From: <George.Beck@exeloncorp.com>
To: <dja1@nrc.gov>
Date: 04/07/2006 6:31:36 PM
Subject: RAI response 4/7/06 (LRA Section 4.7)

Donnie,

Attached is the response to the March 10, 2006 RAI. (LRA Section 4.7)

The paper copy will be sent to the Document Control Desk.

As we discussed, due to the size of the attachments they are being sent as separate emails.

George

<<RAI response (2130-06-20289).pdf>>

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Subject: RAI response 4/7/06 (LRA Section 4.7)
Creation Date: 04/07/2006 6:31:00 PM
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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20289
April 7, 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: Response to NRC Request for Additional Information, dated March 10, 2006, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)

Reference: "Request for Additional Information for the Review of the Oyster Creek Nuclear Generating Station, License Renewal Application (TAC No. MC7624)," dated March 10, 2006

In the referenced letter, the NRC requested additional information related to Section 4.7 of the Oyster Creek Generating Station License Renewal Application (LRA). Enclosed are the responses to this request for additional information.

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 04-07-2006

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

Enclosure: Response to 03/xx/06 Request for Additional Information

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

A114

Enclosure

Response to 3/10/06 Request for Additional Information
Oyster Creek Generating Station
License Renewal Application (TAC No. MC7624)

RAI 4.7.2-1
RAI 4.7.2-2
RAI 4.7.2-3
RAI 4.7.2-4
RAI 4.7.2-5

RAI 4.7.2-1

Based on the monitoring of the drywell thickness to date, the applicant is requested to provide the following information:

(a) For the drywell corrosion existing during the late 1980s, and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done and the areas considered for identifying the areas of corrosion have been adequate.

(b) Provide a summary of the factors considered in establishing the minimum required drywell thicknesses at various elevations of the drywell.

(c) LRA Reference 4.8-21 discusses pros and cons of various methods of mitigating the drywell shell corrosion. Provide a summary of the actual mitigating actions taken and their effectiveness.

(d) Provide a comparative graph (or chart) showing the drywell thickness based on the assumed corrosion rate and that actually found after the mitigating actions were implemented.

Response:

(a) Oyster creek employed a robust process that establishes confidence in the adequacy of the nature and location of sampling done and the areas considered for identifying the areas of corrosion have been adequate. Elements of the process evolved over several years and were defined in several technical documents submitted to the NRC in 1990 (see attachment 1). A summary of this process is provided below.

Inspections using UT thickness measurements were conducted during refueling outages and outages of opportunity between 1986 and 1989 to establish and characterize the extent of corrosion of the drywell shell. The initial UT measurements were not based on a sampling process. Instead the measurements were taken in areas that correspond to locations where water leakage was observed from the sand bed region drains. The UT measurements were then expanded around the drywell perimeter and vertically to establish locations affected by corrosion. Approximately 1000 ultrasonic (UT) thickness measurements were taken to identify thinnest areas. In addition, core samples of the drywell shell were taken at seven locations, believed to be representative of general wastage, to confirm UT results (Ref. 1). Based on the results of these inspections, elevations 11'-3", 50'-2", and 87'-5" were identified for monitoring. Elevation 11'-3", which corresponds to the sand bed region, showed the highest corrosion rate in 1987 (up to 39.1 +/-3.4 mils per year) based on 1986, and 1987 UT measurements. The high rate of corrosion in the sand bed region prompted corrective action of a physical nature that involved removal of the sand. As a result, corrosion of the drywell shell in the sand bed region was addressed differently than the upper region of the drywell.

Corrosion in the sand bed region

The high rate of corrosion in the sand bed region was attributed to galvanic corrosion of the drywell shell caused by water retained in the sand because of lack of proper drainage. To reduce the corrosion rate, Oyster Creek initiated several corrective actions as described in item (c) below. Evaluation of these corrective actions concluded that the most effective action to reduce corrosion rate is to remove the sand from sand bed region and protect the drywell shell from additional corrosion by applying a protective coating.

Location of the UT measurements was not based on a sampling process. Instead the locations were based on UT measurements taken at all accessible locations that correspond to the sand bed region from inside the drywell to establish the thinnest area. After sand was removed in 1992, and prior to coating the shell, thickness measurements were taken in each of the 10 bays, from outside the drywell, to establish the minimum general and local thickness of the thinned shell. The measurements from inside the drywell showed that the minimum general thickness of the sand bed region is 0.800 inches, and the minimum local thickness is 0.618 inches. The measurements from outside the drywell in the sand bed region showed that the minimum general thickness is generally greater than 0.800 inches. There were local areas where the thickness is less than 0.800 inches. However the minimum average thickness in these areas is greater than 0.736 inches, which is required for satisfying ASME Code requirements. The minimum local thickness measured from outside the sand bed region is 0.603 inches. Considering measurement and instrument accuracies, it is concluded that locations examined from inside the drywell represent the condition of the sand bed region.

The results of these measurements and subsequent analysis, which considered all design basis loads and load combinations, confirmed that the "as found" condition of the drywell shell thickness satisfies ASME Section III minimum thickness requirements. Additional thickness measurements taken at all accessible locations (total of 19) from inside the drywell in 1992, 1994, and 1996 show no corrosion, or no significant corrosion (see Table –2). In addition, inspection of the protective coating on exterior surfaces of the drywell shell in the sand bed region, every other refueling outage, shows no degradation of the coating or the underlying shell.

Corrosion of the upper region, above the sand bed region

Based on the results of approximately 1000 UT measurements, Oyster Creek continued to monitor elevations 50'-2", and 87'-5" in the regions above the sand bed region. A third elevation, 51'-10", was added to the scope of inspection after it was determined that the supplied plate thickness is slightly less than the adjacent 50'-2". For each elevation, UT measurements spaced approximately 1" within a 6"x6" array were taken from inside the drywell around the entire perimeter of each elevation. Engineering evaluation of the UT results concluded that monitoring of 12 locations would represent the drywell shell condition and provide reasonable assurance that significant corrosion would be detected prior to a loss of an intended function. This is because the 12 locations were selected considering the degree of drywell shell thinning and the minimum required thickness to satisfy ASME stress requirements. The locations are, 7 locations 50'-2", 3 locations at

elevation 87'-5", and 2 locations at elevation 51'-10". These locations are inspected from the inside of the drywell shell on a frequency of every other refueling outage.

In response to NRC Staff concern regarding whether the inspected locations represent the condition of the entire drywell, in 1990 GPU prepared a new random UT inspection plan (also known as augmented inspection) designed to address the concern. The plan was based on a non-parametric statistical approach using attribute sampling that assumes no prior knowledge of the distribution of corrosion above the sand bed region. It consisted of random UT testing of 57 plates using the 6"x6" grid. Acceptance criteria are that the mean and local thickness of the shell equals or exceeds the required minimum thickness plus a corrosion allowance necessary in order to reach the next inspection.

Inspection results using the new random inspection plan confirmed that previously monitored locations bound the condition of the drywell above the sand bed region; except one location at elevation 60'-10". This elevation was added to elevations 50'-2", 51'-10", and 87'-5" and monitored on the frequency of every other refueling outage since identified in 1992.

The augmented inspection plan, the original inspection plan, and justification for sampling techniques and statistical methodology were submitted to the NRC on November 26, 1990. In its Safety Evaluation dated November 1, 1995, the Staff noted that the licensee provided a table of UT measurement results from the 15th refueling outage inspection. This table shows the locations of the measurements, the nominal as-constructed thickness, the minimum as-measured thickness, the ASME Code required thickness and the corrosion margin available at the time. The Staff found the current program, based on the submitted information acceptable. The Staff also noted in the Safety Evaluation that since water leaking from the pools above the reactor cavity has been the cause of corrosion, the licensee should make a commitment to the effect that an additional inspection of the drywell will be performed about 3 months after discovery of significant water leakage onto the outside of the drywell shell. Oyster Creek is committed to inspect the drains for leakage during refueling outages and during plant operation. The source of water leakage will be investigated and appropriate corrective actions taken, including an evaluation of the drywell shell to ensure drywell integrity. A review of plant documentation did not provide objective evidence that the commitment has been implemented since 1998. Issue Report #348545 was issued in accordance with Oyster Creek corrective action process to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future.

