From: D. Ashley
To: Hansraj Ashar; Louise Lund; Michael Junge; Noel Dudley; Sujit Samaddar; Timothy O'Hara
Date: 12/04/2006 7:18:32 AM
Subject: All-

All-

I just received this package this morning.

I have not read it yet, but wanted to send it to you ASAP.

Noel and I will be working on incorporating the necessary information into the Final SER.

Please review and provide comments to Noel or me.

Thanks for all your efforts on this project.

==============================
regards,

Donnie Ashley
NRR/DLR/RLRA
Oyster Creek
License Renewal Project Manger
301-415-3191
dja1@nrc.gov

CC: Ed Miller; John White; Richard Conte; Ronald Bellamy; Roy Fuhrmeister

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Creation Date 12/04/2006 7:18:32 AM
From: D. Ashley

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AmerGen

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20426
December 3, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Information from October 2006 Refueling Outage Supplementing AmerGen Energy Company, LLC (AmerGen) Application for a Renewed Operating License for Oyster Creek Generating Station (TAC No. MC7624)

References:
1. AmerGen's "Application for Renewed Operating License," Oyster Creek Generating Station, Letter 2130-05-20135, dated July 22, 2005
2. AmerGen's "Response to NRC Request for Additional Information, dated March 10, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," Letter 2130-06-20289, dated April 7, 2006
3. AmerGen's "Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)," Letter 2130-06-20353, dated June 20, 2006
4. AmerGen's "Additional Information Concerning FSAR Supplement Supporting the Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," Letter 2130-06-20358, dated July 7, 2006

In References 1 through 4, AmerGen provided detailed information describing aging management reviews, aging management programs and commitments for future actions associated with the primary containment drywell shell, as part of its license renewal application (LRA) for the Oyster Creek Generating Station (Oyster Creek). In its recently completed Oyster Creek refueling outage, AmerGen performed many of the drywell shell inspection activities that it had committed to perform prior to the period of extended operation.

Per 10 C.F.R. § 54.21, this submittal serves to update the LRA and the other referenced submittals with the results of the 2006 outage activities. For ease of review, various sections of the original LRA and related responses to NRC requests for additional information (RAIs) have been updated to reflect the latest information. To a great extent, the information learned during this outage confirmed the condition of the drywell as described in previous submittals.

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However, as a result of performing planned inspections of the internal surface of the drywell shell in the trenches excavated in the concrete floor in 1986, AmerGen identified an environment/material/aging effect combination that was not included in the LRA. Aging management reviews of this combination have been performed and, as a result, AmerGen has identified additional aging management activities that will be included in aging management programs associated with the drywell.

The Enclosure to this letter more fully describes these reviews and resultant aging management activities. Updates to the affected portions of the LRA are provided, including a revision to the License Renewal Commitment List (LRA Appendix A, Section A.5). The Commitment List update clearly indicates the activities that are being added as part of this submittal.

AmerGen has performed a review to determine whether any additional aspects of the LRA require updating, given the recent identification of a new environment requiring evaluation in support of license renewal. Based on its review, AmerGen concludes that there are no additional revisions required to the LRA. This review has been documented in the corrective action program.

In addition, a consolidated summary of key drywell-related inspections conducted during the outage, with a summary of the results, is provided in the Enclosure.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

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

Respectfully,

Executed on 12/03/2006

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosure: LRA Supplemental Information, Post-2006 Refueling Outage

cc: Regional Administrator, USNRC Region I, w/ Enclosures
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosures
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosures
USNRC Project Manager, NRR - Project Manager, OCGS, w/o Enclosures
USNRC Senior Resident Inspector, OCGS, w/ Enclosures
Bureau of Nuclear Engineering, NJDEP, w/Enclosures
File No. 05040

Enclosure

License Renewal Application
Supplemental Information
Post-2006 Refueling Outage

Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

Note: **Bold** font has been used to designate additions made by this submittal to previously submitted documents.

Summary of Post-2006 Refueling Outage Supplement

This submittal is being made to update the LRA with information that was identified during the October/November 2006 (1R21) refueling outage. Included in this update are the results of various inspections and activities performed which relate to the condition of the drywell shell. Also, the LRA is being updated to reflect the identification of water in contact with the lower portion of the inside surface of the drywell shell.

As noted, this submittal provides the results of numerous visual and ultrasonic examinations performed on the drywell shell during the 1R21 refueling outage. These results serve to confirm the condition of the drywell shell as discussed in previous LRA correspondence.

During inspections of the drywell shell that were performed as part of planned license renewal commitment implementation, water was identified in contact with the interior surface of the drywell shell within an inspection access trench. Moisture was identified on the shell in a second trench. This was indicative of water beneath the drywell floor surface, being in contact with both the drywell shell and drywell concrete. Although water is present at times within the drywell during plant operation, LRA preparation activities did not identify this specific condition as a normal operating environment requiring aging management review and ongoing aging management activities because the drywell floor, curb and drainage system were designed to keep water away from the shell.

AmerGen entered this condition into its corrective action program. Various investigations and corrective actions were undertaken during the outage to understand the condition and to minimize water from coming into contact with the drywell shell and embedded concrete in the future. Corrective actions implemented during 1R21 included repair of the drywell drainage trough and installation of a moisture barrier between the drywell shell and concrete curb adjacent to the drywell floor. As described further in this Enclosure, AmerGen has also performed analysis concluding that the impact of water on the inner surface of the drywell shell and concrete fill slab is insignificant. However, AmerGen has decided to treat the entire internal surface of the lower drywell shell as a wetted component from an aging management perspective. Based upon this approach, additional aging management review activities have been performed and aging management program activities established for the drywell shell and moisture barrier. No additional aging management activities are required for the drywell concrete.

This submittal provides the results of these reviews, including new aging management program activities and associated aging management commitments. For ease of comparison, the results of the outage inspections and aging management reviews are presented as updates to previously submitted LRA information and RAI responses. A consolidated summary of 1R21 drywell inspection activities, correlated to IWE Inspection Program commitments, is also provided.

A specific listing of the contents of this Enclosure is provided on the next page.

Enclosure Contents

Note: **Bold** font has been used to designate additions made by this submittal to previously submitted documents.

2.4.1 Primary Containment

System Purpose

The Primary Containment Structure is comprised of the primary containment, containment penetrations, and internal structures. The structure is enclosed by the Reactor Building, which provides secondary containment, structural support, shielding, shelter, and protection, to the containment and components housed within, against external design basis events.

The primary containment is a General Electric Mark I design and consists of a drywell, a pressure suppression chamber, and a vent system connecting the drywell and the suppression chamber. It is designed, fabricated, inspected, and tested in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, and Nuclear Code Cases1270N-5, 1271N and 1272N-5. The containment is safety related, classified Seismic Class 1 structure.

The drywell is a steel pressure vessel, in the shape of an inverted light bulb, with a spherical lower section and a cylindrical upper section. The lower spherical section is embedded externally in the reinforced concrete foundation and covered internally by a fill slab at the bottom of the drywell. The top portion of the drywell vessel consists of a steel head that is removed during refueling operations. The head is bolted to the drywell flange and is sealed with a double seal arrangement. Access into the drywell is through a personnel airlock/equipment hatch, with two mechanically interlocked doors, and other access hatches. The drywell houses the reactor pressure vessel, the reactor coolant recirculation system, safety relief valves, electromatic relief valves (EMRVs), branch connections of the reactor primary system, containment drywell spray header, and internal structures discussed below. The drywell shell and the enclosing reactor building concrete are separated by an air gap to allow for differential thermal expansion between the shell and the concrete during any mode of plant operation.

The pressure suppression chamber is a toroidal shaped, steel pressure vessel encircling the base of drywell. The suppression chamber, commonly called the torus, is partially filled with demineralized water and includes internal steel framing, and access hatches. The suppression chamber is mounted on support structures that transmit loads to the reactor building foundation. Major components inside the suppression chamber include Emergency Core Cooling Systems (ECCS) suction strainers, which are connected to the ECCS suction header located outside the chamber, torus spray header, and Y-Quenchers.

The vent system consists of ten circular vent lines, which form a connection between the drywell and the pressure suppression chamber. The lines enter the suppression chamber through penetrations provided with expansion bellows and join into a common header contained within the air space of the suppression chamber. The header discharge is through 120 downcomer pipes, which terminate below the water level in the torus. The header and the downcomer pipes are supported from the suppression chamber shell.

The primary containment is provided with a vacuum breaker system to equalize the pressure between the drywell and the suppression chamber, and between the suppression chamber and the reactor building. The vacuum breaker system assures that the external design pressure limits of the two chambers are not exceeded.

The primary containment is penetrated at several locations by piping, instrument lines, ventilation ducts, and electric leads. The penetrations consist of sleeves welded to drywell vessel or suppression chamber and are of two general types. Those required to accommodate thermal movements; and those, which experience relatively little thermal stress. Penetrations required to accommodate thermal movements are provided with expansion bellows.

