No. ML053200475)
November 16, 2005	Memorandum (Signed by D.J. Ashley), NRC Summarizes a October 20, 2005 Meeting Between the NRC and AmerGen to discuss the Results of the Scoping and Screening Methodology Audit for AmerGen (Accession No. ML053200460)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
November 17, 2005	Memorandum (Signed by M Ferdas), NRC Summarizes a November 17, 2005 Telephone Conference Between NRC and OGCS Regarding Questions from the November 1, 2005 Public Meeting (Accession No. ML053290141)
November 17, 2005	Letter from J. Hufnagel, OCGS, to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal - Aging Management Program Review - Support Documents (Accession No. ML053410352)
November 18, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Discussing Details on Delivery of AMP Basis Documents (Accession No. ML060740401)
November 22, 2005	Letter from K Gonick, State of NJ, to KL Wescott, Argonne National Lab, Forwarding Archaeological Sites in the Vicinity of AmerGen (Accession No. ML061070432)
November 22, 2005	Letter from K. Tuccillo, State of NJ, to F.A. Monette, Argonne National Lab, Discussing the Confirmation of Site Audit Information (Accession No. ML061070429)
November 23, 2005	Letter from C.G. Day, US Dept of Interior, Fish & Wildlife Service, to M.T. Lesar, NRC commenting on the License Renewal of OCGS in the township of Forked River, Ocean County, New Jersey (Accession No. ML053360432)
November 28, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053420167)
December 2, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053410369)
December 5, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053410372)
December 5, 2005	Letter from K.E. LaGory, Argonne National Lab to J.A. Ward, Pacific National Lab, Forwarding the Status of Requested Documents (Accession No. ML061070319)

