UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	
	)	Docket No. 50-0219-LR
(License Renewal for the Oyster Creek Nuclear Generating Station)	)	
	)	

CITIZENS' INITIAL STATEMENT REGARDING RELICENSING OF OYSTER CREEK NUCLEAR GENERATING STATION

EXHIBITS

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July 20, 2007

CITIZENS' EXHIBIT LIST

No.	Exhibit	Other Reference
1	GPU Nuclear, Drywell Steel Shell Plate Thickness Reduction (July 21, 1995).	Citizen's Exhibit NC 8
2	Partial Cross Section of Drywell and Torus.	Citizen's Exhibit NC 10
3	Memorandum from Peter Tamburro on the Unclear Documentation of Calculation C-1302-187-5320-024 (AR 00461639 Report) (Mar. 30, 2006).	Exhibit ANC 8
4*	Exelon Nuclear, Calculation C-1302-187-5320-024 Revision 1: O.C. Drywell Ext. UT Evaluation in Sandbed (Jan. 12, 1993).	AmerGen's Exhibit 3
5*	Exelon Nuclear, Calculation C-1302-187-E310-041 Revision 0: Statistical Analysis of Drywell Vessel Sandbed Thickness Data 1992, 1994, 1996, and 2006 (Dec. 12, 2006).	Exhibit SJA 1
6	Affidavit of Peter Tamburro, Mar. 26, 2007.	
7	AmerGen, NRC Information Request: Audit Question Numbers AMP-141, 210, 356 (Apr. 5, 2006).	Citizen's Exhibit NC 1
8*	AmerGen, Passport 00546049 07 (AR A2152754 E09): Water Found in Drywell Trench 5 - UT Data Evaluation (Nov. 7, 2006).	Exhibit SJA 2

* Citizens understand that these exhibits marked with a * will be provided by AmerGen, however, if AmerGen fails to submit these exhibits as anticipated they will be submitted by the Citizens at a later date.

9	Structural Integrity Associates, Inc., Statistical Analysis of Oyster Creek Drywell Thickness Data (Jan. 4, 2007).	AmerGen's Exhibit 4
10	AmerGen, NRC Information Request: Audit Question Numbers AMP-357, 356, 210 (Jan. 24, 2006 and Feb. 16, 2006).	Citizen's Exhibit NC 2
11	Email from Peter Tamburro to Ahmed Ouaou (June 6, 2006, 14:03 EST).	OCLR00013624-13625
12	Memorandum from Dr. Rudolph Hausler, Apr. 25, 2007 (Redacted).	
13	Memorandum from Dr. Rudolph Hausler, July 19, 2007.	
14	AmerGen, Reference Material to the ACRS: Photograph of the Sand Bed Region (1992).	Exhibit SJA 3
15	Transcript of Nuclear Regulatory Commission Proceedings, Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal Oyster Creek Generating Station (Jan. 18, 2007) (Excerpted Pages: p.1-10, p.132-144, p.207-224, p. 353-358).	
16	Transcript of Nuclear Regulatory Commission Proceedings, Advisory Committee on Reactor Safeguards Meeting of Plant License Renewal Subcommittee (Oct. 3, 2006) (Excerpted Pages: p.1-8, p.59-63).	
17	Email from Steven Hutchins to John Hufnagel Jr., with Drywell White Papers attachment (Sept. 18, 2006, 16:51 EST).	OCLR00013714 - 13734
18	Affidavit of Jon R. Cavallo, Mar. 26, 2007.	

19	AmerGen, Action Request: Determine the Proper Sealant for Drywell Sandbed Floor Voids (Oct. 23, 2006).	Exhibit ANC 5
20	Letter from Richard J. Conte, Chief Engineering Branch 1, Nuclear Regulatory Commission, to Richard Webster, Esq., Rutgers Environmental Law Clinic (Nov. 9, 2006).	Exhibit ANC 6
21	Letter from J.C. Devine, Jr., Vice President of Technical Functions, GPU Nuclear, to the Nuclear Regulatory Commission (Dec. 5, 1990) (Attachment 3; GPUN Detailed Summary Addressing Water Intrusion and Leakage Effects Related to the Oyster Creek Drywell).	OCLR00029270-29283
22	GPU Nuclear, Clearing of the Oyster Creek Drywell Sand Bed Drains (Feb. 15, 1989).	OCLR00028912-28918
23	AmerGen, Disclosed Document Relating to Drywell Leakage.	OCLR00013354
24	Transcript of Nuclear Regulatory Commission Proceedings, Advisory Committee on Reactor Safeguards 539th Meeting (Feb. 1, 2007) (Excerpted Pages: p.1-3, p. 172-177, p. 217-224).	
25	Letter from the Nuclear Regulatory Commission to C. Crane (Jan. 17, 2007) ("Inspection Report").	ML070170396
26	Email from Steven Dunsmuir, FIN/Operations RO, Exelon Corp., to Howie Ray, et al. (Oct. 22, 2006, 04:52 EST).	OCLR00014454-14455
27	Email from Tom Quintenz to Kevin Muggleston, et al. (Feb. 1, 2006, 17:02 EST).	OCLR00013629
28	GPU Nuclear, Evaluation of February 1990 Drywell UT Examination Data (Mar. 8, 1990).	Citizen's Exhibit NC 9

29	Affidavit of Gordon, Mar. 26, 2007.	
30	Letter from Jill Lipoti, Director Division of Environmental Safety and Health, New Jersey Dept. of Environmental Protection, to Dr. Pao-Tsin Kuo, Director Division of License Renewal, U.S. Nuclear Regulatory Commission (Apr. 26, 2007).	
31*	AmerGen, Calculation Sheet C-1302-187-5300-01.	
32*	GPU Nuclear, Calculation Sheet C-1302-187-5320-024 Revision 0: Oyster Creek Drywell Exterior Evaluation in Sandbed (1993).	Citizen's Exhibit NC 3
33*	Exelon Nuclear, Calculation C-1302-187-5320-024 Revision 2: O.C. Drywell Ext. UT Evaluation in Sandbed (Mar. 18, 2007).	
34*	ACRS Information Packet (Dec. 2006).	Exhibit ANC 2
35	Letter from AmerGen to the NRC (2103-06-20426) (Dec. 3, 2006) (Excerpted Pages: Dec. 3, 2006 Letter, p.1-3, p. 9-15, p. 17-24).	Exhibit ANC 1
36	Email from Caroline Schlaseman, MPR Associates, Inc., to Howie Ray (Nov. 2, 2006, 12:09 EST).	OCLR00015433-15434

Exhibit 1

GPU Nuclear

Citizen's Exhibit

Technical Functions
Safety/Environmental Determination and 50.59 Review (EP-016)

Unit OCNGS	Page 1 of 69
Document/ActivityTitle Drywell Steel Shell Plate Thickness Reduction	SE Rev. No. 11
Document No. *(if applicable)* Doc. Rev. No.	SE No. 000243-002

Type of Activity *(modification, procedure, test, experiment, or document)*: Document

1. Does this document involve any potential non-nuclear environmental concern? ☐ Yes ☒ No

   To answer this question, review the Environmental Determination (ED) form. Any **YES** answer on the ED form requires an Environmental Impact Assessment by Environmental Controls, per 1000-ADM-4500.03. If in doubt, consult Environmental Controls or Environmental Licensing for assistance. If all answers are **NO**, further environmental review is not required. In any event, continue with Question 2, below.

2. Is this activity/document listed Section I or II of the matrices in Corporate Procedure 1000-ADM-1291.01? ☒ Yes ☐ No

   If the answer to question 1 is **NO**, stop here. This procedure is not applicable and no documentation is required. (If this activity/document is listed in Section IV of 1000-ADM-1291 review on a case-by-case basis to determine applicability.) If the answer is **YES**, proceed to question 3.

3. Is this a new activity/document or a substantive revision to an activity/document? (See Exhibit 2, paragraph 3, this procedure for examples of non-substantive changes.) ☒ Yes ☐ No

   If the answer to question 3 is **NO**, stop here and complete the approval section below. This procedure is not applicable and no documentation is required. If the answer is **YES**, proceed to answer all remaining questions. These answers become the Safety/Environmental Determination and 50.59 Review.

4. Does this activity/document have the potential to adversely affect nuclear safety or safe plant operations? ☒ Yes ☐ No

5. Does this activity/document require revision of the system/component description in the FSAR or otherwise require revision of the Technical Sepcifications or any other part of the SAR? ☒ Yes ☐ No

6. Does the activity/document require revision of any procedural or operating description in the FSAR or otherwise require revision of the Technical Specifications or any other part of the SAR? ☐ Yes ☒ No

7. Are tests or experiments conducted which are not described in the FSAR, the Technical Specifications or any part of the SAR? ☐ Yes ☒ No

   IF ANY OF THE ANSWERS TO QUESTIONS 4, 5, 6, OR 7 ARE YES, PREPARE A WRITTEN SAFETY EVALUATION FORM.

   If the answers to 4, 5, 6, and 7 are **NO**, this precludes the occurrence of an Unreviewed Safety Question or Technical Specifications change. Provide a written statement in the space provided below (use back of sheet if necessary) to support the determination, and list the documents you checked.

   NO, because: ______

   Documents checked: ______

8. Are the design criteria as outlined in TMI-1 SDD-T1-000 Div. I or OC-SDD-000 Div. I Plant Level Criteria affected by, or do they affect the activity/document? ☐ Yes ☒ No

   If **YES**, indicate how resolved: ______

APPROVALS *(print name and sign)*

Engineer/Originator	A. Collado [signature]	Date 4-18-95
Section Manager	J. D. Abramovici [signature]	Date 6.26.95
Responsible Technical Reviewer	S. D. Leshnoff [signature]	Date 8/2/95
Other Reviewer(s)		Date

N5047 (05-93)

OCLR00001306

1.0 PURPOSE

The purpose of this safety evaluation is to assess the structural integrity of the Oyster Creek drywell pressure vessel. This revision incorporates data on vessel thickness, sandbed coating inspections and resulting corrosion rates based on data obtained through September 1994 and assesses the period of time for which vessel structural integrity can be assured.

1.1 Introduction

The Oyster Creek drywell pressure vessel is of steel construction. Its original design incorporates a sandbed which is located around the outside circumference between elevations 8'11¾" and 12'3". The sand was removed during the 14R outage (December 1992) and the steel surfaces coated. Leakage was observed from the sandbed drains during the early to mid 1980's, indicating that water had intruded into the annular region between the drywell pressure vessel and the concrete shield wall. The presence of water in the sand was confirmed later when a water level (i.e., free water) was discovered during core boring operations to install anodes for cathodic protection (CP). Concerns about the potential for corrosion of the vessel resulted in thickness measurements being taken in the sandbed region in 1986. These measurements indicated that the vessel in the sandbed region was thinner than the 1.154 inch nominal thickness originally specified by Chicago Bridge & Iron Company (CBI) (Reference 2.3.1). Additional thickness measurements at elevations 50'2" and 87'5" were taken in 1987. These measurements also indicated areas where the pressure vessel was thinner than the originally specified. The specified nominal thickness at these elevations is 0.770 inches and 0.640 inches respectively.

Since 1987 GPUN has developed and implemented a drywell vessel corrosion monitoring program (Reference 3.1.4.21) in which inspections are conducted at identified corroded locations. Inspections have been periodically performed during refueling outages and outages of opportunity in the former sandbed region, in the spherical region (elevation 50'2" and 51'10"), and in the cylindrical region (elevation 87'5").

1.2 Background Discussion

Discovering that the drywell pressure vessel thickness was less than originally specified necessitated a number of activities. The purpose of these activities was to establish that the vessel was structurally acceptable to support continued safe operation of Oyster Creek. A summary of the activities undertaken and the resulting conclusions are provided herein.

1.2.1 Vessel Thickness Measurements

References 3.1.4.1, 3.1.4.5, 3.1.4.6, 3.1.4.22 and 3.1.4.23 document the non destructive ultrasonic testing examination methods utilized to measure vessel thickness, the locations chosen for thickness measurements, the locations for metallurgical plug samples taken from the drywell vessel and the extensive amount of data taken (in excess of 1,000 individual UT

readings). Obtaining the thickness measurements over a large portion of the vessel's circumference at four elevations enabled GPUN to establish an ongoing corrosion rate monitoring program and assess the structural integrity of the vessel.

As documented in Reference 3.1.4.29 in April of 1991 a supplemental augmented series of inspections were performed on the drywell vessel. Results were that all inspected locations meet code requirements.

1.2.2 Corrosion Assessment

References 3.1.4.2 and 3.1.4.3 document the metallurgical evaluations of the two inch plug samples which were removed from the vessel in the sandbed region in December, 1986 and the upper elevation (EL. 50'2") in November, 1987. Reference 3.1.4.24 documents metallurgical evaluation of an additional two inch plug removed in April, 1990. The type of corrosion noted, coupled with an assessment of the vessel construction and operating history, allowed GPUN to establish the probable cause of the corrosion and to conservatively project corrosion rates. GPUN conducts ongoing periodic vessel thickness measurements which statistically monitor and establish corrosion rates.

The ongoing measurements are not taken in all the locations where measurements were taken initially in 1986, 1987 and 1990. The initial locations where corrosion/material loss was most severe were selected for the ongoing program. This reduction of inspection scope was done primarily to reduce the man-rem exposure received when taking drywell measurements. Note that a spot check of locations measured initially was performed during the 12R (October, 1988) outage which confirmed proper selection for ongoing measurements.

In March, 1990 an additional check was performed at elevation 50'2". This check consisted of a continuous UT "A" scan in all accessible areas in a one inch band at elevation 50'2". Results confirmed that the existing grid in Bay 5 was among the thinnest at this elevation. As a result of this check, three additional grids at elevation 50'2" were added to the program.

Elevation 50'2" is representative of vessel plates originally delivered with a mean nominal thickness of .770 inch and installed between elevation 23'6" to 51'.

In April, 1990 an additional elevation was investigated for corrosion. This elevation at 51'10" is representative of drywell vessel plate originally delivered with mean nominal thicknesses of .722 inch and installed between elevation 51' to 65'. This investigation was performed by continuous UT "A" scan in a one inch band, at elevation 51'10". Results showed only one area which was less than nominal. An inspection grid of this area (Bay 13) was added to the inspection program.

Corrosion assessments have been periodically accomplished as summarized herein. The previous bounding corrosion rate projections (discussed in previous versions of this Safety Evaluation and in Ref. 3.1.4.2 and 3.1.4.3) are no longer accurate and are not discussed in this revision of this safety evaluation.

1.2.3 Corrosion Rate Assessment

Reference 3.1.4.7, 3.1.4.10, 3.1.4.11 through 3.1.4.14, 3.1.4.25 through 3.1.4.28, 3.1.4.31 through 3.1.4.34, 3.1.4.36, 3.1.4.37, and 3.1.4.40 document the ongoing statistical analysis of vessel ultrasonic thickness (UT) measurements as they are taken at specific locations over time. The corrosion rate monitoring program involves the establishment of six inch by six inch grid locations on the vessel interior, the use of a template with 49 holes on one inch centers for locating the UT probe, a specified ± 1/8 inch tolerance on the location of subsequent measurements and taking thickness measurements periodically. This program has enabled GPUN to statistically determine corrosion rates at these grid locations.

Since the grid locations are in the known areas where corrosion/material loss is most severe, the corrosion rates and projected wall thicknesses are determined over a small fraction of the drywell but conservatively applied uniformly.

1.2.4 Structural Assessment

References 3.1.4.17 through 3.1.4.19 provide an overall analysis of the Oyster Creek drywell pressure vessel structural requirements. The UT readings obtained through September, 1994 and resulting statistical analysis coupled with the GE Nuclear structural analyses and a recently NRC approved license amendment establishing a 44 psig design pressure in place of 62 psig (Reference 3.1.2) provide the structural basis for assuring safe operation of Oyster Creek until end of plant license (April 9, 2009).

The corrosion rates, where available, have been used to project material loss. The structural evaluations have been performed assuming minimum uniform thicknesses in the areas of concern. Since corrosion is confined to specific areas, the existing evaluations and resulting vessel thickness requirements are very conservative in that they do not take credit for actual wall thicknesses in excess of the minimum used in the evaluations. In addition, the coating inspection of the former sandbed region insures the corrosion rate at this area remains at zero.

1.3 Purpose Summary

This safety evaluation will demonstrate that (based on data collected through September, 1994) plant operations can continue until end of license life based on the structural evaluation of the drywell. Action has been taken to eliminate leakage from the reactor cavity region, and for periodic surveillance (Ref. 3.1.4.21) of vessel thickness at intervals that ensure that the wall thickness will not decrease below acceptable levels between inspections.

The former sandbed area of the drywell has been cleaned and coated (during 14R Outage) to stop corrosion. The coating is visually inspected to ensure it remains effective. Additionally, the analysis of the UT data collected during the most recent inspection (September 1994) indicates that for the upper elevations of the drywell, there is no evidence of ongoing corrosion.

2.0 SYSTEMS AFFECTED

2.1 System No. 243, Drywell and Suppression System, particularly the drywell vessel structure.

2.2 Drawing showing original thickness - Chicago Bridge and Iron Co., Contract Drawings 9-0971, Drawing Nos. 1 through 11.

2.3 Documents which describe the Oyster Creek drywell pressure vessel design.

2.3.1 "Structural Design of the Pressure Suppression Containment Vessel" for JCP&L/Burns and Roe, Inc., Contract No. 9-0971, by CB&I Co., 1965.

3.0 EFFECTS ON SAFETY

3.1 Documents that Describe Safety Function & Evaluations

3.1.1 OCNGS Unit 1 Facility Description and Safety Analysis Report

3.1.1.1 Licensing Application, Amendment 3, Section V

3.1.1.2 Licensing Application, Amendment 11, Question III-18

3.1.1.3 Licensing Application, Amendment 15

3.1.1.4 Licensing Application, Amendment 68

3.1.2 Technical Specification Documents

3.1.2.1 Technical Specification and Bases - OCNGS Unit, Appendix A to Facility License DRP-16, JCP&L Docket No. 50-219, Sections 3.5, 4.5, 5.2.

3.1.2.2 Technical Specification Amendment 165.

3.1.3 Regulatory Documents

3.1.3.1 10CRF50, Appendix A. General Design Criteria for Nuclear Power plants

- Criterion 2 - Design basis for Protection against natural phenomena
- Criterion 4 - Environmental and Missile Design Bases
- Criterion 16 - Containment Design
- Criterion 50 - Containment Design Basis

3.1.4 GPUN Technical Data Reports (TDR), Calculations and Drawings

3.1.4.1 TDR 851 Assessment of Oyster Creek Drywell Shell.

3.1.4.2 TDR 854 Drywell Sandbed Region Corrosion Assessment.

3.1.4.3 TDR 922 Drywell Upper Elevation, Wall Thinning Evaluation.

3.1.4.4 (This reference has been superseded by References 3.1.4.17 through 3.1.4.19).

3.1.4.5 Sketch 3E-SK-S-89, Ultrasonic Testing - Drywell Level 50'2" - 87'5" Plan.

3.1.4.6 Sketch 3E-SK-S85, Drywell Data UT Location Plan.

3.1.4.7 TDR 948, Statistical Analysis of Drywell Thickness Data.

3.1.4.8 NRC Letter Docket 50-219, dated October 26, 1988, subject "Oyster Creek Drywell Containment".

3.1.4.9 Primary Containment Design Report, dated 9/11/67, Ralph M. Parson Company.

3.1.4.10 Calc. C-1302-187-5360-006 "Projection of Drywell Mean Thickness thru October, 1992".

3.1.4.11 Calc. C-1302-187-5300-008 "Statistical Analysis of Drywell Thickness Data thru 2/8/90".

3.1.4.12 Calc. C-1302-187-5300-009 Rev. 0 "OC Drywell Projected Thickness".

3.1.4.13 Calc C-1302-187-5300-001 Rev. 0, "Statistical Analysis of Drywell Thickness Data thru 4/14/90".

3.1.4.14 Calc C-1302-187-5300-012 Rev. 0, "OCDW Projected Thickness Using Data thru 4/24/90".

3.1.4.15 This reference no longer applicable, therefore, is deleted.

3.1.4.16 This reference no longer applicable, therefore, is deleted.

3.1.4.17 "Justification For Use of Section III, Subsection NE, Guidance in Evaluating The Oyster Creek Drywell", Technical Report TR-7377-1, dated November 1990, Teledyne Engineering Services.

3.1.4.18 "An ASME Section VIII Evaluation of Oyster Creek Drywell for without Sand Case, Part I, Stress Analysis", dated February 1991, GE Nuclear Energy, San Jose, CA.

3.1.4.19 "An ASME Section VIII Evaluation of the Oyster Creek Drywell for without Sand Case, Part 2, Stability Analysis", Rev. 2, dated November 1992, GE Nuclear Energy, San Jose, CA.

3.1.4.20 This reference no longer applicable, therefore is deleted.

3.1.4.21 GPUN Specification IS-328227-004, Revision 10, "Functional Requirements For Drywell Containment Vessel Thickness Examination".

3.1.4.22 Sketch 3E-Sk-M-275, Rev. 0, "UT Drywell Level 50'2", March 1990 Readings".

3.1.4.23 Sketch 3E-Sk-M-358, Rev. 0, "UT Drywell Level 51'-10", April 1990 Readings".

3.1.4.24 "Oyster Creek Drywell Corrosion Evaluation", dated June 1990, GE Nuclear Energy, San Jose, CA.

3.1.4.25 Calc C-1302-187-5300-015, "Statistical Analysis of Drywell Thickness Data Thru 3/3/91".

3.1.4.26 Calc C-1302-187-5300-016, "OCDW Projected Thickness Using Data Thru 3/3/91".

3.1.4.27 Calc C-1302-187-5300-017 "Statistical Analysis of Drywell Thickness Data thru May, 1991".

3.1.4.28 Calc C-1302-187-5300-018, "OCDW Projected Thickness using Data thru May, 1991".

3.1.4.29 GE Report "Final Report - Oyster Creek Drywell Containment Vessel Random UT Project" dated May 8, 1991.

3.1.4.30 IS-402950-001, Rev. 0 Functional Requirements for Augmented Drywell Inspections.

3.1.4.31 Calc C-1302-187-5300-19 "Statistical Analysis of Drywell Thickness Data thru November, 1991".

3.1.4.32 Calc C-1302-187-5300-20 "OCDW Projected Thickness Using Data thru November 1991".

3.1.4.33 Calc C-1302-187-5300-021 "Statistical Analysis of Drywell Thickness Data thru May, 1992".

3.1.4.34 Calc C-1302-187-5300-022 "OCDW Projected Thickness Using Data thru May, 1992".

3.1.4.35 Safety Evaluation SE-402950-005 "Removal of Sand from Drywell Sandbed".

3.1.4.36 Calc C-1302-187-5300-025 "Statistical Analysis of Drywell Thickness Data thru December 1992".

3.1.4.37 Calc C-1302-187-5300-024 "OC DW Projected Thickness Using Data thru December, 1992".

3.1.4.38 TDR 1108 Summary Report of Corrective Action Taken form Operating Cycle 12 through 14R Outage.

3.1.4.39 Calc C-1302-187-5300-024 "O.C. Drywell External UT Evaluations" in the Sandbed.

3.1.4.40 Calc C-1302-187-5300-028 - Statistical Analysis of Drywell Thickness Data thru September, 1994.

3.1.4.41 Memo #5514-94-319 - Dated September 30, 1994 - Subject: Inspection D.W. Sandbed Coating in Bay 11 - O.C.

3.1.4.42 Calc C-1302-243-5320-071 - Rev. 1, "Drywell Thickness Margins."

3.1.4.43 Memo #5340-94-120 - Dated November 9, 1994 - Subject: Video Inspection of DW Sandbed Bay #3.

3.1.4.44 Memo #5340-95-062 - Dated July 12, 1995 - Subject: Life Expectancy of Drywell Shell Coating in Former Sandbed O.C.

3.1.5 Industry Codes and Standards Applicable Codes

3.1.5.1 The ASME Boiler and Pressure Vessel Code and applicable nuclear code cases utilized for the design of the drywell pressure vessel are as listed in References 3.1.4.17 through 3.1.4.19.

3.1.5.2 Applicable Drywell Shell Plate Material Standards/Specification

SA-212 High Tensile Strength Carbon - Silicon Steel Plates for Boilers and other Pressure Vessels.

3.2 Drywell Pressure Vessel Safety Function Drywell Geometry Description

3.2.1 The drywell, sometimes referred to as the containment vessel or containment structure, houses the reactor vessel, reactor coolant recirculating loops, and other components associated with the reactor system. The structure is a combination of a sphere, cylinder, and 2:1 ellipsoidal dome that resembles an inverted light bulb. The spherical section has an inside diameter of 70'.

The cylindrical portion connecting the sphere to the dome has a diameter of 33'. The structure is approximately 99' high. The plate thicknesses vary from a maximum of 2.56" at the transition between the sphere and the cylinder down to a minimum of 0.640" in the cylinder. The dome wall thickness is 1.18".

Figure 1 illustrates the drywell structure along with the pertinent dimensions. The top closure, which is 33' in diameter, is made with a double tongue and groove seal which permits periodic checks for leak tightness. Ten vent pipes, six feet six inches in diameter, are equally spaced around the circumference to connect the drywell and vent header to the pressure suppression chamber.

The drywell interior is filled with concrete to elevation 10'3" to provide a level floor. Concrete curbs follow the contour of the vessel up to elevation 12'3" with cutouts around the vent lines.

On the exterior, the drywell is encapsulated in concrete of varying thickness from the base elevation up to the elevation of the top head. From there, the concrete continues vertically to the level of the top of the spent fuel pool.

The base of the drywell is supported on a concrete pedestal conforming to the curvature of the vessel. For erection purposes a structural steel skirt was first provided supporting the vessel. A portion of the steel skirt was left in place which serves as one of the shear rings that prevent rotation of the drywell during an earthquake.

The proximity of the biological shield concrete surface to the steel shell varies with elevation. The concrete is in full contact with the shell over the bottom of the sphere at its invert elevation 2'3" up to elevation 8'11¼". At that point, the concrete is stepped back 15 inches radially to form a pocket which continues up to elevation 12'3". The pocket was originally filled with sand which formed a cushion to smooth the transition of the shell plate from a condition of fully clamped

between two concrete masses to a free standing condition. The sand pocket was connected to drains which allowed drainage of any water which might enter the sand. The sand was removed during the 14R outage (December 1992).

The sand "springs" helped to ease this transition. GE analysis (Ref. 3.1.4.18 and 3.1.4.19) has shown that the sand is not required so long as vessel thickness in that region is greater than or equal to .736 inches (with margin as stated in 3.3.2.1). Justification for removing sand from the sandbed is covered under a separate Safety Evaluation (Ref. 3.1.4.35). As stated above, the sand was completely removed and the drywell vessel was coated in the sandbed region during the 14R refueling outage (Figure 2). The sand was removed via ten (10) 20" diameter access holes drilled equally spaced through the containment concrete shield wall.

Up from elevation 12'3" there is a 3" gap between the drywell and the concrete biological shield wall which is filled with foam material that provides no structural support. An upper lateral seismic restraint, attached to the cylindrical portion of the drywell at elevation 82.17 ft., allows for thermal, deadweight, and pressure deflection, but not for lateral movement due to seismic excitation. All penetrations for piping, instrumentation lines, vent ducts, electrical lines, equipment accesses, and personnel entrance have expansion joints and double seals where applicable.

The spherical area is described by 10 segments, one at each downcomer, referred to as bays. The bays are odd numbered 1 thru 19 (Figure 3).

3.2.2 Drywell Pressure Vessel Safety Function

3.2.2.1 Functional Design

The drywell pressure vessel is one of the major structural components of the Primary Containment System (PCS) discussed in Section 6.2 of the Oyster Creek Nuclear Generating System Update FSAR. The safety function of the Primary Containment System is to accommodate, with a minimum of leakage, the pressures and temperatures resulting from the break of any enclosed process pipe; and, thereby, to limit the release of radioactive fission products to values which will insure offsite does rates well below 10CFR100 guideline limits.

3.2.2.2 Design Criteria

The design criteria for the Containment are as follows:

a. To withstand the peak transient pressures (coincident with an earthquake) which could occur due to the postulated break of any pipe inside the drywell.

b. To channel the flows from postulated pipe breaks to the torus.

c. To withstand the force caused by the impingement of the fluid from a break in the largest local pipe or connection, without containment failure.

d. To limit primary containment leakage rate during and following a postulated break in the primary system to substantially less than that which would result in offsite doses approaching the limiting values in 10CFR100.

e. To include provisions for leak rate tests.

f. To be capable of being flooded following a Design Basis Accident to a height which permits unloading of the core.

3.2.2.3 Drywell Vessel Design Pressure and Temperature Parameters

- The drywell and connecting vent system tubes are designed for 44 psig, internal pressure at 292°F, and an external pressure of 2 psig at 205°F.

- The design lowest temperature to which the primary containment vessel is subjected is 30°F.

3.3 Effects of Drywell Pressure Vessel Thickness Reduction

In order to demonstrate that the vessel thickness reduction will not adversely affect the ability of the drywell to perform its safety function, GPUN establishes a conservative corrosion rate, projects vessel thickness, and shows by analysis that allowable stresses are not exceeded for the design basis load conditions.

3.3.1 Results of Corrosion Monitoring Program

3.3.1.1 Monitoring Program Summary

Reference 3.1.4.21 defines the drywell corrosion inspection program. This program identifies nine (9) locations for UT inspection. These nine locations were selected for inspection based on extensive drywell thickness investigation performed during the initial corrosion investigation phase (1986 through 1991). These nine (9) locations (exclusive of the former sandbed region) exhibited that worst metal loss and therefore were selected for monitoring wall thickness.

Originally, the knowledge of the extent of corrosion was based on a UT inspection plan involving going completely around the inside of the drywell at several locations. Nine six-by-six grids on either side of each vent penetration were used to characterize the situation at the elevation of the sandbed. At each of the upper elevations a belt-line sweep was used with readings taken on as little as one inch centers wherever thickness changed between successive nominal 6" centers. Grids were established in the upper elevations in this way.

As experience increased with each data collection campaign, only grids showing evidence of change were retained in the inspection program. Additional assurance regarding the adequacy of this inspection plan was obtained by a completely randomized inspection, involving 59 grids,that showed that all inspection locations satisfied code requirements.

As a minimum, the nine locations above the former sandbed region specified in the program, will be inspected during the 16R refueling outage and every third refueling outage thereafter. This frequency of

inspection is considered adequate because most recent data obtained indicates that there is no evident of ongoing corrosion at the upper elevations of the drywell vessel.

Reference 3.1.4.21 also covers coating inspection of the drywell shell exterior at the former sandbed region. The corrosion in this area of the drywell vessel was arrested during the 14R refueling outage (December 1992), as the steel surface was coated for corrosion protection.

As stated in 3.3.1.7 of this safety evaluation, the coating was inspected during the 15R refueling outage on a sample basis. Results of the inspection were satisfactory with no indications of coating failures.

As a minimum, additional inspections of the coating will be conducted during the 16R refueling outage and again during refueling outage 18R. This frequency of inspections is adequate based on results of prior coating inspection and estimated coating life (8-10 years) per reference 3.1.4.44. After the inspection in refueling outage 18R, an assessment will be made, appropriate actions will be taken, and the need for future inspections will be determined to ensure that the drywell integrity is maintained until at least April 2009. The scope of the inspection as set forth in reference 3.1.4.21 of inspecting two bays, is adequate because the environmental conditions and coating application methods were similar for all ten bays when the coating was applied. Also, the two bays selected for inspection are known to be worst leakage areas with most corrosion attack prior to the coating application.

In summary, the inspection program (Reference 3.1.4.21) is adequate to assure drywell vessel integrity until at least April 9, 2009 (end of plant license).

3.3.1.2 Corrosion Rates

Reference 3.1.4.40 discusses the statistical analysis of the UT data taken over the time period February, 1987 through September, 1994 for the sandbed region grids and November, 1987 through September, 1994 for the upper elevation grids. A new monitored location (#50-22) above the sandbed was added to the program in December of 1992. The corrosion rate was determined by calculating the rate of change of the mean thickness at each measured grid using linear regression.

analysis. The corrosion rate has previously been expressed as the slope of the regression line ± the standard error of the slope. Below are the current corrosion status assessments in the most limiting areas for each of the major elevations. The corrosion at the sandbed region was arrested in December, 1992 when the subject surfaces were cleaned and coated. Inspection of the coated surfaces performed in September of 1994 revealed that the coating is performing satisfactory as documented in reference 3.1.4.41.

Sandbed Region	-	Corrosion arrested.
Elevation 50'2"	-	F-Ratio <1.0
Elevation 51'10"	-	F-Ratio <1.0
Elevation 87'5"	-	F-Ratio <1.0
Elevation 60'-11"	-	Insufficient Data

Evaluation of the September, 1994 inspection data indicates that for Elevations 50'-2", 51'-10", 60'11", and 87'5", there is no evidence of ongoing corrosion. This assessment (Ref. 3.1.4.40) is based on the fact that the statistical regression estimate can not be used to define a corrosion rate because the F-ratio is far too low for reliable use, or that there are fewer than four measurements. (See paragraph 3.3.1.3--Sphere elevation 60'-11")

Because the statistical F-test for significance of the regression rate estimate is very low, there is no evidence of ongoing corrosion, only random variation associated with measuring techniques.

3.3.1.3 Projections

Projections are determined by performing regression analysis, when appropriate.

Sandbed

The entire sandbed region of the drywell shell O.D. was coated during the 14R refueling outage (December 1992). This coating was inspected in September 1994. This inspection showed no coating failure or signs of deterioration. Therefore, the corrosion in this region has been arrested and no further corrosion is expected to occur. To ensure that the coating applied will remain effective, visual inspections by direct and/or remote methods will be conducted per reference 3.1.4.21. The coating will again be inspected during refueling outage 16R and again during refueling outage 18R. Should an inspection reveal coating failure, an assessment will

be made, appropriate actions will be taken, and the need for additional inspections will be determined to ensure that the drywell integrity is maintained until at least April 2009 (end of License). The coating has an estimated life prediction of 8-10 years, before signs of local deterioration are expected (Reference 3.1.4.44). Currently, a margin of 70 mils exists between the required metal thickness and the actual mean metal thickness at the thinnest location as measured during the 15R outage in September 1994. This margin provides additional assurance for drywell integrity in the unlikely case of coating failure between inspection intervals.

Based upon the arrested corrosion, and future monitoring of the coating, it is reasonable to conclude that this region will not become limiting prior to April 2009.

Cylinder, Elevation 87'-5"

As a result of low F-ratio at this elevation, it can be concluded that there is no evidence of ongoing corrosion at this location. The September, 1994 data indicates that the thinnest location at this elevation has a mean thickness of 613 mils. Therefore, a margin of 161 mils exists between actual and minimum mean acceptable thickness. With the 161 mils margin which currently exists, minimum mean acceptable thickness could not be reached by April 2009, unless there was an ongoing corrosion rate of approximately 11 MYP. A corrosion rate of this magnitude would be observable. A corrosion rate of 11 MPY has not been observed in any location above the sandbed.

Additional assurance will be provided by volumetric inspection during the next refueling outage (16R) and at least every third refueling outage thereafter.

Sphere, Elevation 50'-2"

As a result of low F-ratio at this elevation, it can be concluded that there is no evidence of ongoing corrosion at this location.

The September, 1994 data indicates that the thinnest location at this elevation has a mean thickness of 733 mils. Therefore a margin of 192 mils exists between actual and minimum mean acceptable thickness.

Although the data on hand does not permit a statistically rigorous calculation of corrosion rate, it is adequate to support a conclusion that this region will not become limiting prior to April 2009, unless there was an ongoing corrosion rate of approximately 13 MPY. A corrosion rate of this magnitude would be observable. A corrosion rate of 13 MPY has not been observed in any location above the sandbed.

Additional assurance will be provided by volumetric inspection during the next refueling outage (16R) and at least every third refueling outage thereafter.