Internal structures consist of a fill slab, reactor pedestal, biological shield wall and its lateral support, and structural steel. The fill slab is reinforced concrete placed in the bottom of the drywell to provide a working base for supporting the reactor pedestal and other structures and components inside the drywell. **A curb is provided above the fill slab around the drywell perimeter to prevent any water that collects on the floor from being in contact with the drywell shell. The curb is removed at two locations where 2 trenches were excavated on the floor to allow UT thickness measurements to be taken below the floor. A moisture barrier was added at the junction of the curb and the drywell shell and inside the trenches, during 2006 refueling outage to prevent water and moisture intrusion into the embedded drywell shell.**

The reactor pedestal is a reinforced concrete cylinder with an outside diameter of 26 feet. The pedestal provides structural support to the reactor pressure vessel, the biological shield wall, and floor framing. The biological shield wall extends above the reactor pedestal and is a composite steel, concrete cylinder with an inside diameter of approximately 21 feet. The wall is framed with steel columns covered with steel plate on each face and filled partly with normal density concrete and partly with high-density concrete. The top of the wall is capped with a steel plate and laterally braced to the drywell vessel.

Structural steel includes floor framing steel for the platforms inside the drywell, and a catwalk inside the suppression chamber. It also includes miscellaneous steel inside the containment such as grating, ladders, connection plates; electrical cable trays, and electrical conduits.

The purpose of the primary containment is to accommodate, with a minimum of leakage, the pressures and temperatures resulting from the break of any enclosed process pipe; and thereby, to limit the release of radioactive fission products to values, which will insure offsite dose rates well below 10CFR100 guideline limits. It also provides a source of water for ECCS and for pressure suppression in the event of a loss-of-coolant accident. The primary containment and internal structures also provide structural support to the reactor pressure vessel, the reactor coolant systems, and other safety and nonsafety related systems, structures, and components housed within. The biological shield wall provides the added function of radiation shielding to maintain drywell environment within equipment qualification parameters.

Included in the evaluation boundary of the Primary Containment are the drywell, drywell head, suppression chamber, vent lines, downcomers, drywell and suppression chamber penetrations, vent line bellows, drywell penetration bellows, personnel air lock/equipment and other hatches, pressure retaining bolting, thermowells, and internal structures listed above.

Not included in the evaluation boundary of the Primary Containment are safety relief valves and EMRVs, EMRV discharge lines, Y-Quenchers, drywell and torus spray headers, vacuum breakers, ECCS suction strainers and header, downcomer bracing, suppression chamber (torus) supports, and other component supports. These components are separately evaluated with their respective license renewal systems. That is, safety relief valves, EMRVs, EMRV discharge lines, and Y-Quenchers are evaluated with Main Steam System. Drywell and torus spray headers, and ECCS suction strainers and header are evaluated with the Containment Spray System. Vacuum breakers are evaluated with the Containment Vacuum Breakers

System. Downcomer bracing, suppression chamber supports, and other component supports are evaluated with the Component Supports Commodity Group.

For more detailed information, see UFSAR Sections 3.8 and 6.2

Reason for Scope Determination

The Primary Containment meets the scoping requirements of 10 CFR 54.4(a)(1) because it is a safety-related structure which is relied upon to remain functional during and following design basis events. It meets 10 CFR 54.4(a)(2) because failure of nonsafety related portions of the structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). It also meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), ATWS (10 CFR 50.62), and Environmental Qualification (10 CFR 50.49). The Primary Containment is not relied upon in the safety analyses and plant evaluations to perform a function that demonstrates compliance with Station Blackout (10 CFR 50.63).

System Intended Functions

1. Controls the release of fission products to the secondary containment in the event of design basis loss-of-coolant accidents (LOCA) so that off site consequences are within acceptable limits. (10 CFR 54.4(a)(1))
2. Provides sufficient air and water volumes to absorb the energy released to the containment in the event of design basis event so that pressure is within acceptable limits. (10 CFR 54.4(a)(1))
3. Provides a source of water for core spray, containment spray, and condensate transfer systems. (10 CFR 54.4(a)(1))
4. Provides physical support, shelter, and protection for safety related systems, structures, and components (SSCs). 10 CFR 54.4(a)(1)
5. Provides physical support, shelter, and protection for nonsafety related systems, structures, and components (SSCs) whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)

UFSAR References

3.8
6.2

License Renewal Boundary Drawings

LR-JC-19702

Table 2.4.1 **Primary Containment**
Components Subject to Aging Management Review

Component Type	Intended Functions
Access Hatch Covers	Pressure Boundary
Beam Seats	Structural Support
Biological Shield Wall - Concrete	Shielding
Biological Shield Wall - Lateral Support	Structural Support
Biological Shield Wall - Liner Plate	Structural Support
Biological Shield Wall - Structural Steel	Structural Support
Cable Tray	Structural Support
Class MC Pressure Retaining Bolting	Pressure Boundary
Concrete embedment	Structural Support
Conduits	Enclosure Protection
	Structural Support
Downcomers	Pressure Boundary
Drywell Head	Pressure Boundary
	Structural Support
Drywell Penetration Bellows	Pressure Boundary
Drywell Penetration Sleeves	Pressure Boundary
	Structural Support
Drywell Shell	Pressure Boundary
	Structural Support
Drywell Support Skirt	Structural Support
Liner (Sump)	Leakage Boundary
Locks, Hinges, and Closure Mechanisms	Pressure Boundary
	Structural Support
Miscellaneous Steel (catwalks, handrails, ladders, platforms, grating, and associated supports)	Structural Support
Moisture Barrier	**Leakage Boundary**
Panels and Enclosures	Enclosure Protection
	Structural Support
Penetration Closure Plates and Caps (spare penetrations)	Pressure Boundary
Personnel Airlock/Equipment Hatch	Pressure Boundary
Reactor Pedestal	Structural Support
Reinforced Concrete Floor Slab (fill slab)	Enclosure Protection
	Structural Support
Seals, Gaskets, and O-rings	Pressure Boundary
Shielding Blocks and Plates	Shielding
Structural Bolting	Structural Support
Structural Steel (radial beams, posts, bracing, plate, connections, etc.)	Structural Support
Suppression Chamber Penetrations	Pressure Boundary
	Structural Support
Suppression Chamber Ring Girders	Structural Support

Suppression Chamber Shell	Pressure Boundary
	Structural Support
Suppression Chamber Shell Hoop Straps	Structural Support
Thermowells	Pressure Boundary
Vent Header Deflector	HELB Shielding
Vent Jet Deflectors	HELB Shielding
Vent line bellows	Pressure Boundary
Vent line, and Vent Header	Pressure Boundary

The aging management review results for these components are provided in
Table 3.5.2.1.1 Primary Containment
-Summary of Aging Management Evaluation

3.5.2.2 AMR Results Consistent With The GALL Report for Which Further Evaluation is Recommended

NUREG 1801 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the LRA. For the Containments, Structures, and Component Supports, those programs are addressed in the following subsections.

3.5.2.2.1 PWR and BWR Containments

1. Aging of Inaccessible Concrete Areas

   Cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in inaccessible areas of PWR concrete and steel containments; BWR Mark II concrete containments; and Mark III concrete and steel containments. The GALL report recommends further evaluation to manage the aging effects for inaccessible areas if the environment is aggressive.

   This is applicable only to PWR and BWR concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

2. Cracks and distortion due to increased stress levels from settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program

   Cracking, distortion, and increase in component stress level due to settlement could occur in PWR concrete and steel containments and BWR Mark II concrete containments and Mark III concrete and steel containments. Also, reduction of foundation strength due to erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. Some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system, the GALL report recommends verification of the continued functionality of the de-watering system during the period of extended operation. The GALL report recommends no further evaluation if this activity is included in the scope of the applicant's structures monitoring program.

   This is applicable only to PWR and BWR concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

3. Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

   Reduction of strength and modulus of elasticity due to elevated temperatures could occur in PWR concrete and steel containments and BWR Mark II concrete containments and Mark III concrete and steel containments. The GALL report recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits, i.e., general area temperature 66°C (150°F) and local area temperature 93°C (200°F).

The normal operating temperature inside the Oyster Creek Primary Containment drywell varies from 139°F (at elev. 55') to 256°F (at elev. 95'). The containment structure is a BWR Mark I steel containment, which is not affected by general area temperature of 150°F and local area temperature of 200°F. Concrete for the reactor pedestal, and the drywell floor slab (fill slab) are located below elev. 55' and are not exposed to the elevated temperature. The biological shield wall extends from elev. 37'-3" to elev. 82'-2" and is exposed to a temperature range of 139°F - 184°F. The wall is a composite steel-concrete cylinder surrounding the reactor vessel. It is framed with 27 in. deep wide flange columns covered with steel plate on both sides. The area between the plates is filled with high density concrete to satisfy the shielding requirements. The steel columns provide the intended structural support function and the encased high density concrete provides shielding requirements. The encased concrete is not accessible for inspection.

The elevated drywell temperature concern was evaluated as a part of the Integrated Plant Assessment Systematic Evaluation Program (SEP Topic III-7.B). The evaluation concluded that the temperature would not adversely affect the structural and shielding functions of the wall.