During a recent walkdown of the torus by the system engineer, water was found in three 5-gallon containers that are installed to collect water leakage from the sand bed drains. Two of the 3 containers were found nearly full. The third container was approximately half full. Inspection of the drain lines shows that the lines are currently dry and that water in the containers is not due to a current water leakage.

The containers are closed such that their overflow is unlikely as confirmed by no water ponding on the floor. Thus it is concluded with reasonable assurance that the volume of

water is limited to what is contained in the containers. This small amount of water is not expected to have significant impact on the drywell shell and on the coating of the shell since the coating is designed for submerged environment. Furthermore, inspection of sand bed region coating conducted in 2004 did not indicate coating degradation or indications of drywell shell corrosion. Similarly, UT examinations on the upper region of the drywell showed a decrease in the corrosion rate since the previous inspection in 2000. Thus, the small volume of water found in the bottles should not have created an environment that would result in significant corrosion to the drywell shell. Issue Report #00470325 was issued, in accordance with Oyster Creek corrective action process, to investigate the source of water and evaluate its impact on the drywell shell.

Based on the discussion above and as indicated in the tables supplied in response to item d) below, Oyster Creek concluded that drywell corrosion is effectively managed both during the current and proposed renewed terms of plant operation. The monitored locations under the current term were subject to extensive UT measurements conducted over several years. NRC Staff found the sampling methodology to identify these locations, and the results of inspections, acceptable for the current term. The same locations will be inspected during the extended period of operation.

In summary Oyster Creek has conducted extensive examinations to identify the cause of drywell corrosion, employed a robust sampling process, quantified with reasonable assurance the extent of drywell shell thinning due to corrosion, and assessed its impact on the drywell structural integrity.

Water intrusion into the gap between the drywell shell and the drywell shield wall was identified as the cause for corrosion. Corrective actions have been taken to mitigate corrosion in the sand bed region and in the upper region of the drywell. Corrosion of the drywell shell in the sand bed region has been arrested. These actions also have effectively reduced the rate of corrosion to a negligible amount in the upper region as demonstrated by UT thickness measurements (see Table-1, and Table-2). Oyster Creek and its consultants performed stress and buckling analyses considering all design basis loads and load combinations. The results of these analyses indicate that buckling controls the minimum drywell shell thicknesses in the sand bed region while areas above the sand bed region are controlled by accident pressure membrane stresses. In both cases, the minimum measured drywell shell thickness satisfies ASME Section III requirements.

(b) The factors considered in establishing the minimum required drywell thickness at various elevations of the drywell are described in detail in engineering analyses documented in two GE Reports, Index No. 9-1, 9-2, and 9-3, 9-4. Report Index No. 9-1, 9-2 was generated for the drywell condition with sand in the sand bed region and Report Index No. 9-3, 9-4 is for the drywell condition without sand in the sand bed region (see Attachment 2 &3) The two reports were transmitted to the NRC Staff in December 1990 and in 1991 respectively. Report Index No. 9-3, 9-4 was revised later to correct errors identified during an internal audit and was resubmitted to the Staff in January 1992. Analysis described in Report Index No. 9-3, 9-4 (i.e., without sand) is the current applicable analysis to the drywell.

The analysis is based on the original Code of record, ASME Code, Section VIII, and Code Cases 1270N-5, 1271, and 1272N-5. The Code and the Code Cases do not provide specific guidance in two areas. The first relates to the size of a region of increased membrane stress due to thickness reductions from local or general corrosion effects, and the second pertains to the allowable stresses for Service Level C or post-accident conditions. In the first case, guidance was sought from ASME Section III, NE-3213.10. For Service Level C or post-accident conditions, the Standard Review Plan was used as guidance to develop the allowable stresses.

The analysis is based on a 36-degrees section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the vent bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis considered drywell geometry and materials, thickness reduction from corrosion, test loads, normal operating loads, design basis accident loads, seismic loads, refueling loads, and design basis load combinations. Pressure and temperature were in accordance with approved Technical Specification Amendment No. 165, which established a revised design bases accident pressure of 44 psig and accident temperature of 292°F. The results of the analysis show that the minimum required ASME Code thickness of the drywell shell above the sand bed region is controlled by membrane stresses and the minimum drywell shell thickness in the sand bed region is controlled by buckling. The minimum required ASME Code thicknesses above the sand bed region are shown in Table-1.

For the sand bed region, the analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches. This thickness satisfies ASME Code requirements and considered the minimum required thickness.

As described above, the buckling analysis was performed assuming a uniform general thickness of the sand bed region of 0.736 inches. However the UT measurements identified isolated, localized areas where the drywell shell thickness is less than 0.736 inches. Acceptance for these areas was based on engineering calculation C-1302-187-5320-024.

The calculation uses a Local Wall Acceptance Criteria". This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick so long as the small 12" by 12" area is at least 0.536" thick. However the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, the minimum required linear distances between a 12" by 12" area thinner than 0.736" but thicker than 0.536" and another 12" by 12" area thinner than 0.736" but thicker than 0.536" were not provided.

The actual data for two bays (13 and 1) shows that there are more than one 12" by 12" areas thinner than 0.736" but thicker than 0.536". Also the actual data for two bays shows that there are more than one 2 ½'" diameter areas thinner than 0.736" but thicker

than 0.490". Acceptance is based on the following evaluation.

The effect of these very local wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load.

To begin the discussion we will describe the buckling of a simply supported cylindrical shell under the influence of lateral pressure and axial load. As described in chapter 11 of the Theory of Elastic Stability, Second Edition, by Timoshenko and Gere, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin walled cylindrical shell both the length and radius would be essentially constants and if the thickness was changed locally the change would have to be significant and continuous over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This approach can be easily extrapolated to any shell of revolution that would experience both an axial load and lateral pressure as in the case of the drywell. This local lobe buckling is demonstrated in The GE Letter Report "Sandbed Local Thinning and Raising the Fixity Height Analysis" where a 12 x 12 square inch section of the drywell sand bed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell. Therefore, to influence the buckling of a shell the very local areas of reduced thickness would have to be contiguous and of the same thickness. This is also consistent with Code Case 284 in Section –1700 which indicates that the average stress values in the shell should be used for calculating the buckling stress. Therefore, an acceptable distance between areas of reduced thickness is not required for an acceptable buckling analysis except that the area of reduced thickness is small enough not to influence a buckling lobe of the shell. The very local areas of thickness are dispersed over a wide area with varying thickness and as such will have a negligible effect on the buckling response of the drywell. In addition, these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region which is located at the midpoint between two vents.

The acceptance criteria for the thickness of 0.49 inches confined to an area less than 2½ inches in diameter experiencing primary membrane + bending stresses is based on ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE-3213.2 and NE-3213.10. In particular NE-3213.10 limits the meridional distance between openings without reinforcement to 2.5 x (square root of Rt) . Also Paragraph NE-3335.1 only applies to openings in shells that are closer than two times their average diameter.

The implications of these paragraphs are that shell failures at these locations from primary stresses produced by pressure cannot occur provided openings in shells have sufficient reinforcement. The current design pressure of 44 psig for drywell requires a

thickness of 0.479 inches in the sand bed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sand bed region exceed the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph are not required for the very local wall thickness evaluation presented in Revision 0 of Calculation C-1302-187-5320-024.