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Date	**Subject**
December 9, 2005	Letter from C.N. Swenson, AmerGen to the NRC Forwarding AmerGen's Response to NRC Request for Additional Information Regarding the AmerGen LRA (Accession No. ML053490231)
December 9, 2005	Letter from C.N. Swenson, AmerGen to the NRC Forwarding Additional Commitments Associated with Application for Renewed Operating License (Accession No. ML053490219)
December 9, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053460234)
December 13, 2005	Letter from G. Beck, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053470213)
December 13, 2005	Letter from F.P. Gillespie, NRC to C.N. Swenson, AmerGen, Informing AmerGen of Schedule Impacts on the Oyster Creek Nuclear Operating Station, License Renewal Application (Accession No. ML053470434)
December 16, 2005	Letter from G. Beck, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053500440)
December 19, 2005	Memorandum (Signed by M.T. Masnik), The NRC Summarizes a 12/19/05 Conference Call Between NRC and AmerGen to Discuss the Severe Accident Mitigation Alternative Requests for Additional Information for AmerGen (Accession No. ML053540100)
December 19, 2005	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding Oyster Creek License Renewal - Aging Management Program Review - Supporting Documents (Accession No. ML053540079)
December 22, 2005	Letter from K.E. LaGory, Argonne National Lab to J.A. Ward, Pacific National Lab, Forwarding Monthly Discharge Monitoring Reports (Accession No. ML061070319)
December 28, 2005	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the Review of the OCGS LRA (Accession No. ML053620072)
December 29, 2005	Memorandum (Signed by D.J. Ashley) the NRC Summarizes a December 2, 2005 Conference Call between the NRC and AmerGen Concerning Draft Request for Additional Information Pertaining to the AmerGen LRA (Accession No. ML053630240)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
January 3, 2006	Letter from K.E. LaGory, Argonne National Lab to W. Maher, OCGS, Forwarding EA Engineering Appendix D (Accession No. ML061070321)
January 5, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the review of the AmerGen LRA (Accession No. ML060060021)
January 9, 2006	Letter from P.B. Cowan, AmerGen to the NRC Forwarding OGCS Response to NRC Request for Additional Information related to Severe Accident Management Alternatives (Accession No. ML060130238)
January 9, 2006	Letter from W. Maher, OCGS to K.E. LaGory, Argonne National lab, Response to Forward of EA Engineering Appendix D (Accession No. ML061070329)
January 17, 2006	Letter from Brookhaven National Lab to L.A. Lund, NRC, Forwarding Audit and Review Plan for Plant Aging Management Programs and Reviews for AmerGen (Accession No. ML060200084)
January 23, 2006	Letter from S Woolard, Engine Systems Inc, to the NRC Forwarding Report of Defects and Non-Compliance - Woodward DRU Controls (Accession No.ML060330345)
January 26, 2006	Letter from P.B. Cowan, AmerGen to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information dated December 28, 2005 Related to Plant License Renewal Application (Accession No. ML060270317)
January 30, 2006	Memorandum (Signed by D.J. Ashley), the NRC Summarizes a December 20, 2005 Conference Call Between NRC and AmerGen. (Accession No. ML060310236)
January 31, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding Oyster Creek License Renewal - GALL Reconciliation Document (Accession No. ML060320211)
February 1, 2006	Letter from JP Jackson, New Jersey Department of Environmental Protection, to NRC Chairman Diaz, Supporting the Oyster Creek License Renewal Hearing (Accession No. ML060450725)
February 3, 2006	Letter from P.B. Cowan, AmerGen, to the NRC Forwarding AmerGen Response to NRC Request for Additional Information Related to AmerGen LRA (Accession No. ML060380264)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
February 6, 2006	Letter from J. Hufnagel, to D.J. Ashley, NRC Forwarding Oyster Creek Program Basis Document B.1.09 BWR Vessel Internals (Accession No. ML060370508)
February 7, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Audit Q&A Database Report (Accession No. ML060750811)
February 9, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Database Report - In Progress Q&As (Accession No. ML060760036)
February 10, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding New RAI on Bolting B.1.12 (Accession No. ML060760038)
February 10, 2006	Letter from KC Chang, NRC to L.A. Lund, NRC, Discussing Audit and Review Plan for Plant Aging Management Programs and Reviews at OGCS (Accession No. ML060410649)
February 13, 2006	Letter from W. Maher, OCGS to M.T. Masnik, NRC Forwarding Draft SAMA RAI Clarification Response (Accession No. ML060810084)