The elevated drywell temperature was also identified as a concern for the reactor building drywell shield wall. Further evaluation for this wall is discussed in subsection 3.5.2.2.2, item (8).

4. Loss of Material due to General, Pitting, and Crevice Corrosion in Inaccessible Areas of Steel Shell or Liner Plate

Loss of material due to general, pitting and crevice corrosion could occur in inaccessible areas of the steel containment shell or the steel liner plate for all types of PWR and BWR containments. The GALL report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if specific criteria defined in the GALL report cannot be satisfied.

At Oyster Creek, the potential for loss of material, due to corrosion, in inaccessible areas of the containment drywell shell was first recognized in 1980 when water was discovered coming from the sand bed region drains. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken during the 1986 refueling outage. As a result, several corrective actions were initiated to determine the extent of corrosion, evaluate the integrity of the drywell, mitigate accelerated corrosion, and monitor the condition of containment surfaces. The corrective actions include extensive UT measurements of the drywell shell thickness, removal of the sand in the sand bed region, cleaning and coating exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. A corrosion monitoring program was established, in 1987, for the drywell shell above the sand bed region to ensure that the containment vessel is capable of performing its intended functions. Elements of the program have been incorporated into the ASME Section XI, Subsection IWE (B.1.27) and provide for:

- Periodic UT inspections of the shell thickness at critical locations,
- Calculations which establish conservative corrosion rates,
- Projections of the shell thickness based on the conservative corrosion rates, and
- Demonstration that the minimum required shell thickness is in accordance with ASME code.

Additionally, the NRC was notified of this potential generic issue that later became the subject of NRC 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.

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 the reduced thickness readings, **two trenches were excavated in 1986 inside the drywell to inspect the embedded drywell shell below the drywell interior concrete floor in areas corresponding to the exterior sandbed region. The sandbed region was inaccessible at that time. UT** thickness measurements were obtained **inside the two trenches in 1986 and in 1988** to determine the vertical profile of the thinning. **One** trench was excavated inside the drywell, in the concrete floor, in the area **corresponding to the exterior sandbed region** where thinning was most severe (bay #17). **A second trench was excavated in bay #5 in the area corresponding to the exterior sand bed region where thinning of the drywell shell at the concrete floor level was less severe. UT** measurements of the

drywell shell exposed in the bay #17 trench demonstrated that thinning of the embedded shell in concrete was no more severe than **thinning of the unembedded shell that was already being monitored.** UT measurements **of the drywell shell exposed in the bay #5 trench demonstrated** less 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 a baseline profile to track future 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 **in 1986**. The core samples validated the UT measurements and confirmed that the corrosion of the **exterior of the** drywell was 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 was 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 the 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.

AmerGen had visually inspected (VT-1) the epoxy coating on the exterior of the drywell shell in the sandbed region in selected bays during refueling outages in 1994, 1996, 2000, and 2004. During the 2006 refueling outage (1R21), AmerGen conducted VT-1 inspections of the epoxy coating in all ten bays in accordance with ASME Section XI, Subsection IWE, and AmerGen's Protective Coating

Monitoring and Maintenance Program. These inspections would have documented any flaking, blistering, peeling, discoloration, and other signs of degradation of the coating. The VT-1 inspections found the coating to be in good condition with no degradation.

Based on these VT-1 inspections, AmerGen has confirmed that no further corrosion of the drywell shell is occurring from the exterior of the epoxy-coated sandbed region. Monitoring of the coating in accordance with the ASME Section XI, Subsection IWE and AmerGen's Protective Coating Monitoring and Maintenance Program will continue to ensure that the drywell shell maintains its intended function during the period of extended operation.

Also during the 2006 refueling outage (1R21), AmerGen performed UT of the drywell shell in the sandbed region from inside the drywell, at the same 19 grid locations where UT was performed in 1992, 1994, and 1996. Location of the UT grid is centered at elevation 11'-3" in an area of the drywell shell that corresponds to the sandbed region. The 2006 UT measurements were made and statistically analyzed in accordance with the enhanced Oyster Creek ASME Section XI, Subsection IWE (B1.27) Aging Management Program. The results of the statistical analysis of the 2006 UT data were compared to the 1992, 1994 and 1996 data statistical analysis results (see below). 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 sandbed region has been arrested.

Analysis of the 2006 UT data, at the 19 grid locations, indicates that the minimum measured 95% confidence level mean thickness in any bay is 0.807" (bay #19). This is compared to the 95% confidence level minimum measured mean thickness in bay #19 of 0.806" and 0.800" measured in 1994 and 1992 respectively. Considering the instrument accuracy of ±0.010" these values are considered equivalent. Thus the minimum drywell shell mean thickness at the grid locations remains greater than 0.736" as required to satisfy the worst case buckling analysis, and the minimum available margin of 64 mils for any bay reported prior to taking 2006 UT thickness measurements remains bounded.

In addition to the UT measurements at the 19 grid locations, 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 the 2006 refueling outage. The computed mean thickness value of the drywell shell taken within the two trenches is 1.074" for bay #5 and 0.986" for bay #17. These values, when compared to the 1986 mean thickness values of 1.112" for the bay #5 trench and 1.024" for the bay #17 trench, indicated that wall thinning of approximately 0.038" has taken place in each trench since 1986. Engineering evaluation of the results concluded that considering that the exterior surface of

bay #5 had experienced a corrosion rate of up to 11.3 mils/yr between 1986 and 1992 and the exterior surface of bay #17 had experienced a corrosion rate of up to 21.1 mils/yr in the same period, the 0.038" wall thinning measured in 2006 is due to corrosion on the exterior surface of the drywell between 1986 and 1992.

Additionally the 95% confidence level minimum computed drywell shell mean thickness based on 2006 UT measurements within the two trenches is greater by a margin of 250 mils than the minimum required thickness of 0.736" for buckling. Also this margin is significantly greater than the minimum computed margin outside the trenches (64 mils). Individual points within the two trenches met the local thickness acceptance criterion of 0.490"for pressure computed based on ASME Section III, Subsection NE, Class MC Components, Paragraph 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 individual points also met a local buckling criterion of 0.536" previously established by engineering analysis.

The above UT thickness measurements were supplemented by additional UT measurements taken at 106 points from outside the drywell in the sandbed region, distributed among the ten bays. The locations of these measurements were established in 1992 as being the thinnest local areas based on visual inspection of the exterior surface of the drywell shell before it was coated. The thinnest location measured in 2006 is 0.602" versus 0.618" measured in 1992. The difference between the two measurements does not necessarily mean a wall thinning of 0.016" has taken place since 1992. This is because the 2006 UT data could not be compared directly with the 1992 data due to the difference in UT instruments and measurement technique used in 2006, and the uncertainty associated with precisely locating the 1992 UT points. A review of the 2006 data for the 106 external locations indicated that the measured local thickness is greater than the local acceptance criteria of 0.490" for pressure and 0.536" for local bucking.

As stated above, the 2006 UT data of the locally thinned areas (106 points) could not be correlated directly with the corresponding 1992 UT data. 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). For these reasons the Oyster Creek ASME Section XI, Subsection IWE Program (B.1.27) will be further enhanced to require UT measurements of the locally thinned areas

In 2008 and periodically during the period of extended operation as explained below.

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 **(51'10" and 60'10")**, the 3rd elevation **(50'2")** is undergoing a corrosion rate of 0.6 mils/year, while the 4th elevation **(87'5")** is subject to 1.2 mils/year. The UT measurements **taken in** 2004 confirmed that the corrosion rate continued to decline, The two elevations that previously exhibited no increase in corrosion **continued to show no additional corrosion.** 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 was 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.

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 sandbed 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 loss of material of 0.004" (0.770" – 0.766") in the 0.770" thick plate is insignificant and is bounded by corrosion experienced in other areas of the drywell above the sandbed region. The thicker plate (1.154") appears not to have experienced observable corrosion.

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 required general thickness to satisfy ASME Code stress requirements is 0.541" for the 0.770" thick plate and 0.736" for the 1.154" thick plate. Thus, the minimum margin at these locations is 225 mils (0.766 –0.541). The minimum required local thickness to satisfy ASME Code stress requirements is 0.490" for 1.154" thick plate and 0.360" for the 0.770" thick plate. The minimum local thickness margin is 268 mils (0.628-0.360).

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 sandbed 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 loss of material of 0.016" (0.640" – 0.624") in the 0.640" thick plate is insignificant and is bounded by corrosion experienced in other areas of the drywell above the sandbed region. The minimum measured average thickness of 0.624" meets the minimum thickness of 0.452" required to satisfy ASME stress requirements with a margin of 172 mils. The minimum measured local thickness on the 0.640" thick plate of 0.449" meets the minimum thickness of 0.300" required to satisfy ASME local stress requirements with a margin of 149 mils.