Sphere, Elevation 51'-10"

As a result of low F-ratio at this elevation, it can be concluded that there is no evidence of ongoing corrosion at this location.

The September, 1994 data indicates that the thinnest location at this elevation has a mean thickness of 695 mils. Therefore a margin of 177 mils exists between actual and minimum mean acceptable thickness.

Although the data on hand does not permit a statistically rigorous calculation of corrosion rate, it is adequate to support a conclusion that this region will not become limiting prior to April 2009. With the 177 mils margin which currently exists, minimum mean acceptable thickness could not be reached by April 2009, unless there was an ongoing corrosion rate approximately 12 MPY. A corrosion rate of this magnitude would be observable. A corrosion rate of 12 MPY has not been observed in any locations above the sandbed.

Additional assurance will be provided by volumetric inspection during the next refueling outage (16R) and at least every third refueling outage thereafter.

Sphere, Elevation 60'-11"

This location was added to the Drywell Corrosion monitoring program with the first UT data set taken in December 10 1992 and a second UT data set taken in September 1994. As a result of the limited data at this elevation, a statistical analysis of the corrosion rate, could not be performed. Therefore, a projection based on regression analysis will not be meaningful. The

September, 1994 data indicates that the thinnest location at this elevation has a mean thickness of 709 mils. Therefore, a margin of 191 mils exists between actual and minimum mean accepted thickness.

Although the data on hand does not permit a statistically rigorous calculation of corrosion rate, it is adequate to support a conclusion that this region will not become limiting prior to April 2009. With the 191 mils margin which currently exists, minimum mean acceptable thickness could not be reached by April 2009, unless there was an ongoing rate of approximately 13 MPY. A corrosion rate of this magnitude would be observable. A corrosion rate of this magnitude has not been observed in any locations above the sandbed.

Additional assurance will be provided by volumetric inspection during the next refueling outage (16R) and at least every third refueling outage thereafter.

3.3.1.4 Projected Local Vessel Thicknesses

Because mean uniform thickness can consist of local values less than the mean, consideration has been given to the significance of such readings. The number of such readings is extremely limited and have been evaluated as not structurally significant as follows (Ref. 4.1.4.40)

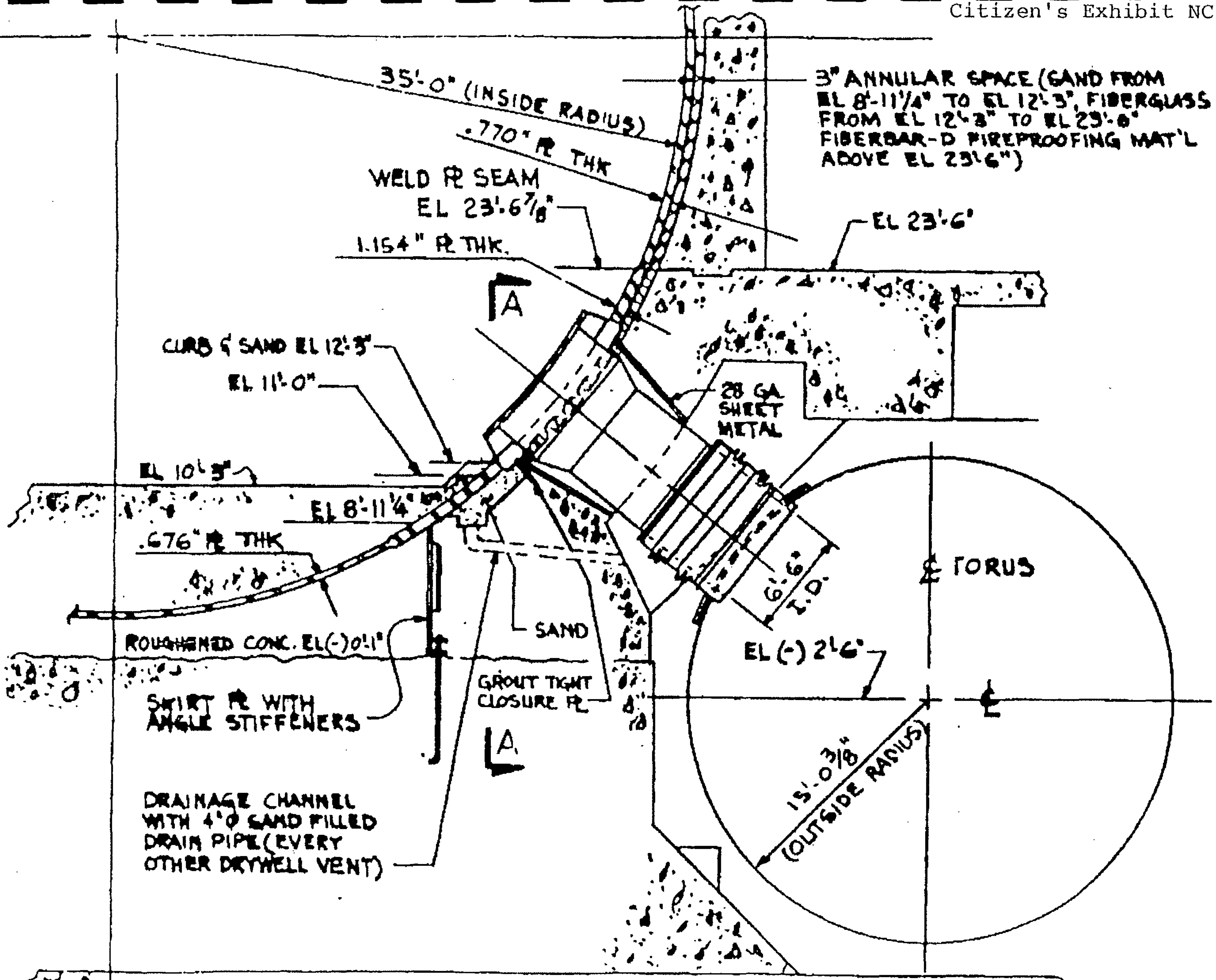
Sandbed

The lowest local reading is .770 inches (Ref. 3.1.4.40). The local acceptable thickness for the sandbed region is .49 inches (Section 3.3.2). As mentioned in 3.3.1.3, the sandbed region was coated and no further corrosion is expected in this area, and the .280" margin is more than adequate for the balance of plant life (April 2009).

Cylinder, Elevation 87'5"

The lowest local reading is .551 inches (Ref. 3.1.4.40). The local acceptable thickness for this elevation is .300 inches (Section 3.3.2). Therefore, a margin of approximately 251 mils exists between actual and local acceptable thickness. If this local area is actually corroding, it would have to corrode at a rate of approximately 17 mils/year to reach the minimum local acceptable thickness by April 2009. A corrosion rate of approximately 17 mils/year has not been observed to date (above the sandbed) and is not considered credible.

Exhibit 2



PARTIAL CROSS SECTION OF DRYWELL & TORUS

Exhibit 3

Go Back Print | New Search | Home

AR 00461639 Report

Aff Fac:	Oyster Creek	**AR Type:**	CR	**Status:**	APPROVED
Aff Unit:	01	**Owed To:**	A5352CAP	**Due Date:**	06/30/2006
Aff System:	187			**Event Date:**	03/03/2006
CR Level/Class:	4/D			**Disc Date:**	03/03/2006
How Discovered:	H02			**Orig Date:**	03/03/2006
WR/PIMS AR:		**Component #:**			

Action Request Details

Subject: CALC C-1302-187-5320-024 IS NOT CLEARLY DOCUMENTED

Description: Originator: PETER TAMBURRO Supv Contacted: Howie Ray

Condition Description:
Operability Evaluation.
The Oyster Creek Drywell Vessel is capable of performing all it design basis functions. The deficiency raises concerns with the clarity of the calculation and not with its conclusions.

Calculation C-1302-187-5320-024 is the Only Safety Related calculation that demonstrates that the 1992 as left Drywell Vessel thicknesses in the former Sandbed region meets design basis. Drywell Vessel Thickness was measured by visual, mechanical and UT inspection after sand and corrosion byproducts were removed but prior to coating application.

In general this calculation does not meet the requirements of CC-AA-309-1001 Section 4.1.3 which has the following requirements:

Provide analysis sufficiently detailed as to purpose, method, assumptions, design input, references and units, such that a person technically qualified in the subject can review and understand the analysis and verify the adequacy of the results without recourse to the originator.

Please note this calculation was generated under the GPUN Calculation Procedure EP-006. However this GPUN procedure contained the same requirement.

For example; four qualified Engineers with at least 15 years experience reviewed this calculation. None could clearly understand how the calculation methodology and acceptance criteria demonstrate the conclusions of the calculations.

Given that this calculation provides design basis for Drywell Vessel thickness in the former Sandbed region it is recommended Engineering revise this calculation so that it can be clearly understood.

The following are specific deficiencies with this calculation

Item 1 -
The measured Drywell Vessel thickness inputs for this calculation are not properly documented and traceable to the original NDE Data Sheets. The thickness values are reproduced in the calculation but there is no reference to the original data sheets, which documented the inspection results. This deficiency does not meet CC-AA-309 Step 4.3.1 and CC-AA-309-1001 and CC-AA-309-1001 Sections: 4.1.3 and 4.3.7. Please note this calculation was generated under the GPUN Calculation Procedure EP-006. However this GPUN procedure contained the same requirement.

Item 2 -

OCLR00014708

The calculation does not provide a methodology section that documents how the calculation is performed. The methodology is barely described in the calculation section. This deficiency does not meet CC-AA-309 Step 4.3.1 and CC-AA-309-1001 Sections: 4.1.3 and 4.3.7. Please note this calculation was generated under the GPUN Calculation Procedure EP-006. However this GPUN procedure contained the same requirement.

Item 3 -
The calculation develops a term called evaluation thickness based on actual measured thicknesses. This value is then compared to the design basis minimum required uniform thickness for the sandbed region of 0.736. The method in which evaluation thickness is developed is poorly explained. In addition the justification as to why it is acceptable to compare the evaluation thickness to the design basis required minimum uniform thickness of 0.736 is not documented in the calculation nor is there a reference to an industry standard.

Item 4 -
The calculation uses a Local Wall Acceptance Criteria. This criteria was developed by GE and is referenced in the calculation. The criteria can be applied to a small area (less than 12 by 12), which are less than 0.736 thick so long as the small area is at least 0.536 thick. In developing the criteria GE developed an ANSYS model of the Drywell Vessel. The model included a 12 by 12 area that was 0.536 thick at the weakest location (with respect to buckling) of the drywell. The 12 by 12 area was then surrounded by a larger 24 by 24area that transitioned from 0.536 to 0.736. The remaining thickness of the Drywell Vessel was then modeled at a uniform thickness of 0.736.

Both the GE referenced report and calculation C-1302-187-5320-024 state that in this case the ultimate theoretical buckling capacity of the drywell vessel shell is reduced by 9.5%. Calculation C-1302-187-5320-024 contains no statement or justification that a 9.5% reduction in buckling load still meets code allowables.

Item 5 -
The calculation uses a Local Wall Acceptance Criteria. This criteria 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. However the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, what is 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.

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.

Item 6 -
The calculation uses a Very Local Wall Acceptance Criteria. This criteria can be applied to small areas (less than 2 1/2 in diameter), which are less than 0.736 thick so long as the very small area is at least 0.49 thick and remaining area surrounding the very small area has a uniform thickness of greater than 0.736. However the calculation does not provide additional criteria as to the acceptable distance between multiple very small areas. For example what is the minimum required linear distances between a 2 diameter area thinner than 0.736 but thicker than 0.49 and another 2 diameter area thinner than 0.736 but thicker than 0.49.

The actual data for two bay (13 and 1) shows that there are more than one 2 diameter areas thinner than 0.736 but thicker than 0.490.

Item 7 -
The calculation uses a Very Local Wall Acceptance Criteria. This criteria can be applied to small areas (less than 2 1/2 in diameter), which are thinner than 0.736 thick so long as the very small area is at least 0.49 thick and remaining area surrounding the very small area has a uniform

thickness of greater than 0.736.

The criteria was obtained from a second calculation (C-1302-24-5320-071), which is referenced. However C-1302-24-5320-071 does a poor job of developing the basis of the criteria and does not state whether the 0.49 criteria is acceptable for buckling loads.

Item 8 -
Calculation Section 5 Sub Section Bay 1 documents that there are 8 small areas in Bay 1 all less than 2 1/2 diameter, thinner than 0.736 but thicker than 0.536. These 8 small areas are scattered in a larger area, which is approximately 25 wide and 50 long. The calculation then selects 2 of the small areas that are closest together and combines these into a 4 by 4 area. The thickness of this 4 by 4 area is then compared to the Local Wall Acceptance Criteria, which is applicable for area up to 12 by 12. The small 4 by 4 area then is judged to be the bounding area for the larger 25 by 50 area. This is then used as justification that the larger 25 by 50 area is acceptable.

However, the calculation does not reconcile between the established criteria, for a 12 by 12 area, and the actual data, which has areas thinner than 0.736 scattered over a 25 by 50 area.

Item 9 -
Calculation Section 5 Sub Section Bay 1 documents that there are 8 small areas in Bay 1 all less than 2 1/2 diameter, thinner than 0.736 but thicker than 0.536. These 8 small areas are scattered in a larger area that is approximately 25 wide and 50 long. The calculation then states that the surrounding area around the 25 by 50 area has a uniform thickness of at least 0.800 inches. However the calculation provides no reference or assumption that justifies this input. The NDE datasheets of Bay 1 do not clearly substantiate this design input.

Item 10 -
Calculation Section 5 Sub Section Bay 13 documents that there are 9 small areas in Bay 13 all less than 2 1/2 diameter, thinner than 0.736 but thicker than 0.536. These small areas are scattered in a larger area, which is approximately 25 wide and 50 long. The calculation then selects a 6 by 6 area within this region that is 0.677. This area is then compared to the Local Wall Acceptance Criteria, which is applicable for area up to 12 by 12. The smaller 6 by 6 area then is judged to be the bounding area for the larger 25 by 50 area. This is then used as justification that the large 25 by 50 area is acceptable.

However, the calculation does not reconcile between the established criteria, for a 12 by 12 area, and the actual data, which has areas thinner than 0.736 scattered over a 25 by 50 area.

Item 11 -
Calculation Section 5 Sub Section Bay 13 documents that there are 9 small areas in Bay 13 all less than 2 1/2 diameter, thinner than 0.736 but thicker than 0.536. These 9 small areas are scattered in a larger area that is approximately 25 wide and 50 long. The calculation then states that the surrounding area has a uniform thickness of at least 0.800 inches. However he calculation provides no reference or assumption that justifies this input. The NDE datasheets of Bay 13 do not clearly substantiate this design input.

Immediate actions taken:
Informed my Supervisor

Recommended Actions:
Listed below are recommendations for the calculation revision:

1) The calculation should be revised to properly reference the NDE data sheets. Critical data sheets should be attached to the calculation.

2) The calculation should have a methodology section that documents how the data is treated. Specifically, how the evaluation thickness is developed and why it s acceptable to compare the evaluation thickness to the criteria of 0.736. It would be very helpful to site an industry standard that prescribes and justifies this methodology.

3) The calculation uses a Local Wall Acceptance Criteria. The basis states that the criteria is associated with a 9.5% reduction is the ultimate theoretical buckling capacity of the drywell vessel shell. Revise calculation C-1302-187-5320-024 to state that a 9.5% reduction in buckling load still meets code allowables.

4) The calculation uses a Local Wall Acceptance Criteria. This criteria can be applied to small areas less than 12 by 12. Revise the calculation with additional criteria that defines the minimum acceptance distance between multiple local thin areas in which the Local Wall Acceptance Criteria can be applied.

5) The calculation uses a Very Local Wall Acceptance Criteria. This criteria can be applied to small areas less than 2 1/2 in diameter. Revise the calculation with additional criteria that defines the minimum acceptance distance between multiple local thin areas in which the Local Wall Acceptance Criteria can be applied.

6) The calculation uses a Very Local Wall Acceptance Criteria. This criteria can be applied to small areas less than 2 1/2 in diameter. Revise the calculation to justify that this criteria is applicable to the buckling loads.

7) The calculation documents that there are 8 small areas in Bay 1 and 9 small areas in bay 13, all less than 2 1/2 diameter, thinner than 0.736 but thicker than 0.536. In both bays the small areas are scattered in an area approximately 25 wide and 50 long. Revise the calculation to clearly demonstrate that these two areas meet design basis. The revision should clearly outline the methodology that is applied and the acceptance criteria.

What activities, processes, or procedures were involved?
License Renewal Review of the Calculation

What are the consequences?
Poor Design Basis Documentation

Were any procedural requirements impacted?
Yes - CC-AA-309-1001

Were there any adverse physical conditions?
None

List of knowledgeable individuals:
Howie Ray and Tom Quintenz

Operable Basis:

Reportable Basis:

SOC Reviewed by: RALPH C LARZO 03/06/2006 19:50:06 CST
SOC Comments:
3/6/2006 RCL: ACIT assigned to revise calculation C-1302-187-5320-024. Close to ACIT.

Exhibit 6

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF PETER TAMBURRO

Lacey Township)
)
State of New Jersey)

Peter Tamburro, being duly sworn, states as follows:

INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station ("OCNGS") operating license, and admitted by the Licensing Board on October 10, 2006.

2. The contention, as admitted by the Licensing Board states: "AmerGen's scheduled [ultrasonic testing ("UT")] monitoring frequency in the sand bed region is insufficient to maintain an adequate safety margin." The purpose of my

Affidavit is to address Citizens' allegations regarding the frequency of AmerGen's UT measurements.

3. It is my expert opinion that these allegations have no technical merit because they are based on a misinterpretation of the governing thickness criteria, calculation errors, and speculation about future conditions.

4. It is also my opinion that the frequency of UT of the sand bed region of the drywell shell reflected in AmerGen's existing commitments to the NRC is sufficient to provide reasonable assurance that the applicable thickness acceptance criteria will be met, that an adequate safety margin will be maintained during the period of extended operation under a renewed license, and that the drywell will continue to serve its intended functions.

EDUCATION AND EXPERIENCE

5. I received my B.S. degree in Chemical Engineering from Clarkson University, Potsdam, New York, in 1980. I received my M.S. in Computer Science from Fairleigh Dickinson University, Teaneck, New Jersey, in 1986. I first registered as a Professional Engineer in the State of New Jersey around 1986.

6. I currently am employed as Senior Mechanical Engineer in the Engineering Department at the Oyster Creek Nuclear Generation Station. My current responsibilities include:

➢ Implementing the above- and below-ground piping monitoring program to ensure piping is capable of performing its intended function. This includes maintaining operating history, risk-ranking plant piping systems, establishing inspection scope and criteria, analyzing inspection results, sponsoring modification and replacement based on inspection results, and overseeing the design and

installation of new piping systems. My responsibilities also include the temporary and permanent repair of piping leaks at OCNGS.

- Implementing the OCNGS Drywell Vessel Monitoring Program. This program ensures that the Drywell Vessel (a.k.a. "shell") is inspected consistent with current regulatory commitments. This includes setting scope for future inspections and analysis of inspection results.

7. My past responsibilities included designing and implementing modifications at OCNGS. This included new below- and above-ground piping from 1992 to 2006, and engineering oversight and implementation of all Security Upgrades at the plant from 1998 to 2006.

8. I am very familiar with the historical corrosion of the OCNGS drywell shell. My involvement began in 1988 when I took over the responsibility for "10 CFR 50.59" Evaluation of the issue. This included comparing the design requirements of the shell with the inspection results. This also included setting the outage-related inspection scope, and reporting to the NRC throughout that time period on the results of those inspections.

9. Since 1996, I have been responsible for ensuring upper drywell inspections are performed every other outage. I have also analyzed those inspection results.

10. With respect to license renewal, I have provided historical perspective on drywell corrosion, corrective actions, and inspection. I reviewed and commented on the drywell-related portions of the OCNGS License Renewal Application ("LRA") submitted to the NRC on July 22, 2005, and the LRA supplement submitted to the NRC on December 3, 2006.

11. I supported the NRC license renewal audits and inspections in 2006 as the lead engineer responsible for drywell–related inspections. I supported the response to the NRC Staff's requests for additional information.

12. I assisted in developing the inspection scope for the October 2006 refueling outage, and I analyzed all inspection results.

13. I also participated, as a site engineer knowledgeable about drywell issues, in meetings with the Advisory Committee on Reactor Safeguards (ACRS) on October 3, 2006, January 18, 2007 and February 1, 2007.

OPINIONS OF PETER TAMBURRO

I. Citizens' Allegation of 0.026" Remaining Margin Is Technically Unsupportable

14. I understand that Citizens have asserted that the drywell shell in the sand bed region is 0.026" or less away from exceeding the acceptance criteria for buckling developed by GE Nuclear in the early 1990s. As I explain below, this assertion is based on a misinterpretation of the 0.536" local area average thickness criterion.

15. By way of background, the acceptance criteria for the drywell shell in the Oyster Creek sand bed region are the minimum thicknesses required for the drywell to perform its intended functions. GE Nuclear analyses established these criteria in 1991 and 1992, and they form part of the Oyster Creek current licensing basis.

16. Before the sand was removed from the sand bed region, GE Nuclear performed an engineering analysis of the drywell shell to determine whether historical corrosion prevented the drywell from performing its intended functions. GE Nuclear conducted this analysis in 1991, based on ASME Code requirements, to establish the minimum

required general thickness, with the sand removed, for both pressure and buckling stresses.

17. The results of GE Nuclear's analysis show that the minimum required thickness in the sand bed region is controlled by buckling. By "controlled", I mean that for the analyses performed to model design conditions that might lead to structural degradation, the analysis for buckling showed the least margin. Moreover, a general thickness of 0.736" will satisfy ASME Code requirements with a safety factor of 2.0 against buckling for the controlling operating load combination (*i.e.*, during refueling), and 1.67 safety factor for the accident flooding load combination (*i.e.*, during operations).

18. At that time, a "very local" area thickness of 0.490", not to exceed 2.5 inches in diameter, was also identified. This "very local" thickness criterion is relevant to Citizens' argument about pinholes or holidays, which I discuss in paragraphs 42 and 43, below. However, it is not pertinent to Citizens' argument about 0.026" remaining margin, as I discuss below.

19. In 1992, GE Nuclear performed a series of sensitivity analyses on the original 0.736" criterion. These analyses sequentially evaluated locally-thinned areas using one square foot areas of 0.636" and 0.536", each with a transition to the surrounding shell at a uniform thickness of 0.736". Since Dr. Hausler only references the 0.536" analysis, I will discuss only that analysis.

20. Thus, there are two criteria relevant to Citizens' argument. The first criterion is a *general* average thickness of 0.736". An area of average thickness less than 0.736" remains adequate if it meets the second criterion, which is the 0.536" *local area* average thickness, and other factors such as location, configuration, etc. This local

area criterion includes a one-foot *transition area* to 0.736" on all four sides of the 0.536" area, such that the total allowable contiguous area with thickness below 0.736 is *nine square feet*. This is clearly shown on Figure 1 which I created, and which is based on the GE Nuclear report that was attached to the AmerGen submittal to the ACRS on December 8, 2006, as Reference 22.

21. Dr. Hausler interprets the *local area* criterion as being exceeded if the area thinner than 0.736" is greater than one square foot. He states in his June 23, 2006, memorandum that an area "approximately 1.6 square feet" thinner than 0.736" would be "well beyond the current acceptance criterion." This statement can only be based on a misunderstanding of the local area thickness criterion, which allows for nine square feet.

22. Dr. Hausler's misunderstanding seems to stem from his belief that the local area acceptance criterion is configured with an abrupt step-change (like a cliff) on all sides of the one square foot area that averages 0.536", such that the thickness increases to 0.736" with no transition. See Figure 2.

23. Thus, even if an area of approximately 1.6 square feet thinner than 0.736" existed, the local area acceptance criterion still would not be exceeded because that criterion allows for an area thinner than 0.736" of nine square feet.

24. The actual bounding general average thickness in the sand bed region is 0.800" located in Bay 19, which leaves a margin of 0.064" when compared to the 0.736" general area thickness criterion, not 0.026". All the other bays have greater margin, ranging from 0.074" in Bay 17, to 0.439" in Bay 3. The thinnest local measurement identified by Dr. Hausler was 0.618" located in Bay 13. This leaves a margin of 0.082" when compared to the 0.536" local area thickness criterion.

25. Citizens' assertion that the margin above the acceptance criteria is as low as 0.026", therefore, is not supported by the data.

26. The entirety of Dr. Hausler's argument about the 0.026" of metal thickness can be found on page 7 of his June 23, 2006 memorandum. I will now walk through Dr. Hausler's argument and demonstrate that in addition to misinterpreting the local area acceptance criterion as one square foot, his calculations also are wrong. In order to argue that this criterion will be exceeded in the future, he takes a thin point in Bay 13, and makes an assumption that future corrosion will increase the area around this point such that the area will be larger than one square foot. In other words, he speculates that corrosion—which cannot occur while the epoxy coating is intact—will make the thinned area wider.

27. Dr. Hausler bases his conclusion about 0.026" on the UT data collected from single measurement points on the exterior of the drywell shell in the sand bed region in Bay 13 in 1992.

28. In general, the drywell shell in the sand bed region of Bay 13, prior to 1992, experienced a significant amount of corrosion from the presence of wetted sand. In that bay, the corrosion caused the formation of indentations in a pattern visually similar to the surface of a golf ball. In 1992, before the exterior drywell shell was coated with epoxy, UT measurements showed that the thinnest of these indentations averaged approximately 0.800" in thickness.

29. In 1992, Bay 13 had nine, locally-thin areas less than 0.736". By "locally-thin", I mean the area was less than 2.5" in diameter. The thinnest of these locally thin areas is referred to as "point 7" which had the single thinnest reading of 0.618". Around

this point, the evaluation of the data from 1992 found a larger 6" by 6" square area that averaged at least 0.677" thick.

30. On page 7 of his June 23, 2006 memorandum, Dr. Hausler states that the total area less than 0.736" at "point 7", referring to the area which averages 0.677", is 0.3 square feet. Although the 1992 Oyster Creek reports describe this area as a 6" by 6" square area, Dr. Hausler elects to convert this area into a circular area. The corresponding radius of the circular area, which is 0.3 feet square, is 3.7 inches. I have created Figure 2 to show a profile representing these measurements.

31. Dr. Hausler's next statement is an assumption that is not supported by the data. Dr. Hausler states on page 7 of his June 23, 2006 memorandum that "this area is very sensitive to corrosion because in a length of around 5 inches, the thickness changed from around 0.736 inches to 0.800 inches. Assuming the edge of the hole is a straight line, this means that a change of 0.064 inches in depth occurs over about 5 inches in length." Dr. Hausler assumes that the transition from the thinner area less than 0.736" to areas that are 0.800" or thicker is 5" long (radially). As I said, this assumption is not supported by the data. However, if you construct a model of a hypothetical indentation as described in this unsupported assumption using the 5" transition zone and the corresponding inner radius of the 3.7", the total radius of the model is 8.7" or 17.4" in diameter. Figure 2 also shows this configuration.

32. Dr. Hausler continues with his unsupported assumptions. He concludes that "[t]hus, for the radius of the thin area to change by two inches, the depth would have to change by only 0.026"." The statement that the radius would change 2" can only be an assumption because such a change could only occur through corrosion, and corrosion on the exterior of the drywell shell in the sand bed region has been arrested.

Regardless, by expanding the radius of the indentation by 2", the diameter of the indentation would increase by 4", for a total diameter of 21.7" (this is larger than Dr. Haulser's memo which mentions 17.4" diameter). I have created Figure 3 to show the increase of the radius of the hypothetical indentation by 2".

33. Dr. Hausler then mistakenly concludes that if the 2" radius expansion occurred, then "the total area below 0.736 inches would be approximately 1.6 square feet, well beyond the current acceptance criterion." This conclusion is misleading for a number of reasons.

34. First, this conclusion is proved false by Dr. Hausler's own model. The radius of the expanded area less than 0.736" (shown on Figure 4) is 5.7". Simply calculating the area of a 5.7" radius circle results in 0.709 square feet. This value is significantly less than the 1.6 square foot value that Dr. Hausler offers.

35. Second, Dr. Hausler underestimates how much metal needs to corrode to meet his (incorrect) definition of the local area acceptance criterion. The radius of a 1.6 square foot circle is approximately 8.6". As I explain in ¶31 above, Dr. Hausler uses 8.7" for this value rather than 8.6". See Figure 2. In my opinion, by arriving at his conclusion that a 1.6 square feet area is less than 0.736", Dr. Hausler has made another assumption that the entire original 17.4" diameter indentation is less than 0.736". This assumption would require an additional section of material, 0.033" deep to simply disappear (see Figure 5). Assuming this metal disappeared through corrosion, this corrosion would be in addition to the 0.026" of corrosion that Dr. Hausler hypothesizes. I have created Figure 5 to show the material that would need to disappear (see area designated as "Second Assumed Material Loss").

36. Finally, as I state above, Dr. Hausler then misinterprets the local area acceptance criterion by assuming that an area of one square foot that is thinner than 0.736" exceeds that criterion. He is wrong and I have created Figure 6 to show how the additional corrosion that Dr. Hausler postulates would not exceed the local area thickness criterion. In Figure 6, I have reproduced the acceptance criteria profile from Figure 1, and overlaid Dr. Hausler's assumed contour from Figure 5. The new Figure clearly shows that the acceptance criterion is not exceeded.

II. A Future 0.017" Annual Corrosion Rate Is Also Technically Unsupportable

37. Citizens next argue that corrosion rates around 0.017" per year have been observed. Corrosion rates in the range of .017" per year were observed in the sand bed region prior to 1992. Those rates were developed based upon UT data gathered between 1987 and 1992.

38. If Citizens are suggesting that a corrosion rate of 0.017" per year continued to occur after removal of the sand in 1992, or could occur in the future, they are incorrect for numerous reasons.

39. First, such an allegation ignores corrective actions implemented to date. Much has happened to prevent corrosion from continuing in the sand bed region of the drywell shell. The source of water—the flooded reactor cavity liner during refueling outages—has been identified and controlled. No water is expected to reach the sand bed region when strippable coating is applied to the reactor cavity during refueling outages. Even if some water did reach the sand bed region during refueling outages, the sand has been removed so there is no media to physically hold the water against the drywell shell's exterior. And the historic corrosion occurred because the drywell

shell in the sand bed region was *not* coated. The exterior shell is now protected by a three-layer epoxy coating.

40. Second, if a corrosion rate of 0.017" per year had occurred between 1992 and 2006, it would have been readily detected by the VT-1 and UT performed during the 2006 refueling outage. VT-1 inspections are visual inspections performed in accordance with ASME Section XI subsection IWE, by ASME-qualified inspectors. Based on the information contained in the VT-1 inspection reports generated for the coating in all ten external drywell bays during the October 2006 outage, the epoxy coating is in good condition with no defects or deterioration.

41. AmerGen also collected UT measurement data from both the interior and exterior of the drywell shell in the sand bed region during the 2006 refueling outage. Between 1992 and 2006, the alleged rate of corrosion of 0.017" per year would have resulted in a loss of 0.238" of metal from the drywell shell (0.017" x 14 years), which would easily have been detected, as it is well within the expected equipment measurement error of 0.020". Yet the UT data, coupled with the VT-1 inspection results, confirmed that corrosion on the exterior of the drywell shell has been arrested.

42. Third, even if there was a 0.017" per year corrosion rate, Citizens only have argued that it would be localized. Specifically, Dr. Hausler, in his July 2006 memorandum, speculates that there might be tiny holes—"pinholes" or "holidays"—in the epoxy coating which could allow water to contact the exposed shell in the pinhole or holiday, causing very localized corrosion.

43. Such very localized corrosion would not call into question the appropriateness of AmerGen's UT frequency. Pinholes and holidays are analyzed against the "very local" area acceptance criterion of 0.490" which applies to areas not to exceed 2.5 inches in diameter. The thinnest external point measurement identified by Dr. Hausler was 0.618" located in Bay 13. Simple math demonstrates that there is 0.128" of margin available for a pinhole or holiday in this thinned area in Bay 13 (*i.e.*, 0.618"-0.490"), and that it would take over seven years for this margin to disappear with a corrosion rate of 0.017" per year (*i.e.*, 0.128"/0.017"). AmerGen, however, is performing UT measurements and visual inspections of the drywell shell in the sand bed region, from internal and external locations, in 2008 and then every four years.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Pete Tamburro

Peter Tamburro
Oyster Creek Nuclear Generating Station
Route 9
Forked River, NJ 08731

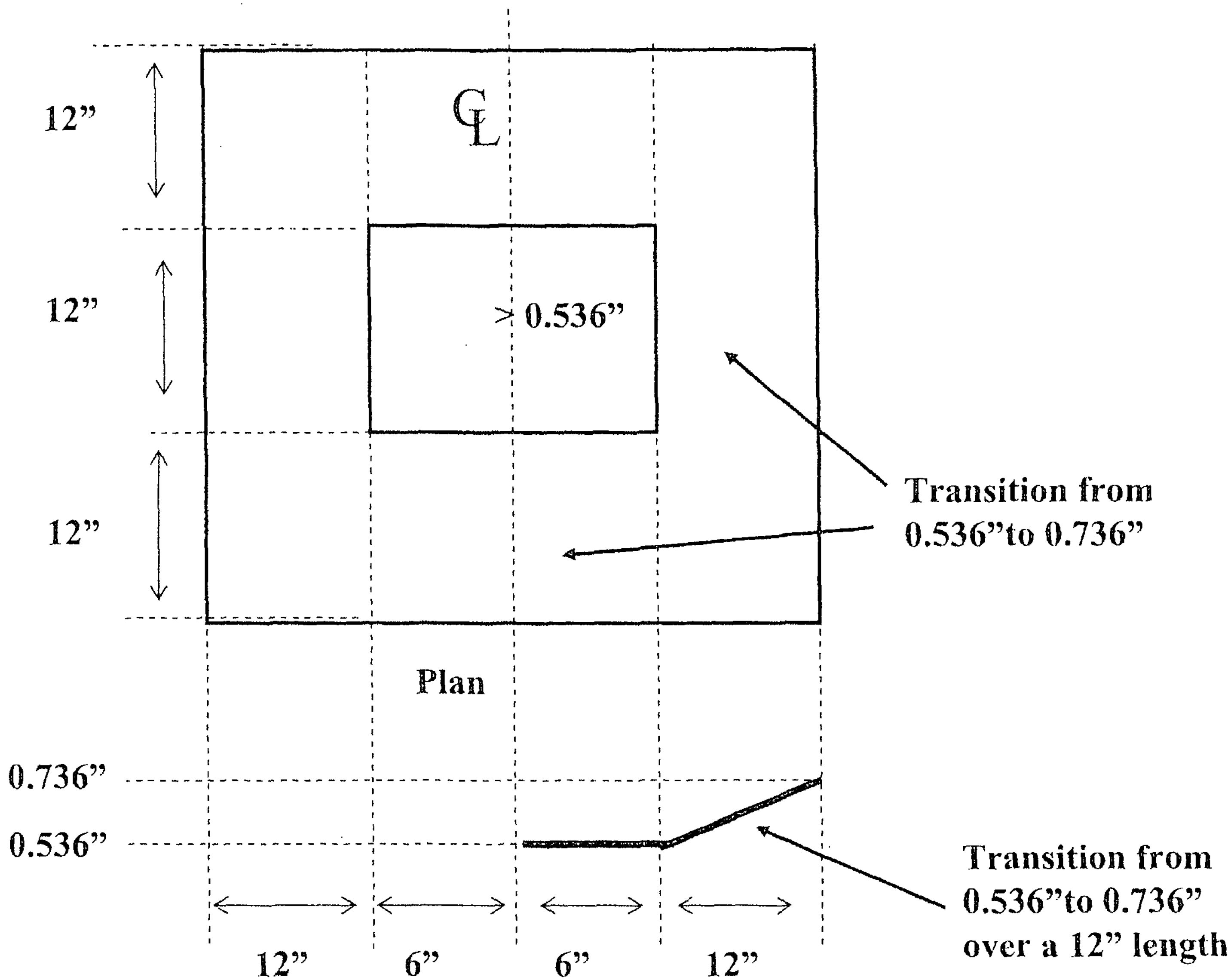
Subscribed and sworn before me this 26 day of March 2007.