February 17, 2006	Letter from G. Beck, OCGS to V.M. Rodriguez, NRC, Forwarding Status of Oyster Creek LRA Draft RAIs (Accession No. ML060750402)
February 23, 2006	Letter from AmerGen to NRC: Clarification write-up on the Press Article Discussion (Accession No. ML060750342)
February 24, 2006	Letter from K.E. LaGory, Argonne National Lab to W. Maher, OCGS, Discussing Permits file (Accession No. ML061070398)
February 24, 2006	Memorandum (Signed by D.J. Ashley), the NRC Summarizes a January 26, 2006 Conference Call Between NRC and AmerGen concerning Draft Request for Additional Information, Pertaining to the AmerGen (Accession No. ML060580345)
February 27, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal AMP-AMR Audit Questions - Set 1 (Accession No. ML060600122)
March 2, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Correction of Minor Errors in the AmerGen LRA (Accession No. ML060660177)
March 2, 2006	Letter from AmerGen to NRC, Transmittal of Determination of Cooling Tower Availability for AmerGen, Final Report (Accession No. ML060720130)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
March 5, 2006	Memorandum (Signed by M.T. Masnik) the NRC Summarizes a January 31, 2006 Conference Call with AmerGen to Discuss Requests for Additional Information Pertaining to NRC Staff's Review of the SAMA Analysis in the AmerGen LRA (Accession No. ML060670480)
March 8, 2006	Letter from G. Beck, OCGS, to D.J. Ashley, NRC, Forwarding of OC LRA - Ventilation PBD (Accession No. ML060790283)
March 8, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC, Forwarding of Oyster Creek Program Basis Document B.2.04 Inspection of Ventilation Systems (Accession No. ML060690026)
March 8, 2006	Letter from M.P. Gallagher, AmerGen to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information Regarding the Environmental License Renewal Review for AmerGen (Accession No. ML060720126)
March 9, 2006	Letter From J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding Oyster Creek, License Renewal AMP-AMR Audit Questions - Set 2 (Accession No. ML060690130)
March 10, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the review of the AmerGen LRA (Accession No. ML060550317)
March 10, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the Review of the AmerGen LRA (Accession No. ML060550452)
March 14, 2006	Letter from D.J. Ashley, NRC to G. Beck, OCGS, Discussing Oyster Creek - Draft RAI-AMP (Accession No. ML060970494)
March 15, 2006	Letter from W. Maher, OCGS to M.T. Masnik, NRC Forwarding AmerGen to NRC: SAMA Clarification Response (Accession No. ML060810080)
March 15, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding AmerGen Response to NRC Request for Additional Information Related to Severe Accident Management Alternatives (Accession No. ML060760379)
March 17, 2006	Letter from NRC to AmerGen: Telecon discussion on apdx. B (Accession No. ML061010646)
March 17, 2006	Letter from NRC to AmerGen: Additional follow-up questions for Audit Q&A database. (Accession No. ML061010644)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
March 17, 2006	Letter from W. Maher, OCGS to K.E. LaGory, Argonne National Lab, Forwarding message regarding Building Names (Accession No. ML060810083)
March 20, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the review of the AmerGen LRA (Accession No. ML060550419)
March 20, 2006	Letter from D.J. Ashley, NRC to L.A. Lund, NRC, Communicating Notice of Forthcoming Exit Meeting with AmerGen Energy Company, LLC on License Renewal Aging Management Programs and Aging Management Review Audits for Oyster Creek Nuclear Generating Station (Accession No. ML060790420)
March 20, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information, Review of the AmerGen LRA (Accession No. ML060790179)
March 20, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the Review of the AmerGen LRA (Accession No. ML060790260)
March 21, 2006	Letter from M.P. Gallagher, AmerGen, to NRC Forwarding AmerGen Response to NRC Request for Additional Information in support of the AmerGen LRA (Accession No. ML060830564)
March 23, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Forwarding of License Renewal - Line Item Comparison to September 2005 GALL (Accession No. ML060870147)
March 24, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing GALL Reconciliation Documents (Accession No. ML061010639)
March 24, 2006	Letter from S.C. Getz, OCGS to the NRC Forwarding Revision 1 to "Reconciliation of Program & Line Item Differences between January 2005 Draft NUREG-1801 & September 2005 Revision 1 of NUREG-1801" (Accession No. ML060870132)
March 30, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding Reconciliation for Oyster Creek License Renewal Application with September 2005 Revision 1 NUREG-1800 and NUREG-1801 (Accession No. ML060950408)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