For the 2.625" plate, the minimum measured average thickness of 2.530" meets the minimum thickness of 2.260" required to satisfy ASME stress requirements with a margin of 270 mils. The loss of material of 0.095" (2.625-2.530) appears to be greater than other periodically monitored locations in the upper regions of the drywell. However the loss of material could be a result of other factors such as a variation in the original nominal plate thickness, and removal of the material during joint preparation for welding and not entirely due to corrosion. Even if the loss of material is attributed entirely to corrosion, the available thickness margin of 270 mils is adequate to ensure that the intended function of the drywell is not impacted before the next inspection planned for 2010 as discussed below. The minimum measured local thickness is 2.428", which is also greater than the minimum required general thickness of 2.260".

Since the 2006 readings are the first UT thickness measurements taken at plate transition at elevation 23'6" and 71'6", a corrosion rate specific to these areas is not established. AmerGen has committed to take UT measurements in 2010 in these areas 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, UT inspections of the areas will be performed on a frequency of every other refueling outage (Commitment 27.10, 27.11 in AmerGen Letter No. 2130-06-20358 dated July 7, 2006).

Inner Drywell Shell in the Embedded Region

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 preparation of a response to NRC question AMR-164 in April 2006 during the Aging Management Review Audit, an internal memo was identified that indicated the intermittent presence of water in the two trenches inside the drywell. This was not an expected condition. That memo, dated January 3, 1995 was referenced in a 1996 Structural Monitoring Walkdown Report but was not entered into the Corrective Action Process such that it could be considered as Operating Experience input to the Aging Management Program reviews.

Based on activities performed under the Structures Monitoring Program and IWE inspection program, and the reviews performed in support of the License Renewal Application, the water on the drywell floor and potentially inside the trenches was previously considered a temporary outage condition and not an operating environment for the embedded shell. However, in its response to NRC Aging Management Review Audit question AMR-164, AmerGen committed to inspect the condition of the drywell interior shell in the trench areas and to evaluate any identified degradation prior to entering the period of extended operation (Commitment 27.5 in AmerGen Letter No. 2130-06-20358 dated July 7, 2006). The results of these inspections and associated corrective actions are described below.

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 #27.5. 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.

As discussed previously, 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 sandbed 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 non-aggressive, 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. Specific enhancements are:

- **UT thickness measurements will be taken from outside the drywell in the sandbed 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 sandbed 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, 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.

The corrective actions taken as discussed above and the continued monitoring of the drywell for loss of material through **the enhanced** ASME Section XI, Subsection IWE **program**, the Protective Coating Monitoring and Maintenance Program, and 10 CFR Part 50, Appendix J provide reasonable assurance that loss of material in inaccessible areas of the drywell will be detected prior to **the** loss of an intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE **program**, the Protective Coating Monitoring and Maintenance, and 10 CFR Part 50 Appendix J programs are described in Appendix B.

5. Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

   Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.5 of this standard review plan.

   This is applicable only to PWR and BWR prestressed concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

6. Cumulative Fatigue Damage

   If included in the current licensing basis, fatigue analyses of containment steel liner plates and steel containment shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header and downcomers are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.6 of the standard review plan.

   At Oyster Creek, cumulative fatigue damage of the primary containment penetration sleeves, penetration bellows, suppression chamber (torus), vent header, downcomers, vent line bellows, main steam expansion joints inside the drywell, and containment vacuum breakers system piping, piping components, and expansion joints is a TLAA as defined in 10 CFR 54.3. The TLAA is evaluated in accordance with 10 CFR 54.21 (c). Evaluation of this TLAA is discussed in Section 4.6

7. Cracking due to Cyclic Loading and Stress Corrosion Cracking

Cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC could occur in all types of PWR and BWR containments. Cracking could also occur in vent line bellows, vent headers and downcomers due to SCC for BWR containments. A visual VT-3 examination would not detect such cracks. Moreover, stress corrosion cracking is a concern for dissimilar metal welds. The GALL report recommends further evaluation of the inspection methods implemented to detect these aging effects.

At Oyster Creek, cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading is considered metal fatigue and is addressed as a TLAA in Section 4.6.

Stress corrosion cracking (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 will eliminate susceptibility to SCC. Stainless steel elements of primary containment and the containment vacuum breakers system, including dissimilar welds, are susceptible to SCC. However these elements are located inside the containment drywell or outside the drywell, in the reactor building, and are not subject to corrosive environment as discussed below.

The drywell is made inert with nitrogen to render the primary containment atmosphere non-flammable by maintaining the oxygen content below 4% by volume during normal operation. The normal operating average temperature inside the drywell is less than 139°F and the relative humidity range is 20-40%. The reactor building normal operating temperature range is 65°F - 92°F; except in the trunion room where the temperature can reach 140°F. The relative humidity is 100% maximum. Both the containment atmosphere and indoor air environments are non-corrosive (chlorides <150 ppb, sulfates <100 ppb, and fluorides < 150 ppb).

Thus SCC is not expected to occur in the containment penetration bellows, penetration sleeves, and containment vacuum breakers expansion joints, piping and piping components, and dissimilar metal welds. A review of plant operating experience did not identify cracking of the components and primary containment leakage has not been identified as a concern. Therefore the existing 10 CFR Part 50 Appendix J leak testing and ASME Section XI, Subsection IWE, are adequate to detect cracking. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE and 10 CFR Part 50 Appendix J programs are described in Appendix B.

8. Scaling, Cracking, and Spalling due to Freeze-Thaw; and Expansion and Cracking due to Reaction with Aggregate

   Scaling, cracking, and spalling due to freeze-thaw could occur in PWR and BWR concrete containments; and expansion and cracking due to reaction with aggregate could occur in concrete elements of PWR and BWR concrete and steel containments. Further evaluation is not necessary if stated conditions are satisfied for inaccessible areas

   This is applicable only to PWR and BWR concrete containments. It is not applicable to the Oyster Creek Mark I steel containment.

3.5.2.2.2 Class I Structures

1. Aging of Structures Not Covered by Structures Monitoring Program

   The GALL report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1-3, 5, 7-9 structures; (2) scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1-5, 7-9 structures; (3) expansion and cracking due to reaction with aggregates for Groups 1-5, 7-9 structures; (4) cracking, spalling, loss of bond, and loss of material due to general, pitting and crevice corrosion of embedded steel for Groups 1-5, 7-9 structures; (5) cracks and distortion due to increase in component stress level from settlement for Groups 1-3, 5, 7-9 structures; (6) reduction of foundation strength due to erosion of porous concrete subfoundation for Groups 1-3, 5-9 structures; (7) loss of material due to general, pitting and crevice corrosion of structural steel components for Groups 1-5, 7-8 structures; (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1-5; and (9) cracking due to SCC and loss of material due to crevice corrosion of stainless steel liner for Groups 7 and 8 structures. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

   Technical details of the aging management issue are presented in Subsection 3.5.2.2.1.2 for items (5) and (6) and Subsection 3.5.2.2.1.3 for item (8).

   Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas for Groups 1-3, 5, 7-9. structures; and expansion and cracking due to reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 1-5, 7-9 structures. The GALL report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL report cannot be satisfied.

   At Oyster Creek, the Structures Monitoring Program (B.1.31) is used to manage aging affects applicable to Groups 2,3, 4, and 8-9 structures as discussed below. The GALL structures Group 1 and Group 7 do not exist for Oyster Creek. Group 5, "Fuel Storage Facility", is included with Group 2 structures.

(1) Loss of material and cracking due to repeated freeze-thaw for Groups 2,3, and 8-9 structures are managed through the Structures Monitoring Program and thus a further evaluation is not necessary.

(2) Scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 2, 4, and 8-9 structures are not applicable. The structures are not exposed to aggressive environment or water – flowing environment. Group 3 structures are also not exposed to aggressive, or water – flowing environments except for the Fire Water Pumphouses (fresh water pumphouse only), and the service water seal well (included with Miscellaneous Yard structures). The structures are within the scope of Structures Monitoring Program and inspected as described in Appendix B.

(3) Cracking due to reaction with aggregates for Groups 2-4, and 8-9 structures is monitored through Structures Monitoring Program, and thus a further evaluation is not necessary.

(4) Loss of material, cracking, and change in material properties due to corrosion of embedded steel for Groups 2-4, and 8-9 structures are monitored through the Structures Monitoring Program and thus a further evaluation is not required.

(5) The Structures Monitoring Program will be used to manage Cracks and distortion due to increase in component stress level from settlement for Groups 2-4, and 8-9 structures. However this aging mechanism is insignificant for Oyster Creek structures because the structures are founded on highly dense soil. Evaluation of soil explorations, during the original construction, predicted no more than 1" settlement for Class I structures. Observed settlement of the reactor building has ranged from 0.33" – 0.75" and was essentially complete soon after construction. Thus a settlement monitoring program is not required; nor is a de-watering system relied upon in the CLB to control settlement.

(6) Reduction of foundation strength due to erosion of porous concrete sub foundation for Groups 2-4, and 8-9 structures. This aging effect and mechanism is not applicable to Oyster Creek. The Oyster Creek design does not include porous concrete into the sub foundation of Groups 2-4 and 8-9 structures.