Reviewing the stability analyses provided in both the GE Report 9-4 and the GE Letter Report Sand bed Local Thinning and Raising the Fixity Height Analysis and recognizing that the plate elements in the sand bed region of the model are 3" x 3" it is clear that the circumferential buckling lobes for the drywell are substantially larger than the 2 ½ inch diameter very local wall areas. This combined with the local reinforcement surrounding these local areas indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from the GE Letter Report that a uniform reduction in thickness of 27% to 0.536" over a one square foot area would only create a 9.5% reduction in the load factor and theoretical buckling stress for the whole drywell resulting in the largest reduction possible. In addition, to the reported result for the 27% reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5% over a one square foot area which only reduced the load factor and theoretical buckling stress by 3.5% for the whole drywell resulting in the largest reduction possible. To bring these results into perspective a review of the NDE reports indicate there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch thickness used in GE Report 9-4 which cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Therefore, to effectively change the buckling margins on the drywell shell in the sand bed region a reduced thickness would have to cover approximately one square foot of shell area at a location in the shell that is most susceptible to buckling with a reduction in thickness greater than 25%. This leads to the conclusion that the buckling of the shell is unaffected by the distance between the very local wall thicknesses, in fact these local areas could be contiguous provided their total area did not exceed one square foot and their average thickness was greater than the thickness analyzed in the GE Letter Report and provided the methodology of Code Case N284 was employed to determine the allowable buckling load for the drywell. Furthermore, all of these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffing effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

In summary the minimum required drywell shell thickness is based on analysis conducted in accordance with ASME Code. Factors considered include drywell geometry, material of construction, reduced wall thickness due to corrosion, and applicable design basis loads and load combinations. Accident pressure and temperature are 44 psig and 292°F respectively in accordance with approved Technical Specification Amendment No. 165.

The minimum required thicknesses of the drywell shell above the sand bed region, shown in Table-1, are controlled by membrane stresses. The minimum required general drywell shell thickness in the sand bed region of 0.736" is controlled by buckling. Localized areas in the sand bed region where the thickness is less than 0.736" are evaluated against a local thickness acceptance criteria (0.49") developed based on

ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. Application of these Code Sections is justified as discussed above and specific buckling sensitivity analysis results support the conclusion that, on an average wall thickness basis, buckling of the shell is unaffected by local wall thickness areas as these are distributed over the sand bed region.

(c) The mitigating actions taken to address drywell corrosion include,

- Cleared the former sand bed region drains to improve drainage
- Replaced reactor cavity steel trough drain gasket, which was found to be leaking (see Fig. 1 & Fig.-2).
- Removed water from the sand bed region
- Installed a cathodic protection system in bays with greatest wall thinning in early 1989. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and was removed from service in 1992
- Removed sand in the sand bed region to break up the galvanic cell
- Removed corrosion products from the external side of the shell in the sand bed region
- Upon sand removal, the sand bed concrete floor was found cratered and unfinished. The concrete floor was repaired, finished and coated to permit proper drainage of the sand bed region.
- Applied a silicone seal at the juncture of the drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the embedded drywell shell in concrete.
- Applied a multi-layered epoxy protective coating to the exterior surfaces of the drywell shell in the sand bed region (*i.e.*, one pre-primer coat, and two top coats).
- Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner. This I limits water intrusion into the gap between the drywell shell and the drywell shield wall.
- Confirmed that the reactor cavity concrete trough drains are not clogged (see fig – 2

These mitigating features have been in place since 1992[1]. The most effective feature is the removal of sand in the sand bed region to break up the galvanic cell, which significantly reduced the rate of corrosion in that region. The sand bed region coating is effective because it is protecting the underlying drywell shell from ongoing corrosion as confirmed by comparison of UT measurements taken in 1992, 1994, and 1996 (see Table-2 below). The other features, except for cathodic protection, are also effective

1 Note: The strippable coating of the reactor cavity wall was not applied during 1994 and 1996 refueling outages.

because their implementation limited water intrusion into the gap between the drywell shell and the drywell shield wall thus reducing the rate of corrosion in the upper region of the drywell. A comparison of UT measurements taken in 1992, 1994, 1996, 2000, and 2004 on the upper region of the drywell shell shows that either the corrosion is no longer occurring, or negligible considering UT instruments accuracy (see Table-1 below).

As stated previously the cathodic protection system was installed in bays with greatest wall thinning in early 1989. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and removed from service in 1992.

(d) The following tables provide historical UT thickness measurements, the minimum required thickness, and the nominal thickness of the drywell shell.

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 Lower 95% Confidence Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993[3]	1994	1996	2000	2004	
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	No 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	0.738
	Bay 5–5L					0.706 0.703	0.703 0.705 0.706	0.703 0.707		0.702	0.705	0.706	0.701	No 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	No 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	No 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	0.738
	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	No Ongoing Corrosion

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 Lower 95% Confidence Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	
Elevation 51' 10"		0.541"												
	Bay 13–32H					0.716	0.715 0.715 0.720	0.717 0.717		0.714	0.715	0.715	0.713	No 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	No Ongoing Corrosion
Elevation 60' 10"		0.518"												
	Bay 1–50-22								0.693	0.711	0.693	0.689	0.689	No 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	0.604.
	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	No 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	0.615

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.

Conclusion:

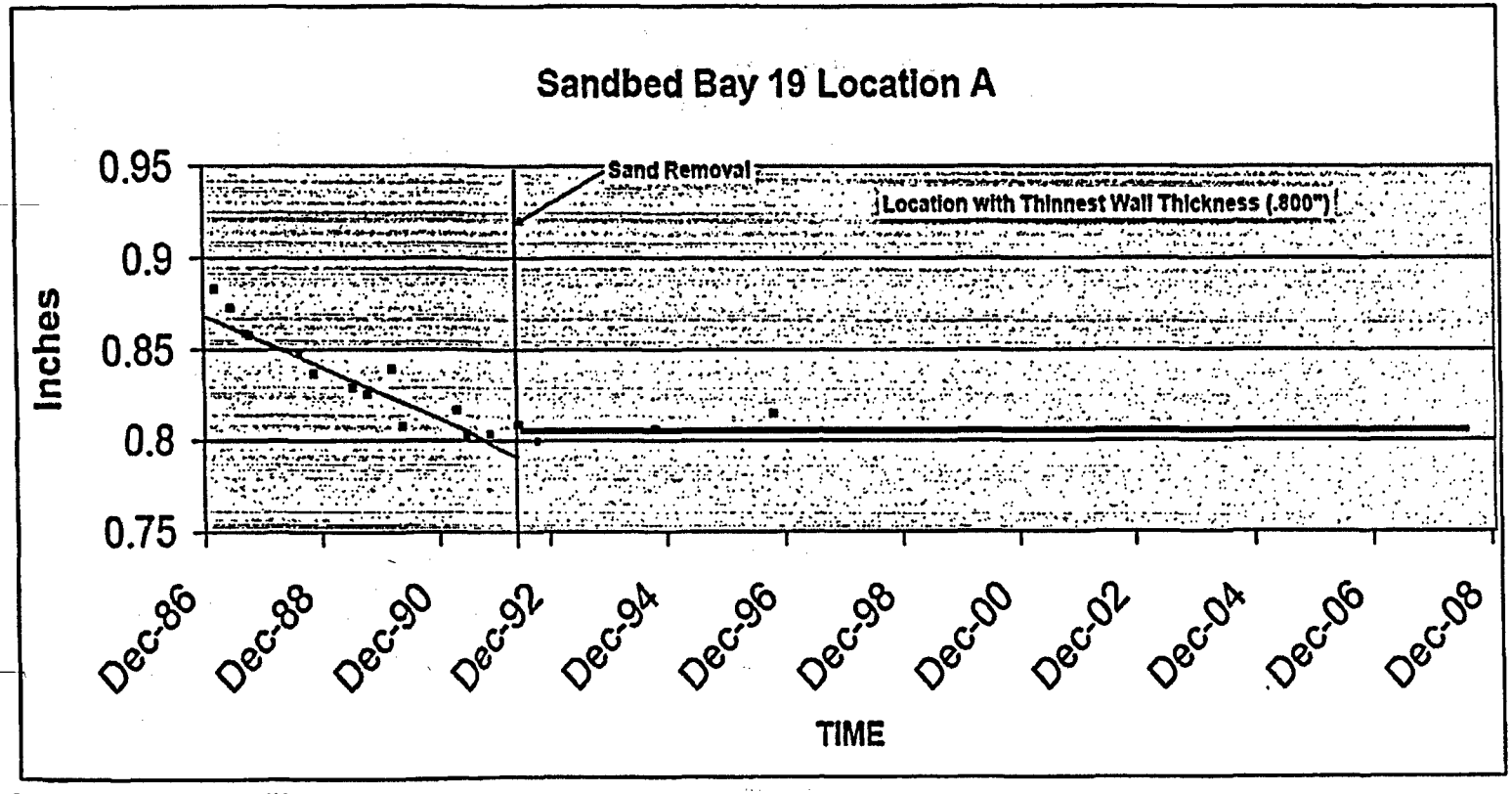
Summary of Corrosion Rates of UT measurements taken through year 2004