Valerie Laudeman

Notary Public

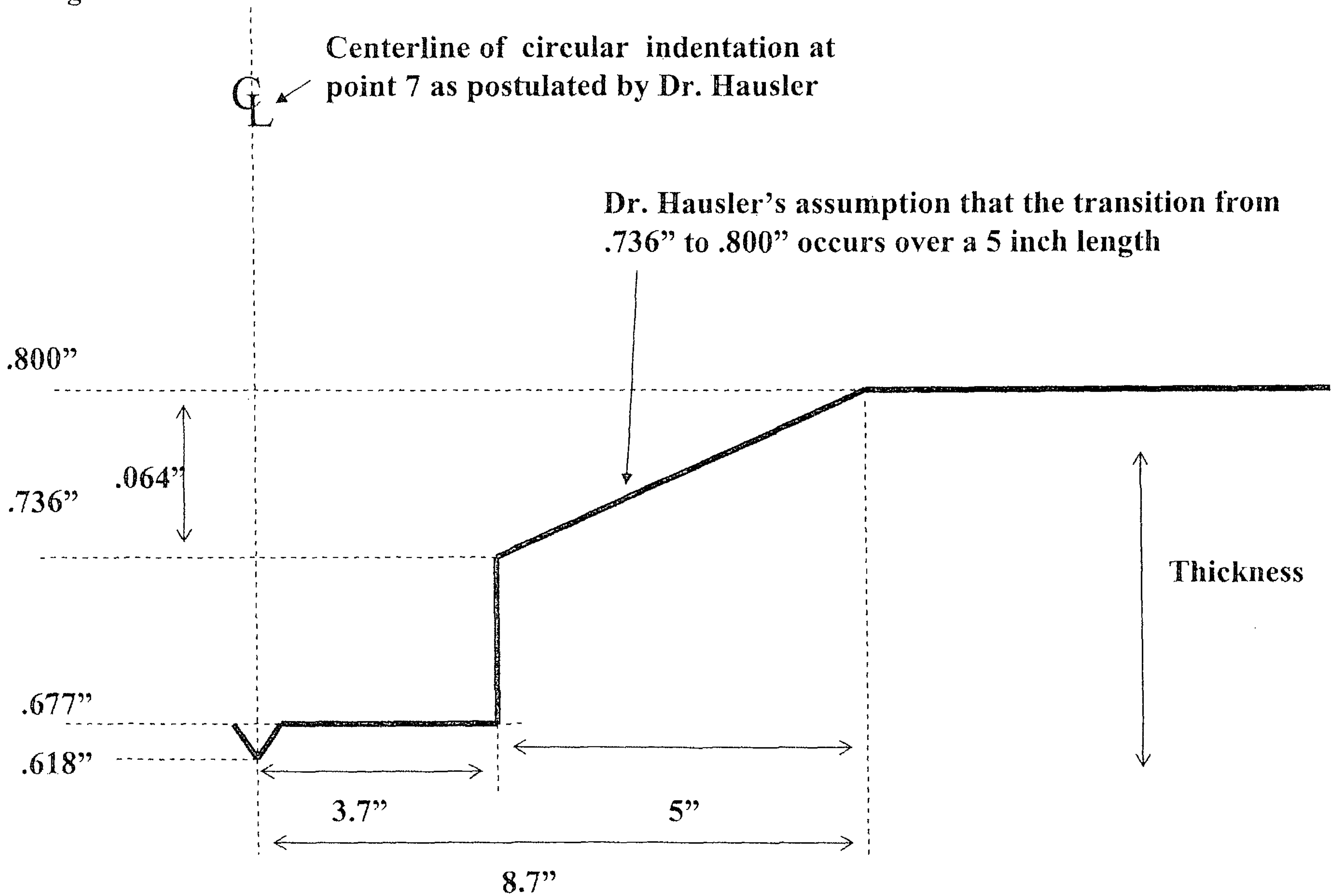
My Commission Expires: VALERIE LAUDEMAN NOTARY PUBLIC OF NEW JERSEY Commission Expires 9/25/2010

Figure 1 Schematic Demonstrating Local Area Average Acceptance Criterion



Not to Scale

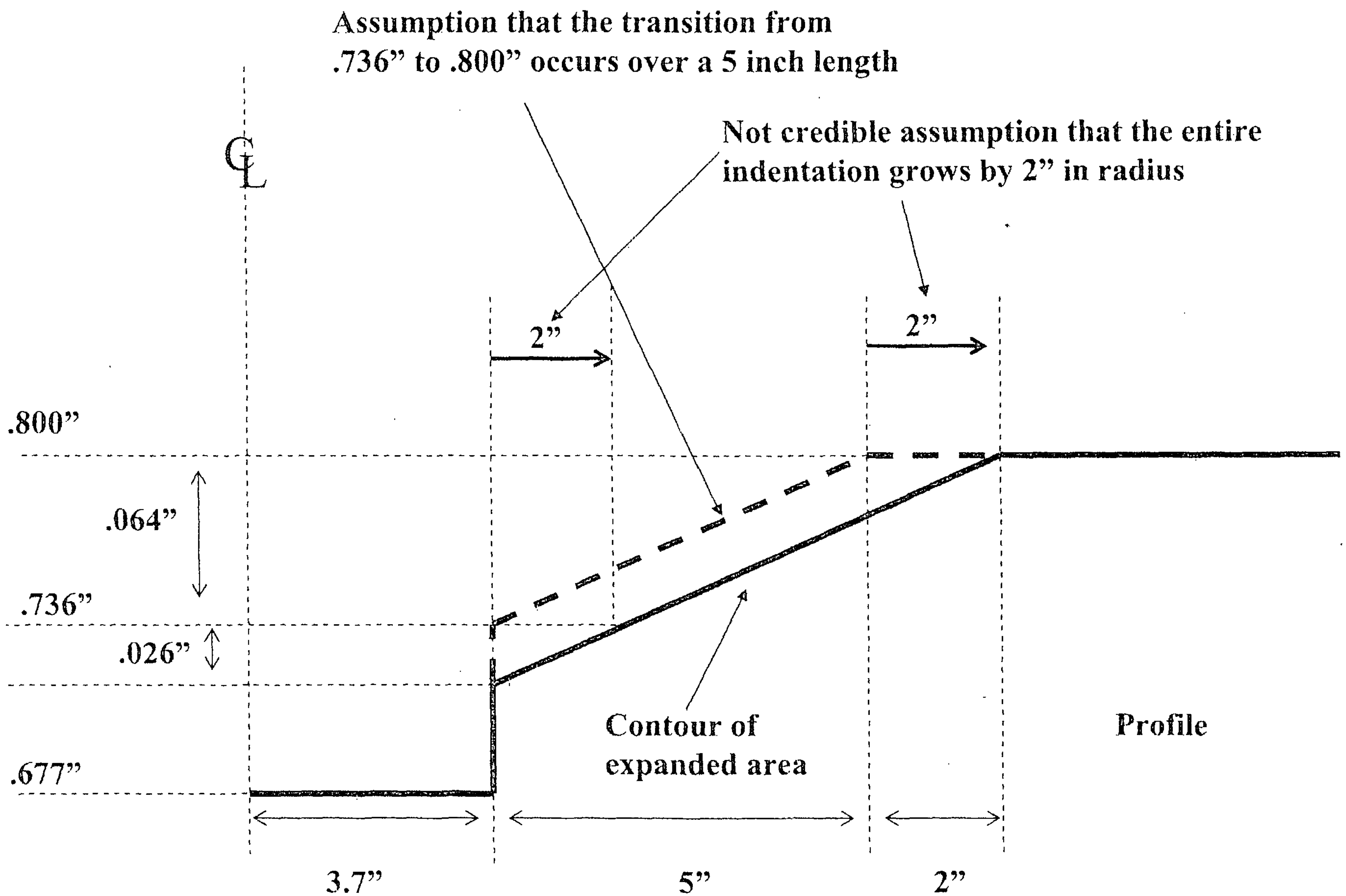
Figure 2



Not to Scale

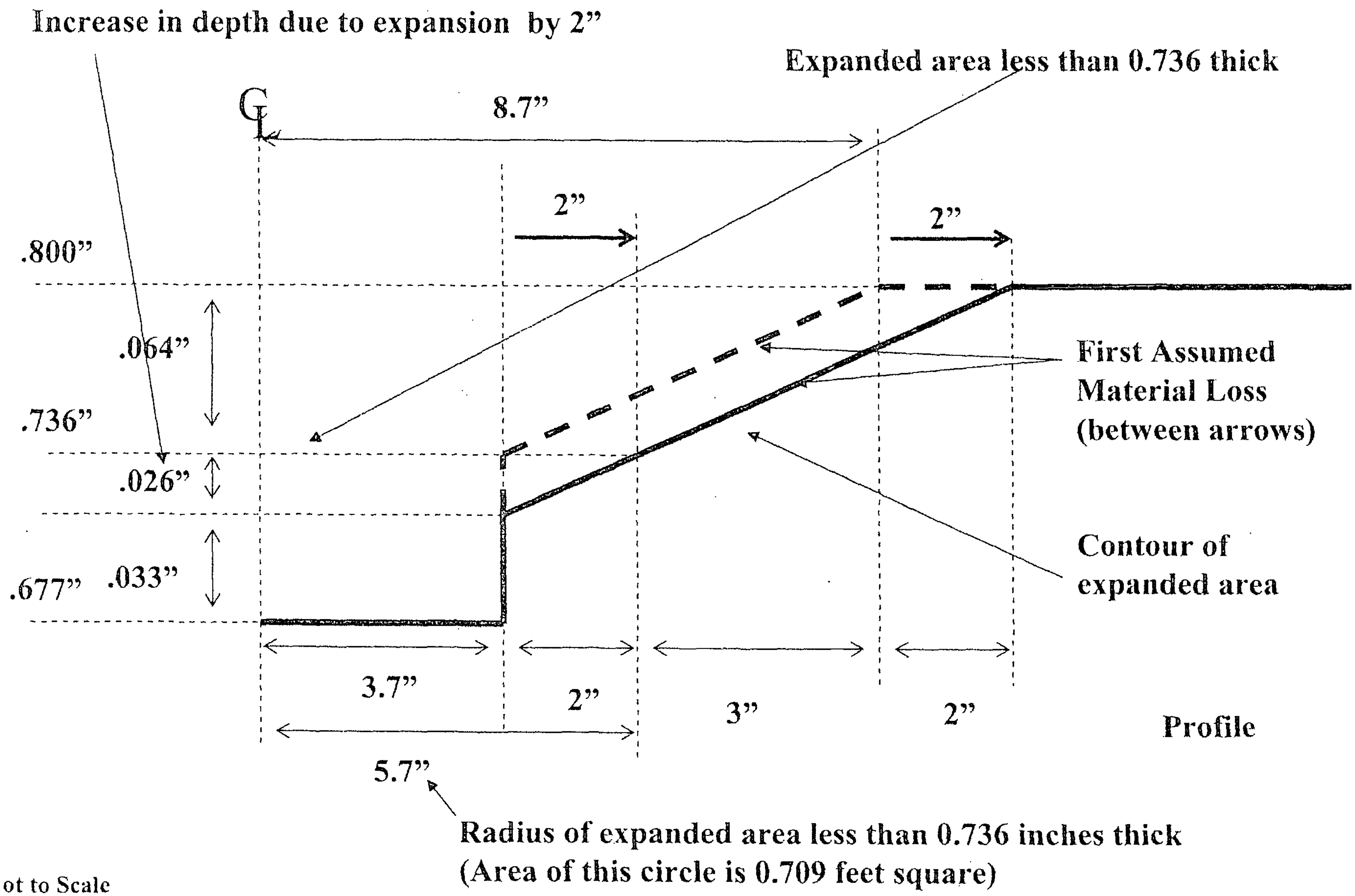
Profile

Figure 3



Not to Scale

Figure 4



Not to Scale

Figure 5

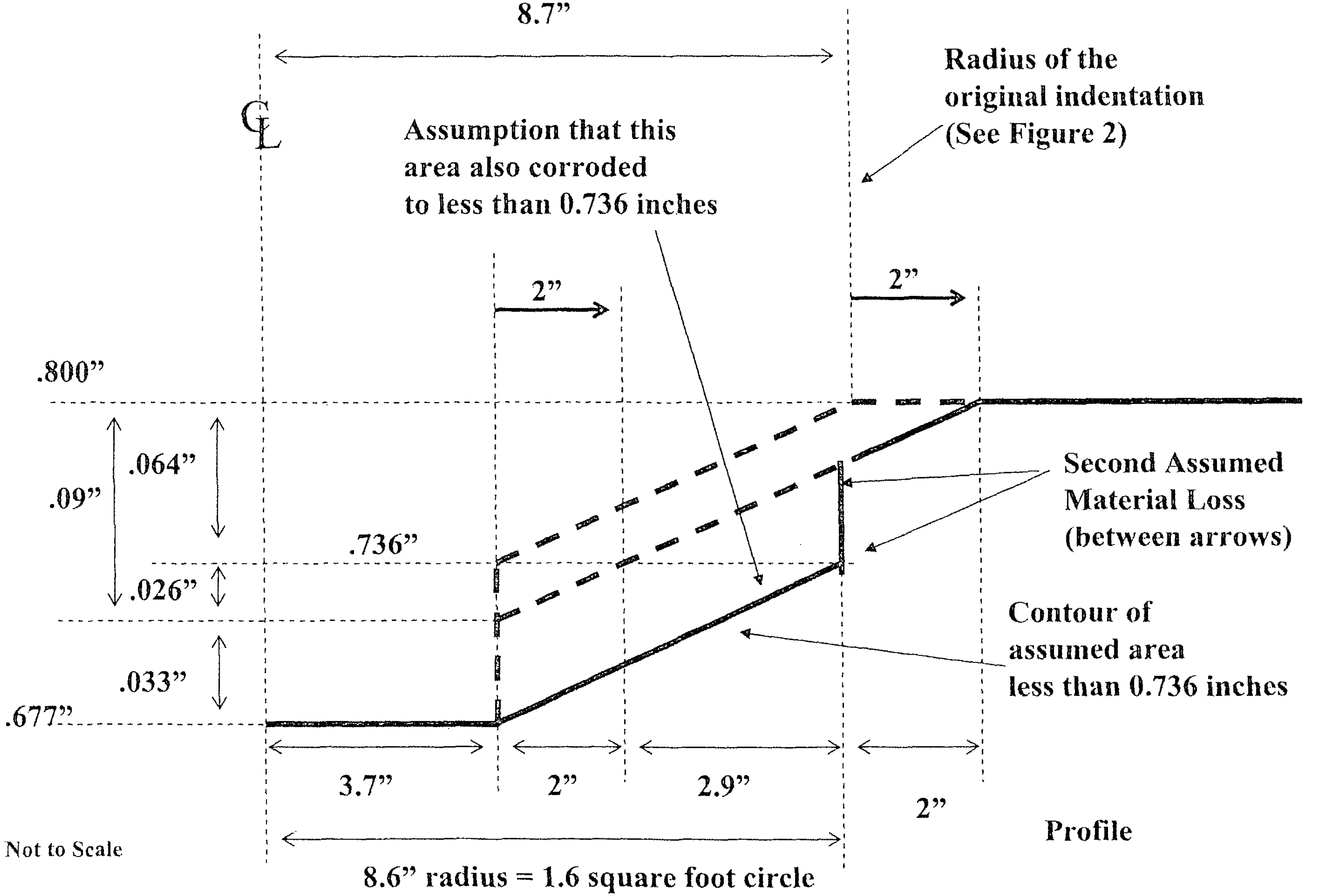


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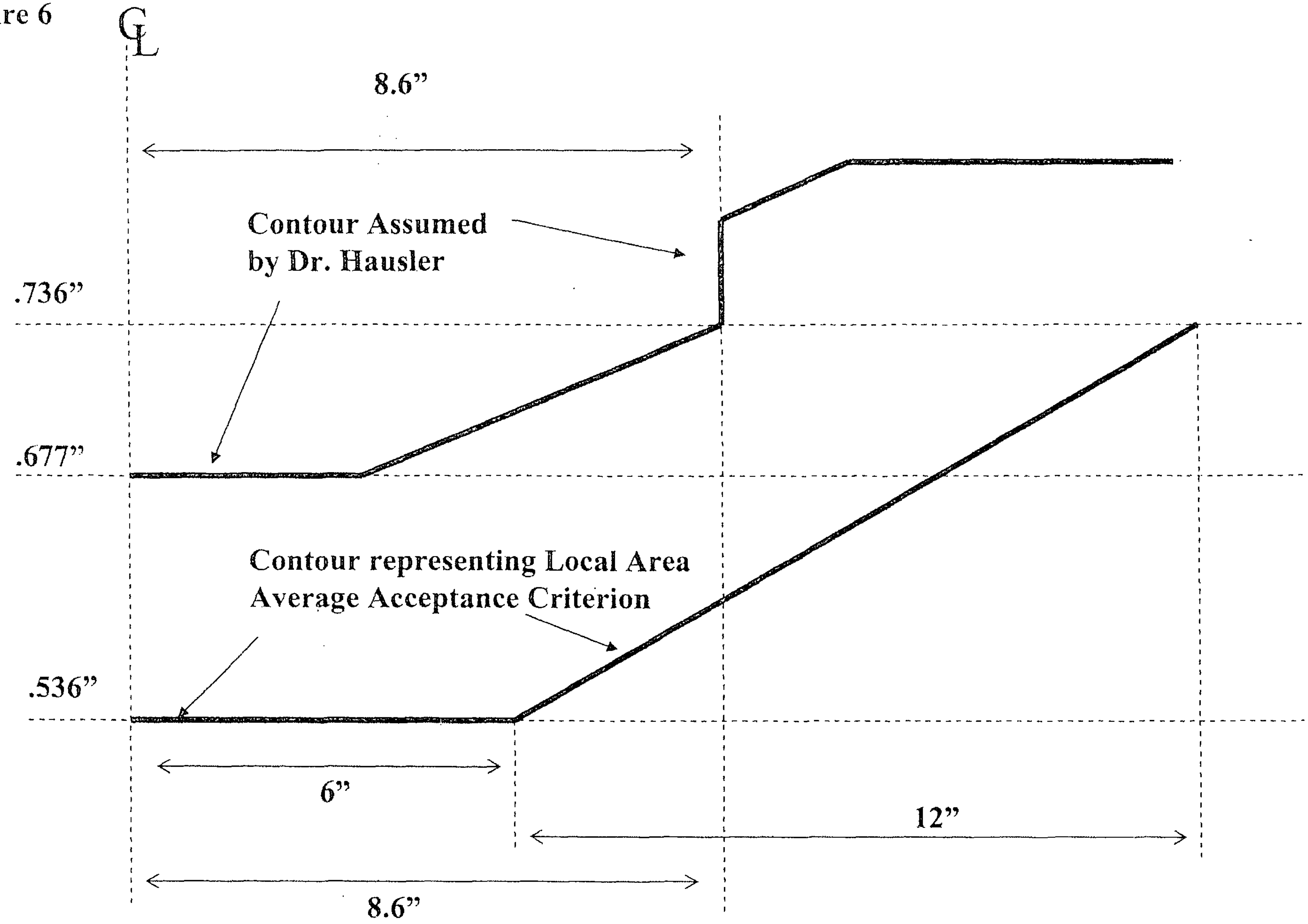
Figure 6



Not to Scale

Profile

Exhibit 7

Citizen's Exhibit NC1

From: <George.Beck@exeloncorp.com>
To: <dja1@nrc.gov>, <rkm@nrc.gov>
Date: 04/05/2006 5:02:53 PM
Subject: FW: Audit Q & A (Question Numbers AMP-141, 210, 356)

Note: As originally transmitted this email was undeliverable to the NRC; it exceeded the size limit. It is being retransmitted without the AMP-210.pdf. This file will be reconstituted and sent in smaller ".pdf"s; the first 11 pages are attached.

George

> -----Original Message-----
> From: Beck, George
> Sent: Wednesday, April 05, 2006 4:39 PM
> To: Donnie Ashley (E-mail); 'Roy Mathew (E-mail) ' (E-mail)
> Cc: Ouaou, Ahmed; Hufnagel Jr, John G; Warfel Sr, Donald B; Polaski, Frederick W
> Subject: Audit Q & A (Question Numbers AMP-141, 210, 356)
>
> Donnie/Roy,
>
> Attached are the responses to AMP-210 and AMP-356 in an updated version of the reports from the AMP/AMR Audit database. Also included is a revised version of AMP-141. These answers have been reviewed and approved by Technical Lead, Don Warfel.
>
> Regarding AMP-210, please note:
> As pointed out in our response to NRC Question AMP-210, (8a)(1), "The 0.806" minimum average thickness verbally discussed with the Staff during the AMP audit was recorded in location 19A in 1994. Additional reviews after the audit noted that lower minimum average thickness values were recorded at the same location in 1991 (0.803") and in September 1992 (0.800"). However, the three values are within the tolerance of +/- 0.010" discussed with the Staff."
>
> Regarding AMP-141, please note:
> Our response to AMP-141 has been revised to reflect additional information developed during the ongoing preparation of RAI responses.
>
> Please let John Hufnagel or me know if you have any questions.
>
> George
>
>
>
> >> <<Pages from AMP-210.pdf>>
> >> <<AMP-141.pdf>>
>
>> <<AMP-356.pdf>>
>
>

****

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CC: <ahmed.ouaou@exeloncorp.com>, <john.hufnagel@exeloncorp.com>, <donald.warfel@exeloncorp.com>, <fred.polaski@exeloncorp.com>

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Subject: FW: Audit Q & A (Question Numbers AMP-141, 210, 356)
Creation Date: 04/05/2006 5:01:46 PM
From: <George.Beck@exeloncorp.com>

Created By: George.Beck@exeloncorp.com

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Pages from AMP-210.pdf	64593	
AMP-141.pdf	47353	
AMP-356.pdf	71556	
Mime.822	262768	

Options
Expiration Date: None
Priority: Standard
Reply Requested: No
Return Notification: None

Concealed Subject: No
Security: Standard

3

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Item No
AMP-210

Date Received: 1/24/2006

Source AMP Audit

Topic:
IWE

Status: Open

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

Pages 25 through 31 of the PBD present a discussion of the OCGS operating experience.

(8a)The following statements related to drywell corrosion in the sand bed region need further explanation and clarification:
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.
Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning found only in these areas?
After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements.
Please describe the concrete surface below the sand that is discussed in paragraph above.
Please provide the following information:
(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster

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Creek sand bed region.

Evaluation of UT measurements taken from inside the drywell, in the in the former sand bed region, in 1992, 1994, and 1996 confirmed that corrosion is mitigated. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.
NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

(8b)The following statement related to drywell corrosion above the sand bed region needs further explanation and clarification:

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.

Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements". Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

(8c)The following statements related to torus degradation need further explanation and clarification:
Inspection performed in 2002 found the coating to be in good condition in the vapor area of the Torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function.
While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continues to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established

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in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to 50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Assigned To: Ouaou, Ahmed

Response:

(8a) Question: Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning only in these area?

Response:
This statement was not meant to indicate that water leaks were limited to only a portion of the circumference. The statement is meant to reflect the fact that water leakage was observed coming out of certain sand bed region drains and those locations were suspect of wall thinning.
No. Wall thinning was not limited to the areas where water leakage from the drains was observed. Wall thinning occurred in all areas of the sand bed region based on UT measurements and visual inspection of the area conducted after the sand was removed in 1992. However the degree of wall thinning varied from location to location. For example 60% of the measured locations in the sand bed region (bays 1, 3, 5, 7, 9, and 15) indicate that the average measured drywell shell thickness is nearly the same as the design nominal thickness and that these locations experienced negligible wall thinning; whereas bay 19A experienced approximately 30% reduction in wall thickness.

Question: Please discuss the concrete surface below the sand that is discussed in paragraph above.

Response:
The concrete surface below the sand was intended to be shaped to promote flow toward each of the five sand bed drains. However once the sand was removed it was discovered that the floor was not properly finished and shaped as required to permit proper drainage. There were low points, craters, and rough surfaces that could allow moisture to pool instead of flowing smoothly toward the drains. These concrete surfaces were refurbished to fill low areas, smooth rough surfaces, and coat these surfaces with epoxy coating to promote improved drainage. The drywell shell at juncture of the concrete floor was sealed with an elastomer to prevent water intrusion into the embedded drywell shell.

Question: Please provide the following information:

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(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster Creek sand bed region.

Response:
1. The minimum recorded thickness in the sand bed region from outside inspection is 0.618 inches. The minimum recorded thickness in the sand bed region from inside inspections is 0.603. These minimum recorded thicknesses are isolated local measurement and represent a single point UT measurement. The 0.806 inches thickness provided to the Staff verbally is an average minimum general thickness calculated based on 49 UT measurements taken in an area that is approximately 6"x 6". Thus the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806".

The 0.806" minimum average thickness verbally discussed with the Staff during the AMP audit was recorded in location 19A in 1994. Additional reviews after the audit noted that lower minimum average thickness values were recorded at the same location in 1991 (0.803") and in September 1992 (0.800"). However, the three values are within the tolerance of +/- 0.010" discussed with the Staff.

2. The minimum projected thickness depends on whether the trended data is before or after 1992 as demonstrated by corrosion trends provided in response to NRC Question #AMP-356. For license renewal, using corrosion rate trends after 1992 is appropriate because of corrosion mitigating measures such as removal of the sand and coating of the shell. Then, using corrosion rate trends based on 1992, 1994, and 1996 UT data; and the minimum average thickness measured in 1992 (0.800"), the minimum projected average thickness through 2009 and beyond remains approximately 0.800 inches. The projected minimum thickness during and through the period of extended operation will be reevaluated after UT inspections that will be conducted prior to entering the period of extended operation, and after the periodic UT inspection every 10 years thereafter.

3.The engineering analysis that demonstrated compliance to ASME code requirements was performed in two parts, Stress and Stability Analysis with Sand, and Stress and Stability Analyses without Sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4, were transmitted to the NRC Staff in December 1990 and in 1991 respectively. Index No. 9-3 and 9-4, were revised later to correct errors identified during an internal audit and were resubmitted to the Staff in January 1992 (see attachment 1 & 2). The analyses are briefly described below.

The drywell shell thickness in the sand bed region is based on Stability Analysis without Sand. As

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described in detail in attachment 1 & 2, the analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches.

As discussed with the Staff during the AMP audit, the basic approach used in the buckling evaluation follows the methodology outlined in ASME Code Case N-284 revision 0 that was reconciled later with revision 1 of the Code Case. Following the procedure of this Code Case, the allowable compressive stress is evaluated in three steps. In the first step, a theoretical buckling stress is determined, and secondly modified using appropriate capacity and plasticity reduction factors. In the final step, the allowable compressive stress is obtained by dividing the buckling stress calculated in the second step by a safety factor of 2.0 for Design and Level A & B service conditions and 1.67 Level C service conditions.

Using the approach described above, the analysis shows that for the most severe design basis load combinations, the limits of ASME Section III, Subsection NE 3213.10 are fully met. For additional details refer to Attachment 1 & 2.

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.

The minimum thickness of 0.733" is not correct. The correct minimum thickness is 0.736".

4. The minimum required thickness for the sand bed region is controlled by buckling.

5. We cannot reconcile the difference between the current (lowest measured) of 0.736" in NUREG-1540 and the minimum measured thickness of 0.806 inches we discussed with the Staff. Perhaps the value in NUREG-1540 should be labeled minimum required by the Code, as documented in several correspondences with the Staff, instead of lowest measured. In a letter dated September 15, 1995, GPU provided the Staff a table that lists sand bed region thicknesses. The table indicates that nominal thickness is 1.154". the minimum measured thickness in 1994 is 0.806", and the minimum thickness required by Code is 0.736". These thicknesses are consistent with those discussed with the Staff during the AMP/AMR audit.

Question: NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

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Response:

Our review of NUREG-1540, page 2 indicates that the statements appear to be based on 1991, or 1993 GPU commitment to perform periodic UT measurements. In fact UT thickness measurements were taken in the sand bed region from inside the drywell in 1992, and 1994. The trend of the UT measurements indicates that corrosion has been arrested. As results GPU informed NRC in a letter dated September 15, 1995 (ref. 2) that UT measurements will be taken one more time, in 1996, and the epoxy coating will be inspected in 1996 and, as a minimum again in 2000. The UT measurements were taken in 1996, per the commitment, and confirmed corrosion rate trend of 1992 and 1994. The results of 1992, 1994, and 1996 UT measurements were provided to the Staff during the AMP/AMR audits.

In response to GPU September 15, 1995 letter, NRC Staff found the proposed changes to sand bed region commitments (i.e. no additional UT measurements after 1996) reasonable and acceptable. This response is documented in November 1, 1995 Safety Evaluation for the Drywell Monitoring Program.

For license renewal, Oyster Creek was previously committed to perform One-Time UT inspection of the drywell shell in the sand bed region prior to entering the period of extended operation. However, in response to NRC Question #AMP-141, Oyster Creek revised the commitment to perform UT inspections periodically. The initial inspection will be conducted prior to entering the period of extended operation and additional inspections will be conducted every 10 years thereafter. The UT measurements will be taken from inside the drywell at same locations as 1996 UT campaign

(8b) Question: Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements. Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

Response:
The measures taken to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to maintain the ASME code requirements are,
1. Cleared the former sand bed region drains to improve the drainage path.
2. Replaced reactor cavity steel trough drain gasket, which was found to be leaking.
3. Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.
4. Confirmed that the reactor cavity concrete trough drains are not clogged
5. Monitored former sand bed region drains and reactor cavity concrete trough drains for leakage during refueling outages and plant operation.

Oyster Creek is committed to implement these measures during the period of extended operation.

(8c) Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to

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50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Response:
(1) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, specifies repair requirements for coating defects exposing substrate and fractured blisters showing signs of corrosion. The repairs referred to in the inspection report included fractured blisters, as well as any mechanically damaged areas, which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters would be candidates for repair, not those blisters that remain intact. The number and location of repairs are tabulated in the final inspection report prepared by Underwater Construction Corporation.
(2) Coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001. Several blistered areas included pitting corrosion where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

(3) In addition to blistering, random deficiencies that exposed base metal were identified in the torus immersion region coating (e.g., minor mechanical damage) during the 19R (2002) torus coating inspections. They ranged in size from 1/16" to ½" in diameter. Pitting in these areas was qualitatively evaluated and ranged from less than 10 mils to slightly more than 40 mils in a few isolated cases. Three quantitative pit depth measurements were taken in several locations in the immersion area of Bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to be representative of typical conditions found on the shell.

Prior to 2002 inspection 4 pits greater than 0.040" were identified. The pits depth are 0.058" (1 pit in 1988), 0.05" (2 pits in 1991), and 0.0685" (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found to be acceptable.

(4) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, includes the pit-depth acceptance criteria for rapid evaluation of observed pitting. The acceptance criteria are supported by a calculation C-1302-187-E310-038. Locations that do not meet the pit-depth acceptance criteria are characterized based on the size of the area, center to center distance between corroded areas, the maximum pit depth and location in the Torus based on major structural features. These details are sent to Oyster Creek Engineering for evaluation.

(5) The acceptance criteria for pit depth is as follows:
-Isolated Pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center to center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated.

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-Multiple Pits that can be encompassed by a 2-1/2" diameter circle shall be limited to a maximum pit depth of 0.141" provided the center to center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or recoated.

Question: Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Response:
Submersed area:
(a) The nominal Design thickness is 0.385 inches
(b) The as-built thickness is 0.385 inches
(c) The minimum uniform measured thickness is,
 0.343 inches - general shell
 0.345 inches - shell - ring girders
 0.345 inches - shell - saddle flange
 0.345 inches - shell - torus straps

(d) The minimum general thickness required to meet ASME Code Acceptance is 0.337 inches.

Technical basis for pitting acceptance criteria included in Specification SP-1302-52-120 is based on engineering calculation C-1302-187-E310-038. At the time of preparation of calculation C-1302-187-E310-038 in 2002 there were no published methods to calculate acceptance standards for locally thinned areas in ASME Section III or Section VIII Pressure Vessel codes. Therefore, the approach in Code Case N-597 was used as guidance in assessing locally thinned areas in the Torus. This is based on the similarity in approaches between Local Thinning Areas described in N597 and Local Primary Stress areas described in Paragraph NE3213.10 of the ASME B&PV Code Section III, particularly small areas of wall thinning which do not exceed 1.0 x (square root of Rt). In addition, the ASME B&PV Code Section III, Subsection NB, Paragraph NB-3630 allows the analysis of pipe systems in accordance with the Vessel Analysis rules described in Paragraph NB-3200 of the same Subsection as an alternate analysis approach. Therefore, the approach used in N597 for local areas of thinning was probably developed using the rules for Local Primary Membrane Stress from paragraph NB-3200 in particular Subparagraph 3213.10. The Local Primary Stress Limits in NB-3213.10 are similar to those discussed in Subsection NE, Paragraph NE-3213.10.

Since the Code Case had not yet been invoked in to the Section XI program, the calculation provided a reconciliation of the results obtained from the code case against the ASME Section III code requirements as discussed above. This reconciliation demonstrated that the approach in N597 used on a pressure vessel such as the Torus would be acceptable since the results are conservative compared to the previous work performed in MPR-953 and Lm(a) (defined in N597 Table- 3622-1) £ (Rmintmin)1/2.

Currently, the maximum pit depth measured in the Torus is a 0.0685" (measured in 1992 in bay 2). It was evaluated as acceptable using the design calculations existing at that time and was not based on

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Calculation C-1302-187-E310-038. This remains the bounding wall thickness in the Torus. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Section III and VIII Code requirements for the Torus.

The Torus inspection program is being enhanced per IR 373695 to improve the detail of the acceptance criteria and margin management requirements using the ASME Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If Code Case N-597-1 is required to develop these criteria for future inspections, NRC review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to periodically monitor to verify they remain bounded.

LRCR #: *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/ 5/2006

Reviewed By: Miller, Mark 4/ 5/2006

Approved By: Warfel, Don 4/ 5/2006

NRC Acceptance (Date):

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Item No	*Date Received:*	*Source*
AMP-356	2/16/2006	AMP Audit
	Status:	Open

Topic:
IWE

Document References:

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

IWE AMP
Question 4 IWE AMP Revised Feb. 17, 2006 R. Morante (AMP-356)

(1) Identify the specific locations around the circumference in the former sandbed region where UT thickness readings have been and will be taken from inside containment. Confirm that all points previously recorded will be included in future inspections.

(2) Describe the grid pattern at each location (meridional length, circumferential length, grid point spacing, total number of point readings), and graphically locate each grid pattern within the former sandbed region.

(3) For each grid location, submit a graph of remaining thickness versus time, using the UT readings since the initiation of the program (both prior to and following removal of the sand and application of the external coating).

(4) Clearly describe the methodology and acceptance criteria that is applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) evaluation.

Assigned To: Ouaou, Ahmed

Response:

Response:
1. The circumference of the drywell is divided into 10 bays, designated as Bays 1, 3, 5, 7, 9, 11, 13, 15, 17, and 19. UT thickness readings have been taken in each bay at one or more locations. The specific locations around the circumference in the former sand bed region where UT thickness reading have been taken from inside containment are Bay 1D, 3D, 5D, 7D, 9A, 9D, 11A, 11C, 13A, 13C, 13D, 15A, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C. For each location, UT measurements were taken centered at elevation 11'-3". These represent the locations where UT measurements were taken in 1992, 1994, and 1996.

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In addition UT measurements were taken one time inside 2 trenches excavated in drywell floor concrete. The purpose of these UT measurements is to determine the extent of corrosion in the lower portions of the sand bed region prior to removing the sand and making accessible for visual inspection.