(7) Loss of material due to general, pitting and crevice corrosion of structural steel components for Groups 2-4, and 9 structures is monitored through the Structures Monitoring Program, and thus a further evaluation is not required.

(8) For loss of strength and modulus of concrete structures due to elevated temperatures for Groups 2-5, GALL recommends a Plant Specific AMP and further evaluation if the general temperature is greater than 150°F or if the local temperature is greater than 200°F. For Oyster Creek, the Structures Monitoring Program is used to manage cracking of concrete structures exposed to elevated temperatures.

Concrete temperature limits specified in the GALL report are exceeded only in a section of the reactor building (Group 2) drywell shield wall that encloses the containment drywell head. Thermocouples mounted on the head, in the general area of the shield wall, indicated a maximum temperature of 285°F. Engineering analysis predicted that the average temperature through the 5' thick concrete wall could be in the range of 180°F-215°F; considering a worst case thermal environment inside the containment of 340°F. As a result, an investigation was initiated to evaluate the impact of the elevated temperature on the structural integrity of the shield wall. The initial inspection of the shield wall identified concrete cracking in the area that is subject to high temperature. A map of the cracked area that includes crack length and width was developed for future monitoring.

Subsequently, an engineering evaluation was conducted to assess the impact of the elevated temperature on the drywell shield wall. For this purpose, a finite element model was created considering geometry of the shield wall and structural elements connected to it. The analysis was based on a temperature of 285°F and a reduced concrete compressive strength that accounts for temperature-induced reduction. The results concluded that concrete and rebar stress limits are in accordance with ACI 349 criteria with an adequate safety margin. NRC staff review found the analysis acceptable and concluded that the wall is capable of performing its intended function. The Staff also recommended condition monitoring of the drywell shield wall to ensure its continued function. The wall has been included in the scope of the Structures Monitoring Program and inspected periodically to ensure its continued function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Structures Monitoring Program is described in Appendix B.

(9) Cracking due to SCC and loss of material due to crevice corrosion of stainless steel liner are not in the scope of Structures Monitoring Program. Instead, the aging effects are managed through the Water Chemistry Program (B.1.2) and monitoring of spent fuel pool water level, consistent with the GALL AMP. Therefore a further evaluation is not necessary.

At Oyster Creek, the Structures Monitoring Program (B.1.31) is used to manage concrete aging effects due to various aging mechanisms.

The program requires periodic inspection of accessible areas and inspection of inaccessible areas when they become accessible. The below-grade concrete structures are inspected, when excavated for any reason. In addition, the criteria defined in the GALL report is satisfied as discussed below.

Oyster Creek is located in a moderate to severe weathering conditions. As a result loss of material (spalling, scaling) and cracking due to free-thaw is applicable to Groups 2-3 and 8-9 structures. However these concrete structures are designed and constructed in accordance with ACI 318 and provide for low permeability and adequate air entrainment (4% - 6%) such that the concrete is not susceptible to freeze-thaw aging effects. Inspections of accessible areas have identified cracks on the exterior walls of the reactor building. The cracks have been attributed to a combination of early concrete shrinkage, expansion, and contraction due to temperature variation. Spalling and scaling of any significance have not been observed.

At Oyster Creek, expansion and cracking due to reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 2-4, and 8-9 structures.

At Oyster Creek, concrete specifications require Type II; low alkali cement shall be used. Alkali content is limited to 0.6 per cent total alkali unless tests performed in accordance with ASTM C295 and C227 demonstrate no potential for alkali reactivity for the aggregate.

Inspection activities in accordance with the Structures Monitoring Program described above, in conjunction with concrete quality that meets ACI 318, ASTM 295, and ASTM C227 standards, provide reasonable assurance that the below-grade concrete will perform its intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Structures Monitoring Program is described in Appendix B.

2. Aging Management of Inaccessible Areas

   Cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas. The GALL report recommends further evaluation to manage these aging effects in inaccessible areas of Groups 1-3, 5, 7-9 structures.

   Recent Oyster Creek groundwater analysis results (pH: 5.6 – 6.4, chlorides: 3 - 138 ppm, and sulfates: 7 – 73 ppm) have shown that the groundwater at Oyster Creek is not aggressive for Groups 2-3, 8-9 structures. Therefore further evaluation of below-grade inaccessible concrete areas for Groups 2, and 8-9 structures is not required. Similarly inaccessible areas of Group 3 structures are not exposed to aggressive environment except for Fire Water Pumphouses (fresh water pumphouse only). Further evaluation of group 3 structures, other than fresh water pumphouse is not required.

The fresh water pumphouse reinforced concrete is subject to slightly aggressive water from the Fire Pond Dam (pH: 4.8, chlorides = 12 ppm, and sulfates = 6 ppm). Inaccessible areas will be inspected if excavated for any reason, or if observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

The Structures Monitoring Program will be enhanced to include periodic groundwater monitoring in order to demonstrate that the below grade environment remains non-aggressive. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Structures Monitoring Program is described in Appendix B.

3.5.2.2.3 <u>Component Supports</u>

1. Aging of Supports Not Covered by Structures Monitoring Program

   The GALL report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports; (2) loss of material due to environmental corrosion, for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

   At Oyster Creek, (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports, (2) loss of material for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports are covered under the Structures Monitoring Program.

   The Structures Monitoring Program will be used to manage loss of material on exterior surfaces of piping, piping components, HVAC components and ductwork, tanks, and other mechanical components located in outdoor air environment. The program will also be used to manage loss of material and change in material properties of exterior surfaces of mechanical system components in indoor air environment as described in Appendix (B.1.31) and as evaluated in sections 3.1, 3.2, 3.3, and 3.4 of this application.

   Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the Corrective

Action Process. The Structures Monitoring Program is described in Appendix B.

2. Cumulative Fatigue Damage Due To Cyclic Loading

   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). The evaluation of this TLAA is addressed separately in Section 4.3 of the standard review plan.

   At Oyster Creek, there are no fatigue analyses applicable to Groups B1.1, and B1.2 component supports in the CLB. Therefore, cumulative fatigue damage for Groups B1.1 and B1.2 component supports is not a TLAA as defined in 10 CFR 54.3.

   The Oyster Creek CLB includes fatigue analysis for certain Group B1.3, ASME Class MC component supports. For these supports (Torus support columns and sway braces), cumulative fatigue damage is a TLAA evaluated in accordance with 10 CFR 54.21(c) in Section 4.6.1.

3.5.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Primary Containment, Structures, and Component Supports components:

- Section 4.6, Primary Containment, Attached Piping and Components
- Section 4.7.1, Reactor Building Crane, Turbine Building Crane, Heater Bay Crane Load Cycles
- Section 4.7.2, Drywell Corrosion
- Section 4.7.3, Equipment Pool and Reactor Cavity Walls Rebar Corrosion

3.5.3 CONCLUSION

The Primary Containment, Structures, Component Supports, and Piping and Component Insulation components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Primary Containment, Structures, Component Supports, and Piping and Component Insulation components are identified in the summaries in Section 3.5.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Primary Containment, Structures, and Component Supports components will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

Table 3.5.1 Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Structures and Component Supports

Item Number	Type	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-13	BWR/ PWR	Steel elements: *liner plate,* containment shell downcomers, drywell support skirt, ECCS suction header	Loss of material *due to general,* pitting and crevice corrosion in accessible and inaccessible areas	Containment ISI *and* Containment leak rate test	Yes, if corrosion is *significant for* inaccessible areas	Consistent with NUREG-1801 with exceptions. The ASME Section XI, Subsection IWE, B.1.27, and 10 CFR Part 50, Appendix J, B.1.29 will be used to manage loss of material for steel elements of the primary containment. In addition loss of material of the drywell is considered a TLAA and evaluated in accordance with 10CFR54.21(c). The ASME Section XI, Subsection IWE, B.1.27, 10 CFR Part 50, Appendix J, B.1.29, will also be used to manage loss of material of the containment vacuum breakers system piping and piping components. Exceptions apply to the NUREG-1801 ASME Section XI, Subsection IWE Loss of material due to corrosion, in the sand bed region and on the exterior surfaces of the upper region of drywell, was identified as a potential concern in early 1980's. As a result, the sand was removed from the sand bed region and a protective coating was applied to the drywell exterior surfaces in that region. The upper regions of the drywell shell are examined periodically by ultrasonic (UT) measurements and evaluated to ensure that the actual thickness meets ASME requirements. **Loss of material due to corrosion of inaccessible inner drywell shell surface has been evaluated and determined to be insignificant; but will be managed in accordance with the enhanced Oyster Creek ASME Section XI, Subsection IWE, B.1.27, and 10 CFR Part 50, Appendix J, B.1.29 during the period of extended operation.** See Subsection 3.5.2.2.1.4.