- There is no ongoing corrosion at two elevations (51' 10" and 60' 10")
- Based on statistical analysis, one location at elevation 50' 2" is undergoing a minor corrosion rate of 0.0003 inches per year,
- Based on statistical analysis, two locations at elevation 87' 5" are undergoing minor corrosion rates of 0.0005 and 0.00075 inches 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
1D									1.115										1.101	1.1514
3D									1.178										1.184	1.181
5D									1.174										1.168	1.173
7D									1.135										1.136	1.138
9A									1.155										1.157	1.155
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
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
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
	Top				1.046	1.109	1.079	1.045	1.009	1.016	1.005	0.952	0.977	0.982	1.018	0.964	1.010	0.970	0.984	1.042
13A		0.919							0.905	0.883	0.883	0.862	0.853	0.855	0.853	0.849	0.865	0.858	0.828	0.843
13C	Bottom													0.909	0.901	0.900	0.931	0.906	0.895	0.933
	Top													1.072	1.049	1.048	1.088	1.055	1.037	1.059
13D									0.962				0.932					1.001	0.959	0.990
15A									1.120										1.114	1.127
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
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
	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
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	0.845
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
	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
19A			0.884		0.873	0.859	0.858	0.849	0.837	0.829	0.825	0.840	0.808	0.817	0.803	0.803	0.809	0.800	0.806	0.815
19B					0.898	0.892	0.888	0.864	0.857	0.826	0.845	0.812	0.837	0.853	0.844	0.846	0.847	0.840	0.824	0.837
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	0.848

Fig. – 3 Corrosion Trend in Sand Bed Region Bay with highest Drywell Shell Wall Thinning



Based on Calculation C-1302-187-5300-021

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.015	0.7911	05/01/92	0.8071	1.154"	0.736"

Dates	Dec-86	Feb-87	Apr-87	May-87	Aug-87	Sep-87	Jul-88	Oct-88	Jun-89	Sep-89	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
19A		0.88364		0.87293	0.8586	0.8529	0.8486	0.8369	0.8288	0.8254	0.8399	0.8076	0.8167	0.8028	0.8032	0.8091	0.8002	0.806	0.815

RAI 4.7.2-2

A number of Mark I containments have experienced corrosion inside their drywells at the junction of the bottom concrete floor and the steel shell. The applicant is requested to provide information regarding corrosion of the drywell shell at this location or any other location of the drywell inside surfaces.

Response:

Oyster Creek has not experienced corrosion on the inside surfaces of the drywell shell including the junction of the bottom concrete floor and the steel shell. The inside of the drywell is coated with Carbo-Zink 11 over an SSPC-SP6/SP5, commercial abrasive blast surface preparation to a dry film thickness of 3-6 mils]

Visual inspections conducted in accordance with ASME Section XI, Subsection IWE have not identified recordable corrosion at the junction of the bottom concrete floor and the steel shell or any other location inside the drywell. Minor surface rust has been noted in some areas where the coating is damaged or removed for UT measurements. The minor surface rust is limited to isolated areas and does not impact the intended function of the drywell.

RAI 4.7.2-3

Leakage from the refueling seal has been identified as one of the reasons for accumulation of water and contamination of the sand-pocket area. The refueling water passes through the gap between the shield concrete and the drywell shell in the long length of inaccessible areas. As there is a potential for corrosion in this area, Subsection IWE of the ASME code would require augmented inspection of this area. The applicant is requested to provide a summary of inspections performed (visual and NDE) and mitigating actions taken to prevent water leaks from the refueling seal components.

Response:

The refueling seals at Oyster Creek consist of stainless steel bellows. In mid to late 1980's GPU conducted extensive visual and NDE inspections to determine the source of water intrusion into the seismic gap between the drywell concrete shield wall and the drywell shell, and its accumulation in the sand bed region. The inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested using helium (external) and air (internal) without any indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in a concrete trough below the bellows. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the seismic gap (see Fig.-2). The drain line has been checked before refueling outages to confirm it is not blocked.

The only other seal is the gasket for the reactor cavity steel trough drain line (see Fig.-2). This gasket was replaced after the tests showed that it was leaking (see Fig. –2). However the gasket leak was ruled out as the primary source of water observed in the sand bed drains

because there is no clear leakage path to the seismic gap. Minor gasket leak would be collected in the concrete trough below the gasket and would be removed by the drain line similar to leaks from the refueling bellows.

Additional visual and NDE (dye penetrant) inspections on the reactor cavity stainless steel liner identified significant number of cracks, some of which were through wall cracks. Engineering analysis concluded that the cracks were most probably caused by mechanical impact or thermal fatigue and not interagranular stress corrosion cracking (IGSCC). These cracks were determined to be the source of refueling water that passes through the seismic gap. To prevent leakage through the cracks, GPU installed an adhesive type stainless steel tape to bridge any observed large cracks, and subsequently applied the strippable coating. This repair successfully greatly reduced leakage and is implemented every refueling outage while the reactor cavity is flooded.

Oyster Creek is currently committed to monitor the sand bed region drains for water leakage. A review of plant documentation did not provide objective evidence that the commitment has been implemented since 1998. Issue Report #348545 was issued in accordance with Oyster Creek corrective action process to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future, including during the period of extended operation.

Oyster Creek is committed to performing augmented inspections of the drywell in accordance with ASME Section XI, Subsection IWE. These inspections consist of UT examinations of the upper region of the drywell and visual examination of the protective coating on the exterior of the drywell shell in the sand bed region. The visual inspection of the coating will be supplemented by UT measurements from inside the drywell once prior to entering the period of operation, and every 10 years thereafter during the period of extended operation. With regards to previously performed visual and NDE inspections, refer to RAI 4.7.2-1(a).