March 30, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the Review of the AmerGen LRA - Application Sections 3.2, 3.4, 4.7, and B.2 (Accession No. ML060890412)
March 30, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the Review of the AmerGen LRA - Application Sections 4.3 and 4.7 (Accession No. ML060890395)
March 30, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen, Forwarding NRC Request for Additional Information for the Review of the AmerGen LRA - Application Sections 4.2 and 4.7 (Accession No. ML060890660)
March 31, 2006	Letter from K.E. Watkins, TransWare Enterprises to the NRC Forwarding Fluence Evaluation for Oyster Creek Reactor Pressure Vessel (Accession No. ML060830567)
March 31, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek, License Renewal AMP-AMR Audit Questions AMP-359, AMP-360, and AMP-362 (Accession No. ML060930255)
April 1, 2006	Letter from NRC Chairman Nils Diaz to New Jersey Governor John S. Corzine: Independent Safety Review of Oyster Creek (Accession No. ML060580601)
April 3, 2006	Letter from K.R. Jury, AmerGen to the NRC, Forwarding 60 Day Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power" (Accession No. ML060940024)
April 3, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Forwarding Oyster Creek License Renewal AMP-AMR Audit Questions AMP-072, 141, 209, 357, 164 (Accession No. ML060940146)
April 3, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Drywell Q & As (Accession No. ML061510300)
April 4, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Commitment letter-OC Containment items (Accession No. ML061510299)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
April 4, 2006	Letter from M.P. Gallagher, AmerGen to the NRC, Forwarding Commitments Associated with Containment (Drywell and Torus) Condition Monitoring Related to AmerGen Application for Renewed Operating License (Accession No. ML060970288)
April 5, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Discussing Audit Q&A (Question Numbers AMP-141, 210, 356) (Accession No. ML061510298)
April 5, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Discussing Audit Q&A (Question Numbers AMP-141, 210, 356) (Accession No. ML061510294)
April 5, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Discussing Audit Q&A (Questioin Numbers AMP-141, 210, 356) (Accession No. ML061510294)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (LRA Section 4.7) (Accession No. ML061510274)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (LRA Section 4.7) (Accession No. ML061510281)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (Attachment 1-B) (Accession No. ML061510280)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (Attachment 1-C) (Accession No. ML061510296)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (Attachment 1-D) (Accession No. ML061510301)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (LRA Section B.1.12, B.2.3, 2.3 & 3.3) (Accession No. ML061510288)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (LRA Section 4.7) (Accession No. ML061510261)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding RAI response 4/7/06 (Attachment 1-A) (Accession No. ML061510271)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
April 7, 2006	Letter from M.P. Gallagher, AmerGen to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information dated March 10, 2006, Related to License Renewal application. (Accession No. ML061010242)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding AmerGen License Renewal AMP-AMR Audit Questions AMP-141, 356, 210 Set 1 and cover Email (Accession No. ML060960563)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding AmerGen License Renewal AMP-AMR Audit Questions AMP-210 Set 2 (Accession No. ML060960568)
April 7, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding AmerGen License Renewal AMP-AMR Audit Questions AMP-210 Set 3 (Accession No. ML060960568)
April 7, 2006	Letter from M.P. Gallagher, AmerGen to D.J. Ashley, NRC Forwarding AmerGen Response to NRC Request for Additional Information dated March 10, 2006, Related to AmerGen LRA (Accession No. ML061020637)
April 7, 2006	Letter from D.J. Ashley, NRC to D.B. Jones, Transware, Discussing Transware Request for Withholding Information from Public Disclosure for Fluence Evaluation for OC Reactor Pressure Vessel for the AmerGen LRA (Accession No. ML060970463)
April 10, 2006	Memorandum (Signed by D.J. Ashley), the NRC Summarizes a February 2, 2006 Conference Call between the NRC & AmerGen, Concerning Draft Request for Additional Information Pertaining to AmerGen LRA (Accession No. ML060590260)
April 10, 2006	Memorandum (Signed by D.J. Ashley), the NRC Summarizes a February 2, 2006 Conference Call between the NRC and AmerGen Concerning Draft Request for Additional Information Pertaining to AmerGen LRA (Accession No. ML060590260)