Table 3.5.2.1.1
Primary Containment
Summary of Aging Management Evaluation

Table 3.5.2.1.1 Primary Containment

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Drywell Shell	Pressure Boundary	Carbon and low alloy steel	Concrete (Internal w/water)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10
					TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
			Water (Internal)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10
					TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
	Structural Support	Carbon and low alloy steel	Concrete (Internal w/water)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10

Table 3.5.2.1.1 Primary Containment (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Drywell Shell	Structural Support	Carbon and low alloy steel	Concrete (Internal w/water)	Loss of Material	TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
			Water (Internal)	Loss of Material	10 CFR Part 50, Appendix J (B.1.29)	II.B1.1-2 (C-19)	3.5.1-13	A, 10
					ASME Section XI, Subsection IWE (B.1.27)	II.B1.1-2 (C-19)	3.5.1-13	B, 10
					TLAA, evaluated in accordance with 10 CFR 54.12(c)	II.B1.1-2 (C-19)	3.5-1-13	E, 4
Moisture Barrier	Leakage Boundary	Elastomer	Containment Atmosphere	Change in Material Properties	ASME Section XI, Subsection IWE (B.1.27)	II.B4-7 (C-18)	3.5.1-6	B, 11, 12
			Treated Water	Change in Material Properties	ASME Section XI, Subsection IWE (B.1.27)			G, 11,12
Reinforced Concrete Floor Slab (fill slab)	Enclosure Protection	Concrete	Treated Water (Submerged)	Change in Material Properties	Structures Monitoring Program (B.1.31)			G, 13
				Cracking	Structures Monitoring Program (B.1.31)			G, 13
				Loss of Material	Structures Monitoring Program (B.1.31)			G, 13
	Structural Support	Concrete	Treated Water (Submerged)	Change in Material Properties	Structures Monitoring Program (B.1.31)			G, 13

Table 3.5.2.1.1 Primary Containment (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Reinforced Concrete Floor Slab (fill slab)	Structural Support	Concrete	Treated Water (Submerged)	Cracking	Structures Monitoring Program (B.1.31)			G, 13
				Loss of Material	Structures Monitoring Program (B.1.31)			G, 13

Notes	Definition of Note
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1. The biological shield wall high density concrete is unreinforced, encased in steel plates (biological shield wall liner plate) and is inaccessible.
2. ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J are the applicable aging management programs for Class MC pressure retaining bolting.
3. The Aging effects and Aging Management Program identified for this material/environment combination are consistent with industry guidance.
4. Loss of material due to corrosion is a TLAA for the drywell shell in Oyster Creek CLB
5. Protective coatings applied to the external surfaces of the drywell where the sand is removed (sand pocket region) has been credited for mitigating loss of material due to corrosion in CLB.
6. Concrete in contact with the embedded containment shell meets the requirements of ACI 318 and the guidance of 201.R.
7. Reduction of strength and modulus due to elevated temperature is not an aging effect requiring management. See further evaluation in Section 3.5.2.2.1.3
8. Structures Monitoring Program is the applicable aging management program for this component
9. Primary containment leakage is controlled in accordance with Oyster Creek Technical Specifications.
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 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 (spalling, 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.

A.1.27 ASME SECTION XI, SUBSECTION IWE

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic inspection of primary containment surfaces and components, including integral attachments, and containment vacuum breakers system piping and components for loss of material, loss of sealing, and loss of preload.

Examination methods include visual and volumetric testing as required by the Code. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action process. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied to bolting.

In accordance with commitments made during the Oyster Creek license renewal application review process, 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. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:
   - 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.

   These actions will be completed prior to restart from the associated outage.

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.

3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:

- 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 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:
  - 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 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.

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, 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.

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.

7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

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).

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 one location using the 6"x6" grid. 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).

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 one location using the 6"x6" grid. 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).

12. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected.

13. The reactor cavity seal leakage concrete trough drain will be verified to be clear from blockage once per refueling cycle.

14. **UT thickness measurements will be taken from outside the drywell in the sandbed 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 sandbed 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.**

A.5 License Renewal Commitment List

The following table identifies modifications made to license renewal commitment # 27, for the ASME Section XI, Subsection IWE Primary Containment Inspection Program, being made in this supplemental response. Previous updates to commitment # 27 were most recently made in AmerGen letter 2130-06-20358, dated July 7, 2006. The new information is displayed in **bold** font.

Any other actions discussed in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments.

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
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 in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:	A.1.27	Prior to the period of extended operation Prior to the period of extended operation, and then two refueling outages after that. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals	Section B.1.27

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	• 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. These actions will be completed prior to restart from the associated outage.			
	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. • The sand bed region drains will be monitored daily during refueling		Periodically Daily during refueling outages	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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 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: • Inspection of the drywell shell coating and moisture barrier (seal) in		Quarterly during non-outage periods	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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 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.		Prior to the period of extended operation and every ten years during the period of extended operation	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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, 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.		Prior to the period of extended operation	
	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 and during the period of extended operation	
	7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the		Every other refueling outage prior to and during the period of	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	same locations as are currently measured.		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	
	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 one location using the 6"x6" grid. 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		Prior to the period of extended operation and two refueling outages later	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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).			
	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 one location using the 6"x6" grid. 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, item 4), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.		Coincident with the sand bed region drywell shell coating inspection	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	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 sandbed 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**	
	15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sandbed 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.		**Starting in 2010, two bays will be inspected per outage, such that the shell will be inspected from all 10 sandbed bays within a 10-year period. See commitment for scope expansion criteria.**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	16. Perform visual inspection 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 2008 refueling outage and subsequent outages until trenches are restored to original configuration In accordance with ASME Section XI, Subsection IWE	

B.1.27 ASME SECTION XI, SUBSECTION IWE

Program Description

The ASME Section XI, Subsection IWE aging management program provides for inspection of primary containment components and the containment vacuum breakers system piping and components. It is implemented through station plans and procedures and covers steel containment shells and their integral attachments; containment hatches and airlocks, seals and gaskets, containment vacuum breakers system piping and components, and pressure retaining bolting. The program includes visual examination and limited surface or volumetric examination, when augmented examination is required, to detect loss of material. The program also provides for managing loss of sealing for seals and gaskets, and loss of preload for pressure retaining bolting. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied. The Oyster Creek program complies with Subsection IWE for steel containments (Class MC) of ASME Section XI, 1992 Edition including 1992 Addenda in accordance with the provisions of 10 CFR 50.55a. Enhancements to the program, which are negotiated with NRC, to provide reasonable assurance that drywell corrosion is adequately managed during the period of extended operation are described below.

NUREG-1801 Consistency

The ASME Section XI, Subsection IWE aging management program is consistent with the ten elements of aging management program XI.S1, "ASME Section XI, Subsection IWE," specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 evaluation is based on ASME Section XI, 2001 Edition including 2002 and 2003 Addenda. The current Oyster Creek ASME Section XI, Subsection IWE program plan for the First Ten-Year inspection interval effective from September 9, 1998 through September 9, 2008, approved per 10CFR50.55a, is based on ASME Section XI, 1992 Edition including 1992 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

Enhancements

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. Subsequent inspection frequency will be established as appropriate, not to exceed 10-year intervals. The UT measurements will be taken from the

inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following:

- 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.

These actions will be completed prior to restart from the associated outage.

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.

3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:

- 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 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:

- 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 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. Inspection of the coating is accomplished through the Protective Coating Monitoring and Maintenance Program (B.1.33)

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, 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.

6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Monitoring and Maintenance Program (B.1.33). 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.

7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.

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).

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 one location using the 6"x6" grid. 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).

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 one location using the 6"x6" grid. 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).

12. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected

13. The reactor cavity seal leakage concrete trough drain will be verified to be clear from blockage once per refueling cycle.

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 concluded 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. Specific enhancements are:

14. **UT thickness measurements will be taken from outside the drywell in the sandbed 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 sandbed 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 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.

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.

Operating Experience

ASME Section XI, Subsection IWE as described in Oyster Creek First-10 Year Containment (IWE) Inservice Inspection Program Plan and Basis is effective September 9, 1998 to September 9, 2008. Base line inspection of containment surfaces was completed in 2000 and a second inspection was completed in 2004. The 2004 inspection identified (2) recordable conditions, a loose locknut was identified on a spare drywell penetration and a weld rod was found stuck to the underside of the drywell head. Engineering evaluation concluded the stuck weld rod has no adverse impact on drywell head structural integrity and the loose locknut did not affect the seal of the containment penetration.

The upper region of drywell shell has experienced loss of material, due to corrosion, as result of water leakage into the gap between the containment and the reactor building in the 1980's. As a result the area is subject to augmented examinations as required by ASME Section XI, Subsection IWE. The examination is by ultrasonic (UT) thickness measurements. UT measurements taken in 2004 showed that the drywell shell thickness meets ASME criteria and that the rate of corrosion is in a declining trend. 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 Section 4.7.2, "Drywell Corrosion" TLAA evaluation.

Similarly the sand bed region also experienced loss of material due to corrosion. Corrosion was attributed to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. As a corrective measure, the sand was removed and a protective coating was applied to the shell to mitigate further corrosion. Subsequent inspections confirmed that corrosion of the shell has been arrested. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program, B.1.33. Refer to program B.1.33 for additional details.