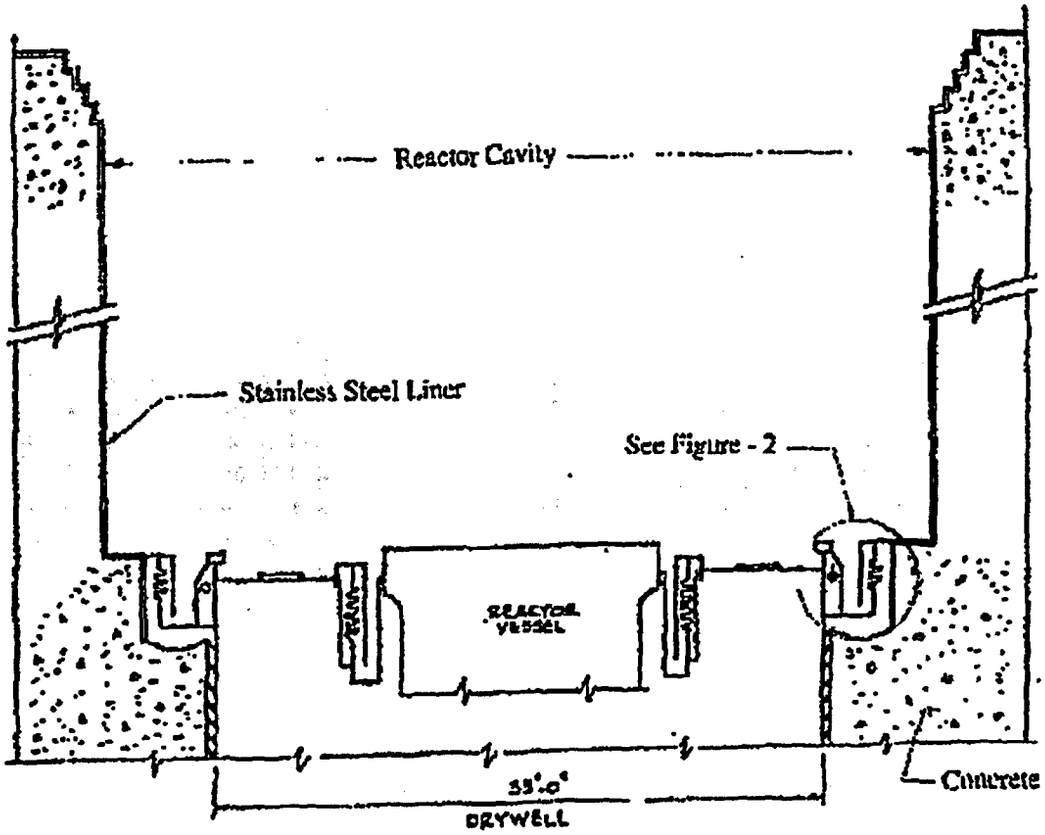


Figure 1 - Drywell and Reactor Cavity Section

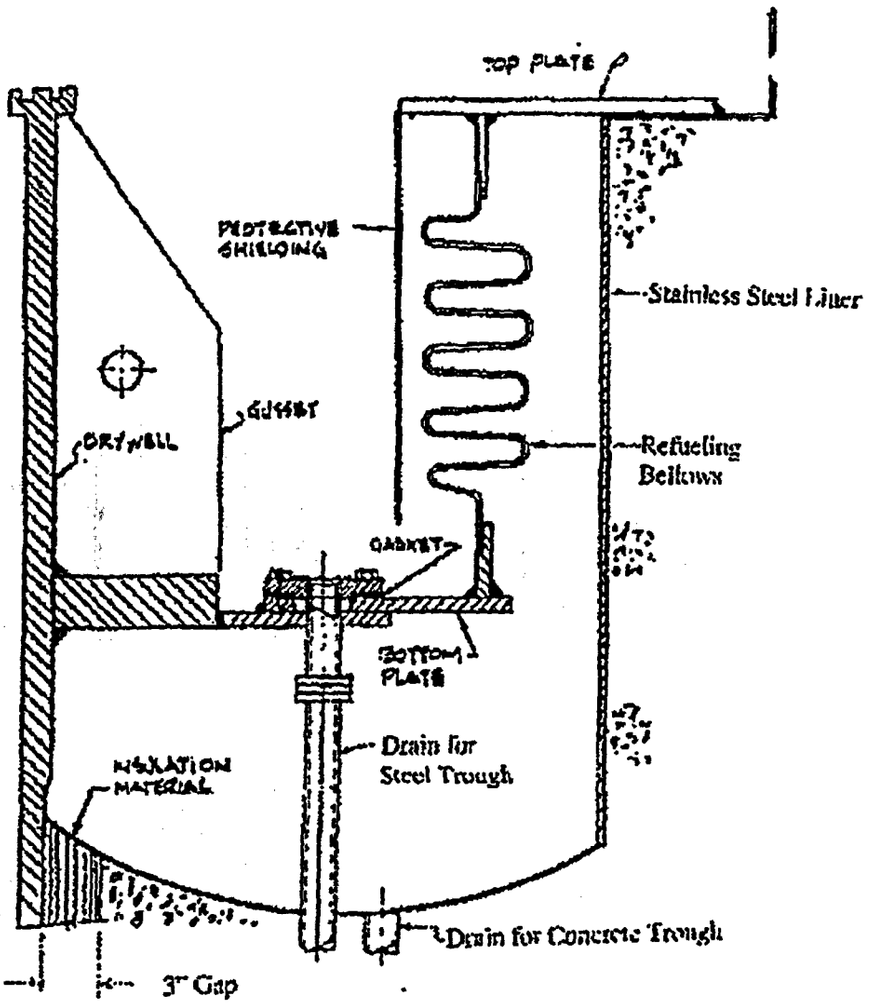


Figure 2 - Drywell to Reactor Cavity Seal Detail

RAI 4.7.2-4

Industry wide operating experience indicated a number of incidences of torus corrosion in Mark I containments. Neither LRA Table 3.5.2.1.1 nor AMP B.1.27 describes operating experience related to corrosion of the torus. The staff request the applicant to provide a summary of the results of IWE inspections performed on the torus, and a description of torus condition.

Response:

A review of industry operating experience has confirmed that corrosion has occurred in containment shells. NRC Information Notice (INs) 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. A review of plant operating experience at Oyster Creek shows that corrosion degradation has occurred in the suppression chamber (torus) and vent system. The Oyster Creek ASME Section XI, Subsection IWE aging management program, and the Protective Coating Monitoring and Maintenance Program, have identified and are managing the degradation.

Background/Chronology:

The Oyster Creek torus was designed without a corrosion allowance (0.385" nominal thickness). Prior to construction of the torus, the carbon steel segments were given a shop coat of red lead primer and transported to the site. After assembly, the structure was touched up with a red lead primer coating and a phenolic epoxy "belly-band" coating was applied at the liquid-vapor interface. Inspections of the torus interior from original startup through 1977 showed that the red lead primer on the torus shell in the vapor space region was in satisfactory condition. However, inspections conducted during the 7th refueling outage (1977) showed extensive pinpoint rusting under the red lead primer in the area above the epoxy belly-band coating. Pitting of local areas was also observed below the epoxy belly-band coating. In both cases, the corrosion was attributed to contaminants in the torus water. The pinpoint rusting above the epoxy coating was the result of an actual water/vapor interface located above the belly-band. This was corrected by broadening the belly-band coating by 10 inches. The identified pitting was weld repaired and a fresh coat of red lead primer was applied where needed.

As a result of the 1977 inspection, it was determined that the red lead primer coating had a limited ability to protect the carbon steel against corrosion attack. In addition to the lead primer, sodium chromate had been utilized in the torus water as a corrosion inhibitor. In a 1981 report prepared by the GPU Nuclear Materials Technology Section, it was recommended that all torus water impurities, including chromates due to the uncertainty of their behavior on reactor core austenitic steels following a safety injection, be removed and an epoxy coating be applied to the immersion and vapor phase regions of the torus to mitigate corrosion.