Future UT thickness measurements will be taken at the same locations as those inspected in 1996 in accordance with Oyster Creek commitment documented in NRC Question #AMP-209.

2. For locations where the initial investigations found significant wall thinning (9D, 11A, 11C, 13A, 13D, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C) the grid pattern consists of 7 x 7 grid centered at elevation 11'-3 (meridian) and centered at the centerline of the tested location within each bay, which consists of 6"x 6" square template. The grid spacing is 1" on center. There are 49 point readings. For graphical location of the grid, refer to attachment 1.

For locations where the initial investigations found no significant wall thinning (1D, 3D, 5D, 7D, 9A, 13C, and 15A) the grid pattern consists of 1 x 7 grid centered at elevation 11'-3" (meridian) on 1" centers. There are 7 point readings. For graphical location of the grid, refer to attachment 1.

3. A graph representing the remaining thickness versus time using UT reading since the initiation of the program (both prior to and following removal of the sand and application of the external coating) for location 9D, 11A, 11C, 13A, 13D,15D,17A,17D,17/19, 19A, 19B, and 19C is included in the attached graph. Other locations (i.e. 1D, 3D, 5D, 7D, 9A, 13C, and 15A) are not included because wall thinning is not significant and the trend line will be essentially a straight line.

4. The methodology and acceptance criteria that is applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) is described in engineering specification IS-328227-004 and in calculation No. C-1302-187-5300-011. These documents were submitted to the NRC in a letter dated November 26, 1990 and provided to the Staff during the AMP/AMR audit. A brief summary of the methodology and acceptance criteria is described below.

The initial locations where corrosion loss was most severe in 1986 and 1987 were selected for repeat inspection over time to measure corrosion rate. For location where the initial investigations found significant wall thinning UT inspection consists of 49 individual UT data points equally spaced over a 6"x 6" area. Each new set of 49 values was then tested for normal distribution.

The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736. In addition each individual reading is compared to the local minimum required criteria of 0.49. The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to NRC Question #AMP-210.

A decrease in the mean value over time is representative of corrosion. If corrosion does not exist, the mean value will not vary with time except for random variations in the UT measurements.

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If corrosion is continuing, the mean thickness will decrease linearly with time. Therefore the curve fit of the data is tested to determine if linear regression is appropriate, in which case the corrosion rate is equal to the slope of the line. If a slope exists, then upper and lower 95% confidence intervals of the curve fit are calculated. The lower 95% confidence interval is then projected into the future and compared to the required minimum uniform thickness criteria of 0.736.

A similar process is applied to the thinnest individual reading in each grid. The curve fit of the data is tested to determine if linear regression is appropriate. If a slope exists, then the lower 95% confidence interval is then projected into the future and compared to the required minimum local thickness criteria of .49.

LRCR #: *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/ 4/2006

Reviewed By: Getz, Stu 4/ 5/2006

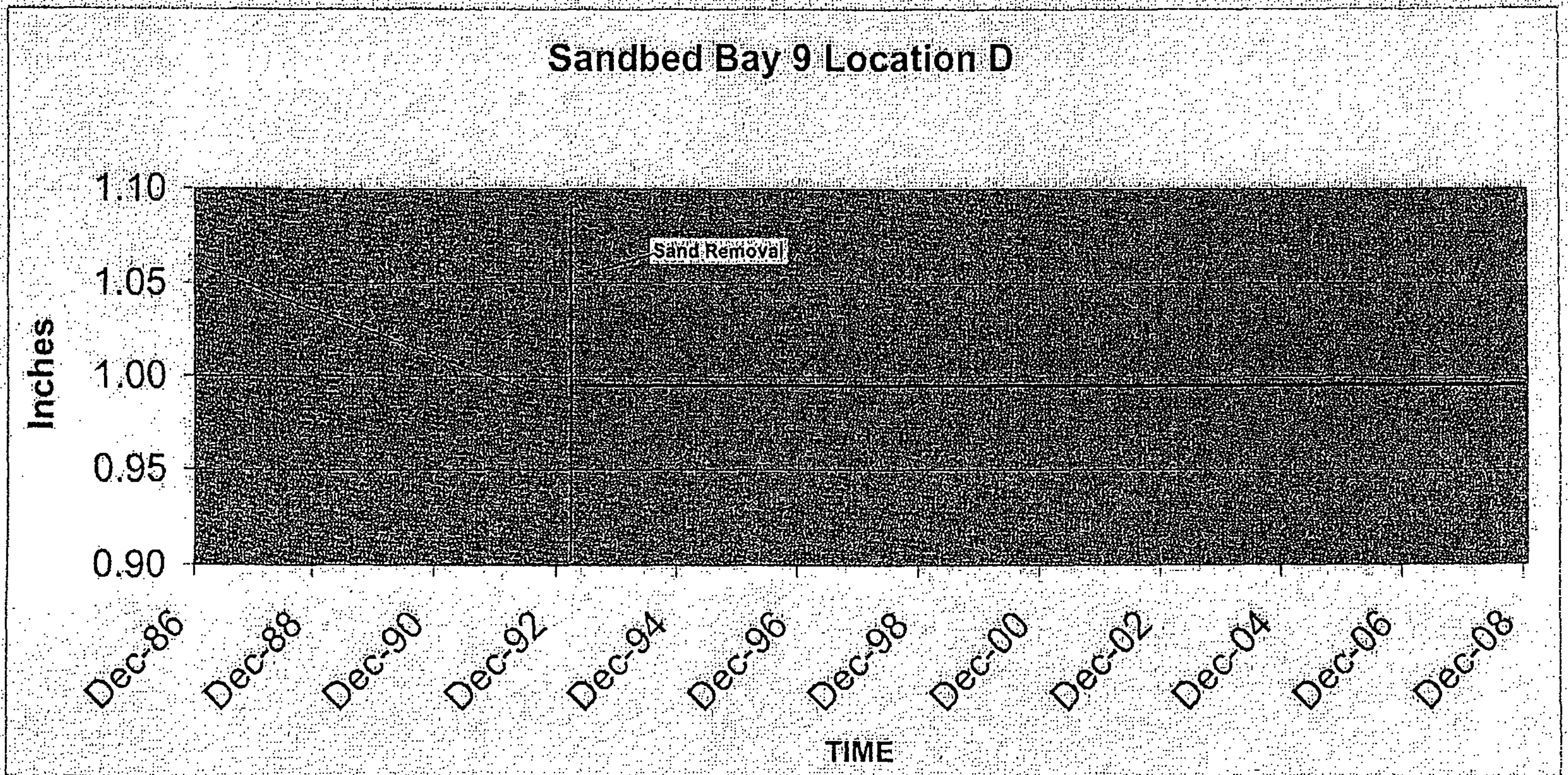
Approved By: Warfel, Don 4/ 5/2006

NRC Acceptance (Date):

Oyster Ceek Drywell Vessel Corrosion Rate Trending Program

Average Measured Thicknesses

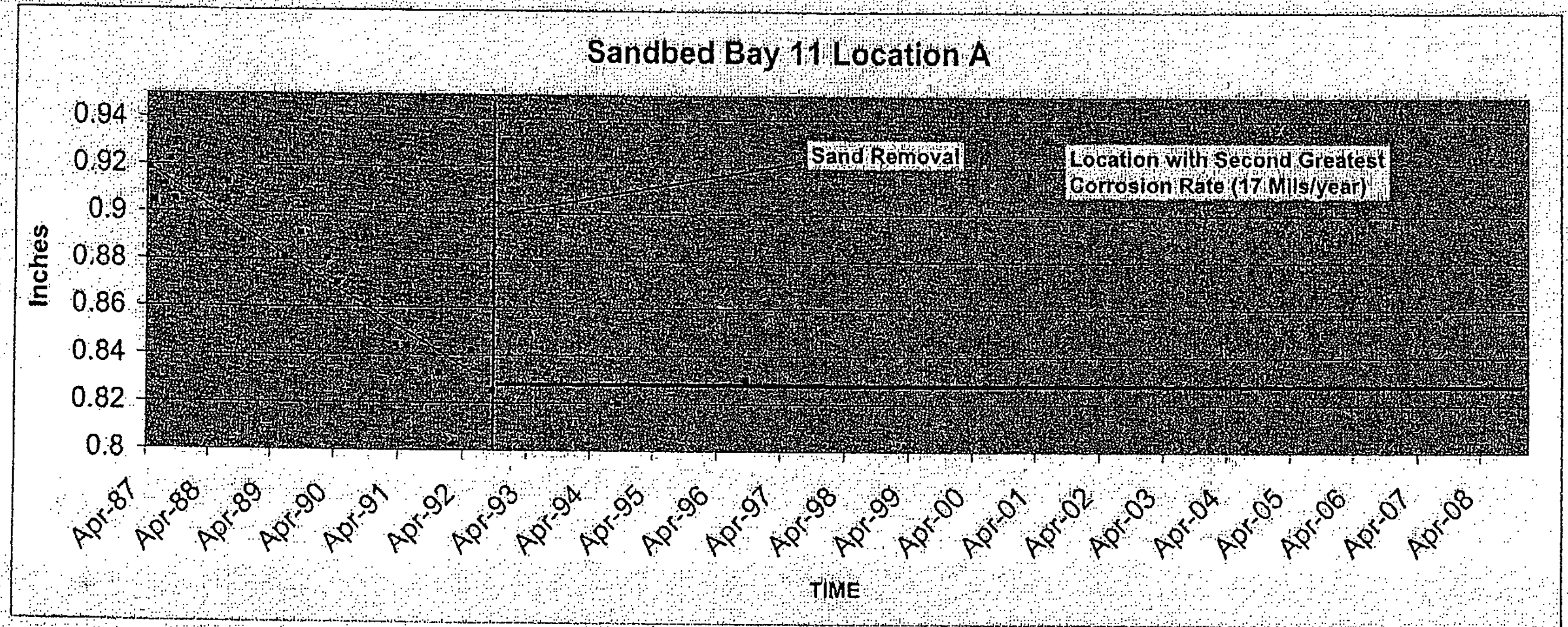
Bay	Date	Dec-86	Feb-87	Apr-87	May-87	Aug-87	Sep-87	Jul-88	Oct-88	Jun-89	Sep-89	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
1D									1.115										1.191	1.151
3D									1.178										1.184	1.181
5D									1.174										1.168	1.173
7D									1.135										1.136	1.135
9A									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	1.044	0.993	1.004
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	0.835	0.820	0.831
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	0.854	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	1.043
13A		0.919							0.905	0.883	0.883	0.862	0.853	0.855	0.853	0.849	0.865	0.838	0.832	0.843
13C	Bottom													0.909	0.901	0.900	0.931	0.904	0.893	0.933
	Top													1.072	1.049	1.048	1.088	1.055	1.037	1.059
13D									0.982				0.932					1.001	0.959	[illegible]
15A									1.120										1.114	1.127
15D		[illegible]							[illegible]	[illegible]	[illegible]	[illegible]	1.057	1.060	1.050	1.042	1.065	[illegible]	[illegible]	[illegible]
17A	Bottom	0.999							0.957	0.965	0.955	0.954	0.951	0.935	0.942	0.933	0.946	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	1.124	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	0.828	0.822	0.823	0.817	0.810	0.843
17/19	Bottom								1.004	0.999	0.955	1.010	1.006	0.987	0.982	0.971	0.990	[illegible]	0.975	[illegible]
	Top								0.982	1.019	1.131	0.990	0.986	0.975	0.969	0.934	0.972	0.976	[illegible]	0.967
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	[illegible]	[illegible]	0.815
19B					0.898	0.892	0.868	0.864	0.857	0.826	0.845	0.812	0.837	0.853	0.844	0.848	0.847	0.840	0.834	0.837
19C					0.901	0.868	0.868	0.873	0.858	0.845	0.845	0.831	0.825	0.843	0.823	0.822	0.832	0.819	[illegible]	0.848



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

Slope	Best Est	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.0125	0.9932	05/01/91	1.00012	1.154"	0.736"

Dates	Dec-86	Feb-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
9D	1.0715						1.0214	1.0540	1.0200	1.0260	1.0217	0.9926	1.0075	0.9924	1.0000	1.0036	0.9920	1.0080



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

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.0171	0.83311	05/01/92	0.8251	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
11A			0.9187	0.90464	0.92209	0.9052	0.913	0.8882	0.881	0.8916

Dates	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
11A	0.8808	0.8704	0.8446	0.844	0.8326	0.842	0.8252	0.82	0.83

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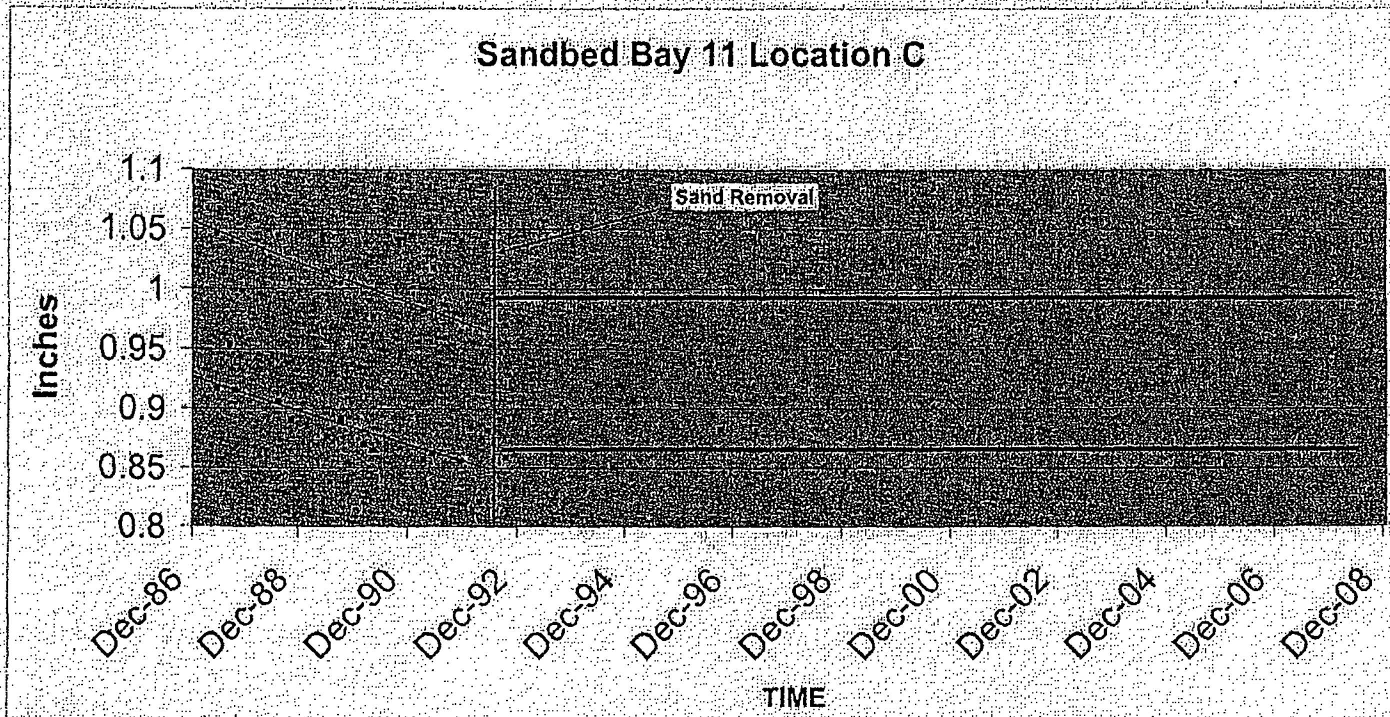
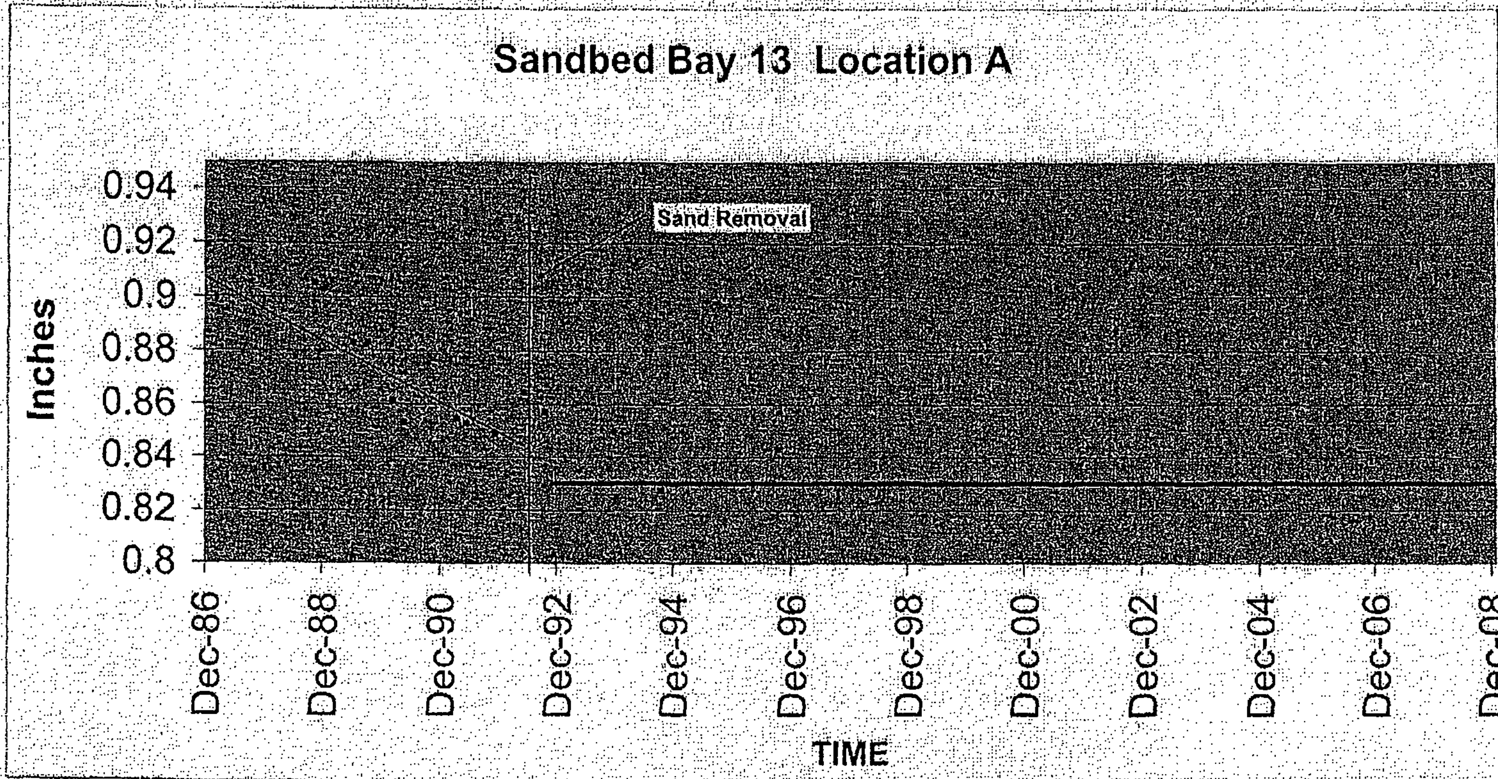


Based on Calculation C-1302-187-5300-021

Slope	Slope	Best Est. Low	Best Est. High	Date	Average Since 1992	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.0143	-0.0171	0.8498	0.9642	05/01/92	0.8641	0.9984	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
11C Bottom				0.91679	0.95364	0.91571	0.9061	0.8907	0.8768	0.8907	0.8703	0.865	0.8576	0.8628	0.8563	0.882	0.8591	0.8503	0.883
11C Top				1.046	1.1086	1.0791	1.0454	1.0089	1.0158	1.005	0.9522	0.977	0.9817	1.018	0.9643	1.01	0.9697	0.9836	1.0418



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

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.012	0.8442	05/01/92	0.8386	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
	0.91908							0.9053	0.8828	0.883	0.8615	0.8531	0.8545	0.8529	0.8486	0.8645	0.8576	0.8275	0.843

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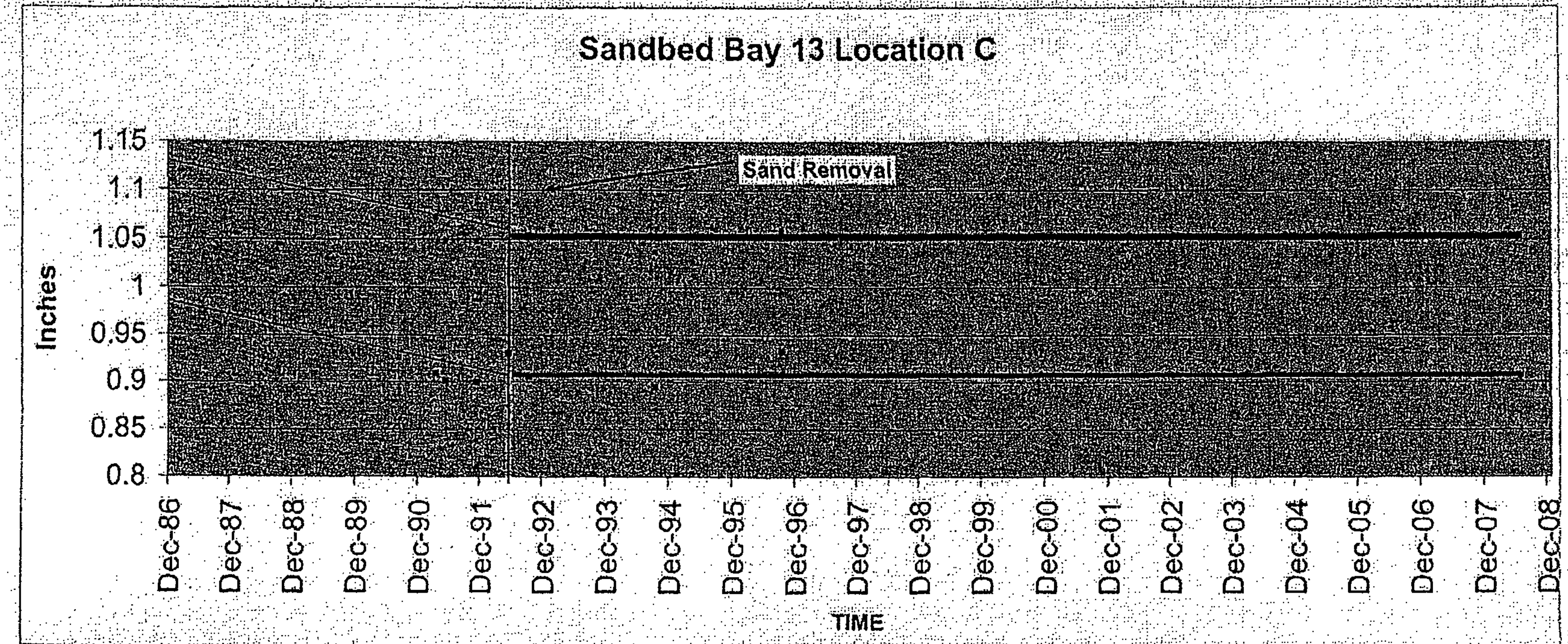

Based on Calculation C-1302-187-5300-021

Slope	Slope	Best Est. Low	Best Est. Hig	Date	Average Since 1992	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.013	-0.0146	0.9073	1.06	05/01/92	1.0505	0.9114	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
13C Bottom													0.9094	0.9013	0.8996	0.9305	0.906	0.8953	0.933
13C Top													1.0722	1.0488	1.0479	1.0882	1.0546	1.037	1.0593

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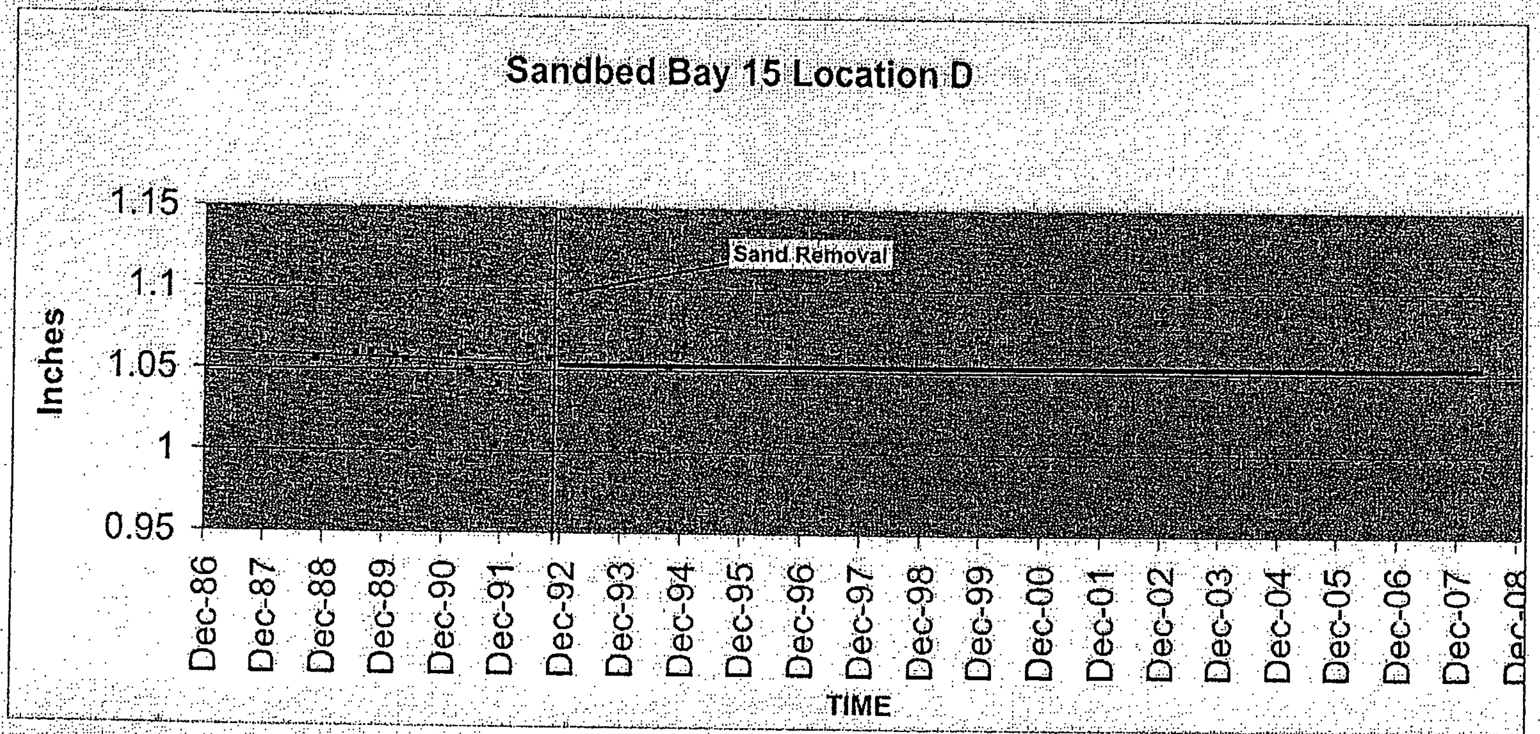

Based on Calculation C-1302-187-5300-021

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.001	1.055	05/01/92	1.0588	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
	1.089							1.056	1.06	1.0609	1.0586	1.0565	1.0598	1.0502	1.0417	1.0652	1.0577	1.053	1.066

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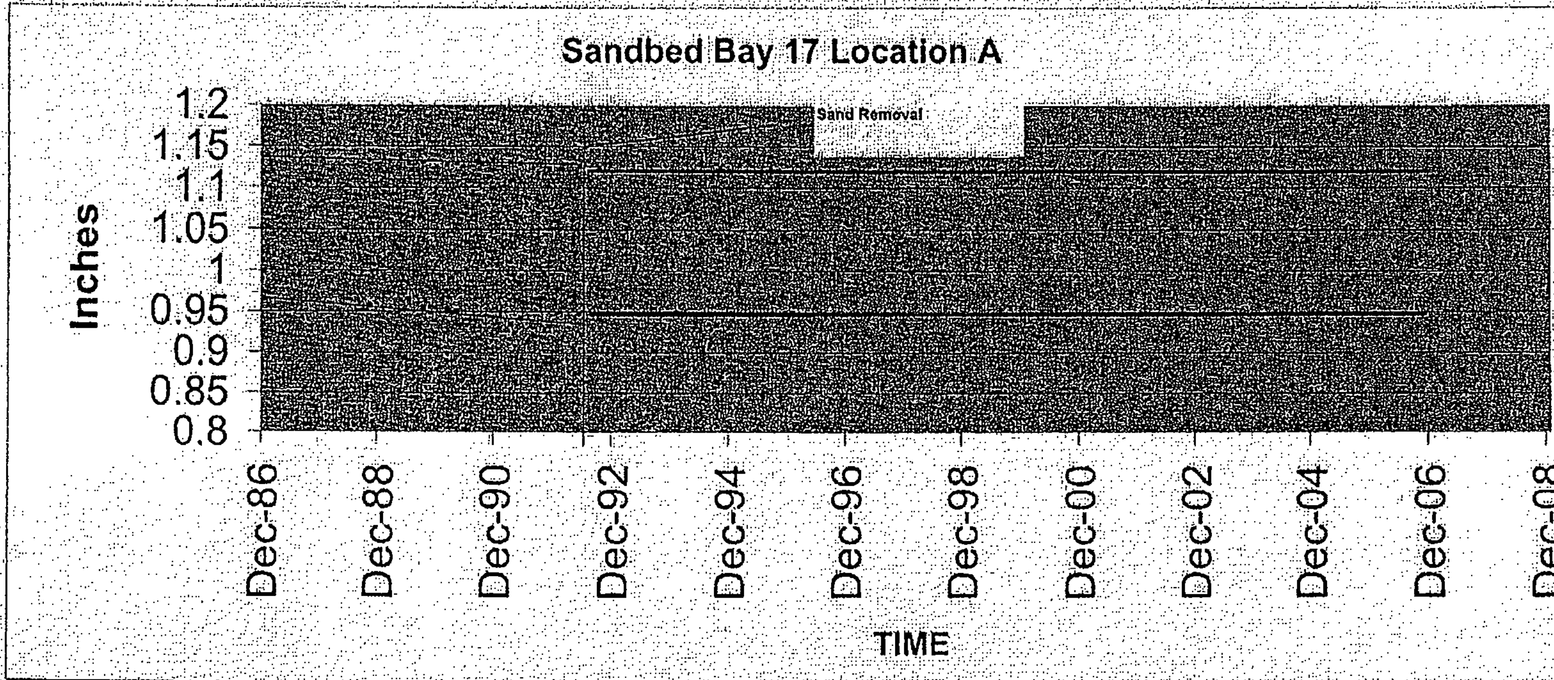


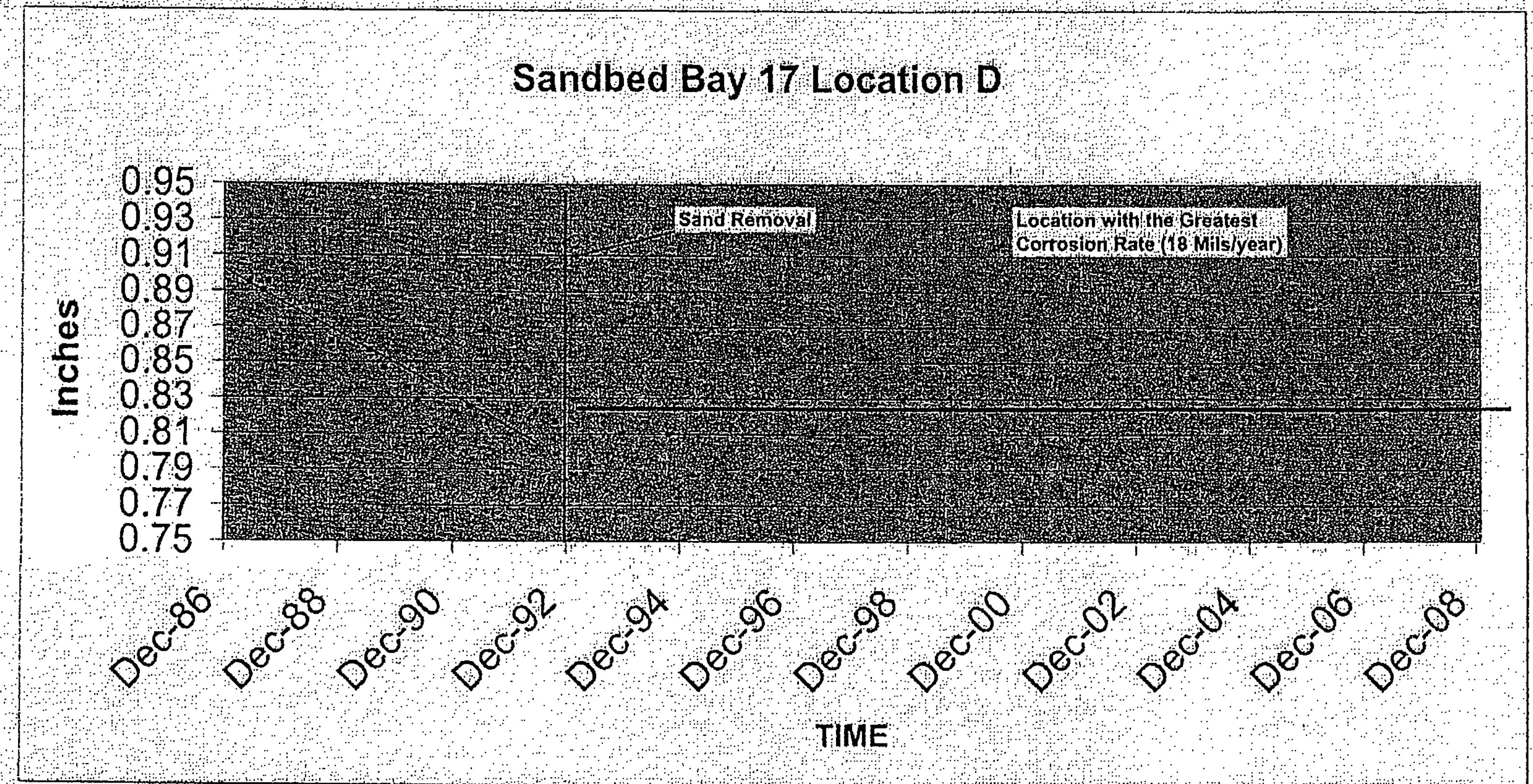
Based on Calculation C-1302-187-5300-021

Slope	Slope	Best Est. Low	Best Est. High	Date	Average Since 1992	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.0058	-0.0017	0.9352	1.1278	08/01/92	1.1326	0.9573	1.154"	0.736"

Dates	Dec-86	Feb-87	Apr-87	May-87	Aug-87	Sep-87	Jul-88	Oct-88	Jun-89
17A random	0.999							0.9574	0.9645
17A Tpp	0.999							1.1331	1.13

Dates	Sep-89	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
17A random	0.9552	0.9536	0.9508	0.9347	0.9424	0.9328	0.9481	0.9413	0.9138	0.9989
17A Tpp	1.1308	1.128	1.1203	1.1309	1.1293	1.1226	1.1254	1.1248	1.1289	1.1441

