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U. S. Nuclear Regulatory Commission
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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. bwever, 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.

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

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