April 12, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing the Update to Drywell related response AMP-141 (Accession No. ML061510247)
April 12, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing AmerGen License Renewal AMP-AMR Audit Questions update to AMP Question AMP-141 (Accession No. ML061030419)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
April 13, 2006	Letter from D.J. Ashley, NRC to J. Hufnagel, OCGS, Discussing Request to add to Database (Accession No. ML061510245)
April 17, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Discussing the Audit Follow up Letter (Accession No. ML061510243)
April 17, 2006	Letter from M.P. Gallagher to the NRC, Forwarding AmerGen Responses to Action Items Associated with Plant License Renewal Audits (Accession No. ML061150320)
April 18, 2006	Letter from G. Beck, OCGS, to the NRC, Forwarding AmerGen Transmittal of 2130-06-20298 Response to RAI on 2.5.2 (Accession No. ML061510254)
April 18, 2006	Letter from G. Beck, OCGS, to the NRC, Forwarding AmerGen Transmittal of 2130-06-20298 Response to RAI on 2.4, 3.5 (Accession No. ML061510236)
April 18, 2006	Letter from G. Beck, OCGS, to the NRC, Forwarding AmerGen Transmittal of 2130-06-20298 Response to RAI on 3.1, & B.1-23 (Accession No. ML061510240)
April 18, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information dated March 20, 2006, related to AmerGen LRA (Accession No. ML061100129)
April 18, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information dated March 20, 2006, related to AmerGen LRA (Accession No. ML061100127)
April 18, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information for the dated March 20, 2006, related to AmerGen LRA (Accession No. ML061100138)
April 20, 2006	Letter from D.J. Ashley, NRC to C.N. Swenson, AmerGen Forwarding NRC Request for Additional Information for the Review of the AmerGen LRA (Accession No. ML061100131)
April 24, 2006	Letter from R.K. Mathew, NRC to D.J. Wrona, NRC Discussing Highlights from RLRC (Accession No. ML061420106)
April 24, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding Questions to go over tomorrow (Accession No. ML061500442)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
April 24, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding AmerGen License Renewal AMP-AMR Audit Questions update AMP-071, 204, 072, and others (Accession No. ML061150330)
April 25, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding AmerGen License Renewal AMP-AMR Audit Questions Update AMP-072 and AMP-358 (Accession No. ML061160161)
April 26, 2006	Letter from G. Beck, OCGS to D.J. Ashley, NRC Forwarding AmerGen Transmittal of 2130-06-20298 Response to Rai on 4.2 & 4.7 (Accession No. ML061510249)
April 26, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information, dated March 30, 2006, Related to Plant LRA (Accession No. ML061210114)
April 28, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Response to "Mechanical" RAI set (NRC Letter March 30, 2006) (Accession No. ML061510239)
April 28, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information, dated March 30, 2006 related to Plant LRA (Accession No. ML061220306)
May 1, 2006	Letter from K.I. Parczewski, NRC to D.J. Ashley, NRC Forwarding a Question to the Applicant (Accession No. ML061500449)
May 1, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC, Discussing RAI Response on Fatigue or Rebar Corrosion (Accession No. ML061510224)
May 1, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Transmittal of Supplemental Commitments Associated with AmerGen Application for Renewed Operating License (Accession No. ML061240171)
May 1, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information, dated March 30, 2006, Related to AmerGen LRA (Accession No. ML061240217)
May 2, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Supplemental Commitments Letter (Accession No. ML061510214)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
May 3, 2006	Letter from R.K. Mathew, NRC to R. Lofaro, Brookhaven National Lab, Discussing Commitments (Accession No. ML061380647)
May 3, 2006	Letter from R.K. Mathew, NRC to D.J. Ashley, NRC, Forwarding Meeting Preparation Notes (Accession No. ML061510095)
May 3, 2006	Letter from P.T. Kuo, NRC to D.A. Lochbaum, Nuclear Energy Institute Forwarding Federal Register Notice w/attachments - Proposed License Renewal Interim Staff Guidance LR-ISG-2006-01: Plant-Specific Aging Management Program for Inaccessible Areas of Boiling Water Reactor Mark I Steel Containment Drywell Shell - Public Comment (Accession No. ML061120003)
May 3, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Supplemental Response to NRC Request for Additional Information, dated march 20, 2006, related to Plant License Renewal Application. (Accession No. ML061250172)
May 9, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Response to NRC Request for Additional Information, Dated April 20, 2006 (Accession No. ML061310139)