25

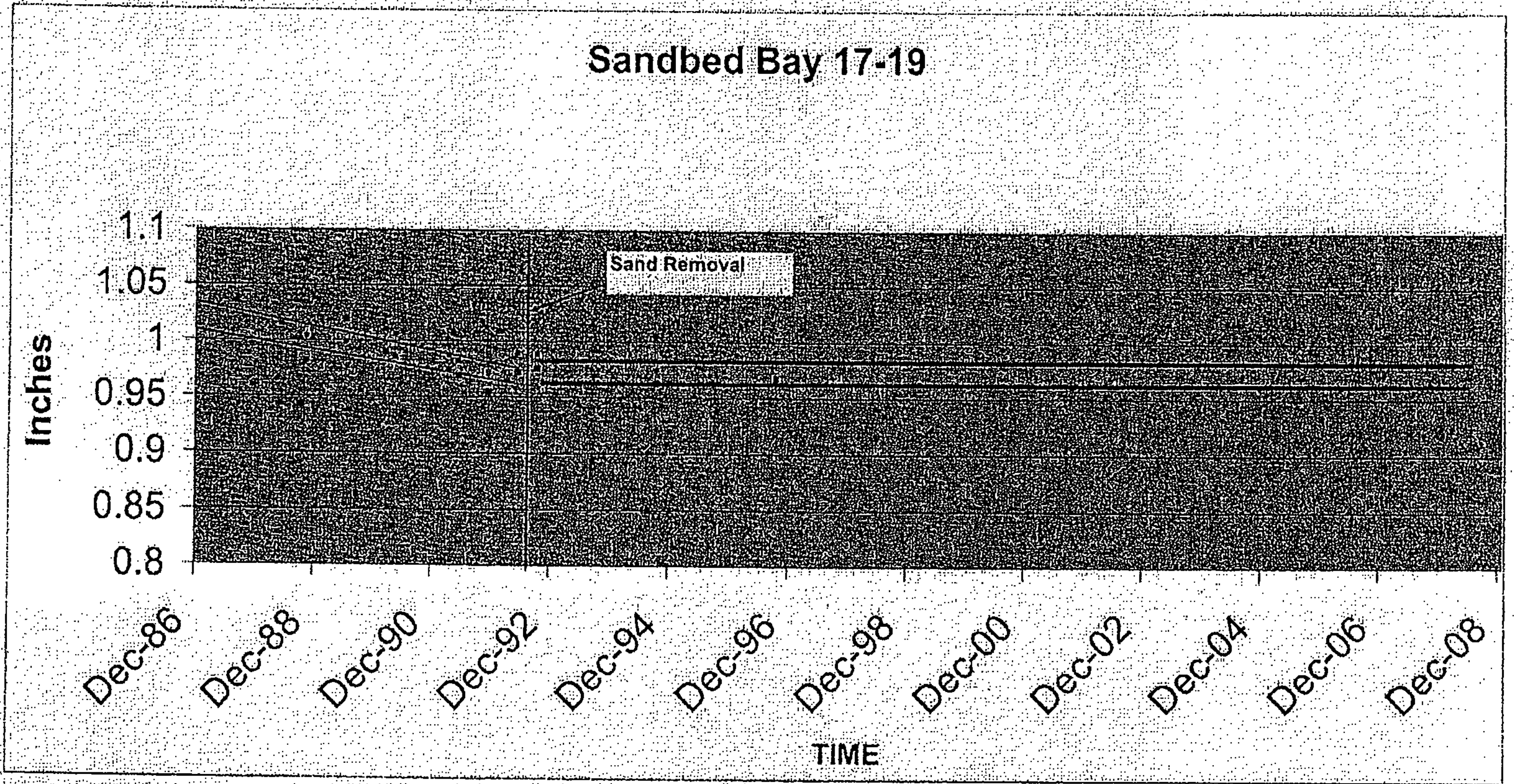


Based on Calculation C-1302-187-5300-021

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.018	0.8057	05/01/92	0.8239	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
17D		0.92217		0.89507	0.89069	0.89528	0.8779	0.8622	0.8568	0.8471	0.8358	0.829	0.8253	0.8291	0.8222	0.823	0.8172	0.81	0.845

26

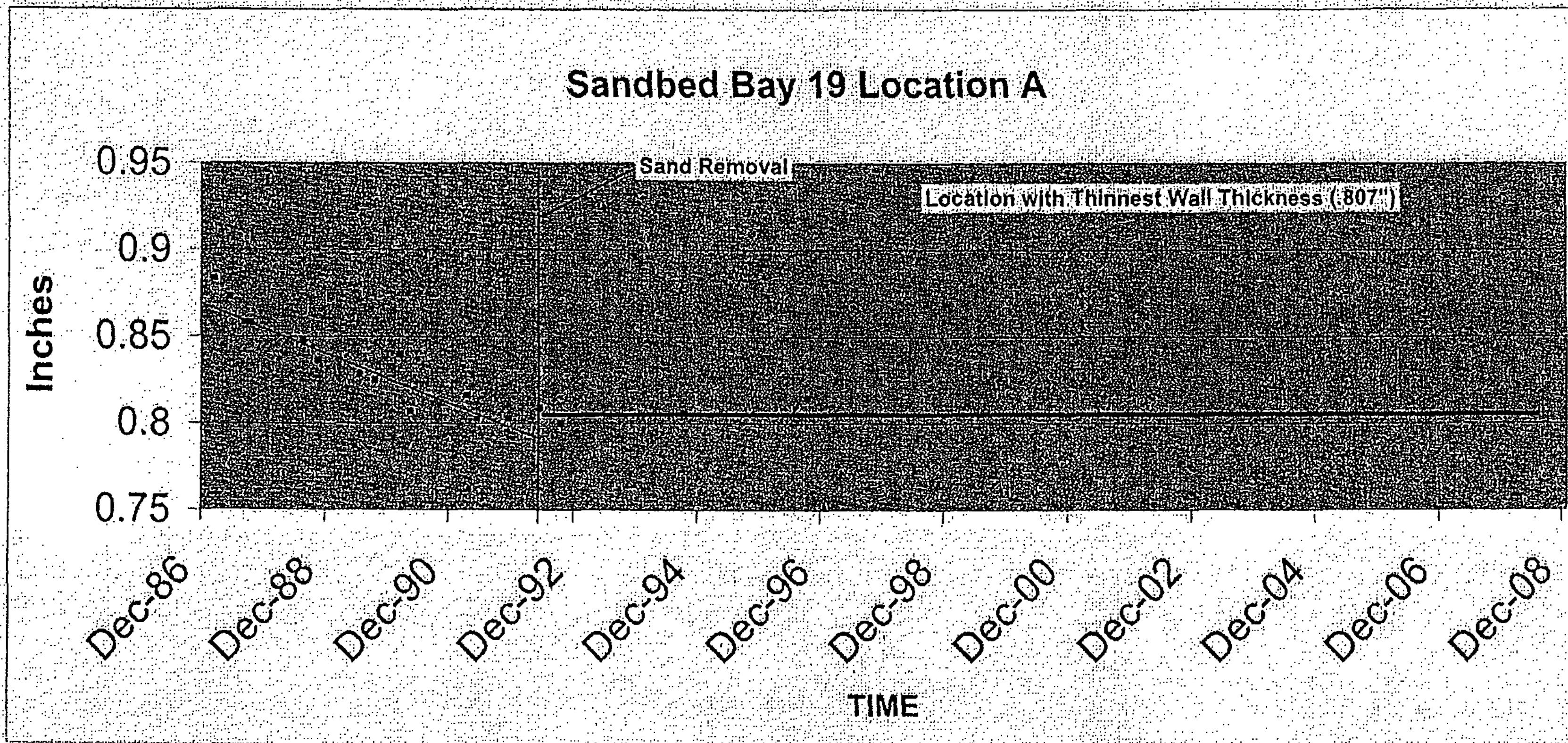


Based on Calculation C-1302-187-5300-021

Slope	Slope	Best Est. Low	Best Est. High	Date	Average Since 1992	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.0087	-0.0107	0.9621	0.9761	05/01/92	0.9871	0.9689	1.154"	0.736"

Dates	Dec-86	Feb-87	Apr-87	May-87	Aug-87	Sep-87	Jul-88	Oct-88	Jun-89
17/19 Top								0.9817	1.0191
17/19 Bottom								1.0038	0.9988

Dates	Sep-89	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
17/19 Top	1.1308	0.9898	0.986	0.9746	0.9693	0.9542	0.9722	0.976	0.963	0.9674
17/19 Bottom	0.9552	1.01	1.0057	0.987	0.9824	0.9711	0.99	0.9887	0.9748	0.9914

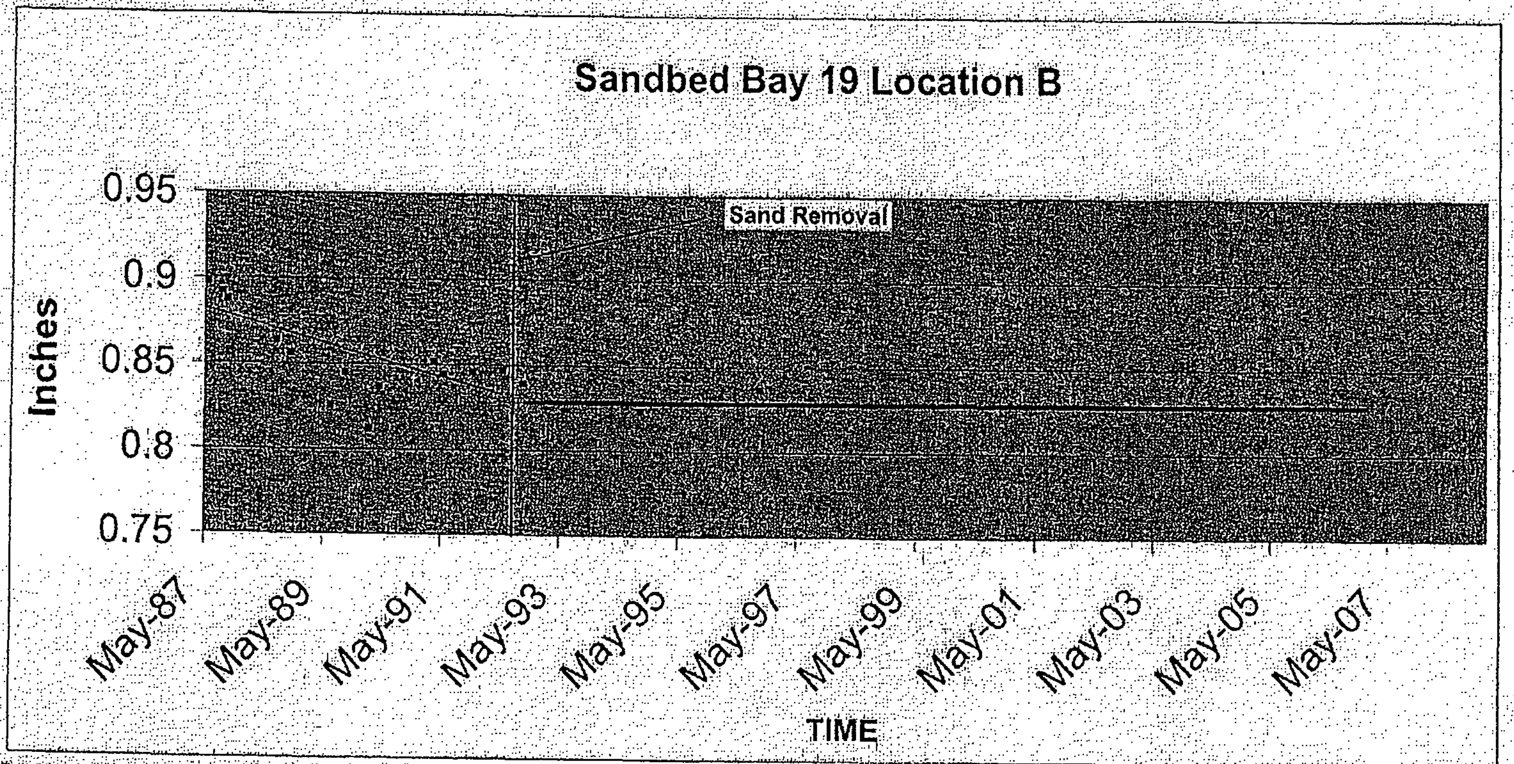


Based on Calculation C-1302-187-5300-021

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	0.85829	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

26



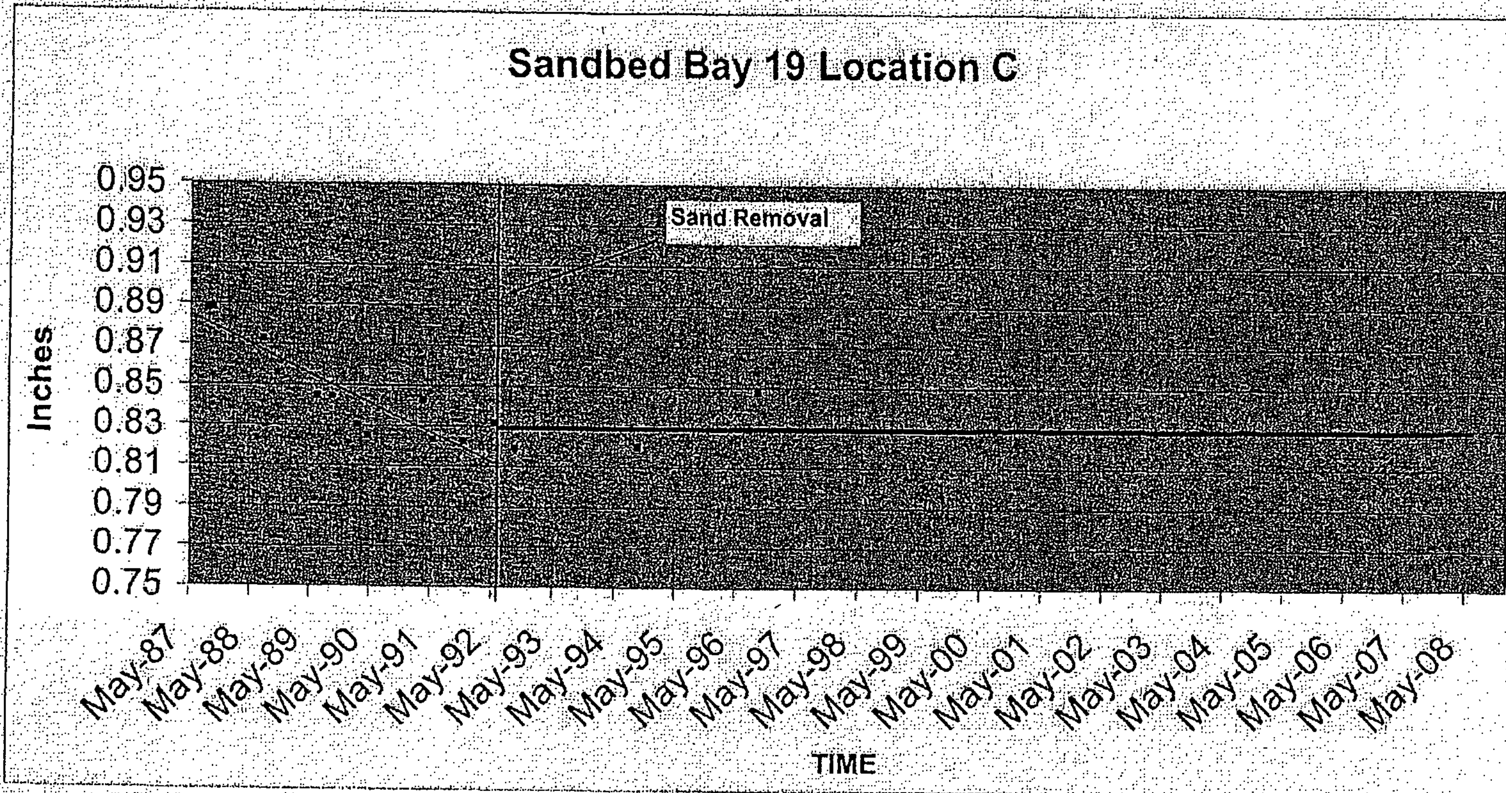
Based on Calculation C-1302-187-5300-021

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Unform Required Thickness
-0.0099	0.8330	05/01/92	0.8337	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
19B				0.89763	0.89221	0.8876	0.864	0.8565	0.8256	0.84549

Dates	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96
19B	0.812	0.8369	0.8525	0.8444	0.8463	0.8472	0.8396	0.824	0.837

21



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

Slope	Best Est.	Date	Average Since 1992	Original Nominal Thickness	Minimum Uniform Required Thickness
-0.015	0.8117	05/01/92	0.829	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
19C				0.90051	0.88816	0.88831	0.8735	0.8563	0.845	0.8447	0.8305	0.8251	0.8428	0.8232	0.8223	0.8319	0.8192	0.82	0.848

NRC Information Request Form

Item No
AMP-141

Date Received: 10/ 6/2005

Source AMP Audit

Status: Open

Topic:
IWE

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

AMP B.1.27 IWE

a. Visual inspection of the coatings in the former sandbed region of the drywell is currently conducted under the applicant's protective coatings monitoring and maintenance program; only this AMP is credited for managing loss of material due to corrosion for license renewal. Visual inspection of the containment shell conducted in accordance with the requirements of IWE is typically credited to manage loss of material due to corrosion.

The applicant is requested to provide its technical basis for not also crediting its IWE program for managing loss of material due to corrosion in the former sandbed region of the drywell.

B. During discussions with the applicant's staff on 10/04/05 about augmented inspection conducted under IWE, the applicant presented tabulated inspection results obtained from the mid 1980s to the present, to monitor the remaining drywell wall thickness in the cylindrical and spherical regions where significant corrosion of the outside surface was previously detected.

The applicant is requested to provide (1) a copy of these tabulated inspection results, (2) a list of the nominal design thicknesses in each region of the drywell, (3) a list of the minimum required thicknesses in each region of the drywell, and (4) a list of the projected remaining wall thicknesses in each region of the drywell in the year 2029.

AMP B.1.27 IWE Question on Remaining Wall Thickness in the Former Sandbed Region of the Drywell

c. During discussions with the applicant's staff on 10/05/05, the applicant described the history and resolution of corrosion in the sandbed region. After discovery, thickness measurements were taken from 1986 through 1992, to monitor the progression of wall loss. Remedial actions were completed in early 1993. At that time, the remaining wall thickness exceeded the minimum required thickness. The applicant concluded that it had completely corrected the conditions which led to the corrosion, and terminated its program to monitor the remaining wall thickness. At that time, the remaining years of operation was expected to be no more than 16 years (end of the current license term).

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NRC Information Request Form

The applicant's aging management commitment for license renewals is limited to periodic inspection of the coating that was applied to the exterior surface of the drywell as part of the remedial actions. The applicant has not made a license renewal commitment to measure wall thickness in the sandbed region in order to confirm the effectiveness of the remedial actions taken.

Assigned To: Ouaou, Ahmed

Response:

a) Visual inspection of the containment drywell shell, conducted in accordance with ASME Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containment is considered inaccessible by ASME Section XI, Subsection IWE, thus visual inspection is not possible for a typical Mark I containment including Oyster Creek before the sand was removed from the sand bed region in 1992. After removal of the sand, an epoxy coating was applied to the exterior surfaces of the drywell shell in the sand bed region. The region was made accessible during refueling outages for periodic inspection of the coating. Subsequently Oyster Creek performed periodic visual inspection of the coating in accordance with an NRC current licensing basis commitment. This commitment was implemented prior to implementation of ASME Section XI, Subsection IWE. As a result inspection of the coating was conducted in accordance with the Protective Coating Monitoring and Maintenance Program. Our evaluation of this aging management program concluded the program is adequate to manage aging of the drywell shell in the sand bed region during the period of extended operation consistent with the current licensing basis commitment, and that inclusion of the coating inspection under IWE is not required. However we are amending this position and will commit to monitor the protective coating in the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Section XI, Subsection IWE during the period of extended operation. For details related to implementation of this commitment, refer to the response to NRC AMP Question #188.

b) A tabulation of ultrasonic testing (UT) thickness measurement results in monitored areas of the drywell spherical region above the sand bed region and in the cylindrical region is included in ASME Section XI, Subsection IWE Program Basis Document (PBD-AMP-B.1.27) Notebook. The tabulation contains information requested by the Staff and is available for review during AMP audit. The tabulation is also provided in Table -1, and Table-2 below.

c) In December 1992, with approval from the NRC a protective epoxy coating was applied to the outside surface of the drywell shell in the sand bed region to prevent additional corrosion in that area. UT thickness measurements taken in 1992, and in 1994, in the sand bed region from inside the drywell confirmed that the corrosion in the sand bed region has been arrested. Periodic inspection of the coating indicates that the coating in that region is performing satisfactorily with no signs of deterioration such as blisters, flakes, or discoloration, etc. Additional UT measurements, taken in 1996 from inside the drywell in the sand bed region showed no ongoing corrosion and provided objective evidence that corrosion has been arrested.

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As a result of these UT measurements and the observed condition of the coating, we concluded that corrosion has been arrested and monitoring of the protective coating alone, without additional UT measurements, will adequately manage loss of material in the drywell shell in the sand bed region. However to provide additional assurance that the protective coating is providing adequate protection to ensure drywell integrity, Oyster Creek will perform periodic confirmatory UT inspections of the drywell shell in the sand bed region. The initial UT measurements will be taken prior to entering the period of extended operation and then every 10 years thereafter. The UT measurements will be taken from inside the drywell at the same locations where the UT measurements were taken in 1996. This revises the license renewal commitment communicated to the NRC in a letter from C. N. Swenson Site Vice President, Oyster Creek Generating Station to U. S. Nuclear Regulatory Commission, "Additional Commitments Associated with Application for renewed Operating License - Oyster Creek Generating Station", dated 12/9/2005. This letter commits to one-time inspection to be conducted prior to entering the period of extended operation. The revised commitment will be to conduct UT measurements on a frequency of 10 years, with the first inspection to occur prior to entering the period of extended operation.

This response was revised to incorporate additional commitments on UT examinations for the sand bed region discussed with NRC Audit team on 1/26/2006.
This response was revised to reference response to NRC Question #AMP-188 and RAI 4.7.2-1(d). AMO 4/1/2006.
The response was revised to add Table-1, and Table-2, and delete reference to RAI 4.7.2-1(d) AMO 4/5/2006.

LRCR #: 229 *LRA A.5 Commitment #:* 27

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/ 5/2006

Reviewed By: Getz, Stu 4/ 5/2006

Approved By: Warfel, Don 4/ 5/2006

NRC Acceptance (Date):

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	0.758 0.758		0.754	0.757	0.754	0.756	0.7384
	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
Elevation 51' 10"		0.541"												

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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	
	Bay 13–32H					0.716	0.715 0.715 0.719	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 1–5-22								0.693	0.711	0.692	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

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.

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

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										1.164	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	0.876	0.862	0.857	0.847	0.836	0.829	0.826	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

Exhibit 9

EXHIBIT 4

Report No.: SIR-06-482
Revision No.: 0
Project No.: OC-12
File No.: OC-12-402
December 2006

Statistical Analysis of Oyster Creek Drywell Thickness Data

Prepared for:

AmerGen Energy Company, LLC
Oyster Creek Generating Station
Forked River, NJ
Expert Witness Agreement Letter, 3-28-06

Prepared by:

Structural Integrity Associates, Inc.
San Jose, California

Prepared by:	George J. Licina	Date:	1-3-07
Reviewed by:	Ryan Perry	Date:	1-4-07
Approved by:	George J. Licina	Date:	1-4-07

Structural Integrity Associates, Inc.

REVISION CONTROL SHEET

Document Number: SIR-06-482

Title: Statistical Analysis of Oyster Creek Drywell Thickness Data

Client: Exelon

SI Project Number: OC-12

Section	Pages	Revision	Date	Comments
1.0	1-1	0	1/4/07	Initial Issue
2.0	2-1 – 2-2			
3.0	3-1			
4.0	4-1 – 4-10			
5.0	5-1 – 5-2			
6.0	6-1 – 6-2			
7.0	7-1			

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1.0 INTRODUCTION

In 1986, Oyster Creek experienced a problem with corrosion of the exterior of their drywell at the "sand cushion". The problem that was determined at that time was that the sand cushion had become wet from leakage that dripped along the outside of the drywell, the sand remained wet, and the exterior of the carbon steel drywell began to corrode.

The plant performed extensive analysis to demonstrate that loading of the drywell would remain within acceptable limits even without the sand cushion to disperse the loads from the drywell to the ground. The plant then removed all of the sand and sealed off the steel-concrete interface on the exterior of the drywell to make sure it remained dry. In addition, several trenches were jack-hammered into the concrete inside the drywell to permit UT thickness measurements of the steel to be performed from inside the drywell. In the 1986 time frame, thickness measurements from the ID and from the OD all confirmed that the minimum thickness of the drywell exceeded minimum required thickness at all locations.

Now that the plant has applied for license renewal, the issue of the condition of the drywell steel has been reopened. During the most recent refueling outage (October 2006), the concrete in the trenches was found to be wet (one trench had 5" of standing water) so the question of the condition of the steel in the (former) sand bed region, above the sand bed, and embedded in the concrete was raised again.

2.0 BACKGROUND

The drywell (see Figure 2-1) is a huge (30' diameter or more where it intersects the concrete) but thin steel structure. The portion that is embedded in concrete (much of it has concrete on its interior as well) is basically a hemisphere. The drywell structure itself is shaped like a light bulb (upside down) with the reactor vessel, pumps, piping, etc. inside. The drywell is a secondary containment structure for radionuclides (fuel cladding, then the reactor vessel, then the containment). Because the containment and drywell are key safety features, the condition of the containment and drywell receives significant regulatory scrutiny and attention from the public.

2.1 Objective

Plant and corporate personnel from Exelon have indicated that a thorough and statistically based review of drywell thickness data is required. For example, the UT thickness methods applied in 1986, 1992, and 2006 are all different; the prior examinations (1986 and 1992) were done on bare steel while the 2006 examination was done with a different technique and was done through the coating. Questions associated with repeat UT thickness determinations always have some uncertainty regarding whether the exact locations were examined at the different points in time. Further, the limited data from Zone 4 (above the 12'4" elevation; an area that should never have been wet) appears to exhibit a thinning between the 1992 and 2006 inspections. That observation, as well as the use of the different UT techniques, suggests that a bias may exist between the 1992 and 2006 measurements. A key objective of this evaluation was to determine whether there was indeed a bias between those two different time points, to quantify the magnitude of the bias, and to determine how best to compare the thickness measurements between 2006 and 1992. For example, is it reasonable to simply subtract the bias from all of the apparent deltas to account for the technique differences?

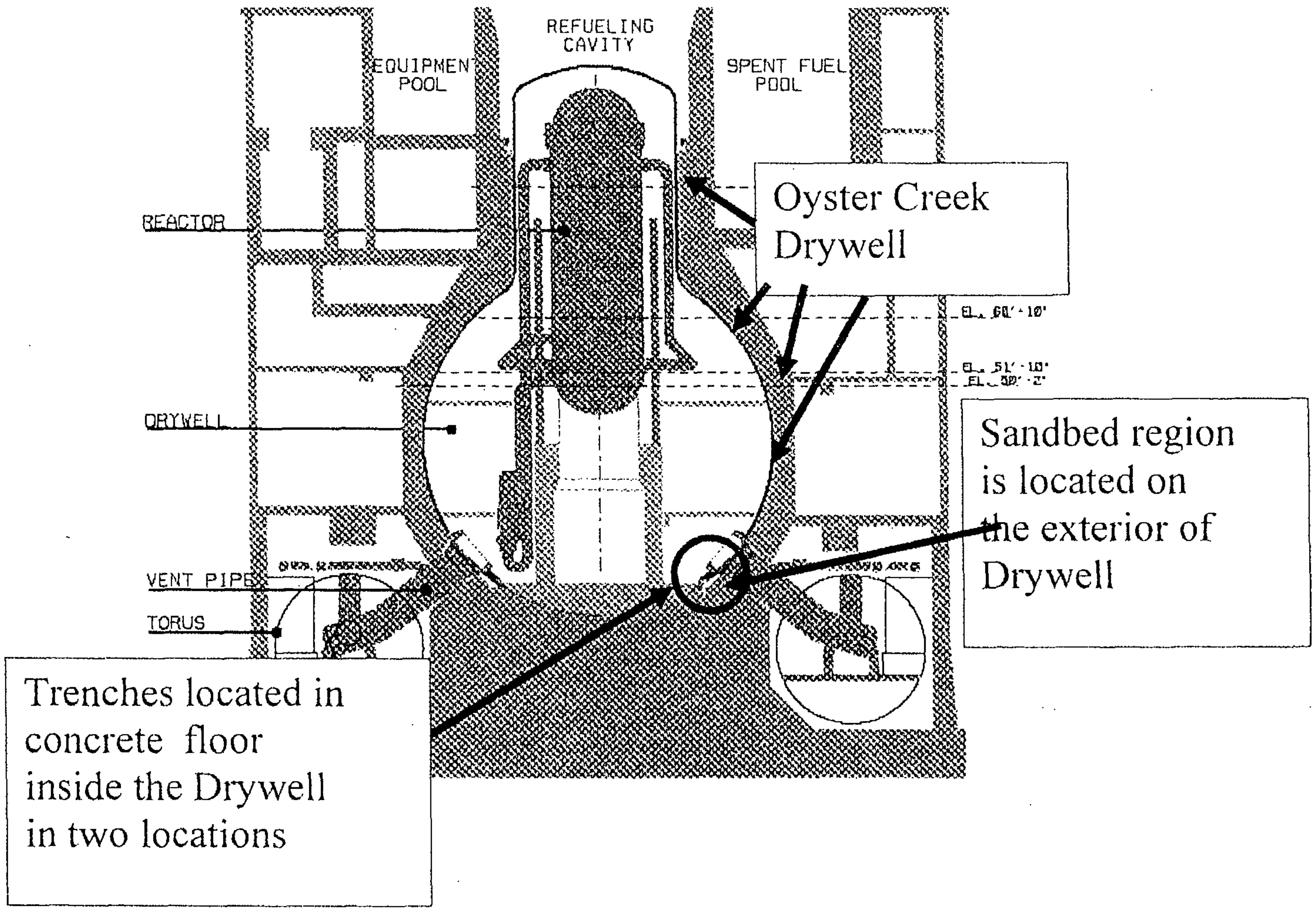

Figure 2-1. Schematic of Oyster Creek Drywell

3.0 APPROACH

A data set including UT thickness measurements from 106 points, measured from the outside of the drywell in 1992, then repeated in 2006, was received from Wayne Choromanski [1].

A Tech Eval prepared by Oyster Creek [2] was also received. The Tech Eval includes data in various forms from 1986, 1992, and 2006. It focuses on present thickness with a lesser emphasis on the trends. Most of the evaluation is for data collected for Bays 5 and 17, where the trenches are. The Tech Eval concludes that "the Drywell Vessel in the region below the concrete floor at elevation 10'3" may have been corroding at a rate of .002 to .003 inches per year between 1986 and 2006. UT readings below the concrete floor at Elevation 10'3" confirm that all locations meet the required thickness criteria."

The data were reviewed from numerous perspectives to ascertain systematic conditions (e.g., any bias) between measurements, differences among zones, among bays, and any oddities or obvious outliers. Fits of the data were also developed to test for the most appropriate distribution to use and to determine coefficients that would enable quantitative analysis of the statistics.

Those evaluations of deltas and thicknesses included graphical and numerical checks for the proper distribution to describe the variations in the data and included comparisons and evaluations of means and standard deviations of all values (thicknesses in 1992 and 2006 and the difference between those two thickness measurements), and creation of cumulative distribution functions to check for fit to normal or other distributions.

4.0 RESULTS

All 106 data points were included in the spreadsheet assembled and checked by Wayne Choromanski and denoted in this report as Reference 1. This analysis processed those data in an Excel spreadsheet graphically and numerically with results described below.

4.1 Apparent Deltas

The original focus in the evaluation was on the deltas (2006 thickness minus 1992 thickness). Those deltas were evaluated as a function of "original" (1992) plate thickness, and the distribution of delta by zone and by bay (Figures 4-1 through 4-4). Figure 4- 2 clearly shows that the mean delta varied by bay and by zone and that the distribution of deltas (Figures 4-3 and 4-4) looked very much like a normal distribution centered at a small negative value, implying a small metal loss. There was no apparent effect of original (1992) plate thickness (Figure 4-1). The variation of delta among bays was significantly larger than the variation among zones, despite the fact that the time of wetness among the different zones would be very dramatic. The lowest zone would be wet the longest, Zone 2 would be wet for a shorter time (as any water rolled down the drywell), and the upper two zones (Zones 3 and 4) would be expected to be wet for the least amount of time. Key data are summarized in Table 4-1.

A cumulative distribution of the deltas was created by ordering the deltas from smallest to largest and applying a look-up table from standard statistical texts to assign a parameter PHI. PHI is related to where in a normal distribution the point lies, based on the point's rank. For example, the point that is in the exact middle of the distribution (F = 0.50000) is at the mean (i.e., PHI = 0; which means 0 standard deviations from the mean). The first (lowest value) point defines the extreme of the data that is available and will be in the lower tail of the distribution (PHI will be a relatively large negative number). Similarly, the largest value will correspond to a relatively large positive PHI. When the data are plotted as PHI vs. delta, the data generate a reasonably straight line. The better the straight line, the better the fit to the normal distribution. The mean of the distribution is where PHI = 0 and the breadth of the distribution (i.e., how large the

standard deviation is) can be determined by how small the slope of the curve is (i.e., a horizontal line would have a very large standard deviation). For example, if all of the values were at exactly the same value, that value would obviously be the mean and the standard deviation would be zero (no variation in the data).

The CDF plot for the deltas (Figure 4-5) produced a very nice straight line over much of the population, however, the larger negative deltas were the values that destroyed the quality of the linear fit. The best fit line had an R^2 value of 0.83 (a perfect fit has $R^2 = 1.000$); not a bad fit but not a great one. Figure 4-5 also includes an eyeball best fit to the well behaved data.

Physical observations of the coating condition at the 2006 examination indicated that the coating was still in excellent condition. The expected corrosion rate for an intact coating would be zero. That is, the coating provides a barrier between the electrolyte and the metal so that the anodic and cathodic half-reactions that are critical to any corrosion process would be totally eliminated. Actual metal losses of a mil or more are not consistent with a coating that is still in good condition; the condition that was found in 2006. Apparent deltas of 70 mils or more (six such deltas were reported) are totally unreasonable in view of the physical condition of the coating as well as examination of the drywell from the inside. Those large negative deltas, like the positive values of delta (i.e., the drywell was thicker in 2006 than in 1992) indicate that the deltas determined from the difference between the 1992 thickness (t_{1992}) and the 2006 thickness (t_{2006}) were subject to significant uncertainty and the use of delta only would be misleading.

4.2 Thickness Evaluations

Using the difference between separate measurements as discussed in Section 4.1 clearly magnifies the potential error. The 1992 and 2006 thickness measurements were each evaluated as separate populations to determine the appropriate distribution and to assess any systematic differences between the two measurements such that bias and any corrosion effects could be separated. As shown in Figures 4-6 and 4-7, the primary attribute that the thickness analyses determined was that thickness was a strong function of the bay and much less a function of zone.

The cumulative distribution functions for the 1992 and 2006 thickness populations were created as described below.

As was done for the deltas (Figure 4-5), the individual thickness measurements from 1992 and from 2006 were ordered, from smallest to largest. A look-up table was applied to assign a parameter PHI, where PHI is related to where in a normal distribution the point lies, based on the point's rank. For example, the point that is in the exact middle of the distribution (F = 0.50000) is at the mean (i.e., PHI = 0; which means 0 standard deviations from the mean). The first (lowest value) point defines the extreme of the available data and will be in the lower tail of the distribution (PHI will be a relatively large negative number). Similarly, the largest value will correspond to a relatively large positive PHI. When the data are plotted as PHI vs. thickness, the data should generate a straight line. The better the straight line, the better the fit to the normal distribution. The mean of the distribution is where PHI = 0 and the breadth of the distribution (i.e., how large the standard deviation is) can be determined by how horizontal the curve is. For example, if all of the values were at exactly the same value, that value would obviously be the mean and the standard deviation would be zero (no variation in the data).