During the 10th refueling outage (1983-84), Mark I Containment modifications were made to the Oyster Creek Torus. During this outage, the torus interior surfaces, the interior of the vent system up to the drywell and all external surfaces of the vent system were grit blasted to SSPC-10 or SSPC-5 at 1 1/2 - 3 mils profile. Inspections revealed pitting corrosion on the inside surface of the torus shell below the waterline. No visible corrosion was observed on the portion

of the shell above the waterline. The corroded areas and depths of corrosion were documented for each bay. Repair criteria were developed to provide margin based on Mark I program stress analysis results. No credit was taken for other potential sources of margin (e.g., actual material properties of the plate, actual plate thickness, and permissible ASME Code undertolerance on plate thickness). A repair criterion based on acceptable metal loss due to pitting corrosion was established. Weld repair was performed if the average effective metal loss due to pitting corrosion exceeded these depths. Thus, these metal losses represent the maximum allowable metal loss that may have been left in the torus shell following the 1983 inspections and repairs:

Torus Shell Region	Acceptable Metal Loss Due to Pitting Corrosion (inch)
General Shell	0.040
Within 1" of Ring Girder	0.050
1"-8" Away from Ring Girder	0.080
Within 1" of Saddle Weld	0.035
1"-8" Away from Saddle Weld	0.090

Pitted surfaces of the immersed torus shell requiring repair were repaired by weld overlay. Pitted surfaces where repair was not required were filled with Mobil 46-X-16 Epoxy prior to recoating. Surfaces in the vent system thinned by corrosion were repaired by weld overlay. Rough areas of the torus shell were blended by grinding. The immersion portion of the torus shell, the interior of the downcomer and the entire interior surfaces of the vent system were given 3 coats of Mobil 78 Hi-Build Epoxy (DFT-16 mils). The vapor phase portion of the torus shell, exterior of the vent header and vent lines portions inside the torus were given two coats of Mobil 78-Hi Build epoxy (DFT-10 mils). Following coating application, the entire torus interior was heat cured at 108°F for 48 hours. Demineralized water was put back in the torus. No coating was applied to the exterior surface of the torus shell at that time.

During the 11th refueling outage (1986), a Material Nonconformance Report (MNCR 86-285) identified general corrosion on the outside surface of the torus shell. Wall thickness measurements were taken to determine the metal loss due to the observed corrosion. The corrosion was categorized as uniform and superficial with no evidence of rust scale. No appreciable metal loss was associated with this condition (i.e., the loss was estimated to be no more than 2 mils). Also in 1986, analysis MPR-953, "Torus Shell Thickness Margin" was performed to determine a corrosion allowance for the torus shell based on the as-left condition of the torus following the 1983 shell repairs. The scope of the analyses included:

- Review of Mark I containment torus stress analysis results to determine the minimum thickness for which the torus shell would meet ASME Code allowable stress values. This included formally documenting the analyses and corrosion allowance criteria used.

- Review of manufacturers' material certificates to determine actual plate thickness and strength.

- Determination of underthickness tolerance permitted by the ASME Code.

- Review of the 1983 GPUN torus inspection reports to determine the maximum

depths of pitting corrosion which were not weld repaired.

Torus shell thickness margins were determined based on calculated stresses, actual material properties, actual plate thicknesses, and ASME Code permitted undertolerance. It was concluded that the calculated stress margin alone exceeded the maximum corrosion depth left in the torus shell for all regions of the torus and that the difference between the stress margin and maximum corrosion depth could be considered a corrosion allowance. The following table summarizes the results of the analysis.

Torus Shell Location	Thickness Margin Based on Mark I Program Stress Requirements (inch)	Material Property Margin (inch)	Plate Thickness Margin (inch)	ASME Code Undertolerance (inch)	Maximum Depth of Corrosion Left in Torus Shell After 1983 Repairs (inch)
General Shell	0.060	0.013	0	0.010	0.040
Within 1" of SRV Supporting Ring Girders	0.061	0.013	0	0.010	0.050
Within 1" of Non-SRV Supporting Ring Girders	0.079	0.013	0	0.010	0.050
Between 1"-8" Away From All Ring Girders	0.103	0.013	0	0.010	0.040
Within 1" of Saddle Flange	0.060	0.013	0	0.010	0.035
Between 1"-8" Away From Saddle Flange	0.151	0.013	0	0.010	0.040
Within 1" of Torus Straps	0.057	0.013	0	0.010	0.040
Remaining Portion of Shell Between Torus Straps	0.060	0.013	0	0.010	0.040

In 1988, a coating system consisting of two (2) coats was applied to the outside surface of the torus shell. The first coat was a penetrating primer (1-1/2 to 2 mils DFT) designed to impregnate and tie up loose rust (Devoe-Napko Pre-Pime 467 Rust Penetrating Sealer No. 467-K-9920). The second coat was Chemfast 100 primer (3 to 10 mils DFT) manufactured by Devoe-Napko Corporation.

To assure coating integrity, periodic inspections of the torus interior have been performed since the coating was first applied in 1983. A review of past inspections of the torus shell and the vent system indicates that the majority of the problems found have been attributed to blistering of the coating and localized pitting. The following provides an "Executive" level summary of the results of these inspections:

- 11th refueling outage (1986): The inspection consisted of a visual examination of the vapor space region and shell surface at the water line. No coating damage or evidence of corrosion was observed.

- 12th refueling outage (1988-1989): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. The coating in the vapor space was in excellent shape. No tests were performed to quantify the condition of the coating in this area. The inspection focused on the immersion region using divers qualified to perform detailed coating and corrosion assessment. The inspection revealed a blistering condition in the coating at the torus invert and areas of minor mechanical damage. It was determined that the blistering condition occurred where the 46-X-16 epoxy filler had been used to fill pits that did not require weld repair prior to torus coating in 1983. These blisters were observed on all the 20 bays to a varying degree. It was suspected that the 46-X-16 material never achieved full cure and was softened by immersion in the torus and by reaction with the solvents contained in the Mobil 78 topcoats.

  The three most severely blistered bays (bays 6, 7, and 9) were identified for future inspections. Three one foot square test patches were established in bays 6 and 7. The test patches were outlined with the Brutem 15 repair coating. The size and degree of frequency of the blisters within each test patch were recorded as a baseline for comparison against future inspection results.

  Adhesion tests using a vacuum box were conducted on blisters, and elcomèter (an instrument used to measure coating adhesion in psi) and putty knife adhesion tests were conducted on the unblemished coating. Results were evaluated and maintained for future comparison.

  Corrosion attack under nonfractured blisters was minimal and limited to surface discoloration. A portion of the fractured blisters examined exhibited small (less than 1/32" dia.) pits on the substrate. Loss of base metal in the affected areas was no greater than 0.002". One area inspected in bay 5 revealed deep pitting in the range of 15 to 50 mils in depth. However, the general condition of the steel did not show signs of recent corrosion. The steel surface was shiny with evidence of the previous surface prep observable. Some of the deepest pits held residue of the 46-X-16 epoxy filler. It was concluded that the pitting observed was documented and coated over during the coating operation in 1984. Fractured blisters exposing substrate were repaired using Brutem 15.

  Four (4) UT shell thickness readings were taken adjacent to a 0.058" pit located in bay 10. The minimum shell thickness recorded was 0.387".

Minor mechanical damage (e.g., abrasion) was also observed. Areas exhibiting pitting were limited to mechanical damage that completely exposed the substrate. These areas were repaired using Brutem 15. The maximum pit depth measured at the areas of mechanical damage was 30 mils.

- 13th refueling outage (1991): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. The objective of the inspection was to assess the coating condition by repeating the same series of tests performed in bays 6, 7, and 9 during the 12th refueling outage. The three one foot square test patches in bays 6 and 7 were also inspected. The inspection was expanded to include visual examination of the vent header system and inspection of blistered coating near the torus invert in bays 5, 10, and 11.

  All the adhesion tests conducted in the12th refueling outage were repeated to allow for direct correlation between the two sets of data. It was concluded that the adhesion qualities measured in the 12th refueling outage did not change.