May 15, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Forwarding Supplemental Letter w/ Upper Shelf Energy Info - RAI 4.2.2-1 (Accession No. ML061500339)
May 15, 2006	Letter from M.P. Gallagher, AmerGen, to the NRC, Forwarding AmerGen Supplemental Information for Response to NRC Request for Additional Information, dated March 30, 2006, Related to Plant License Renewal Application (Accession No. ML061380109)
May 16, 2006	Letter from J.E. Dyer, NRC to Maureen E. Flach Discussing the Renewal of Oyster Creek (Accession No. ML061230406)
May 17, 2006	Letter from D.J. Ashley, NRC to L.A. Lund, NRC, Forwarding Notice of Forthcoming Meeting with AmerGen on License Renewal for AmerGen (Accession No. ML061380579)
May 17, 2006	Letter from GP Little, Board of Chosen Freeholders, to NRC Chairman Diaz: Forwarding Concerns about Airspace Above the Oyster Creek Nuclear Generating Station (Accession No.ML061460122)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
May 18, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Addressing the Forked River Combustion Turbine Quality Assurance Attributes, Related to the Plant License Renewal Application. (Accession No. ML061440152)
May 24, 2006	Memorandum (Signed by M.S. Ferdas) the NRC Summarized a Phone Call Between Marc Ferdas, NRC, and Public Stakeholder, Mr. Donald Warren in Regards to Questions Asked at Annual Assessment Public Meeting. (Accession No. ML061500071)
May 24, 2006	Letter from D.J. Ashley, NRC to L.A. Lund, NRC Forwarding a Revised Notice of Forthcoming Meeting with AmerGen on License Renewal for AmerGen (Accession No. ML061430377)
May 25, 2006	Letter from J. Hufnagel, OCGS to V.M. Rodriguez, NRC Forwarding Bolting Follow Up Discussion (Accession No.ML061770492)
June 1, 2006	NRC Transmittal of Supp 28, DFC "Generic Environmental Impact Statement for the License Renewal of Nclear Plants: Regarding Oyster Creek Nuclear Generating Station" (Accession No. ML061520231)
June 1, 2006	Official Transcript of Proceedings - AmerGen License Renewal - Public Meeting to discuss drywell issues (Accession No. ML061580242)
June 2, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Related to AmerGen LRA (Accession No. ML061570333)
June 5, 2006	Letter from NRC EDO L.A. Reyes to Rep. Robert Andrews Discussing License Renewal Application of Oyster Creek (Accession No. ML061420240)
June 7, 2006	Letter from D.J. Ashley, NRC to L.A. Lund, NRC Forwarding Notice of Forthcoming Meeting with AmerGen on Licensing Renewal for AmerGen (Accession No. ML061580543)
June 7, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Related to AmerGen LRA (Accession No. ML061600246)
June 7, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing Accession Number Request (Accession No.ML061770478)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
June 8, 2006	Letter from P. Gunter, NIRS to D.J. Ashley, NRC, Communication of Request for Inclusion on the AMR Service list for Docket 050219 (Accession No.ML061770473)
June 9, 2006	Memorandum (Signed by D.J. Ashley) the NRC Summarizes a June 1, 2006 Meeting With AmerGen Representatives to Discuss the Staff's Concerns on the Drywell Shell and the AmerGen LRA (Accession No. ML061600368)
June 9, 2006	Letter from F.P. Gillespie, NRC to P.A. Kurkul, Dept of Commerce, Communicating Request Initiation of a Section 7 Consultation Regarding License Renewal of Oyster Creek Nuclear Generating Station (Accession No. ML061500192)
June 12, 2006	NRC Press Release-I-06-037: NRC Seeks Public Input on Draft Environmental Report for AmerGen LRA; Meetings July 12 (Accession No. ML061630287)
June 12, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplement to AmerGen Response to NRC Request for Additional Information RAI 4.3-4, Related to Oyster Creek LRA (Accession No. ML061660072)
June 13, 2006	Letter from B.E. Holian, NRC to C.M. Crane, AmerGen Communicating NRC Office of Investigations Case No. 1-2005-033 (Accession No. ML061660078)
June 13, 2006	Letter from R.L. Franovich, NRC to D. Guzzo, NJ Historic Preservation Office Discussing the Oyster Creek License Renewal Application Review (Accession No. ML061580022)
June 13, 2006	Letter from P. Gunter, NIRS to D.J. Ashley, NRC, Communicating Oyster Creek - Teledyne request (Accession No. ML061770519)
June 14, 2006	Letter from P. Gunter, NIRS to D.J. Ashley, NRC: Communicating NRC/NEI meeting 6/22 Oyster Creek RAI (Accession No. ML061770468)
June 15, 2006	Letter from J. Hufnagel, OCGS to D.J. Ashley, NRC Discussing June 22nd meeting (Accession No. ML061770467)
June 16, 2006	Letter from B.M. Carle, Township of Berkeley, NJ to the NRC Discussing the Statement of Limited Appearance of Beverly Carle on behalf of the Township of Berkeley, NJ (Accession No. ML062010480)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