Figure 4-8 shows that the 2006 thickness data are described well by a normal distribution, with an excellent straight line fit to the data ($R^2 = 0.98$). Figure 4-8 also shows that the 1992 plate thickness data were also described by a normal distribution (linear; $R^2 = 0.98$). The cumulative distribution of the 1992 thickness data also showed that the 1992 measurements were thicker at all values of PHI than those from 2006 (i.e., the drywell apparently lost thickness between 1992 and 2006 as might be expected). At the mean (PHI = 0), that difference was about 20 mils of thinning. At PHI = -3 (3 standard deviations below the mean, approximately the 99th percentile), the thickness difference was about 29 mils (29 mils of thinning). At PHI = 3, approximately the 1st percentile, the difference was about 12 mils. Those observations suggest that the measurements made in 2006 were systematically lower than the those in 1992 by 12 to 20 mils. It can be argued that the ***actual*** thickness differences based upon subtracting the 2006 thickness from the 1992 thickness (and ignoring the error associated with performing the measurements at

exactly the same locations in both 1992 and 2006) are actually 12 to 20 mils less than the delta values that are reported.

Table 4-2 summarizes the comparison between the 1992 and 2006 measurements, including the means and standard deviations determined graphically and those same parameters determined for the two populations using the appropriate functions in Excel. The agreement between the graphical analysis and the computational analysis using Excel is excellent.

Note that this analysis does not say whether the 1992 measurements are better than the 2006 measurements or vice versa; only that the difference between the two has a bias in it.

Table 4-1

Mean Deltas by Bay

	Deltas				
Bay	Mean	S.D.	n[1]	n'[2]	
1	-19	21.8	23	23	
3	-3	6.8	9	9	
5	-34	31.1	8	8	
7	-13	13.7	5	7	
9	-10	9.6	10	10	
11	-14	14.7	8	8	
13	-17	30.9	15	19	
15	-1	15.2	11	11	
17	-13	32.0	9	11	
19	-24	27.8	8	10	
Population	-15	23	106	116	
Total Population			t_{1992}	t_{2006}	**Delta**
	Mean		865	849	-15
	Std. Dev		114	112	23
	Max		1156	1160	27
	Min		618	602	-118

[1] Thickness measurements in 1992 and 2006
[2] Thickness measurements in 1992 or 2006

Table 4-2

Comparison of Cumulative Distributions of Thickness (1992 and 2006)

Best fits to CDFs for 1992 and 2006 thicknesses									
2006:	PHI_{2006} =	0.0086	t	-7.2708					
1992:	PHI_{1992} =	0.0084	t	-7.2742				Per Excel (RawData2)	
OR					implying	Mean	Std. Dev.	Mean	Std. Dev.
2006:	t_{2006} =	116.2791	PHI_{2006}	845.4419		845	116	849	112
1992:	t_{1992} =	119.0476	PHI_{1992}	865.9762		866	119	865	114
PHI	Delta, mils[3]								
-3	28.8								
-2.5	27.5								
-2	26.1								
-1.5	24.7								
-1	23.3								
-0.5	21.9								
0	20.5								
0.5	19.2								
1	17.8								
1.5	16.4								
2	15.0								
2.5	13.6								
3	12.2								

[3]Determined from the difference between best fits for thickness distributions from 2006 and 1992. Note that sign is opposite that for Table 4-1 and Figures 4-1 through 4-4.

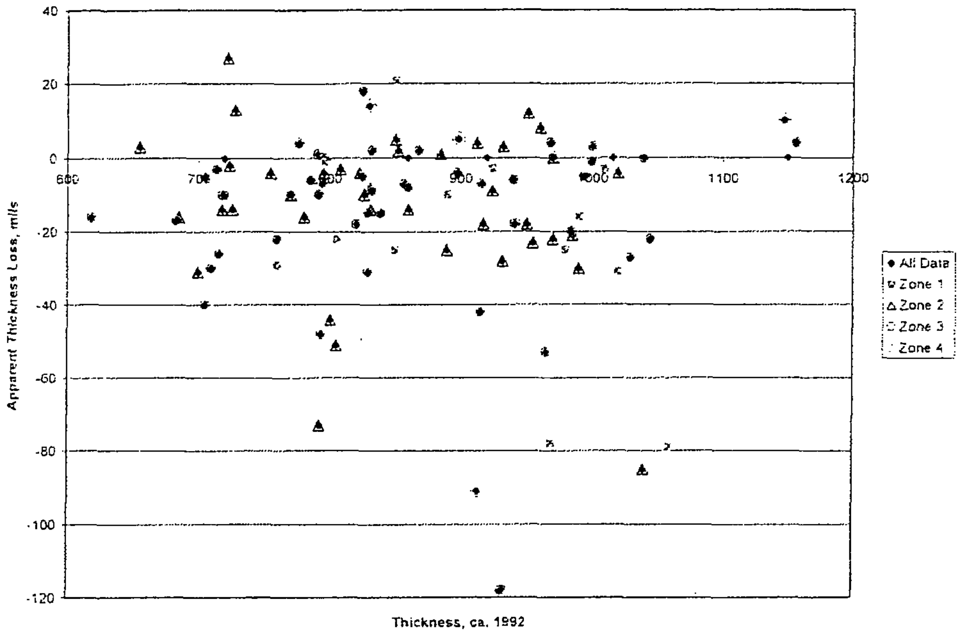

Figure 4-1. Apparent Thickness Change as a Function of Thickness Determined in 1992

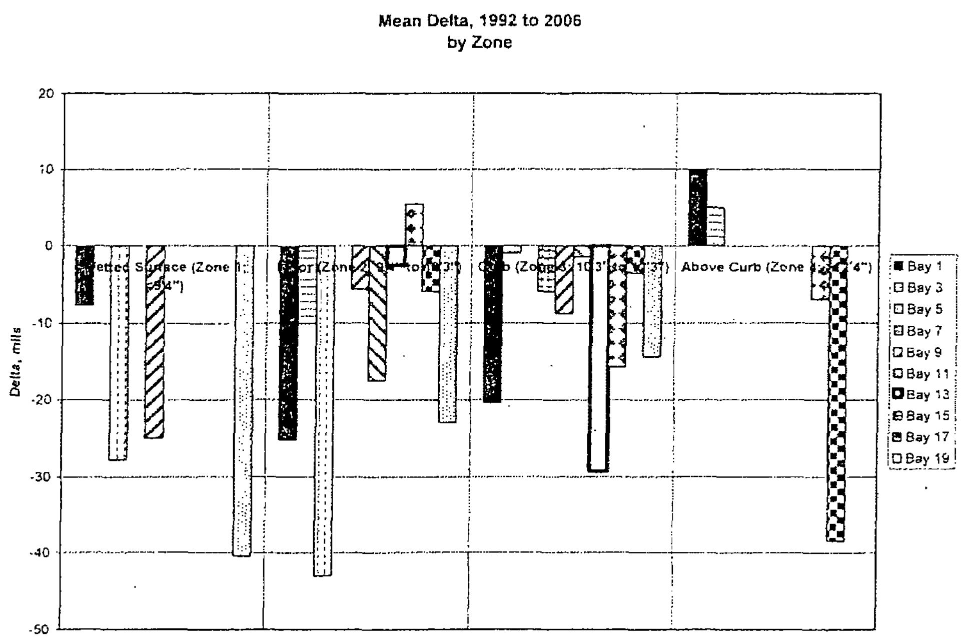

Figure 4-2. Delta by Zone and by Bay

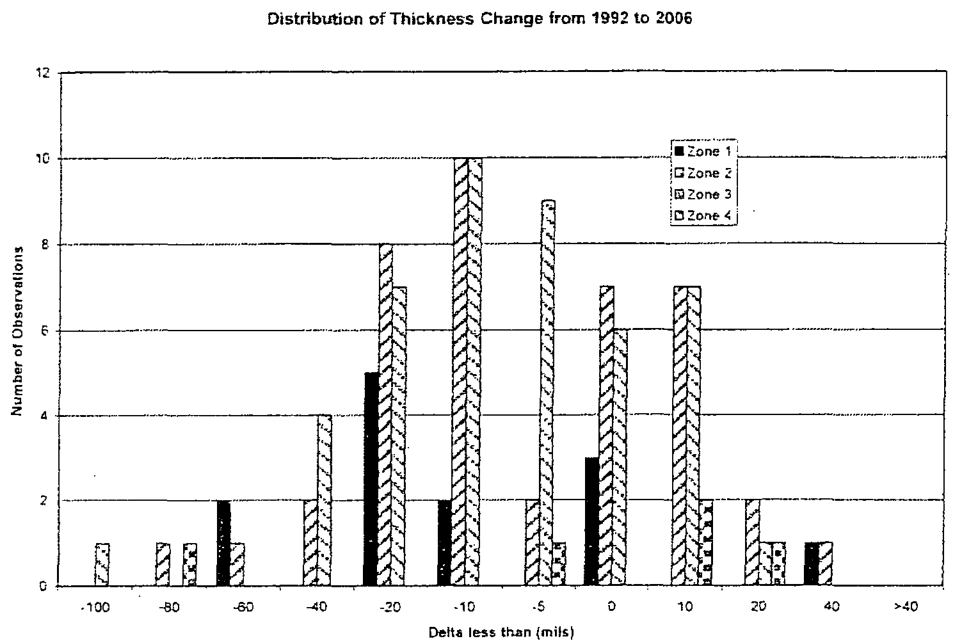

Figure 4-3. Distribution of Delta by Zone

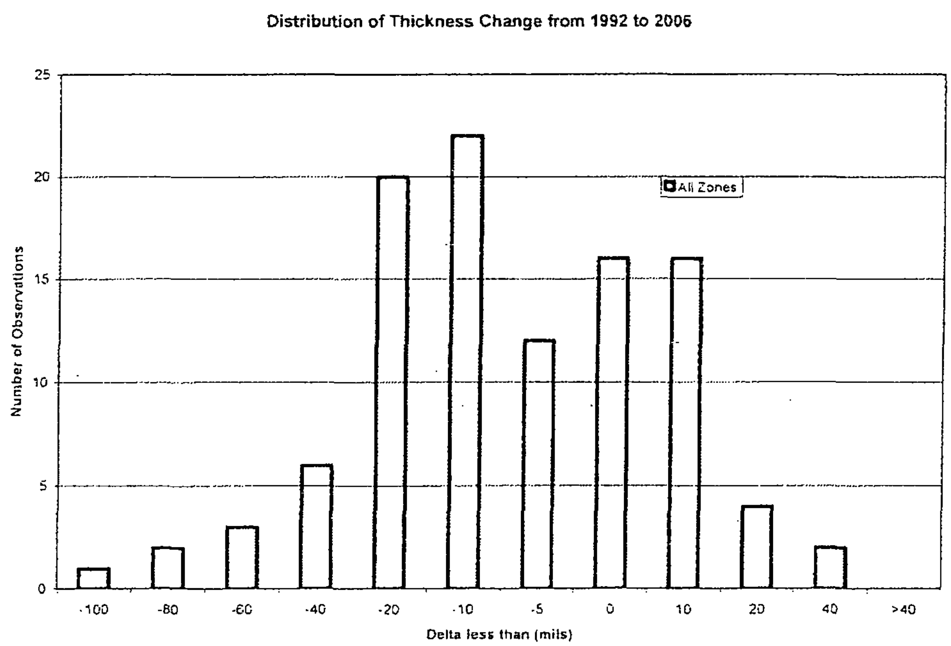

Figure 4-4. Distribution of Delta – All Zones

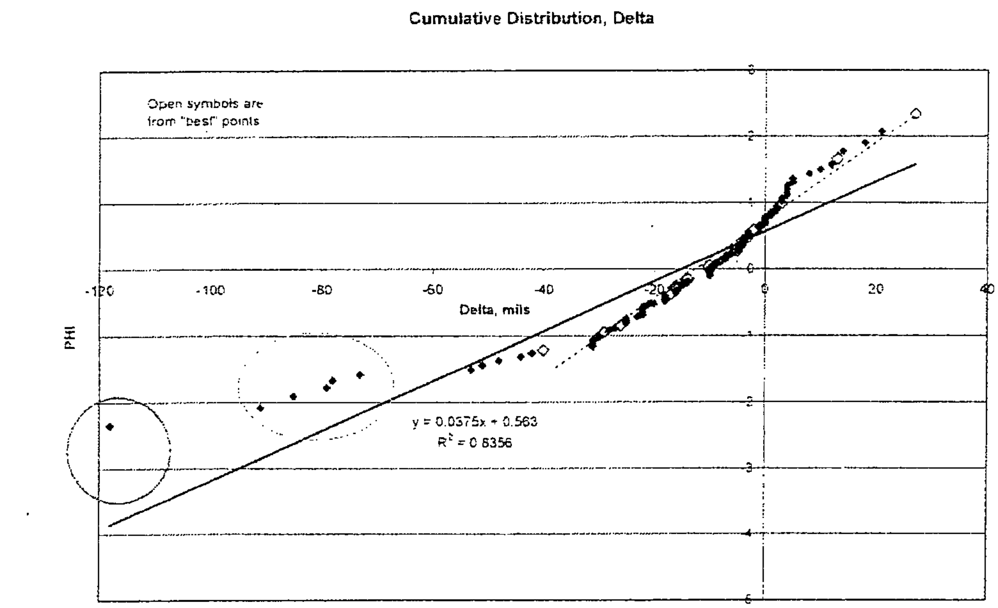

Figure 4-5. Cumulative Distribution, Delta

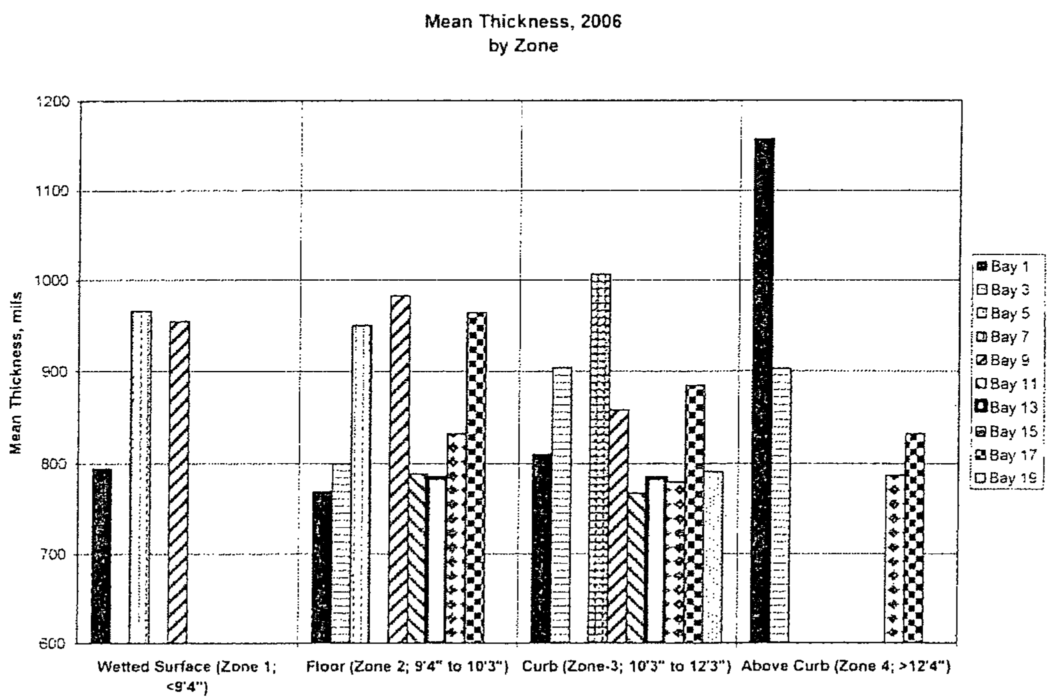

Figure 4-6. Mean Thickness (2006) by Zone and by Bay

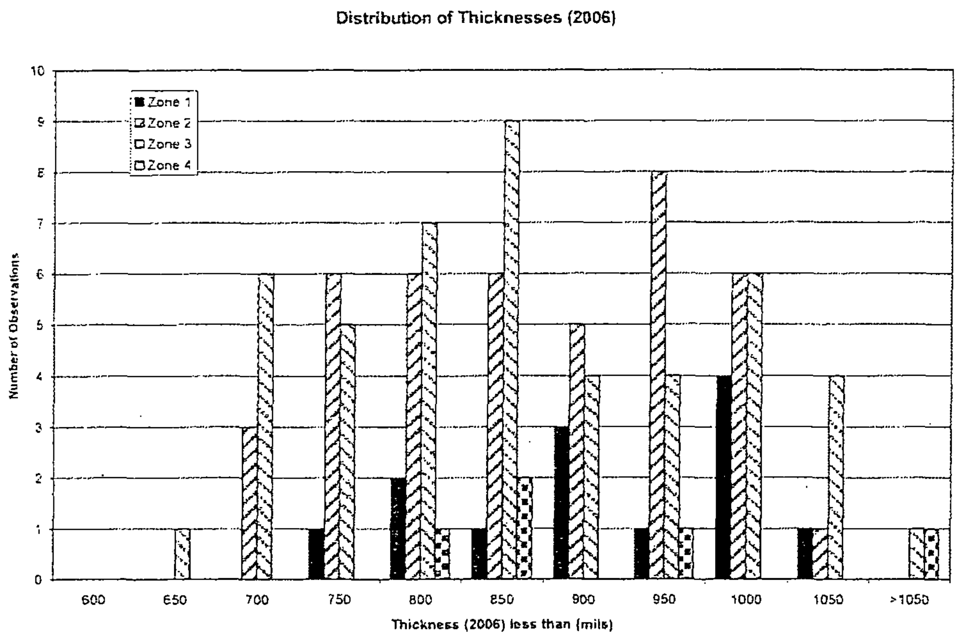

Figure 4-7. Distribution of Thickness (2006) by Zone

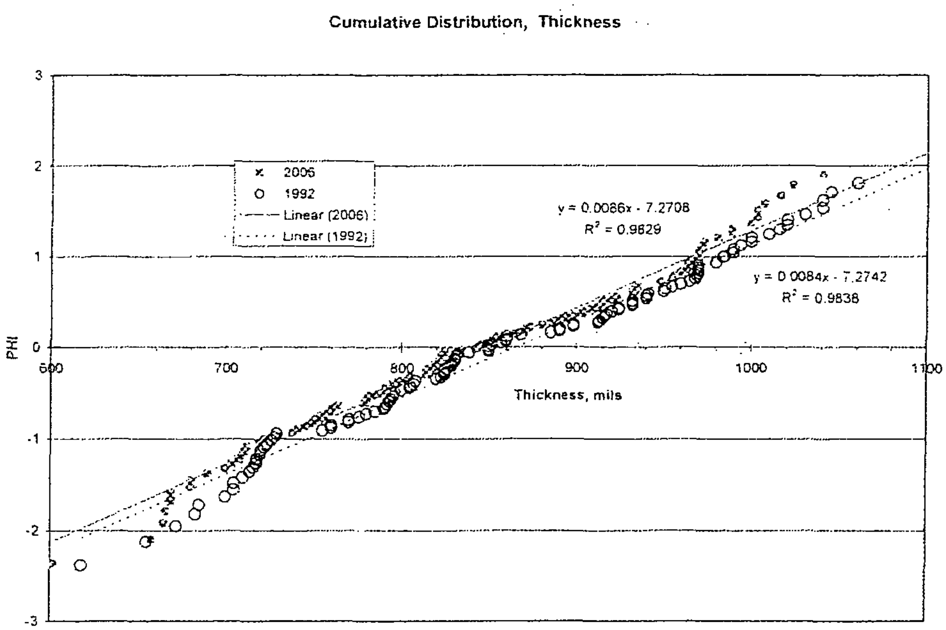

Figure 4-8. Cumulative Distributions, t_{2006} and t_{1992}

5.0 DISCUSSION

The delta, determined by the difference between separate UT thickness measurements taken at the same locations in 1992 and 2006, will be the sum of several terms as shown below:

Delta = Any Corrosion + bias (technique and operator) ± random error in measurements (both 1992 and 2006).

Random errors in the separate measurements will result from the inherent uncertainty in each UT thickness measurement plus the uncertainty associated with placing the transducer on exactly the same location at both points in time. Standardizing the procedure (e.g., scanning each location over a small, pre-determined area, and always reporting the minimum or average reading) can minimize the latter contribution to error. The site reported that different techniques were used in 1992 (done prior to coating; only a single point reported for each location) and 2006. The 2006 measurements were done through the coating, with software corrections to account for the coating and to adjust for the "air gap" resulting from placement of a flat transducer on a slightly curved (dimpled to provide a smooth and readily discernible location for repeat measurements) surface. Perhaps most significantly, the 2006 measurements scanned the defined areas and reported the minimum thickness. The differences in technique between 2006 would be expected to introduce some amount of bias (e.g., reporting minimum values vs. a single value) and could increase or decrease the random error.

Those separate thickness measurements will magnify the error, especially when two separate measurements at different points in time are intended to define a delta, where the expected delta is actually very near zero. The result is that some fraction, 21% in this case, of the locations appear to become thicker while others become thinner. The use of the difference between the 2006 and 1992 thickness measurements suggests that some locations appear to have become much thinner; clearly in stark contrast to the physical observation of the condition of the coating. In all cases, the delta is the difference between two thickness values that are very close in value. The error in individual measurements is clearly greater than the actual difference between drywell thickness in 1992 vs. that in 2006.

The statistical evaluation discussed in Section 4.1.2 clearly demonstrates that there is a bias in the thickness measurements, where the magnitude of that bias is at least 12 mils and is probably more like 20 mils. Clearly, that bias should be added to all of the 1992 readings, which defines the 2006 thickness data as the reference point (i.e., improved technique vs. 1992). Still, random errors can produce differences between individual measurements that do not correspond to the physical observation of coating condition.

Combining the statistical analysis with the physical observation of coating condition and the maximum corrosion rate that could occur beneath an intact coating provides clear evidence that the actual mean value of the difference between the 2006 and 1992 thickness measurements is zero or a value very near zero and that the six points (possibly twelve points) that indicate large negative deltas are actually outliers that should be ignored. That is, the actual differences in thickness between the 2006 and 1992 measurements have a mean that is essentially zero and a maximum of four mils or less. Those mean and maximum differences are far less than the bias introduced by the different techniques.

The most effective use of these data is to define the 2006 thickness measurements as the baseline as of 2006. Corrosion rate, as defined by physical observation of coating condition and a thorough analysis of the 106 thickness measurements done in both 1992 and 2006 confirms that the apparent corrosion over that 14 year period is essentially nil. The latter determination (i.e., corrosion or corrosion rate defined by the difference in the thickness measurements at each of the 106 locations) is subject to systematic and random errors that make the use of the differences less useful. Those latter measurements should be used with caution. Future determinations of corrosion of the drywell must be sure to combine physical observation of coating condition and supplement (but not replace) those observations with the thickness differences.

6.0 CONCLUSIONS

A statistically based review was performed on Oyster Creek drywell thickness data from 1992 and 2006. That review showed that the variation in individual thickness values varied significantly by bay and to a lesser extent by zone (i.e., height above or below the drywell floor).

Differences between the 1992 and 2006 UT thickness measurements, taken at the same 106 locations at both times showed that the vast majority of the difference data (deltas) were distributed around zero. More than 20% of the difference measurements indicated that the drywell became thicker over time; a few measurements suggested that there were large decreases in thickness over the 14 year period.

The several differences that suggested that there were very large thickness losses were in sharp contrast to the physical observation of the coating, which was in good condition. Metal losses beneath an intact coating would be non-existent or extremely small; clearly not losses of 70 mils or more.

Evaluation of the thicknesses in 1992 and 2006 showed that the thickness populations at both times were described well by a normal distribution. The statistical evaluation clearly demonstrates that there is a bias in the thickness measurements, where the magnitude of that bias is at least 12 mils and is probably more like 20 mils. Clearly, that bias should be added to all of the 1992 readings, which defines the 2006 thickness data as the reference point (i.e., improved technique vs. 1992). Still, random errors can produce differences between individual measurements that do not correspond to the physical observation of coating condition.

Combining the statistical analysis with the physical observation of coating condition and the maximum corrosion rate that could occur beneath an intact coating provides clear evidence that the actual mean value of the difference between the 2006 and 1992 thickness measurements is zero or a value very near zero and that the six points (possibly twelve points) that indicate large negative deltas are actually outliers that should be ignored. That is, the actual differences in thickness between the 2006 and 1992 measurements has a mean that is essentially zero and a

maximum of four mils or less. Those mean and maximum differences are far less than the bias introduced by the different techniques.

The most effective use of these data is to define the 2006 thickness measurements as the baseline as of 2006. Corrosion rate, as defined by physical observation of coating condition and a thorough analysis of the 106 thickness measurements done in both 1992 and 2006 confirms that the apparent corrosion over that 14 year period is essentially nil. The latter determination (i.e., corrosion or corrosion rate defined by the difference in the thickness measurements at each of the 106 locations) is subject to systematic and random errors that make the use of the differences less useful. Those latter measurements should be used with caution. Future determinations of corrosion of the drywell must be sure to combine physical observation of coating condition and supplement (but not replace) those observations with the thickness differences.

7.0 REFERENCES

1. "Data submittal 2006 vs. 92.xls", e-mail from Wayne Choromanski (Exelon) to George Licina, 11-3-2006.

2. Tech Eval A2152754 E09 (transmitted to SI by Wayne Choromanski. 11-1-2006).

Exhibit 10

Citizen's Exhibit NC2

From: <john.hufnagel@exeloncorp.com>
To: <dja1@nrc.gov>, <rkm@nrc.gov>
Date: 04/24/2006 6:17:58 PM
Subject: Questions to go over tomorrow...

Roy and Donnie,

These attached questions are those from the database that we currently have statused as Open, but which have responses that should allow closure. Although in the closed status, AMP-071 and AMP-204 were also included because they were updated to reference additional information provided in AMP-072.

Also, we did not send AMP-358, which is the item on Fatigue Analysis. We plan on sending that to you tomorrow.

Hope to talk with you tomorrow PM.

- John.

<<AMP-071.pdf>> <<AMP-072.pdf>> <<AMP-141.pdf>> <<AMP-204.pdf>> <<AMP-209.pdf>> <<AMP-210.pdf>> <<AMP-264.pdf>> <<AMP-356.pdf>> <<AMP-357.pdf>> <<AMP-359.pdf>> <<AMP-360.pdf>> <<AMP-361.pdf>> <<AMP-362.pdf>> <<AMR-164.pdf>> <<AMR-167.pdf>> <<AMR-355.pdf>>

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*****
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Thank You.
****
*****

CC: <donald.warfel@exeloncorp.com>, <fred.polaski@exeloncorp.com>

excerpt.

NRC Information Request Form

Item No
AMP-357

Date Received: 2/16/2006

Source AMP Audit

Topic:
IWE

Status: Open

Document References:

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

(1) When a new set of point thickness readings is taken is the former sandbed region, prior to entering the LR period, what will be the quantitative acceptance criteria for concluding that corrosion has or has not occurred since the last inspection in 1996.

(2) If additional corrosion is detected in the upcoming inspection, describe in detail the augmented inspections and other steps that will be taken to evaluate the extent of the corrosion, and describe the approach to ensuring the continued structural adequacy of the containment.

Assigned To: Ouaou, Ahmed

Response:

(1).The new set of UT measurements for the former sand bed region will be analyzed using the same methodology used to analyze the 1992, 1994, and 1996 UT data. The results will then be compared to the 1992, 1994,1996 UT results to confirm the previous no corrosion trend. Because of surface roughness of the exterior of the drywell shell, experience has shown that UT measurements can vary significantly unless the UT instrument is positioned on the exact point as the previous measurements. Thus acceptance criteria will be based on the standard deviation of the previous data (+/-11 mils) and instrument accuracy of (+/-10 mils) for a total of 21 mils. Deviation from this value will be considered unexpected and requires corrective actions described in item (2) below.

(2). If additional corrosion is identified that exceeds acceptance criteria described above, Oyster Creek will initiate corrective actions that include one or all of the following, depending on the extent of identified corrosion.
a. Perform additional UT measurements to confirm the readings
b. Notify NRC within 48 hours of confirmation of the identified condition
c. Conduct inspection of the coatings in the sand bed region in areas where the additional corrosion was detected.
d. Perform engineering evaluation to assess the extent of the condition and to determine if additional inspections are required to assure drywell integrity.
e. Perform operability determination and justification for continued operation until next scheduled

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NRC Information Request Form

inspection.

These actions will be completed before restarting from an outage

LRCR #: 293 *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/ 1/2006

Reviewed By: Muggleston, Kevin 4/ 3/2006

Approved By: Warfel, Don 4/ 3/2006

NRC Acceptance (Date):

3

NRC Information Request Form

Item No
AMP-356

Date Received: 2/16/2006

Source AMP Audit

Topic:
IWE

Status: Open

Document References:

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

IWE AMP
Question 4 IWE AMP Revised Feb. 17, 2006 R. Morante (AMP-356)

(1) Identify the specific locations around the circumference in the former sandbed region where UT thickness readings have been and will be taken from inside containment. Confirm that all points previously recorded will be included in future inspections.

(2) Describe the grid pattern at each location (meridional length, circumferential length, grid point spacing, total number of point readings), and graphically locate each grid pattern within the former sandbed region.

(3) For each grid location, submit a graph of remaining thickness versus time, using the UT readings since the initiation of the program (both prior to and following removal of the sand and application of the external coating).

(4) Clearly describe the methodology and acceptance criteria that is applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) evaluation.

Assigned To: Ouaou, Ahmed

Response:

Response:
1. The circumference of the drywell is divided into 10 bays, designated as Bays 1, 3, 5, 7, 9, 11,13, 15, 17, and 19. UT thickness readings have been taken in each bay at one or more locations. The specific locations around the circumference in the former sand bed region where UT thickness reading have been taken from inside containment are Bay 1D, 3D, 5D, 7D, 9A, 9D, 11A, 11C, 13A, 13C, 13D, 15A, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C. For each location, UT measurements were taken centered at elevation 11'-3". These represent the locations where UT measurements were taken in 1992, 1994, and 1996.

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In addition UT measurements were taken one time inside 2 trenches excavated in drywell floor concrete. The purpose of these UT measurements is to determine the extent of corrosion in the lower portions of the sand bed region prior to removing the sand and making accessible for visual inspection.

Future UT thickness measurements will be taken at the same locations as those inspected in 1996 in accordance with Oyster Creek commitment documented in NRC Question #AMP-209.

2. For locations where the initial investigations found significant wall thinning (9D, 11A, 11C, 13A, 13D, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C) the grid pattern consists of 7 x 7 grid centered at elevation 11'-3 (meridian) and centered at the centerline of the tested location within each bay, which consists of 6"x 6" square template. The grid spacing is 1" on center. There are 49 point readings. For graphical location of the grid, refer to attachment 1.

For locations where the initial investigations found no significant wall thinning (1D, 3D, 5D, 7D, 9A, 13C, and 15A) the grid pattern consists of 1 x 7 grid centered at elevation 11'-3" (meridian) on 1" centers. There are 7 point readings. For graphical location of the grid, refer to attachment 1.

3. A graph representing the remaining thickness versus time using UT reading since the initiation of the program (both prior to and following removal of the sand and application of the external coating) for location 9D, 11A, 11C, 13A, 13D,15D,17A,17D,17/19, 19A, 19B, and 19C is included in the attached graph. Other locations (i.e. 1D, 3D, 5D, 7D, 9A, 13C, and 15A) are not included because wall thinning is not significant and the trend line will be essentially a straight line.

4. The methodology and acceptance criteria that is applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) is described in engineering specification IS-328227-004 and in calculation No. C-1302-187-5300-011. These documents were submitted to the NRC in a letter dated November 26, 1990 and provided to the Staff during the AMP/AMR audit. A brief summary of the methodology and acceptance criteria is described below.

The initial locations where corrosion loss was most severe in 1986 and 1987 were selected for repeat inspection over time to measure corrosion rate. For location where the initial investigations found significant wall thinning UT inspection consists of 49 individual UT data points equally spaced over a 6"x 6" area. Each new set of 49 values was then tested for normal distribution.

The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736. In addition each individual reading is compared to the local minimum required criteria of 0.49. The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to NRC Question #AMP-210.

A decrease in the mean value over time is representative of corrosion. If corrosion does not exist, the mean value will not vary with time except for random variations in the UT measurements.

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If corrosion is continuing, the mean thickness will decrease linearly with time. Therefore the curve fit of the data is tested to determine if linear regression is appropriate, in which case the corrosion rate is equal to the slope of the line. If a slope exists, then upper and lower 95% confidence intervals of the curve fit are calculated. The lower 95% confidence interval is then projected into the future and compared to the required minimum uniform thickness criteria of 0.736.

A similar process is applied to the thinnest individual reading in each grid. The curve fit of the data is tested to determine if linear regression is appropriate. If a slope exists, then the lower 95% confidence interval is then projected into the future and compared to the required minimum local thickness criteria of .49.

LRCR #: *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/ 4/2006

Reviewed By: Getz, Stu 4/ 5/2006

Approved By: Warfel, Don 4/ 5/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No
AMP-210

Date Received: 1/24/2006

Source AMP Audit

Topic:
IWE

Status: Open

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

Pages 25 through 31 of the PBD present a discussion of the OCGS operating experience.

(8a)The following statements related to drywell corrosion in the sand bed region need further explanation and clarification:
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.
Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning found only in these areas?
After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements.
Please describe the concrete surface below the sand that is discussed in paragraph above.
Please provide the following information:
(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster

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Creek sand bed region.

Evaluation of UT measurements taken from inside the drywell, in the in the former sand bed region, in 1992, 1994, and 1996 confirmed that corrosion is mitigated. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.
NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

(8b)The following statement related to drywell corrosion above the sand bed region needs further explanation and clarification:

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.

Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements". Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

(8c)The following statements related to torus degradation need further explanation and clarification:
Inspection performed in 2002 found the coating to be in good condition in the vapor area of the Torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function.
While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continues to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established

in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to 50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Assigned To: Ouaou, Ahmed

Response:

(8a) Question: Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning only in these area?

Response:
This statement was not meant to indicate that water leaks were limited to only a portion of the circumference. The statement is meant to reflect the fact that water leakage was observed coming out of certain sand bed region drains and those locations were suspect of wall thinning.
No. Wall thinning was not limited to the areas where water leakage from the drains was observed. Wall thinning occurred in all areas of the sand bed region based on UT measurements and visual inspection of the area conducted after the sand was removed in 1992. However the degree of wall thinning varied from location to location. For example 60% of the measured locations in the sand bed region (bays 1, 3, 5, 7, 9, and 15) indicate that the average measured drywell shell thickness is nearly the same as the design nominal thickness and that these locations experienced negligible wall thinning; whereas bay 19A experienced approximately 30% reduction in wall thickness.

Question: Please discuss the concrete surface below the sand that is discussed in paragraph above.

Response:
The concrete surface below the sand was intended to be shaped to promote flow toward each of the five sand bed drains. However once the sand was removed it was discovered that the floor was not properly finished and shaped as required to permit proper drainage. There were low points, craters, and rough surfaces that could allow moisture to pool instead of flowing smoothly toward the drains. These concrete surfaces were refurbished to fill low areas, smooth rough surfaces, and coat these surfaces with epoxy coating to promote improved drainage. The drywell shell at juncture of the concrete floor was sealed with an elastomer to prevent water intrusion into the embedded drywell shell.

Question: Please provide the following information:

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(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster Creek sand bed region.

Response:
1. The minimum recorded thickness in the sand bed region from outside inspection is 0.618 inches. The minimum recorded thickness in the sand bed region from inside inspections is 0.603. These minimum recorded thicknesses are isolated local measurement and represent a single point UT measurement. The 0.806 inches thickness provided to the Staff verbally is an average minimum general thickness calculated based on 49 UT measurements taken in an area that is approximately 6"x 6". Thus the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806".

The 0.806" minimum average thickness verbally discussed with the Staff during the AMP audit was recorded in location 19A in 1994. Additional reviews after the audit noted that lower minimum average thickness values were recorded at the same location in 1991 (0.803") and in September 1992 (0.800"). However, the three values are within the tolerance of +/- 0.010" discussed with the Staff.