  The blistered condition found in the 12th refueling outage was stable (blister count data of the test patches indicated no significant change had occurred between the 12th and 13th refueling outages). The inspection of the substrate under intact blisters after removal of the blister cap identified slight discoloration and pitting with pit depths of less than 0.001". Light wire brushing by hand easily removed the magnetite deposit leaving bright metal prior to coating repair. Visual observations and pit depth measurements indicated that corrosion underneath broken blisters was also minimal. The substrate beneath fractured blisters exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

  Pit depth readings and/or ultrasonic thickness measurements were taken in bays 5, 6, 7, 9, 10, and 11. No pitting in excess of 0.030" was identified in bays 9, 10, and 11. Several pits in the range of 0.010" to 0.041" were observed in bay 5. UT shell thickness readings taken in bay 5 near pitted areas ranged from 0.390" to 0.400". Several pits in the range of 0.003" to 0.050" were observed in bay 6. UT shell thickness readings taken in bay 6 near pitted areas ranged from 0.380" to 0.400". Several pits in the range of 0.014" to 0.035" were observed in bay 7. UT shell thickness readings taken in bay 7 near pitted areas ranged from 0.400" to 0.420". It was noted that the deepest pits in these bays held residue of 46-X-16 indicating that these pits were evaluated as acceptable and coated over as part of the torus coating effort in 1984.

  In the vent header system, the general condition of the coating appeared good. Blistering, pinpoint rusting, and mechanical damage to the coating was minimal. Visual observation and pit depth measurements showed minor pitting corrosion (less than 0.010") on substrate in the immersion area. Blister caps were removed from sample intact blisters in the immersion area. The exposed substrate exhibited no sign of corrosion attack.

  The coating areas repaired with underwater epoxy (Brutem 15) during the previous (12th) refueling outage appeared in excellent condition.

- 14th refueling outage (1992-1993): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. Inspections were performed in the immersion portion of torus bays 1 through 10, in the torus vapor space, and in the vent header to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. Inspection activities included qualitative visual inspection of the submerged portion of the torus in all ten bays, and, in the vapor region and vent header to document the location and extent of coating defects and resultant corrosion. Qualitative inspections included the evaluation of blisters. Inspection activities also involved quantitative inspections including depth measurements of pitting corrosion in selected bays, the evaluation of test patches established during the 12th refueling outage, vacuum box testing of areas, peel tests, adhesion tests, and removal of blister caps with the evaluation of substrate.

  In the immersion region of the torus, blister count and quantity of fractured blisters had "moderately" increased. Coating adhesion and integrity were comparable to previous inspections. The removal of intact blister caps indicated that the coating system was still providing an effective corrosion barrier. A total of three quantitative pit depth measurements were taken. Three pits were identified with total metal loss values of 0.0215 (bay 6), 0.0325 (bay 7), and 0.0685 (bay 2) inches. Wall thickness measurements immediately adjacent to these areas revealed adequate remaining wall thickness (0.38" to 0.40"), which indicated that these areas are extremely localized in nature. All pits were repaired using UT #15 epoxy coating.

  In the vapor region, no blistering or pitting corrosion was identified. In the vent header, the majority of the blisters identified were in the lower areas of the caps at the intersection of the vent header and vent line where water was present. Defects identified were minor in nature and distribution.

The above summary of inspections performed through the 14th refueling outage was provided to the NRC in a revised response to an RAI associated with TSCR No. 216 (Technical Specification Change Request to increase the Electromagnetic Relief Valves (EMRV) setpoints). In that response, GPUN concluded that, based on the coating inspections performed to date, "the torus shell thickness is virtually unchanged since the repair and coating effort in 1983." Additionally, no new pitting or general corrosion was found during the subsequent inspections performed since 1983, and, data collected to date provided a high confidence level that the coating material was adequately adhering to the shell and providing corrosion protection. In the NRC SER related to Amendment No. 177, the staff found the explanations provided to be acceptable provided GPUN continue its coatings monitoring and maintenance program.

GPUN's 1994 submittal of TSCR No. 216 to increase the setpoint values of the EMRVs required an evaluation of the torus shell for the consequent increase in the EMRV loads. This evaluation revised the Mark I thickness margin due to the increase in EMRV loads. The following table summarizes the results of the reanalysis.

Torus Shell Location	Thickness Margin Based on Mark I Program Stress Requirements (inch)	Revised Mark I Thickness Margin Due to Increase in EMRV Loads (inch)
General Shell	0.060	0.047
Within 1" of SRV Supporting Ring Girders	0.061	0.048
Within 1" of Non-SRV Supporting Ring Girders	0.079	0.067
Between 1"-8" Away From All Ring Girders	0.103	0.092
Within 1" of Saddle Flange	0.060	0.047
Between 1"-8" Away From Saddle Flange	0.151	0.142
Within 1" of Torus Straps	0.057	0.044
Remaining Portion of Shell Between Torus Straps	0.060	0.047

- 15th refueling outage (1994): No underwater coating inspections performed.

- 16th refueling outage (1996): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. A detailed qualitative inspection of the torus shell and internals was performed in bays 6, 7, 9 and 11 through 20 to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. Overall, no significant failure or problems concerning the integrity of the coating system in the immersion region were identified. Coating defects identified included blistering, rust stains, isolated areas of pinpoint rusting and mechanical damage of the coating. Immersion region coating repairs were performed as required using UT #15 epoxy coating.

  Inspection activities in the immersion region also involved quantitative inspections including the evaluation of test patches established during the 12th refueling outage, vacuum box testing, peel tests, adhesion tests (also performed for vapor space region), and removal of blister caps with the evaluation of substrate. Blister count and quantity of fractured blisters had moderately increased. Coating system adhesion and integrity were comparable to previous inspections. Removal of blister caps indicated the coating system was still providing an effective corrosion barrier. There were no areas of pitting corrosion identified. UT wall thickness measurements taken in bay 6 indicated that the measured thickness of 0.394 to 0.404" exceeded the nominal thickness of 0.385".

  Inspections performed in the vent header and vapor space region of the torus yielded no significant findings. Coating defects identified included blistering (vent header only), rust stains, isolated areas of pinpoint rusting and mechanical damage of the coating. Minor coating repair was performed in the vent header and at adhesion test areas of the vapor space region.

Repairs made with Brutem-15 and UT#15 during previous outages continued to perform well with no indications of failure or weakness. No rework was required on previous repair areas.

Based on the results of the inspections performed during the outage and comparison to previous outage findings, it was concluded that periodic maintenance using underwater coating inspection and repairs was providing proper and adequate protection to the torus coating system.

- 17th refueling outage (1998): Inspection was performed by Underwater Engineering Services, Inc., a wholly owned subsidiary of S. G. Pinney & Associates, Inc.. Outage scope included ECCS pump suction strainer replacement. A qualitative visual inspection of the torus shell was performed in all 20 bays to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. As reported during previous inspections, dense blistering was present on the lower pressure boundary invert. It was noted that little growth in the size or population density of the blisters had occurred over the past 10 years. Broken blisters were the most commonly occurring coating deficiency identified which resulted in corrosion. A total of 223 broken blisters were found throughout the immersion area (mostly attributed to underwater radiation survey probes used during ECCS suction strainer replacement activities). Areas of minor mechanical damage were also identified. There were no areas of pitting corrosion identified. Underwater coating repairs using UT#15 epoxy coating were performed on 100% of the coating deficiencies that resulted in corrosion on the torus shell immersion area.

  Based on the results of the inspections performed during the outage and comparison to previous outage findings, it was concluded that periodic maintenance using underwater coating inspection and repairs was providing proper and adequate protection to the torus coating system.

- 18th refueling outage (2000): No underwater coating inspections performed.

- 19th refueling outage (2002): Inspection was performed by Underwater Construction Corporation. A qualitative visual inspection of the immersed torus shell, torus vapor space, and vent header was performed in all bays to assess the condition of the coating and to identify any significant deficiencies or changes since previous inspections. Qualitative and quantitative pit assessment was performed to assess corrosion rates and to document any pit that exceeded the pre-established pit depth criteria.