June 20, 2006	Letter from J.E. Dyer, NRC to AmerGen Forwarding a General Notice, Letter B, Orders EA-06-137 (Accession No. ML061600034)
June 20, 2006	Letter from D.J. Ashley, NRC to L.A. Lund, NRC Forwarding Meeting Notice - Cancelled Forthcoming Meeting with AmerGen on LRA for AmerGen (Accession No. ML061710405)
June 20, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's LRA (Accession No. ML061740573)
June 22, 2006	Letter from F.P. Gillespie, NRC to A.W. Avery, Ocean Count, NJ: Discussing Oyster Creek Nuclear Generating Station Relicensing Lacey Township, New Jersey (Accession No. ML061650168)
June 23, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Updated FSAR Supplement Information Supporting the Oyster Creek Generating Station License Renewal Application (Accession No. ML061800302)
June 23, 2006	Letter from R. Webster, Grandmothers, Mothers & More for Energy Safety, Jersey Shore Nuclear Watch, etc to ASLB Judges Filing Motion for Leave to Supplement the Petition to Add a New Contention, with Citizen's Exhibits NC1 to NC10 (Accession No. ML061810167)
July 7, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Related to the Aging Management Program for the Plant Drywell Shell, Associated with AmerGen's License Renewal Application (Accession No. ML061930401)
July 7, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Related to the License Renewal Application FSAR Supplement (Accession No. ML061940020)
July 10, 2006	Letter from M.P. Gallagher, AmerGen to the NRC Forwarding Supplemental Information Related to License Renewal Application for AmerGen (Accession No. ML061940019)
July 18, 2006	Letter from M.P. Gallagher, AmerGen to NRC Forwarding Oyster Creek, 20CFR 54.21(b), Annual Amendment to License Renewal Application (Accession No. ML0602010142)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
August 18, 2006	Letter from F.P. Gillespie, NRC to AmerGen Transmitting the Oyster Creek Safety Evaluation Report with Open Items (Accession No. ML062280337)
August 18, 2006	Letter from F.P. Gillespie, NRC to AmerGen Transmitting the Oyster Creek Audit and Review (AMP/AMR) Report (Accession No. ML062280388)
October 3, 2006	Transcript of ACRS Plant License Renewal Subcommittee, October 3, 2006 in Rockville, MD. Pages 1 - 232. With Related Documentation (Accession No. ML062900390)
October 20, 2006	Letter from M. P. Gallagher, AmerGen to NRC Forwarding Oyster Creek Response to Open Items Associated with Draft Safety Evaluation Report (Accession No. ML062970099)
October 31, 2006	Letter from M. P. Gallagher, AmerGen to NRC Forwarding Oyster Creek Comments on the Draft Safety Evaluation Report (Accession No. ML063100326)
November 1, 2006	Letter from M. P. Gallagher, AmerGen to NRC Forwarding Oyster Creek Change Timing of Submittal to ACRS Subcommittee (Accession No. ML063100456)
December 3, 2006	Letter from M. P. Gallagher, AmerGen to NRC Forwarding Oyster Creek Supplemental Information (Accession No. ML063390664)
December 15, 2006	Letter from M. P Gallagher, AmerGen to NRC Providing Corrections "Information from October 2006 Refueling Outage Supplementing AmerGen Energy Company" (Accession No. ML063530042)
December 20, 2006	Letter from R. Webster, Grandmothers, Mothers & More for Energy Safety, Jersey Shore Nuclear Watch, etc to ASLB Judges Filing Motion for Leave to Add a New Contention, (Accession No. ML063610360)
January 18, 2007	Transcript of ACRS Plant License Renewal Subcommittee, January 18, 2007 in Rockville, MD. Pages 1 - 371 (Accession No. ML070240433)
February 1, 2007	Transcript of 539th ACRS Meeting in Rockville, MD. Pages 1 - 342 (Accession No. ML070440100)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
February 6, 2007	Letter from R. Webster, Grandmothers, Mothers & More for Energy Safety, Jersey Shore Nuclear Watch, etc to ASLB Judges Filing Motion for Leave to Add a New Contention, (Accession No. ML070460103)
February 8, 2007	Report from William Shack, Chairman of the Advisory Committee on Reactor Safeguards, to Dale Klein, Chairman of the NRC on the Safety Aspects of the License Renewal Application for the Oyster Creek Generating Station (Accession No. ML070390474)
February 15, 2007	Letter from M. P Gallagher, AmerGen to NRC Providing Additional Commitments Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application. (Accession No. ML070520252)
March 8, 2007	Letter from L. A. Reyes to Dr. William J. Shack, Chairman of the Advisory Committee on Reactor Safeguards, Response to Advisory Committee on Reactor Safeguards Report on the Safety Aspects of the License Renewal Application for the Oyster Creek Generating Station. (Accession No. ML070460091)
March 29, 2007	E-Mail from M.P. Gallagher, AmerGen to Donnie Ashley, NRC Forwarding AmerGen Response to NRC E-Mail concerning License Conditions in the Oyster Creek Safety Evaluation Report. (Accession No. ML070880696)