2. The minimum projected thickness depends on whether the trended data is before or after 1992 as demonstrated by corrosion trends provided in response to NRC Question #AMP-356. For license renewal, using corrosion rate trends after 1992 is appropriate because of corrosion mitigating measures such as removal of the sand and coating of the shell. Then, using corrosion rate trends based on 1992, 1994, and 1996 UT data; and the minimum average thickness measured in 1992 (0.800"), the minimum projected average thickness through 2009 and beyond remains approximately 0.800 inches. The projected minimum thickness during and through the period of extended operation will be reevaluated after UT inspections that will be conducted prior to entering the period of extended operation, and after the periodic UT inspection every 10 years thereafter.

3.The engineering analysis that demonstrated compliance to ASME code requirements was performed in two parts, Stress and Stability Analysis with Sand, and Stress and Stability Analyses without Sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4, were transmitted to the NRC Staff in December 1990 and in 1991 respectively. Index No. 9-3 and 9-4, were revised later to correct errors identified during an internal audit and were resubmitted to the Staff in January 1992 (see attachment 1 & 2). The analyses are briefly described below.

The drywell shell thickness in the sand bed region is based on Stability Analysis without Sand. As

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described in detail in attachment 1 & 2, the analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches.

As discussed with the Staff during the AMP audit, the basic approach used in the buckling evaluation follows the methodology outlined in ASME Code Case N-284 revision 0 that was reconciled later with revision 1 of the Code Case. Following the procedure of this Code Case, the allowable compressive stress is evaluated in three steps. In the first step, a theoretical buckling stress is determined, and secondly modified using appropriate capacity and plasticity reduction factors. In the final step, the allowable compressive stress is obtained by dividing the buckling stress calculated in the second step by a safety factor of 2.0 for Design and Level A & B service conditions and 1.67 Level C service conditions.

Using the approach described above, the analysis shows that for the most severe design basis load combinations, the limits of ASME Section III, Subsection NE 3213.10 are fully met. For additional details refer to Attachment 1 & 2.

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

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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.

The minimum thickness of 0.733" is not correct. The correct minimum thickness is 0.736".

4. The minimum required thickness for the sand bed region is controlled by buckling.

5. We cannot reconcile the difference between the current (lowest measured) of 0.736" in NUREG-1540 and the minimum measured thickness of 0.806 inches we discussed with the Staff. Perhaps the value in NUREG-1540 should be labeled minimum required by the Code, as documented in several correspondences with the Staff, instead of lowest measured. In a letter dated September 15, 1995, GPU provided the Staff a table that lists sand bed region thicknesses. The table indicates that nominal thickness is 1.154". the minimum measured thickness in 1994 is 0.806", and the minimum thickness required by Code is 0.736". These thicknesses are consistent with those discussed with the Staff during the AMP/AMR audit.

Question: NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

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Response:

Our review of NUREG-1540, page 2 indicates that the statements appear to be based on 1991, or 1993 GPU commitment to perform periodic UT measurements. In fact UT thickness measurements were taken in the sand bed region from inside the drywell in 1992, and 1994. The trend of the UT measurements indicates that corrosion has been arrested. As results GPU informed NRC in a letter dated September 15, 1995 (ref. 2) that UT measurements will be taken one more time, in 1996, and the epoxy coating will be inspected in 1996 and, as a minimum again in 2000. The UT measurements were taken in 1996, per the commitment, and confirmed corrosion rate trend of 1992 and 1994. The results of 1992, 1994, and 1996 UT measurements were provided to the Staff during the AMP/AMR audits.

In response to GPU September 15, 1995 letter, NRC Staff found the proposed changes to sand bed region commitments (i.e. no additional UT measurements after 1996) reasonable and acceptable. This response is documented in November 1, 1995 Safety Evaluation for the Drywell Monitoring Program.

For license renewal, Oyster Creek was previously committed to perform One-Time UT inspection of the drywell shell in the sand bed region prior to entering the period of extended operation. However, in response to NRC Question #AMP-141, Oyster Creek revised the commitment to perform UT inspections periodically. The initial inspection will be conducted prior to entering the period of extended operation and additional inspections will be conducted every 10 years thereafter. The UT measurements will be taken from inside the drywell at same locations as 1996 UT campaign

(8b) Question: Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements. Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

Response:
The measures taken to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to maintain the ASME code requirements are,
1. Cleared the former sand bed region drains to improve the drainage path.
2. Replaced reactor cavity steel trough drain gasket, which was found to be leaking.
3. Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.
4. Confirmed that the reactor cavity concrete trough drains are not clogged
5. Monitored former sand bed region drains and reactor cavity concrete trough drains for leakage during refueling outages and plant operation.

Oyster Creek is committed to implement these measures during the period of extended operation.

(8c) Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to

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50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Response:
(1) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, specifies repair requirements for coating defects exposing substrate and fractured blisters showing signs of corrosion. The repairs referred to in the inspection report included fractured blisters, as well as any mechanically damaged areas, which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters would be candidates for repair, not those blisters that remain intact. The number and location of repairs are tabulated in the final inspection report prepared by Underwater Construction Corporation.
(2) Coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001. Several blistered areas included pitting corrosion where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

(3) In addition to blistering, random deficiencies that exposed base metal were identified in the torus immersion region coating (e.g., minor mechanical damage) during the 19R (2002) torus coating inspections. They ranged in size from 1/16" to ½" in diameter. Pitting in these areas was qualitatively evaluated and ranged from less than 10 mils to slightly more than 40 mils in a few isolated cases. Three quantitative pit depth measurements were taken in several locations in the immersion area of Bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to be representative of typical conditions found on the shell.

Prior to 2002 inspection 4 pits greater than 0.040" were identified. The pits depth are 0.058" (1 pit in 1988), 0.05" (2 pits in 1991), and 0.0685" (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found to be acceptable.

(4) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, includes the pit-depth acceptance criteria for rapid evaluation of observed pitting. The acceptance criteria are supported by a calculation C-1302-187-E310-038. Locations that do not meet the pit-depth acceptance criteria are characterized based on the size of the area, center to center distance between corroded areas, the maximum pit depth and location in the Torus based on major structural features. These details are sent to Oyster Creek Engineering for evaluation.

(5) The acceptance criteria for pit depth is as follows:
-Isolated Pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center to center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated.

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-Multiple Pits that can be encompassed by a 2-1/2" diameter circle shall be limited to a maximum pit depth of 0.141" provided the center to center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or recoated.

Question: Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Response:
Submersed area:
(a) The nominal Design thickness is 0.385 inches
(b) The as-built thickness is 0.385 inches
(c) The minimum uniform measured thickness is,
  0.343 inches - general shell
  0.345 inches - shell - ring girders
  0.345 inches - shell - saddle flange
  0.345 inches - shell - torus straps

(d) The minimum general thickness required to meet ASME Code Acceptance is 0.337 inches.

Technical basis for pitting acceptance criteria included in Specification SP-1302-52-120 is based on engineering calculation C-1302-187-E310-038. At the time of preparation of calculation C-1302-187-E310-038 in 2002 there were no published methods to calculate acceptance standards for locally thinned areas in ASME Section III or Section VIII Pressure Vessel codes. Therefore, the approach in Code Case N-597 was used as guidance in assessing locally thinned areas in the Torus. This is based on the similarity in approaches between Local Thinning Areas described in N597 and Local Primary Stress areas described in Paragraph NE3213.10 of the ASME B&PV Code Section III, particularly small areas of wall thinning which do not exceed 1.0 x (square root of Rt). In addition, the ASME B&PV Code Section III, Subsection NB, Paragraph NB-3630 allows the analysis of pipe systems in accordance with the Vessel Analysis rules described in Paragraph NB-3200 of the same Subsection as an alternate analysis approach. Therefore, the approach used in N597 for local areas of thinning was probably developed using the rules for Local Primary Membrane Stress from paragraph NB-3200 in particular Subparagraph 3213.10. The Local Primary Stress Limits in NB-3213.10 are similar to those discussed in Subsection NE, Paragraph NE-3213.10.

Since the Code Case had not yet been invoked in to the Section XI program, the calculation provided a reconciliation of the results obtained from the code case against the ASME Section III code requirements as discussed above. This reconciliation demonstrated that the approach in N597 used on a pressure vessel such as the Torus would be acceptable since the results are conservative compared to the previous work performed in MPR-953 and Lm(a) (defined in N597 Table- 3622-1) £ (Rmintmin)1/2.

Currently, the maximum pit depth measured in the Torus is a 0.0685" (measured in 1992 in bay 2). It was evaluated as acceptable using the design calculations existing at that time and was not based on

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Calculation C-1302-187-E310-038. This remains the bounding wall thickness in the Torus. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Section III and VIII Code requirements for the Torus.

The Torus inspection program is being enhanced per IR 373695 to improve the detail of the acceptance criteria and margin management requirements using the ASME Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If Code Case N-597-1 is required to develop these criteria for future inspections, NRC review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to periodically monitor to verify they remain bounded.

Supplemental information - 04/19/2006.
This supplements response to item 8a(1) above.
The lowest recorded reading was 0.603 in December 1992. A review of the previous readings for the period 1990 thru 1992 and two subsequent readings taken in September 1994 and 1996 show this point should not be considered valid. The average reading for this point taken in 1994 and 1996 was 0.888 inches.

Point 14 in location 17D was the next lowest value of 0.646 inches recorded during the 1994 outage. A review of readings, at this same point, taken during the period from 1990 through 1992 and subsequent reading taken in 1996 are conistent with this value. Thus the minimum recorded thickness in the sand bed region from inside inspections is 0.646 inches, instead of 0.603 inches.

For additional information on torus coating refer to AMP-072.

LRCR #: *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/20/2006

Reviewed By: Miller, Mark 4/20/2006

Approved By: Warfel, Don 4/20/2006

NRC Acceptance (Date):

Exhibit 11

From: Tamburro, Peter <Peter.Tamburro@exeloncorp.com>
Sent: Thursday, June 8, 2006 9:15 AM
To: Ouaou, Ahmed <u999ao2@ucm.com>
Subject: RE: Proposed Answer to Item 4

Ahmed

I got the 21 mils by calculating the average of all readings in 1996 and subtracting the average of all readings in 1994.

I got the 15 mils by calculating the average of all readings in 1996 and subtracting the average of all readings in 1992.

-----Original Message-----
From: Ouaou, Ahmed
Sent: Wednesday, June 07, 2006 7:27 AM
To: Tamburro, Peter
Subject: RE: Proposed Answer to Item 4

Pete: how did you arrive at 21 mils and 15 mils?.

-----Original Message-----
From: Tamburro, Peter
Sent: Tuesday, June 06, 2006 2:03 PM
To: Ouaou, Ahmed
Cc: Quintenz, Tom; Ray, Howie; Polaski, Frederick W
Subject: Proposed Answer to Item 4

The mean thickness values for the 1996 data are consistently greater than the 1992 and 1994 data. On average the 1996 is approximately 21 mils greater than the corresponding 1994 data values and approximately 15 mils greater than the corresponding 1992 data values. It's not clear why the 1996 data is consistently greater.

Inspection process variables were recently researched in April and May of 2006 by the site NDE Ultrasonic Level III personnel. The variables were assessed while comparing the 1996 data to the 1994 data as follows.

1) Grid Shift and Transducer Rotation. This factor is not applicable. Grid shift would cause readings to be less in some cases and greater in others which would average out.

2) Significant Temperature difference between 1996 and 1994. This factor is not applicable. The NDE data sheets from 1994 and 1996 indicate only a 7 F difference. This is not a greater enough temperature difference to result in a 21 mil increase.

3) Transducer/cable. This factor is not applicable. The same model was used in 1992, 1994 and 1996.

4) Ultrasonic unit. This factor is not applicable. The same model units were used in 1992, 1994 and 1996. Both units that were used during these inspections were tested in April and May of 2006 and found to be in satisfactory working condition.

5) Batteries. This factor is not applicable. Plant procedures require the installation of new batteries prior to each series of inspections.

6) Technician. This factor is not applicable. A review of the 1992, 1994 and 1996 data sheets shows that the personnel who collected the data were certified to SNT-TC-1A or an equivalent procedure.

7) Calibration Block - This factor is not applicable. Both calibration blocks used during this inspection are similar and were receipt inspected to verify that the ultrasonic response equals the physical measurement.

8) Internal Surface Cleanliness. This factor is potentially applicable. The inspection areas are covered with a qualified grease to protect the examination surface from rusting between inspection periods. The grease should be removed prior to the inspection (since sound waves propagate in the grease), and reapplied after the inspection. Tests performed in April and May of 2006 show that the presence of the grease will increase the readings as much as 12 mils. The 1996 inspections were performed by a qualified outage contractor, while the 1992 and 1994 inspections were performed by qualified plant personnel. The governing specification did not clearly specify the requirement to remove the grease prior to the inspection. Therefore it may be possible that the requirement to remove of the grease was not communicated to the contractor, and that the contractor who performed the 1996 inspection may have not removed all or some of the grease.

9) UT unit settings and the application of the external coating. This factor is potentially applicable. It is possible that the ultrasonic unit can be set in a "high gain" setting which may have biased the machine into including the external coating as part of the thickness. The 1996 NDE data sheet neither confirm nor discount whether the unit was set on "high gain".

Exhibit 12

Corro-Consulta
8081 Diane Drive | Rudolf H. Hausler | Kaufman, TX 75142
Tel: 972 962 8287 (office) | *rudyhau@msn.com* | *Fax: 972 932 3947*
Tel: 972 824 5871 (mobile)

Memorandum – REDACTED VERSION – July 19, 2007

To: Richard Webster, ESQ
Rutgers Environmental Law Clinic
123 Washington Street
Newark, NJ, 07102

April 25, 2007

From: Rudolf H. Hausler

Subject: **Update of Current Knowledge Regarding the State of Integrity of OCNGS Drywell Liner and Comments Pertaining to Aging Management Thereof**

Summary

- The proposed aging management plan for the Oyster Creek Drywell Liner, as proposed by AmerGen, is being discussed. It is shown that the UT monitoring locations (6 by 6 inch grids inside the drywell) as defined in 1989 are not representative of the corrosion, which had occurred in the sandbed region.
- Furthermore, since the outside of the drywell in the sandbed region had been coated in 1992, corrosion in the upper regions of the sandbed (i.e. where monitoring is being proposed) has become less relevant because water accumulations (the primary causes for corrosion) will now more likely occur towards the bottom of the former sandbed region.
- The primary cause for additional damage to the drywell by continued corrosion will be the formation of defects in the epoxy coating.
- Since there is no way to assess the **rate** of deterioration of a coating, which for all intents and purposes is already past its useful life, the frequency of inspections must be increased because the coating could fail at any time.
- Frequency of monitoring depends on the remaining safety margins. It is therefore important to gain understanding of the areal extent of the existing corrosion damage. Based on the limited understanding of the extent of locally thin areas, the drywell shell could already be in unacceptable condition. Averages from point measurements (UT measurements) are not the best measure to define average thickness of the whole sandbed region, because the mean itself has uncertainty attached. At minimum, the lower 95% confidence limit of the mean of a number of UT measurements over that area should be employed. A comparison between

Deleted: <#>These changes represent a completely new paradigm for the drywell aging management. The entire program, which had been in use since1987 or 1998, needs rethinking. The best approach would be to make use of continuous moisture monitors and possible online corrosion monitors (it is possible to monitor electrochemical potentials as indications of the onset of corrosion) to supplement the UT testing. ¶

these values with the safety criteria shows that the margins have become very thin in the areas where an assessment is possible, and that therefore frequent monitoring needs to be instituted to ensure significant further corrosion is prevented.

I. Background

Since severe corrosion had been found in the late 1980's in the "sand bed area" of the drywell liner containing the nuclear reactor at the Oyster Creek power generating station, much work has gone into assessing the degree of the damage and modeling the effects of the damage on the integrity of the vessel. Since the drywell liner is a vital safety component, and in light of the pending application for re-licensing reactor operations for another 20 years, the questions surrounding the integrity of the drywell liner have come to the front and center of the stage once again.

There is no question that deterioration of the surface of the drywell shell will continue at some rate over time. Thus, at some point in the future the liner may no longer serve its intended function. This memorandum discusses how to estimate the residual life of the liner and plan an appropriate aging management program around such an estimate.

The bases for such considerations must necessarily be:

- The current state of deterioration of the liner, i.e. the extent of corrosion and how well has it been estimated in the past.
- The criteria by means of which serviceability is ascertained and the remaining margins to condemning the vessel
- The estimated potential future corrosion rate
- And finally the combination of remaining margin and potential rate of deterioration defines the minimum frequency of inspection.

While all of the above items have been estimated and hard numbers have been proffered and written in granite, there is, as will be shown below, great uncertainty surrounding all of the assertions, which have been used by Exelon/AmerGen to support its current approach of taking UT measurements once every four years in the sandbed region.

II. Current Knowledge Regarding the True State of Deterioration.

After corrosion had been found in the sandbed area a concerted effort was made to assess the corrosion rate in order to project the life of the structure. The tools in this effort were ultrasonic measurements (UT) at well-defined locations. In order to assure repeatability of the measurements, a template was constructed containing 49 openings for placement of the UT transducer. The 49 openings were spaced 1 inch apart over a 6 by 6 inch square. This 6 by 6 inch grid was placed repetitively at the inside of the drywell liner just below the vent pipe where the inside curb was lowered from about 2

feet to just over 9 inches (see Figure 1). In this manner, every bay was monitored systematically at intervals over the past 20^+ years.[1)] In 1992 the sand was removed from the sandbed, and all steel surfaces as well as the sandbed floor were coated with an epoxy resin. UT measurements using the 6 by 6 inch grid performed in 1992, 1994, 1996 and 2006, always at exactly the same position, indicated that within the accuracy of the test (measuring procedure) the continued corrosion was at most small. That should not be surprising because a) the outside steel surface was now coated, b) water would not accumulate against the vessel at the location were the measurements were made because of the drains in the sandbed floor, and c) if corrosion were to commence it would most likely be at imperfections in the coating near the sandbed floor where indeed, standing water could be present (see discussion below).[2]

There are however a number of additional monitoring techniques that were used. In 1986 trenches were dug in the reactor floor in bays 17 and 5 to a depth about equal to the sandbed floor on the outside. It is noted that these trenches were not dug in the bays where the most severe corrosion had been observed. These trenches enabled the operator to perform UT measurements below the sandbed surface (prior to removal) from the inside. Additionally, after the sandbed had been removed, and upon visual inspection of the corroded areas, UT and other thickness measurements were made from on the outside of the drywell in the sandbed area. It was believed at that point that the most corroded areas had been selected visually for these measurements. As a consequence of all these measurements the operator AmerGen assured the NRC that the locations where the "grid measurements" had been performed were quite representative of the corrosion that had occurred on the outside of the drywell in the sandbed area (Ref. 4).

We take issue with this statement. In support of this contention, an effort was made to show graphically the remaining wall thickness observed in all of these various locations. Thus Figure 2 shows, by way of example, the remaining wall thickness from the 2006 UT measurements made with the help of 6 by 6 inch grids as a function of elevation in the **trench of Bay 17**. It is understood, as is described in Ref. 3 that 6 such grids were placed one on top of the other in the trench in order to capture the corrosion from the bottom to the top of the sandbed. Hence, if the bottom of the trench had the elevation about 9 feet, then the top of the 6 grids would have had an elevation of about 12 feet, which according to Figure 1 corresponds to the top of the sandbed and is at least 9 inches higher than the top of the grid used for UT measurements from the inside. (Note, none of these elevations is terribly accurate, however, the top of the trench measurements were definitely lower (deeper pits) by a good margin than the inside grid measurements). Figure 2 plots all individual 2006 measurements from the trench in bay 17. The 6 traces represent the variation of the wall thickness in the horizontal direction while the traces themselves extend from the bottom of the trench (left hand side) to the top of the trench (right hand side). The

[1)] 7 Bays were monitored only with 1 by 6 inch templates – probably placed in the horizontal direction – Bay 1 was among those, even though Bay 1 was one of the most corroded Bays.
[2] Note that this region is above the concrete floor but just above or below the epoxy coating above the concrete and so is part of the sandbed region, not the embedded region.

undulations of the 6 traces, which are at times (at the same elevation) in synch and at other times out of phase clearly depict the nature of the "golf ball type" surface described in AmerGen literature (Ref. 1 pg. 4). Where the undulations are in synch one can estimate that the extent of the pit at that location extends over an area larger than just one inch in diameter [3]. It should also be noted that the average amplitude of the undulations in Fig. 2 are of the order of 0.1 inch, i.e. the roughness of the surface at this point is only of that order of magnitude. AmerGen estimated the "roughness" of the surface to be rather of the order of 0.2 inches (Ref. 5 pg. 5).

The most striking observation is that the corrosion is most severe at the top, almost uniform in severity over most of the depth of the sandbed and again somewhat more severe at the very bottom.

Deleted: In other words, one sees already in this presentation that it would be difficult to single out one small area by means of a 6 by 6 inch grid and claim it to be representative of the corrosion having occurred in the sandbed area.

In Figure 3 an effort is being made to compare the average remaining wall thickness from trench measurements (averaged over the horizontal direction) with the average of the 6 by 6 grid measurement from the inside and the direct UT measurements from the outside. Also graphed in this figure are the averages of the outside measurements for the three zones for which data are reported (Ref. 5). What one can see is that the averages for the grid and the trench data overlap quite well at the same elevation. However, the average outside measurements are significantly lower at comparable elevations.[4] This is probably because the choice of location for the external measurements was deliberately biased towards thin spots.

Finally in Figure 4 we see the spread of the 6 by 6 inch inside grid measurements superimposed on the averages of the other measurements.

<u>Conclusion:</u> **What the superposition of the UT measurements in Bay 17 demonstrates is that wall loss ranges from zero to 33 percent, however, only the trench and outside measurements come close to represent the most severe corrosion at the highest elevations. It should also be remembered that the grid measurements at the inside curb cutout as well as those in the trench are only 6 inches wide. One does not have, therefore any indications as to how far serious corrosion may have spread laterally around the circumference of the bay.**

Deleted: The inside grid measurements give a distorted picture.

Figure 5 shows an analysis of the available 2006 data for Bay 13. Bay 13 is probably the second worst corroded bay apart from Bay 1. The averages for the external measurements for each zone are fairly similar, as are the 95% limits for the data spread. There is a 95% percent probability for the deepest penetration to be of the order of 48% of the original wall thickness. The superposition of the internal grid data shows a higher average and a narrower distribution of the data spread. Again one recognizes that the internal 6 by 6 inch grid measurements do not represent the worst corrosion degradation.

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[3] AmerGen suggested that the "dimples" are about 0.5 inches in diameter (Ref. 1 pg. 4)

[4] For the outside measurement averages had to be used in the graphical representations because exact elevations (or coordinates) of each point were not known. We only had the classifications into Zones as had been described in Ref. 5.

Finally in Figure 6 we show the distribution of the external measurements for Bay 1. One observes that the 95% lower limit of the data spread is around 40% of the original wall thickness, or indeed at a remaining wall thickness of 450 mils, which is 0.04 inches below the required sandbed thickness for the Design Pressure and Temperature. Because the external sampling in Bay 1 was designed to capture the thinnest points, this is a conservative estimate of the minimum wall thickness. However, given the need for a very high degree of confidence that the drywell shell is ready to withstand accident pressures and the uncertainty created by the sparse data set, I believe that a conservative approach is required in this case.

Conclusion: The deterioration of the drywell liner at Oyster Creek has been examined in various ways by UT measurements. These were in part systematic thickness measurements in predetermined locations (6 by 6 inch grids placed on the inside of the drywell at curb cut-outs –see Fig. 1, and in trenches dug below the inside floor to a depth roughly equal to the outside sandbed floor). These measurements were supplemented by residual wall thickness measurements performed on the outside of the drywell in locations where "visually" it had been determined that the deepest pits were located. (It must be interjected at this point that a pit of 600 mils cannot be distinguished visually from a pit of 500 mils). The location of these measurements is therefore rather arbitrary, but was presumed repeatable for the measurements in question.

All external UT measurements had been summarized by AmerGen (Ref. 7) for the purpose of determining the minimum safety margin still available. In order to better understand the prevailing corrosion mechanism the data had been separated in "zones" corresponding to increasing elevation above the sandbed floor (zone 1: < 9'4", zone 2: 9'4" to 10-'3", zone 3: 10'3" to 12'3", and zone 4 > 10'3"). The data obtained in 1992 and 2006 were combined and statistically analyzed for the following three effects: a) the two sets of measurements separated by time (and probably methodology or instrumentation), b) the effect of the elevation, and c) differences in the bays.

It was found that there is no significant effect of the time (Fig.7a). While there is a decrease of 19 mils between 1992 and 2006, this difference is not statistically significant within the variability of the data. The differences between the zones, however are significant. Zone 2 is by far the most corrosive zone. When the bays are compared, one finds as expected that some bays have experienced little corrosion in contrast to others. The importance of these observations is obvious: they point again to the fact that the intensity of corrosion is a clear function of elevation and bay. Hence, averaging data and generalization may lead to doubtful conclusions.

In 2006 the validity of some of the external UT measurements was explored by measuring around the nominal original locations. These data were statistically evaluated in Figures 8, 9, 10 for Bays 15, 1 and Bay 19. The additional data collected in Bays 19 and 15 had been identified as "up" or "down", hence additional data sets

identified as 2006 up and 2006 down were compared with the original 2006 data. It turns out for Bay 19 for instance that the UT penetrations identified as 2006 up were significantly lower than the measurements of 1992 with a probability of better than 95%. The difference between the 1992 and 2006 up data is 0.1 inch. Similarly for Bay 15 one finds that the 2006 up data are significantly lower than the original 1992 data by about 0.06 inches, although this difference is not significant at the 5% level. For Bay 1 there is practically no difference between the 2006 and the 1992 data sets, because of the two or three measurements in the non-corroded areas. Summarizing these results in Table 1, one finds that the lower 95% confidence limits for Bays 1, 15 are marginally within the 0.736-inch limit. Since one does not know exactly how extensive the "cancer of corrosion" in the sand bed area really is, it is very difficult to put this interpretation in perspective with the assessments made by AmerGen relative to areal criteria for thinned areas (see discussion below).

Two points must be made with regards to the evaluation of these measurements. All measurements are point measurements, and even though they are closely spaced it is nevertheless difficult to estimate the area over which the measured corrosion penetration may have occurred. This is all the more so for the external measurements.

Pitting on metal surfaces may be considered random if the surrounding environment is uniform, homogenous, and clearly identifiable, because the imperfections in the metal are most likely randomly distributed. (There are of course many well-known arguments against this, such as oriented inclusions due to metalworking, however the assumptions simplify the argument without distorting it). In case of the sandbed there is no randomness because of the predictable decrease in oxygen availability with increasing depth and very likely uneven water content as well. This inhomogeneity is illustrated in Figure 2, where one can see greater corrosion attack toward the top of the sandbed. Similarly, the data show that in Bay 1 the corrosion below the ventpipe occurred more or less in a band of increased corrosion. This band appears to be about 6 to 7 feet long and perhaps a foot wide, although the lowest residual wall thickness (0.669) is found much deeper in the sandbed (Ref. 3). These data shown numerously in various discussions and appendices clearly demonstrate how difficult it is to assess the extent of the damaged areas as is necessary for comparison with the integrity criteria. For instance, the data gathered in Bay 1 in 2006 (and previous years) represent but a small fraction of the overall drywell liner surface exposed to the sandbed environment, and no amount of statistics can predict the pit distribution seen in Bay 1 (Fig. 5). Furthermore, again, the measurements which assess the corrosion in Bay 1 are all point measurements, and one has no way of assessing whether the pits are as local as the representation suggests or whether in fact the thin areas extend from one measurement to the next. I believe that when assessing the extent of severe corrosion, reviewers should assume that the measured points connect unless other measurements show this not to be the case.

III. The Fitness for Use Criteria

Deleted: Furthermore, the pit distribution has been assumed to be random or Gaussian. AmerGen chose to disregard "outliers" which were two standard deviations from the mean (of 49 points) as erroneous or atypical measurements (Ref. 6 pg 16). However, the distribution of pit depth is not necessarily normal but can be exponential, depending on the sensitivity of the measuring technique. It is therefore totally inadmissible from a statistical point of view to discard, or disregard outliers <u>for which there is no physical explanation.</u> ¶

It has been observed in the oil field for instance that wall penetration may occur in pipelines as single events totally unpredicted and unpredictable by statistical means; one single event within 18 miles after 6 months surrounded by practically virgin surface.

Deleted: GE's original calculations stipulated that "if all UT wall thickness measurements in one Bay were above 736 mils, the bay would be evaluated as acceptable In bays where measurements were below 736 mils, more detailed evaluation had to be performed" (Ref. 4, pg. 11 and Ref. 1 pg.4). ¶

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Subsequent calculations determined that if a 1 sq. ft. area were found with a thickness of 536 mils the theoretical load factor/eigenvalue would be reduced by 9.5%. The model stipulated that the1 sq. ft. area was surrounded by a tapering to 0.736 inches (Ref. 1 pg. 6) over a further one foot area. This additional area of reduced thickness contributed to the reduced load factor, hence also the stipulated safety factor. Similar calculations were performed for a reduction of the 1 sq. ft. area to 636 mils in which case the theoretical load factor and buckling stress would be reduced by 3.9%. ¶

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There are a number of questions that do arise in the context of these calculations and their application to the present situation of the OC drywell liner. We would like to make it clear from the outset that we are in no position to verify these calculations and are readily disposed to accept their veracity and results. We would, however, like to note the limitations of these results to put them in proper perspective. ¶

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<#>AmerGenAmerGen states that GE established these criteria as acceptance criteria for the minimum thickness for the drywell to perform its intended function. That is incorrect, GE modeled the drywell, but the operator then derived acceptance criteria. For example, GE calculated both the 536 inch local thickness and the 636 local thickn ... [1]

IV. Statistics

It has also been shown that the 6 by 6 grid measurements (let alone the 1 by 6 inch matrix measurements) do not represent the entire corroded areas. (Ref. 4: *A review of the 2006 inspection data of 106 external locations shows all the measured local thicknesses meet the established design criteria.* ***Comparison of this new data to the existing 19 locations used for corrosion monitoring leads to the conclusion that the 19 monitoring locations provide a representative sample population of drywell vessel in the sandbed.)*** This statement is patently wrong. However, it is not only wrong because the measurements in the trenches and the external measurements do not agree with the grid measurements (19 monitoring locations), it is also wrong because corrosion, if it were to accelerate significantly, would now more likely occur near the bottom of the sand bed rather than the top as was the case with the sandbed in place.

All this not withstanding, it is also recognized that safety codes exist and that safety criteria have been developed. These codes and criteria specify the minimum thickness for *areas* while the corrosion measurements (UT) are highly localized **(points)**, and are said not to capture more than about 0.5 inches in diameter. One now has to confront the problem of translating point measurements to (average) area characteristics. This has been done by making a limited number of measurements in locations, which have been chosen by accessibility and convenience (grid locations).

However, in the absence of scans it would seem prudent to maybe accept the notion that failures do not happen because of averages, but rather where there are extremes, in this case extremely thin areas. In this sense it is suggested that to use the variability of the corrosion data (spread of pit depths) and calculate the likely deepest pit or the most likely thinnest areas. Hence if an average of 10 measurements over a specific area results in a thickness of .750 inches with a variability (standard deviation) for the average of 0.03 inches, the lower 95% confidence limit for this average would be 0.69 (0.75 – 0.06).

In this sense the external measurements of Bays 1, 15, and 19 have been reexamined, and as Table 1 shows, at least in Bay 15 there is no additional margin for continued corrosion in the areas that have been monitored to this point.

V. Corrosion Underneath Coating

It is pretty well established that corrosion underneath an intact epoxy coating, especially a two-layer coating, will be immeasurably small. If it were to occur it would be of the rate of either oxygen or water diffusion through the coating, and either process is very slow. Furthermore, as we have said before, corrosion is more likely to occur near the concrete floor of the sandbed above and below the epoxy coating on the floor as we have pointed out before.

Deleted: Statistics have been used all through this discussion for different purposes. I think it is important to put the use of statistics in perspective as well. Basically there are three kinds of variabilities in the UT measurements as they have been used. First there is the variability of the instrument. The manufacturer usually specifies the "instrument error", in the case of modern UT instruments of the order of 1% of the thickness to be measured. The error usually is given as a standard deviation which means that the 95% confidence limits for the "naked" UT measurement is +/- 2% of wall thickness, in the present case about +/- 20 mils. This is the variability one would find if a calibration block was measured say 100 times. The next variability is a lot more difficult to define: It has to do with the placement of the sensor in the matrix, finding the same spot over again, holding the sensor in the same direction (vertical to the surface) each time etc. This variability (or variance) is additive to the instrumental variability. Finally the thing to be measured varies in thickness as well. This last variability is precisely the response that is desired. Because there have been no planned duplicate measurements (unless one were to assume that since 1992 no corrosion occurred) one cannot assess either the variability of the instrument nor the variability of the measuring technique. However, it is fair to say that the variability of a single measurement overall (i.e. the combination of the instrumental variance and the variance of the technique) are larger than the manufacturer's stated standard deviation, probably double. With that assumption one might expect say 100 measurements of a single location to be distributed about their mean with a 95% confidence interval of +/- 40 mils. Hence a single measurement of a true value of 800 mils might l[... [2]

Deleted: The measured data are then translated by averaging and assuming that the average represents the entire surface even though only 1% of the total may have been measured and even though it has been shown that the assumption won't hold.

Deleted: It had for these reasons been suggested that the entire surface should be scanned in place of point measurements in selected areas.

Deleted: For this reason alone the current monitoring program could miss significant corrosion, no matter how often UT measurements are being performed. ¶
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The entire paradigm of the drywell aging management program needs to be changed, as we have also pointed out before.

What is clear is that any defects in the coating will lead to corrosion damage, provided that there is water present. Hence, the first line of defense is to make sure that there is no water present. This is easier said than done since leaks have occurred before and condensation has also been an issue. Since one still is not sure where the water may be coming from one can safely assume that water could be present at some time in the future and at least during each outage.

The second line of defense is to make sure that the coating is intact. Originally the coating life was quoted as being 10 years. Then AmerGen increased the coating life to 15 years, since the 10 years have already elapsed. However, a 15 year coating life will bring its end of service up to September of this year, hence the coating life has to be 20 years, or at least into the next twenty years of service. All of this has been documented in AmerGen literature. Now, we know that the coating on the floor has suffered damage. The most recent inspection has shown that the coating on the floor was cracked in some bays along with the concrete of the former sandbed floor (Ref. 6) [5]. The cause was attributed to the concrete "shifting and breaking up". However, the other possibility that the coating failed (it was applied too thick to begin with) whereupon water entered the cracks in the concrete, which were there dating back to construction, was not considered. Nevertheless, it has been established in the 2006 inspection that the floor had broken up and that water had entered the cracks underneath the coating. This is a dangerous situation, because now water can migrate in the concrete underneath the coating to the concrete – steel interface.

Deleted: As a consequence corrosion can occur either above or below the floor level where it had been established previously by means of measurements from the trenches that considerable corrosion had already occurred. Hence monitoring has to occur frequently in those areas. It is doubtful that UT measurements in the trenches in Bays 5 and 17 would provide enough coverage for the entire system since essentially every other bay presents worse problems.

Coatings are never 100 % perfect. There are always holidays present, albeit perhaps few. AmerGen has chosen to discount that possibility on the grounds that two layers of coatings had been applied. While extensive qualification of the coating had occurred in 1992 in a mock-up outside the system, and while test coatings were extensively tested for holidays, such tests, albeit standardized and very easy to perform, were never performed once the coating had been applied in the sandbed area. Rather AmerGen insists that relying on visual observations is sufficient. Well, visual observation did not for the past 14 years reveal the defects in the coating on the floor until 2006 and there is no telling just how much damage may have occurred as a consequence. (The coating had been found in perfect conditions in 1994, 1996, 2000 and so on until 2006 when it was found broken up).

The coating is apparently colored gray. It is said that visual inspection will reveal damage and rust if it occurs. That is true after the deterioration has become noticeable, however, the question is not whether the coating has already failed, it is how much damage might occur between inspections after the coating fails.