  Coating deficiencies in the vapor space and vent header were minor. Isolated areas of mechanical damage, pinpoint rusting, and minor pitting corrosion were identified. The maximum pit depth in the vapor space was less than 0.005". Pit depths in the vent header ranged from 0.001" to 0.010". The overall condition of the vapor space and vent header coating was judged to be "good to excellent".

Coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001".

Several blistered areas included pitting damage where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate. Other coating deficiencies identified consisted primarily of spot rust, pinpoint rusting, and minor mechanical damage. Qualitative assessment of a sample of the pitting corrosion on exposed base metal indicated that pit depths overall did not exceed 0.050". Selected areas of exposed base metal representing worst case pitting corrosion were repaired using UT#15 epoxy coating.

Three quantitative pit depth measurements were taken in several locations in bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to represent typical conditions found on the shell. The identified pits where the blisters were fractured indicated that the measured pit depths (less than 50 mils) were significantly less than the criteria established in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

To further characterize the changes in blister condition, a quantitative assessment was performed on the bay 6 and 7 test patches. Blister count indicated a general increase in the formation of new blisters and in the occurrence of fractured blisters. The rates of increase appear to be decreasing with the exception of new blisters recorded on the test patch vertical and horizontal bisecting centerlines which divide the test patch into four quadrants.

As a result of the 19th refueling outage coating inspection, Underwater Construction Corporation recommended that a qualitative coating and corrosion inspection be performed during the 20th refueling outage to confirm that the condition of the coating system has not changed significantly. It was also recommended that the requirements for the frequency of underwater coating inspection and repair be based on the as-found coating condition at the next inspection.

At the request of AmerGen, the results of the 19th refueling outage coating inspection were reviewed independently by industry coating expert Jon R. Cavallo of Corrosion Control Consultants and Labs, Inc. The Cavallo assessment also included the review of previous written and photographic/video records of underwater inspections of the torus immersion region back to 1988. It was concluded that:

- the coating system continues to perform its design function to protect the underlying carbon steel substrate from corrosion,

- the amount and condition of coating blisters in the Mobil 78 Hi-Build coating material applied in 1984 over the Mobil 46-X-16 epoxy filler have remained stable since discovered in 1988,

- the coating blisters in the Mobil 78 Hi-Build coating material applied in 1984 over the Mobil 46-X-16 epoxy filler do not appear to fracture spontaneously; rather, the coating blisters fracture when mechanically stressed during desludging and other maintenance operations,

- the small areas of carbon steel substrate exposed by mechanical damage to the coating system or fracture of coating blisters corrode at a very low rate (less than 5 mpy), and,

- the repair of torus coating damage which exposes bare steel substrate can be postponed until two refueling outages (21st refueling outage).

- 20th refueling outage (2004): Based on the review of inspection data by AmerGen, and, based on the independent review of the inspection data by an industry coatings expert, no underwater coating inspections were required.

- 21st refueling outage (2006): Underwater coating inspections scheduled.

Current Torus Condition:

The current torus condition has been determined based on UT thickness measurements and pit depth measurements taken over past inspections:

	Minimum Uniform Thickness	
	Measured	Allowable (nominal 0.385" less Mark I thickness margin revised for EMRVs)
General Shell	0.343"	0.338"
Shell ~ ring girders	0.345"	0.337"
Shell ~ saddle flange	0.345"	0.338"
Shell ~ Torus straps	0.345"	0.341"

Where local pitting corrosion measurements are less than the uniform thickness requirements, local area thickness acceptance criteria has been applied.

- Criteria was established in 2002 for local thickness acceptance criteria from nominal 0.385" for the torus shell area:
  - Isolated Pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center to center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated.
  - Multiple Pits that can be encompassed by a 2-1/2" diameter circle are limited to a maximum pit depth of 0.141" provided the center to center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or recoated.
- Pitting corrosion less than or equal to 0.040" is acceptable without any size restriction since it satisfies minimum uniform thickness requirements.
- Existing pitting corrosion depths that have exceeded 0.040" were evaluated for acceptability and include:
  - 1 pit of 0.042" in Bay 1 meets local pit depth criteria (2002)
  - 1 pit of 0.0685" in Bay 2 meets local pit depth criteria (1992)
  - 2 pits of 0.050" in Bay 6 greater than 20" apart meets local pit depth criteria (1991)
  - 1 pit of 0.058" in Bay 10 meets local pit depth criteria (1988)

Conclusion:

- The Torus has been inspected, evaluated, repaired, and continuously monitored to manage the identified shell corrosion discovered in the 1970's.
- Numerous engineering evaluations and calculations exist to demonstrate that the torus thickness is meeting current design and licensing basis requirements.
- The Torus shell deficiencies are related to:
  - Problems with the original coating specification (use of redlead primer)
  - Improper curing of the improved replacement coating from 1983.
- The blisters will typically remain intact unless broken by mechanical force or agitation.

- Structural Integrity of the Torus will not be adversely impacted if the pit dimensions remain within established acceptance criteria and the coating on top of the localized pit is properly repaired in a timely manner.

- Proper maintenance of the coating performed every other refueling outage will ensure that there are no aging effects / mechanisms associated with the structural integrity of the Torus.

RAI 4.7.2-5

Drywell corrosion is a safety concern; therefore, the staff believes that the updated final safety analysis report (UFSAR) supplement should, at a minimum, briefly describe the quantitative aspect of the drywell corrosion, and applicant's assertions to maintain it above a certain thickness to ensure that the containment could performs its intended function during the period of extended operation. The TLAA and Subsection IWE of the ASME code are the procedures by which it will maintain the containment functionality. The staff requests the applicant to address this matter.

Response:

UFSAR Section 3.8.2.8, Drywell Corrosion, provides historical information on drywell corrosion and corrective actions taken to control it. The section also describes aging management activities that are implemented during the current term consistent with existing NRC commitments. The section is revised periodically to include, by reference, the results of quantitative engineering analyses, the UT measurements in the upper regions of the drywell, and inspection of the coating of the drywell shell in the sand bed region.

Appendix A.1.27 ASME Section XI, Subsection IWE, and A.5 license renewal commitment list, item number 27, which are included in the application will be incorporated in the UFSAR as a supplement. However, both Appendix A and A.5 commitment list do not include additional commitments to the NRC Staff on drywell corrosion for the period of extended operation. The A.5 commitment list will be revised to include details of these additional commitments and will be the basis for the drywell corrosion aging management program during the period of extended operation. The revised A.5 commitment list and Appendix A.1.27 will be incorporated in the UFSAR. The supplement therefore will include elements of the drywell corrosion aging management program in sufficient detail to ensure that program commitments are documented in the UFSAR.

References:

1. Letter from J. A. Zwolinski (NRC) to P. B. Fiedler (GPU), Interim Operation for Cycle 12 following corrosion of the outer surface of the drywell shell, dated December 29, 1986.
2. Letter from J. C. DeVine (GPU) to U.S. NRC, Oyster Creek Drywell Containment, dated May 26, 1992.
3. Oyster Creek UFSAR Section 3.8.2.8, Drywell Corrosion
4. Meeting Minutes of November 13, 1987, Meeting with GPU Nuclear Corporation to Discuss Matters Related to Oyster Creek Drywell Corrosion.
5. TDR No. 1027, Design of UT Inspection Plan for the Drywell Containment Using Statistical Interference Methods.
6. Letter from J.C. Devine, Jr. (GPU) to U. S. NRC, Oyster Creek Drywell Containment, dated November 26, 1990.

ATTACHMENT 1

(GPU Letter to NRC dated November 26, 1990)

ADAMS
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ATTACHMENT 2

(GPU Letter to NRC dated March 4, 1991)

ADAMS
ML061020614

ATTACHMENT 3

(GPU Letter to NRC dated January 16, 1992)

ADAMS
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