The suppression chamber (Torus) and vent system were originally coated with Carboline Carbo-Zinc 11 paint. The coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion. Refer to program B.1.33 for additional details.

Operating experience review concluded that ASME Section XI, Subsection IWE is effective for managing aging effects of primary containment surfaces.

During the October 2006 refueling outage UT thickness measurements in the sandbed 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 sandbed 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 sandbed 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 sandbed 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 sandbed 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.

Inner Drywell Shell in the Embedded Region

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 #27.5. 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 sandbed 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 non-aggressive, 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.

Conclusion

The enhanced ASME Section XI, Subsection IWE aging management program ensures that loss of material, loss of sealing, and loss of preload of primary containment components and the containment vacuum breakers system piping and components are adequately managed so that there is a reasonable assurance their intended function will be maintained consistent with the current licensing basis during the period of extended operation.

B.1.31 STRUCTURES MONITORING PROGRAM

Program Description

The Structures Monitoring Program provides for aging management of structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in Regulatory Guide 1.160 Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01 Revision 2, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

The scope of the program also includes condition monitoring of masonry walls and water-control structures as described in the Masonry Wall Program and in the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants aging management program. As a result, the program elements incorporate the requirements of NRC IEB 80-11, "Masonry Wall Design", the guidance in NRC IN 87-67, "Lessons learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11", and the requirements of NRC Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The program relies on periodic visual inspections by qualified personnel to monitor structures and components for applicable aging effects. Specifically, concrete structures are inspected for loss of material, cracking, and a change in material properties. Steel components are inspected for loss of material due to corrosion. Masonry walls are inspected for cracking, and elastomers will be monitored for a change in material properties. Earthen structures associated with water-control structures and the Fire Pond Dam will be inspected for loss of material and loss of form. Component supports will be inspected for loss of material, reduction or loss of isolation function, and reduction in anchor capacity due to local concrete degradation. Exposed surfaces of bolting are monitored for loss of material, due to corrosion, loose nuts, missing bolts, or other indications of loss of preload. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied consistent with the NUREG-1801 bolting integrity program.

The scope of the program will be enhanced to include structures that are not monitored under the current term but require monitoring during the period of extended operation. Details of the enhancements are discussed below.

Inspection frequency is every four (4) years; except for submerged portions of water- control structures, which will be inspected when the structures are dewatered, or on a frequency not to exceed 10 years. The program contains provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process

NUREG-1801 Consistency

The Structures Monitoring Program is consistent with the ten elements of aging management program XI.S6,"Structures Monitoring Program," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

The scope of the program will be increased to add 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, liner for sumps, structural seals, and anchors and embedment.

The scope of the program will be enhanced to include Station Blackout System 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.

The scope of the program will be increased to include component supports, other than those in scope of ASME XI, Subsection IWF.

The scope of the program will be enhanced to include inspection of external surfaces of Oyster Creek and Forked River Combustion Turbine mechanical components that are not covered by other programs, including exterior surfaces of HVAC duct, damper housings, and HVAC closure bolting. Inspection and acceptance criteria of the exterior surfaces will be the same as those specified for structural steel components and structural bolting.

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.

The program will provide for inspections of, electrical panels and racks, junction boxes, instrument racks and panels, cable trays, offsite power structural components and their foundations, and anchorage.

The program will provide for periodic sampling and testing of ground water and review its chemistry data to confirm that the environment remains non-aggressive for buried reinforced concrete.

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, including trash racks at the Intake Structure and Canal.

The program will require inspection of penetration seals, structural seals, and other elastomers for change in material properties by inspecting the elastomers for cracking and hardening.

The program will require inspection 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 current inspection criteria will be enhanced 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. Accessible wooden piles and sheeting will be inspected for loss of material and a 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.

The program will be enhanced to include periodic inspection of the Fire Pond Dam for loss of material and loss of form.

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 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 structures. Enhancements will be implemented prior to the period of extended operation.

Operating Experience

The review of program documentation, and other plant operating experience before the program was implemented, identified cracking of reinforced of 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 shrinkage of concrete and temperature changes. Engineering evaluation concluded that the structural integrity of the walls is 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 would 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 taking into consideration the existing cracked condition. The shield wall cracking was addressed in NRC SEP review of the plant under Topic III-7B. The cracks have been mapped and inspected periodically under the program. 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 non-destructive testing to determine the depth of the cracks, it was concluded that the beams would perform their intended function, and that continued monitoring with crack monitors is not required. The cracks are examined periodically under the program and have shown little change.

Inspection of the intake canal, performed in 2001, identified cracks and fissures, voids, holes, and localized washout of coatings that protect embankment slopes from erosion. The degradations were evaluated and determined not to impact the intended function of the intake canal (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 discussed above have not become worse and remains essentially the same as identified in previous inspections. In addition minor cracking, rust stains, water stains, localized exposed rebars and rebar corrosion, and damage to siding were observed. The degradations were evaluated and determined not to have an impact on the structural integrity of affected structures. Operating experience review concluded that the program is effective for managing aging effects of structures, structural components, and water-control structures.

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 #27.5 (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.

Conclusion

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. Inspection frequency is every four (4) years (except for water-control structures) with provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. Submerged portions of water-control structures will be inspected when dewatered or on a frequency not to exceed ten (10) years.

The scope of the program will be enhanced to include all structures, and component supports not covered by other programs, the Fire Pond Dam, and exterior surfaces of mechanical components in the scope of license renewal that are not covered by other programs. Inspection criteria will also be enhanced to provide reasonable assurance that the aging effects are adequately managed so that the intended functions of structures and components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Monitored Elevation	Location	Minimum Required Thickness, inches [5]	Average Measured Thickness [1,2,4], inches 1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	2006	Projected Thickness in 2029
Elevation 50' 2"		0.541"													
	Bay 5–D12					0.743 0.745 0.746	0.742 0.745 0.748	0.747 0.747		0.741	0.748	0.741	0.743	**0.747**	**No Observable** Ongoing Corrosion
	Bay 5–5H					0.761 0.761	0.755 0.758 0.760	0.759 0.759		0.754	0.757	0.754	0.756	**0.760**	**No Observable Ongoing Corrosion**
	Bay 5–5L					0.706 0.703	0.703 0.705 0.706	0.703 **0.702** (7)		0.702	0.705	0.706	0.701	**0.705**	No Observable Ongoing Corrosion
	Bay 13–31H					0.762 0.779	0.760 0.758 0.765	0.765 0.763		0.759	0.766	0.762	0.758	**0.762**	No Observable Ongoing Corrosion
	Bay 13–31L					0.687 0.684	0.689 0.678 0.688	0.685 0.688		0.683	0.690	0.682	0.693	**0.678**	No Observable Ongoing Corrosion
	Bay 15–23H					0.758 0.764	0.762 0.762 0.765	0.767 0.763		0.758	0.760	0.758	0.757	**0.749**	**0.720**
	Bay 15–23L					0.726 0.728	0.726 0.729 0.725	0.726 0.724		0.728	0.724	0.729	0.727		

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Monitored Elevation	Location	Minimum Required Thickness, inches [5]	Average Measured Thickness [1,2,4], inches												Projected Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	2006	
Elevation 51' 10"		0.518" (6)													
	Bay 13–32H					0.716	0.715 0.715 0.720	0.717 0.717		0.714	0.715	0.715	0.713	**0.715**	No Observable Ongoing Corrosion
	Bay 13–32L					0.686	0.683 0.683 0.682	0.683 0.676		0.680	0.684	0.679	0.687	**0.685**	No Observable Ongoing Corrosion
Elevation 60' 10"		0.518"													
	Bay 1–50-22								0.693	0.711	0.693	0.689	**0.693 (8)**	**0.691**	No Observable Ongoing Corrosion
Elevation 87' 5"		0.452"													
	Bay 9–20		0.619	0.622 0.620	0.619	0.620	0.614 0.612	0.629 0.614		0.613	0.613	0.604	0.612	**0.617**	**No Observable Ongoing Corrosion**
	Bay 13–28		0.643	0.641 0.642	0.645	0.643	0.635 0.629	0.641 0.637		0.640	0.636	0.635	0.640	**0.642**	No Observable Ongoing Corrosion
	Bay 15–31		0.638	0.636 0.636	0.638	0.642	0.628 0.627	0.631 0.630		0.633	0.632	0.628	0.630	**0.633**	**No Observable Ongoing Corrosion**

Table –1. UT Thickness measurements for the Upper Region of the Drywell Shell

Notes:

1. The average thickness is based on 49 Ultrasonic Testing (UT) measurements performed at each location
2. Multiple inspections were performed in the years 1988, 1990, 1991, and 1992.
3. The 1993 elevation 60' 10" Bay 5-22 inspection was performed on January 6, 1993. All other locations were inspected in December 1992.
4. Accuracy of Ultrasonic Testing Equipment is plus or minus 0.010 inches.
5. Reference SE-000243-002.
6. **Minimum required thickness for elevation 51' 10" was inadvertently listed as 0.541" in the original RAI response. The correct value is 0.518". There is no impact on the analysis, as this was a transcription error between the calculation and Table 1.**
7. **This 1992 value for Location Bay 5-5L was inadvertently reported as 0.707" (instead of 0.702") in the original RAI response. There is no impact on the analysis, as this was a transcription error between the calculation and Table 1.**
8. **The 2004 value for Location Bay 1-50-22 was inadvertently listed as 0.689 in the original RAI response. This was the result of an error identified in the old calculations that has been subsequently corrected and factored into the latest analysis.**

Conclusion:

Summary of Corrosion Rates of UT measurements taken through year **2006**

- There is no **observable** ongoing corrosion at **three** elevations (51' 10", 60' 10", **and 87'5"**)
- Based on statistical analysis, one location at elevation 50' 2" is undergoing a minor corrosion rate of **0.66 mils** per year.