APPENDIX C

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APPENDIX D

REFERENCES

This appendix contains a list of the references used throughout this safety evaluation report for review of the license renewal application (LRA) for Oyster Creek Generating Station.

APPENDIX D: REFERENCES	
Number	**Reference**
1	NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 1, dated September 2005
2	NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 5, dated September 2005
3	NUREG-1801,"Generic Aging Lessons Learned (GALL) Report," Revision 1, dated September 2005
4	AmerGen Energy Company, LLC, License Renewal Application for Oyster Creek Generating Station dated July 22, 2005
5	Letter from the NRC to AmerGen Company, LLC, "REQUEST FOR ADDITIONAL INFORMATION (RAI) FOR THE REVIEW OF THE OYSTER CREEK NUCLEAR STATION, LICENSE RENEWAL APPLICATION," dated September 28, 2005 (ADAMS Accession No. ML052710157)
6	Letter from AmerGen Company, LLC, to the NRC, "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 (ADAMS Accession No. ML052910091)
7	Letter from AmerGen to the NRC, "Supplemental Response to NRC Request for Additional Information (RAI 2.5.119-1)," dated November 11, 2005 (ADAMS Accession No. ML053200475)
8	Letter from AmerGen to the NRC, "Supplemental Information Addressing the Forked River Combustion Turbine Quality Assurance Attributes, Related to the Oyster Creek Generating Station License Renewal Application," dated May 18, 2006 (ADAMS Accession No. ML061440152)
9	Letter from AmerGen to the NRC, "Supplemental Information Related to Oyster Creek Generating Station License Renewal Application," dated June 7, 2006 (ADAMS Accession No. ML061600246)

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Donnie J. Ashley

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8. PERFORMING ORGANIZATION - NAME AND ADDRESS *(If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)*

Division of License Renewal
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

9. SPONSORING ORGANIZATION - NAME AND ADDRESS *(If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)*

Same as above

10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Oyster Creek Generating Station (OCGS) license renewal application (LRA) by the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff). By letter dated July 22, 2005, AmerGen Energy Company, LLC submitted the LRA for OCGS in accordance with Title10, Part 54, of the Code of Federal Regulations (10CFRPart54). AmerGen Energy Company, LLC requests renewal of the operating license for OCGS (Facility Operating License Number DPR-16), for a period of 20 years beyond the current expiration date of midnight April 9, 2009.

OCGS is located in Lacey Township, Ocean County, New Jersey, approximately two miles south of the community of Forked River, two miles inland from the shore of Barnegat Bay, and nine miles south of Toms River, New Jersey. The NRC issued the OCGS construction permit on December 15, 1964, the OCGS provisional operating license on April 9, 1969, and the OCGS operating license on July 2,1991. OCGS is a single unit facility with a single-cycle, forced-circulation boiling water reactor (BWR)-2 and a Mark 1 containment. The nuclear steam supply system was furnished by General Electric and the balance of the plant was originally designed and constructed by Burns&Roe. OCGS licensed power output is 1930 megawatt thermal with a gross electrical output of approximately 619 megawatt electric.

This SER presents the status of the staff's review of information submitted through February 15, 2007, the cutoff date for consideration in the SER. The staff identified open items that were resolved before the staff made a final determination on the application. SER Section1.5 summarizes these items and their resolution. Section 6.0 provides the staff's final conclusion on the review of the OCGS LRA.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

10 CFR 54, license renewal, Oyster Creek, scoping and screening, aging management, time-limited aging analysis, TLAA, safety evaluation report

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