Table –2 UT Thickness measurements for the Sand Bed Region of the Drywell Shell

Location Bay	Sub Location	Dec 1986	Feb 1987	Apr 1987	May 1987	Aug 1987	Sep 1987	Jul 1988	Oct 1988	Jun 1989	Sep 1989	Feb 1990	Apr 1990	Mar 1991	May 1991	Nov 1991	May 1992	Sep 1992	Sep 1994	Sep 1996	Oct 2006
1D									1.115										1.101	1.151	1.122
3D									1.178										1.184	1.175 (4)	1.180
5D									1.174										1.168	1.173	1.185
7D									1.135										1.136	1.138	1.133
9A									1.155										1.157	1.155	1.154
9D		1.072							1.021	1.054	1.020	1.026	1.022	0.993	1.008	0.992	1.000	1.004	0.992	1.008	0.993
11A				0.919	0.905	0.922	0.905	0.913	0.888	0.881	0.892	0.881	0.870	0.845	0.844	0.833	0.842	0.825	0.820	0.830	0.822
11C	Bottom				0.917	0.954	0.916	0.906	0.891	0.877	0.891	0.870	0.865	0.858	0.863	0.856	0.882	0.859	0.850	0.883	0.855
	Top				1.046	1.109	1.079	1.045	1.009	1.016	1.005	0.952	0.977	0.982	1.002 (3)	0.964	1.010	0.970	0.982 (4)	1.042	0.958
13A		0.919							0.905	0.883	0.883	0.862	0.853	0.855	0.853	0.849	0.865	0.858	0.837 (4)	0.853 (4)	0.846
13D (1)	Bottom								0.962 (1)				0.932 (1)	0.909	0.901	0.900	0.931	0.906	0.895	0.933	0.904
	Top													1.072	1.049	1.048	1.088	1.055	1.037	1.059	1.047
13C (1)																		1.149 (1)	1.140 (1)	1.154 (1)	1.142
15A									1.120										1.114	1.127	1.121
15D		1.089							1.056	1.060	1.061	1.059	1.057	1.060	1.050	1.042	1.065	1.058	1.053	1.066	1.053
17A	Bottom	0.999							0.957	0.965	0.955	0.954	0.951	0.935	0.942	0.933	0.948	0.941	0.934	0.997	0.935
	Top	0.999							1.133	1.130	1.131	1.128	1.128	1.131	1.129	1.123	1.125	1.125	1.129	1.144	1.122
17D			0.922		0.895	0.891	0.895	0.878	0.862	0.857	0.847	0.836	0.829	0.825	0.829	0.822	0.823	0.817	0.810	0.848 (4)	0.818
17/19	Top								0.982	1.019	1.131	0.990	0.986	0.975	0.969	0.954	0.972	0.976	0.963	0.967	0.964
	Bottom								1.004	0.999	0.955	1.010	1.006	0.987	0.982	0.971	0.990	0.989	0.975	0.991	0.972
19A			0.884		0.873	0.859	0.858	0.849	0.837	0.829	0.825	0.812 (2)	0.808	0.817	0.803	0.803	0.809	0.800	0.806	0.815	0.807
19B					0.898	0.892	0.888	0.864	0.857	0.826	0.845	0.840 (2)	0.837	0.853	0.844	0.846	0.847	0.840	0.824	0.837	0.848
19C					0.901	0.888	0.888	0.873	0.856	0.845	0.845	0.831	0.825	0.843	0.823	0.822	0.832	0.819	0.820	0.854 (4)	0.824

Table –2 UT Thickness measurements for the Sand Bed Region of the Drywell Shell

Table 2 Notes:

1. **The Location Bay identifications for 13C and 13D were inadvertently reversed in the original RAI response, and erroneous low values were entered for Location Bay 13C. There is no impact on the analysis, as this was a transcription error between the calculation and Table 2.**

2. **The February 1990 values for Location Bays 19A and 19B were inadvertently reversed in the original RAI response. There is no impact on the analysis, as this was a transcription error between the calculation and Table 2.**

3. **The May 1991 value for Location Bay 11C Top was inadvertently reported as 1.018" (versus 1.0018" which rounds to 1.002") in the original RAI response. There is no impact on the analysis, as this was a transcription error between the calculation and Table 2.**

4. **The remaining changes are minor errors identified in the old calculations that have been subsequently corrected and factored into the latest analysis.**

IWE Program Inspections/Actions Performed During 2006 Refueling Outage

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
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 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. These actions will be completed prior to restart from the associated outage.	1. Ultrasonic inspections of the drywell shell at locations previously measured, as outlined in the previous column, were performed. Review of the 1992, 1994, 1996 and 2006 data for all grids show that these monitored locations have not experienced any observable corrosion. This conclusion is based on a statistical comparison with the mean thicknesses measured in 1992, 1994, 1996 and 2006 at each location.

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
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. 3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage. • 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 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. Any degraded coating or moisture barrier will be repaired.	2. Strippable coating was applied to the reactor cavity liner prior to flooding the cavity with water for refueling activities. 3. The reactor cavity seal leakage trough drain was monitored for leakage daily after the reactor cavity was flooded up for refueling. There was a small stream of water (approximately one gallon per minute) observed to be coming from the reactor trough drain line. This rate was observed to be consistent throughout the period that the cavity was filled with water. Also, the sandbed region drain lines were monitored daily during the outage, after the cavity was flooded. No leakage was observed from any of the drain lines, in the sand bed area itself, nor was any collected in the associated poly collection bottles. Note that the sand bed drains were checked to ensure that they were clear. Some debris was found and cleared from two of the five drain lines.

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
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 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.	4. 100% of the epoxy coating applied to the external surface of the drywell shell in the sandbed region in 1992 was inspected in accordance with the inspection specification and the condition of the coating was determined to be satisfactory (i.e., no evidence of flaking, blistering, peeling, discoloration or other signs of coating distress).
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, 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.	5. Visual and ultrasonic examinations of the drywell shell were performed from the inspection access trenches. Visual inspection of the trenches identified approximately 5" of standing water in the trench in Bay 5, and moisture in the trench in Bay 17, and minor surface oxidation on the exposed shell areas. The ultrasonic test measurements determined that the drywell shell retains significant thickness margin in these areas. Also, additional concrete was excavated during 1R21 to expose approximately six more inches of previously embedded drywell shell surface at the bottom of the trench in bay 5 for inspection. UT results indicate that the average thickness in this area of the shell is approximately 0.041 inches (41 mils) below the nominal thickness of 1.154 inches, signifying that

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
	substantial margin exists in this previously embedded plate material.
7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.	7. UT thickness measurements in the upper drywell were taken. Statistical evaluation of the mean data indicates that the upper drywell shell is not undergoing observable corrosion, with the exception of one grid location. Analysis of the data at that grid location indicates a corrosion rate of 0.66 mils per year.
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).	9. 106 areas that had been identified in 1992 as locally thinned were ultrasonically examined. These areas are geometrically distributed throughout the periphery of the drywell shell, at various elevations within the sand bed region. The results indicate that all the measured local thicknesses meet the established design basis criteria.
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	10. Two sets of UT thickness measurements were taken 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, using a 6"x6" grid. Evaluation of these first-time readings shows that the mean and individual thicknesses currently meet acceptance criteria, with adequate margin. Note that, per the commitment, an additional two sets of measurements will be taken at different azimuths at

IWE Program Commitments (Numbers consistent with LRA A.5 table, Commitment # 27)	2006 (1R21) Outage Results
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).	this elevation prior to the period of extended operation.
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).	11. Two sets of UT thickness measurements were taken in the drywell shell knuckle area at the junction between the 0.640 inch thick and 2.625 inch thick plates, using a 6"x6" grid. Evaluation of these first-time readings shows that the mean and individual thicknesses currently meet acceptance criteria, with adequate margin. Note that, per the commitment, an additional two sets of measurements will be taken at different azimuths at this elevation prior to the period of extended operation.
12. When the sand bed region drywell shell coating inspection is performed (commitment 27, item 4), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.	12. A visual inspection of the seal at the junction between the sand bed region concrete and drywell shell was performed in all 10 bays. The inspection revealed the seal at this junction to be in acceptable condition with no repairs required.
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.	13. The reactor cavity trough drain was inspected with a boroscope and verified to be clear.