For that reason it is held that a four-year inspection cycle is not enough by a long shot. First, one needs to monitor for water continuously. As experience has shown on

[5] "During visual inspection of the drywell vessel's exterior coating in the sandbed region (Bays 1, 7, 9, 15) areas were observed to have voids. ... To prevent water from seeping underneath the epoxy, an expandable (?) sealer is required for the seams/voids.

the interior, water can easily percolate through the concrete, as has indeed happened and the operator still does not know where it comes from.

I don't want to go into the mechanism of corrosion once a defect has occurred other than to say the following: Once a defect (crack, pinhole, holiday etc) provides access for water to the steel surface underneath, corrosion begins slowly, hardly noticeable from the surface. However, as corrosion progresses the coating will start to crack, opening up a larger defect. (Thick coatings crack more easily than thin ones). Corrosion will progress underneath the coating and cause larger blisters, which may or may not be seen visually, but can be detected with simple test methods referenced earlier. The question of course is how rapidly will corrosion occur, and what is a reasonable time interval for inspection. I venture to say that nobody knows the answer to the first question with any certainty. It is therefore a matter of making a reasonable assumption, as I did previously. Overall, the applicant must now deal with the uncertainty is has created by taking very few UT measurements over space and time and relying on ad hoc methods for detection of moisture and coating degradation. Because we are dealing with a primary safety containment for a nuclear reactor, the uncertainties must be resolved against the applicant to ensure that a reasonable assurance of safety is maintained.

Deleted: Second, defects in the coating need to be established where subsequent damage is most likely to occur, i.e. on the former sand bed floor and in the crease between the floor and the outside of the liner. ¶

Kaufman, April 25, 2007

Rudolf H. Hausler

References

1. GPU Nuclear Calculation Sheet C-1302-187-5320-024, 1993, page 7 of 117

2. Affidavit of Peter Tamburro before the Atomic Safety and Licensing Board, Docket No 50-219, March 26, 2007

3. AmerGen Passport Document 005546049 07 (AR A2152754 E09), page 5, November 11, 2006

4. AmerGen Calculation sheet C-1302-187-E310-041, 2006, page 4 of 55

5. AmerGen Calculation Sheet C-1302-187-5300-01

6. OCLR R00014655

Schematic Cross Section through Sandbed Area
(not to size)

Figure 1

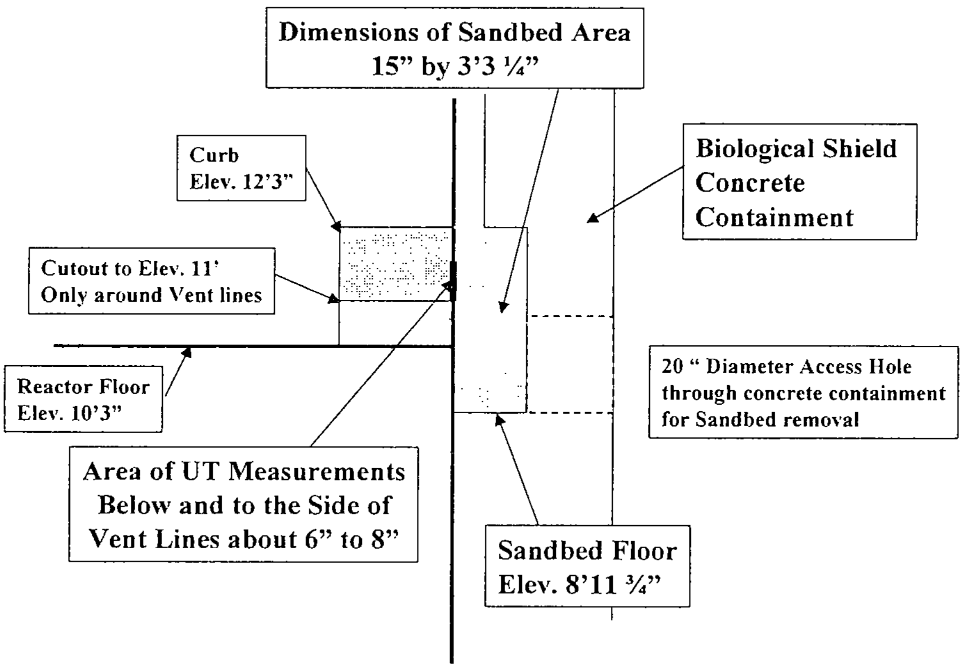
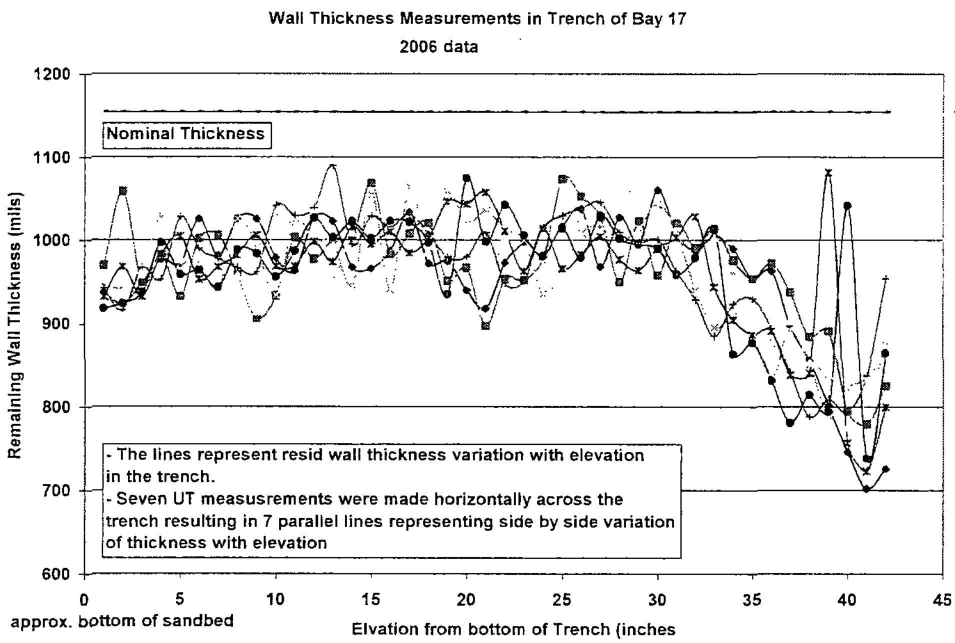
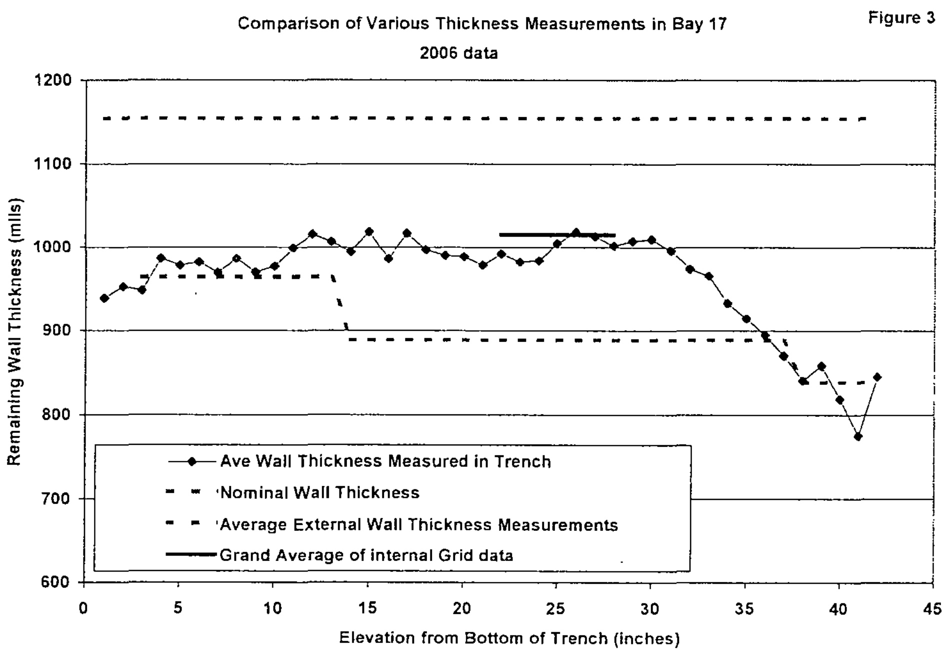


Figure 2


Wall Thickness Measurements in Trench of Bay 17
2006 data
Nominal Thickness
- The lines represent resid wall thickness variation with elevation in the trench.
- Seven UT measusrements were made horizontally across the trench resulting in 7 parallel lines representing side by side variation of thickness with elevation
Remaining Wall Thickness (mils)
1200
1100
1000
900
800
700
600
0
5
10
15
20
25
30
35
40
45
approx. bottom of sandbed
Elvation from bottom of Trench (inches



Comparison of Various Thickness Measurements in Bay 17
2006 data
Figure 3
Remaining Wall Thickness (mils)
1200
1100
1000
900
800
700
600
0
5
10
15
20
25
30
35
40
45
Elevation from Bottom of Trench (inches)
Ave Wall Thickness Measured in Trench
Nominal Wall Thickness
Average External Wall Thickness Measurements
Grand Average of internal Grid data

Figure 4

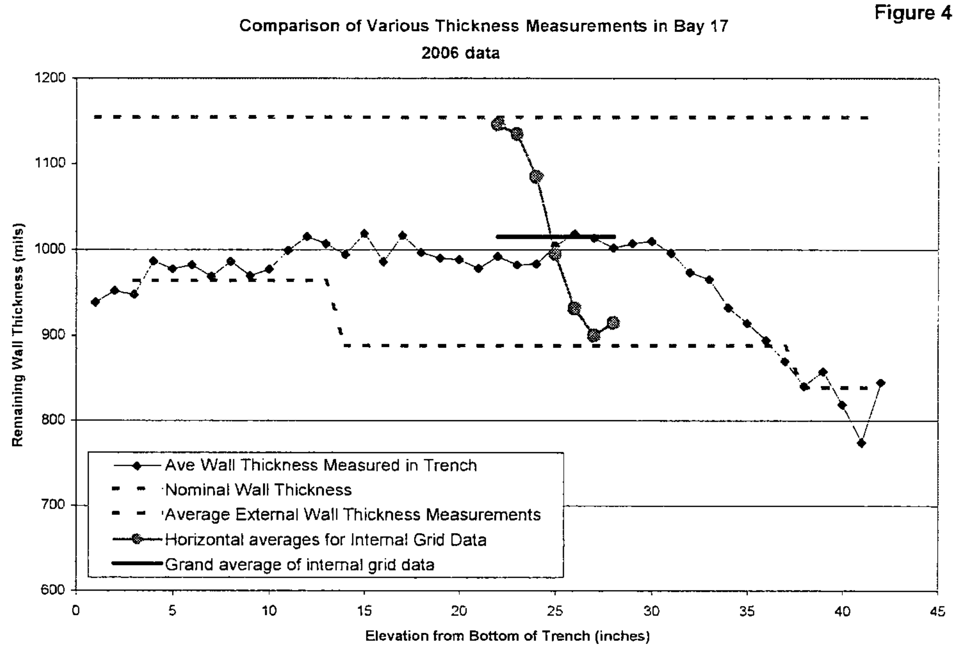


Figure 5

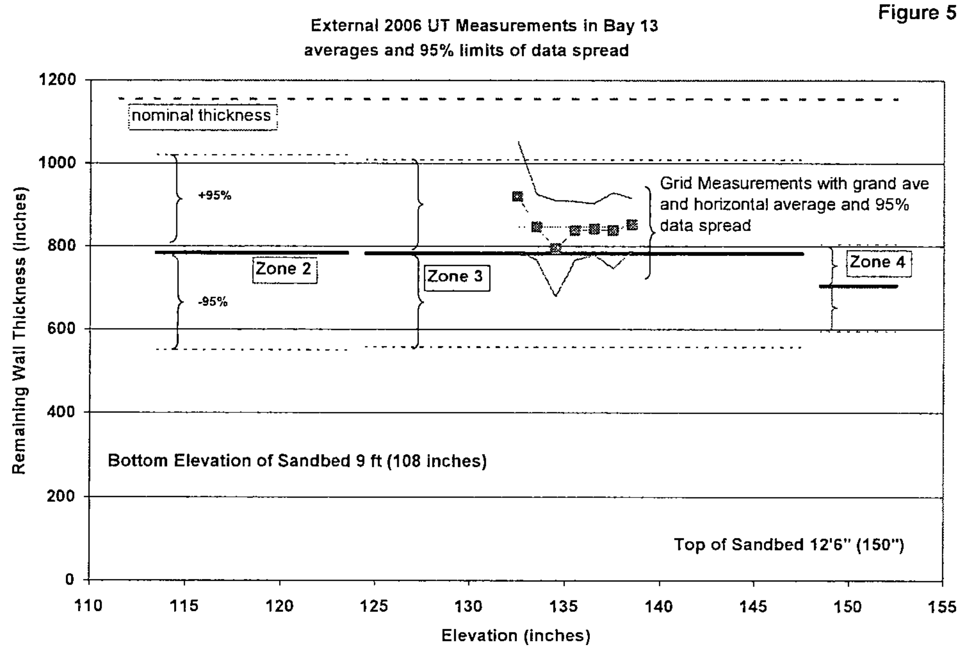


Figure 6

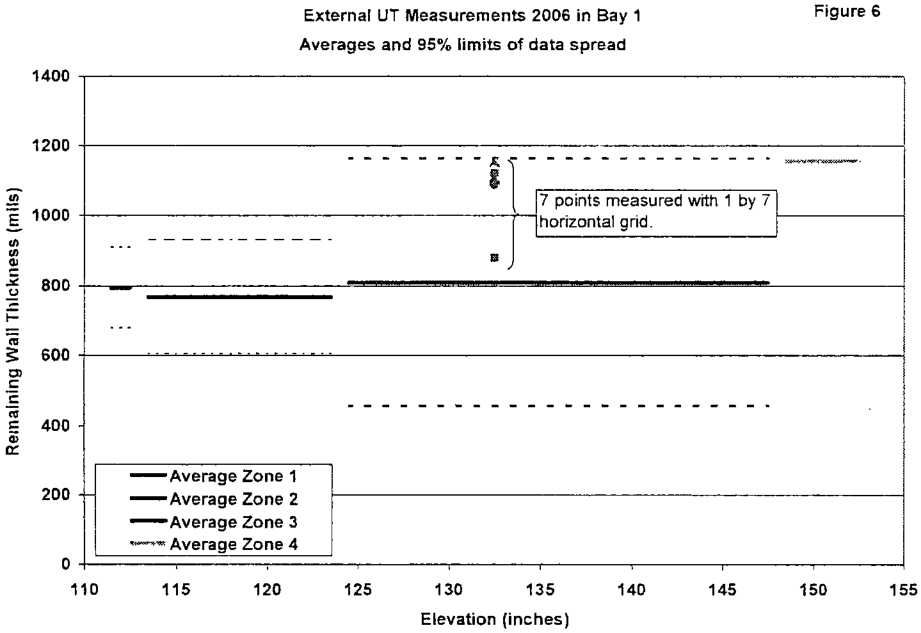
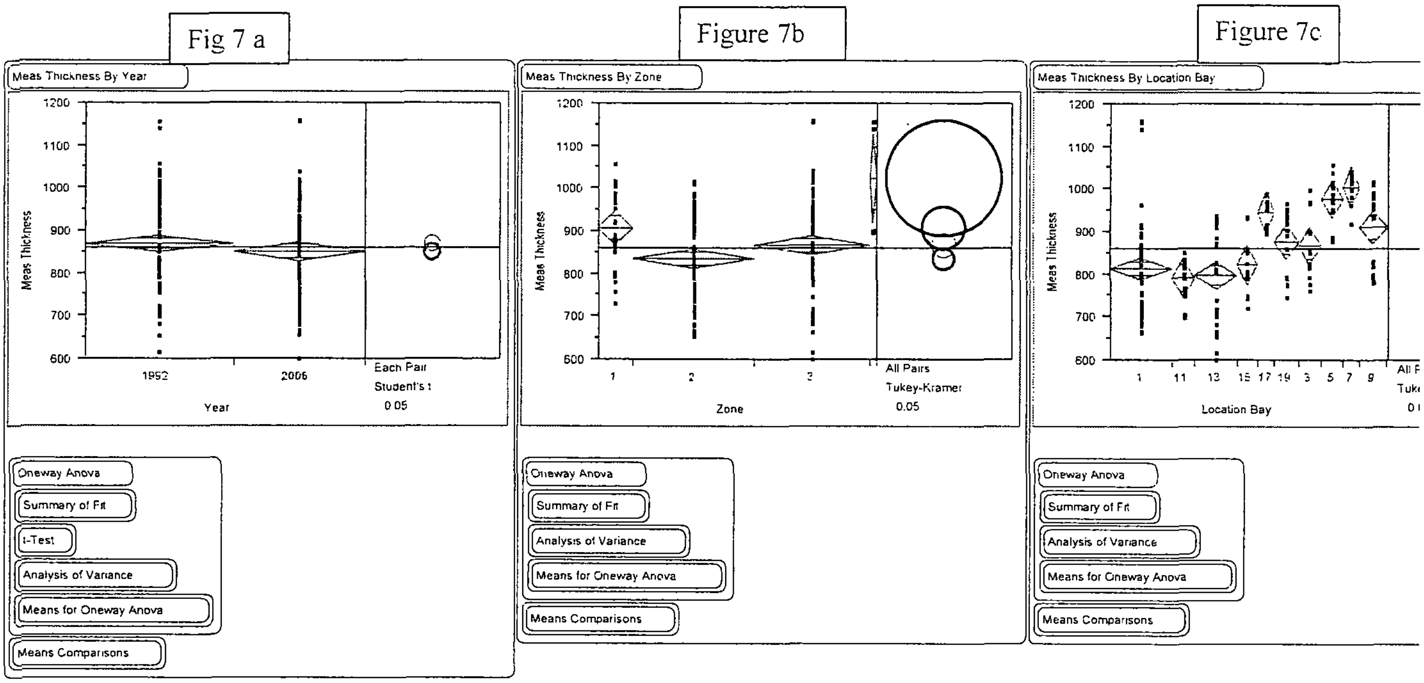

External UT Measurements 2006 in Bay 1
Averages and 95% limits of data spread
1400
1200
1000
800
600
400
200
0
Remaining Wall Thickness (mils)
7 points measured with 1 by 7 horizontal grid.
Average Zone 1
Average Zone 2
Average Zone 3
Average Zone 4
110
115
120
125
130
135
140
145
150
155
Elevation (inches)

Figure 7

Statistical Analysis of all External UT Measurements



Comments: Figure 7a: Comparison between measurements I 1992 and 2006 show no significant difference. The mea 1992 and 2006 show a bias of 0.018 inches, but the bias is statistically not significant despite of the many points. Fig. 7b: The comparison between the "zones" (elevations) is significant. Zones 1 is significantly different from zones 2 and 3. For zone 4 there are not enough data for statistical significance. Fig. 7c: So bays, red ones, are significantly different from the black ones.

Figure 8: External UT Measurements in Bay 15

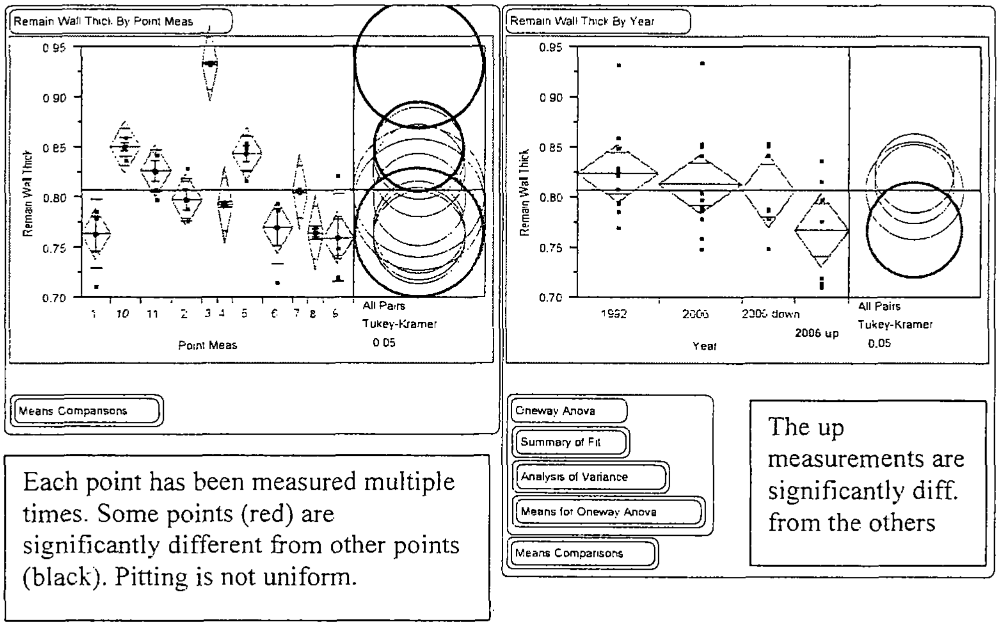


Figure 9: External UT Measurements in Bay 1.

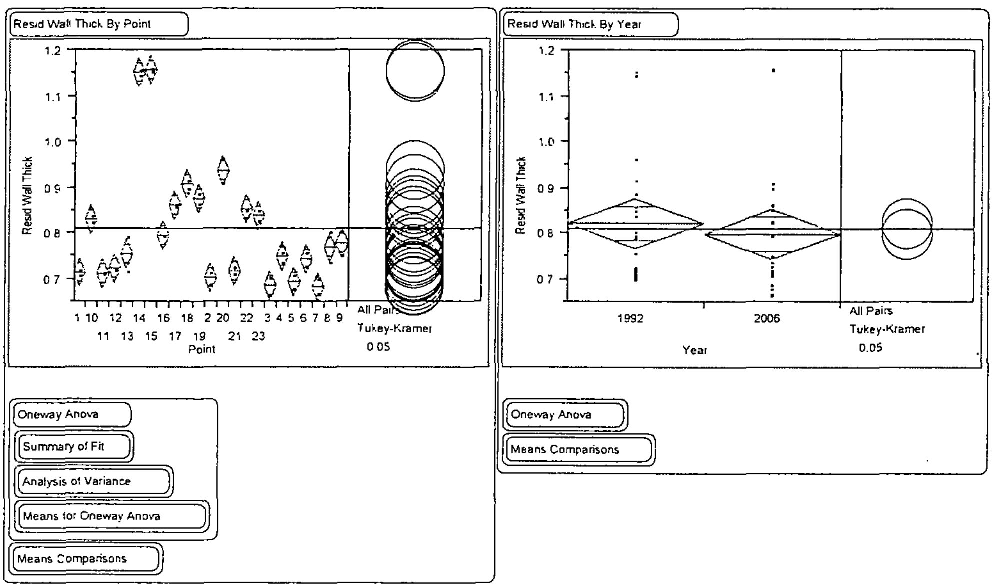
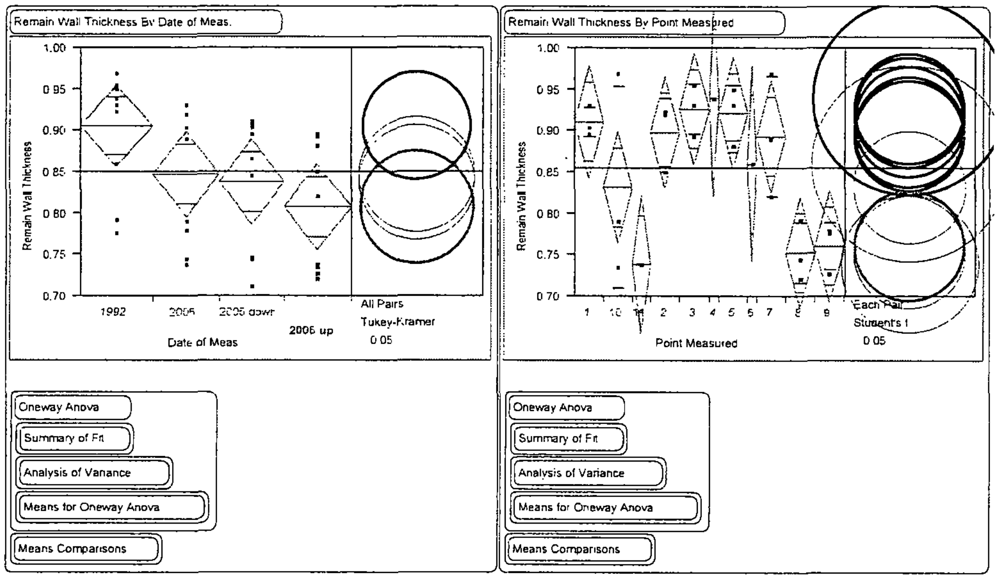


Figure 10: External UT measurements in Bay 19



Again one finds that the "up" measurements are significantly lower from the 1992 measurements.

Table 1

Average Remaining Wall Thickness Measured Externally in the Sandbed Region by UT

Bay	1992		2006		2006-up		2006 down	
	Average	Std Dev	Average	Std Dev	Average	Std Dev	Average	Std Dev
1	0.822	0.027	0.8	0.027				
15	0.825	0.014	0.814	0.014	0.808	0.018	0.768	0.0184
19	0.907	0.025	0.848	0.026	0.837	0.26	0.807	0.026

95 % Confidence Limits of lowest significant measusrements

Bay 1	**0.746**
Bay 15	**0.731**
Bay 19	**0.755**

GE's original calculations stipulated that "if all UT wall thickness measurements in one Bay were above 736 mils, the bay would be evaluated as acceptable. In bays where measurements were below 736 mils, more detailed evaluation had to be performed" (Ref. 4, pg. 11 and Ref. 1 pg.4).

Subsequent calculations determined that if a 1 sq. ft. area were found with a thickness of 536 mils the theoretical load factor/eigenvalue would be reduced by 9.5%. The model stipulated that the1 sq. ft. area was surrounded by a tapering to 0.736 inches (Ref. 1 pg. 6) over a further one foot area. This additional area of reduced thickness contributed to the reduced load factor, hence also the stipulated safety factor. Similar calculations were performed for a reduction of the 1 sq. ft. area to 636 mils in which case the theoretical load factor and buckling stress would be reduced by 3.9%.

There are a number of questions that do arise in the context of these calculations and their application to the present situation of the OC drywell liner. We would like to make it clear from the outset that we are in no position to verify these calculations and are readily disposed to accept their veracity and results. We would, however, like to note the limitations of these results to put them in proper perspective.

AmerGenAmerGen states that GE established these criteria as acceptance criteria for the minimum thickness for the drywell to perform its intended function. That is incorrect, GE modeled the drywell, but the operator then derived acceptance criteria. For example, GE calculated both the 536 inch local thickness and the 636 local thickness with the same assumptions and both led to a reduced load factor. AmerGen and the previous operator then interpreted these results into the current local area acceptance criteria.
It is also not clear how the criteria deal with areas that are below 736 mils thick, but are not square.

While the acceptance criteria, whatever they may be, have been developed for certain well-defined geometries, one cannot immediately relate these to other geometries as they occur in real life.

Now, a new criterion has crept in which would render all previous criteria obsolete. Ref. 4 (pg 11 of 55) states that *if an area is less than 0.736 inches then that area shall be greater than 0.693 inches thick and shall be no larger than 6 inch by 6 inch wide. C-1302-187-5320-024 has previously positioned an area of the magnitude in bay 13, and within the uncertainties of measurement, such an area also exists in Bay 1.*

It is furthermore stated if an area is less than 0.693 inches thick then that area shall be greater than 0.490 inches thick and shall be no larger than 2 inches in diameter.

At present, if we assume that the external points measured in Bay 13 represent the surface, it appears that around 2 sq. ft. clustered around points 7, 15, 6, and 11 is less than 0.693 inches in thickness. In addition, over 4 sq. ft. containing points 12, 16, 7, 8, 11, 6, 15, and 5 appears to be less than 0.736 inches in average thickness. Similarly, in Bay 1 around 4 sq ft emcompassing points 12, 5, 13, 4, 12, 3, and 11

appear to be than less than 0.736 inches in average thickness. It is unclear how AmerGen decided that these results were acceptable, given the latest statement of the local area acceptance criterion.

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Statistics have been used all through this discussion for different purposes. I think it is important to put the use of statistics in perspective as well. Basically there are three kinds of variabilities in the UT measurements as they have been used. First there is the variability of the instrument. The manufacturer usually specifies the "instrument error", in the case of modern UT instruments of the order of 1% of the thickness to be measured. The error usually is given as a standard deviation which means that the 95% confidence limits for the "naked" UT measurement is +/- 2% of wall thickness, in the present case about +/- 20 mils. This is the variability one would find if a calibration block was measured say 100 times. The next variability is a lot more difficult to define: It has to do with the placement of the sensor in the matrix, finding the same spot over again, holding the sensor in the same direction (vertical to the surface) each time etc. This variability (or variance) is additive to the instrumental variability. Finally the thing to be measured varies in thickness as well. This last variability is precisely the response that is desired. Because there have been no planned duplicate measurements (unless one were to assume that since 1992 no corrosion occurred) one cannot assess either the variability of the instrument nor the variability of the measuring technique. However, it is fair to say that the variability of a single measurement overall (i.e. the combination of the instrumental variance and the variance of the technique) are larger than the manufacturer's stated standard deviation, probably double. With that assumption one might expect say 100 measurements of a single location to be distributed about their mean with a 95% confidence interval of +/- 40 mils. Hence a single measurement of a true value of 800 mils might lie anywhere between 760 and 840 mils, and this is probably an optimistic estimate.

Now, it has been assumed that the pitting phenomenon observed at the Oyster Creek drywell liner in the sandbed region was occurring in a truly random manner. It has been pointed out that this is very likely not the case. Nevertheless, lets just assume that Gaussian statistics might be applicable, simply because they are easy to calculate and are the most easily understood. If one measures with single measurements, as was done in all UT measurements, a number of locations say by means of a grid (template), one obtains a series of data reflecting the variation of metal thickness over a given area. At this point it is important to understand that these measurements are not members of a common universe which can be averaged to obtain an average measurement more truly characteristic of the universe than an individual measurement. Rather each measurement is a representative of a different universe – i.e. representing different pitting (corrosion) characteristics, or kinetics. Hence it really does not make much sense to average these measurements and say that on average "this is the corrosion rate". Rather on needs to characterize the variability of the results and superimpose onto them the instrument error. Hence if a specific measurement is, say 756 mils, it is with 95% probability somewhere between 716 and 796 mils. **Therefore, in order to be on the conservative side one would compare**

the 716 mils to the single point acceptance criteria, rather than the reported measurement.

Furthermore, using the average of the grids to represent the entire surface is problematic for many reasons. First, suppose all the sensors had been placed at the low points in the pits. In that case the estimated average would be lower than the true average surface. More importantly, if in fact the corroded surface is like a golf ball surface, how does one average the thickness over the surface area when in fact one only has point measurements within the spherical depressions?

Clearly the entire approach is problematic and perhaps the saving grace is that the design codes require large safety margins. Nevertheless, in this case, when it has been shown that in some situations thickness measurements have been observed well below 693 mils (+/- 40 mils) and below to the 490-mil boundary (with 95% certainty), more detailed measurements are needed.

Exhibit 13

CORRO-CONSULTA
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Memorandum

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July 18, 2007

Subject: **Review of Fitness for Service Assessment of Oyster Creek Dry Well on the Basis of Extended Data Analysis**

I. Objective

One of the basic questions involved in the relicensing of the Oyster Creek nuclear power generating station aims at assessing the confidence one might have in the continued integrity of the *corroded and damaged* Dry Well Shell, the primary radiation barrier in case of an event. Specifically, should Oyster Creek continue to operate for another 20 years, and should corrosion continue, even at a low rate, one needs to define the remaining margins with a high degree of confidence in order to determine the frequency of monitoring.

It is the objective of this study to review all external wall thickness measurements from 1993 and 2006 in order to determine how well one understands the corrosion damage at this time and how much confidence one can have in the remaining margins.

II. Summary

A statistical analysis was performed of all available external corrosion data measured in various Bays in 1992/1993 and 2006.

Since there were duplicate and in some cases triplicate UT measurements available for several locations each in Bays 5, 7, 15, and 19, it was possible to establish a solid standard deviation for these UT measurements. Although these standard deviations varied somewhat with the extent and severity of corrosion from Bay to Bay, where

severe corrosion existed the standard deviation of the measurements is between 40 and 50 mils for 95% confidence limits of +/- 90 mils.

The interpretation of the data for the individual Bays was aided by "Contour Plots" which are three-dimensional plots of contours of equal wall thickness within the space of the UT measurements.

The paucity of data, particularly in the heavily corroded Bays makes definite conclusions very difficult and an assessment of the extent of the corroded areas somewhat intuitive.

Nevertheless, taking into consideration the inherent variability of the measurements and the overall paucity of the data, it is my view that the data do not allow AmerGen to show that the drywell currently meets the safety requirements at the 95% confidence level. Indeed, the extent of the corroded areas in the drywell shell is probably already larger than permitted by most versions of the acceptance criteria.

III. Background

Traditionally, corrosion of the Dry Well Liner in the sandbed area was monitored from the inside by means of UT wall thickness measurements with the help of 6 inch by 6 inch templates placed strategically such that corrosion damage could be monitored in locations corresponding to the top of the sand bed. However, a previous study (**Ref. 1**) demonstrated unequivocally on the basis of the UT data presented by AmerGen that the inside measurements obtained by means of the templates were not representative of the entire corrosion damage and severity of corrosion having occurred in the sandbed area.

The present study takes a closer look at the available UT wall thickness data obtained from the outside and below the top of the former sandbed. The locations for such measurements had been determined on the basis of *"visual observations"*, since presumably it had been deemed too cumbersome and to labor intensive to examine each bay in its entirety. The results of this analysis are then discussed in the light of the general and local wall thickness criteria, which had been derived from "buckling models" and other engineering specifications (**Ref. 2**). The confidence one may have in the current assessment of the nature, extent and severity of the corrosion damage will then:

- support the assessment of the remaining margins
- And together with estimates of future corrosion rates (pitting rates) suggest the applicable monitoring frequencies.

We do not intend to take issue with the pertinent structural questions, such as the derivation of the minimum wall thickness criteria, (even though their definitions and application have varied over the years), nor will we discuss the methodologies of

obtaining the wall thickness data. We do, however, intend to make use of the available data as reported, and ask the question of how much additional information may be extracted from these data with methods, which may complement those used by AmerGen. Specifically, as we have in the past, we aim at contributing to the aging management plan by critically looking at the available data and by extending and broaden our understanding of what the data may tell us.

IV. Numbers and Numbers

It is well to remember that there are two kinds of number, absolute ones and estimates. If a number, such as the minimum acceptable wall thickness of 0.736 inches is derived from a model be means of calculation we would consider that an absolute number valid within the framework of the assumptions which had been made in the development of the model. On the other hand, numbers arrived at by measurements are really only *estimates,* afflicted with a certain probability of reflecting the true reality. It is known that UT measurements have a standard deviation defined by the manufacturer of the device of 1% of wall thickness. Hence a single wall thickness measurement of 0.750 inches reflects (estimates) a true wall thickness value of 0.750 +/- 0.015 inch with a probability of 95%[1]. In view of the fact that it is difficult to reproducibly put the UT probe at the same location, and therefore to measure the same thickness, the confidence limits with respect to the true thickness at the location in question are larger. In Bay's 5, 15, and 19 repeat measurements were made in 2006. The standard deviation of these repeat measurements was 33, 50, and 43 mils, respectively, resulting in 95% confidence limits of about +/- 90 mils (if pooled). As a consequence of this reality it is difficult to accept AmerGen's assurances which state categorically for instance (Ref. 3, page 59) that: "the average of these three readings is 0.773 inches which is greater than 0.736". Therefore area 5 meets the 0.736 uniform criteria". Taking into consideration that the 95% confidence limit of the average of three measurements is 50 mil, there is more than a 5% probability that the average for area 5 is less than 0.736.

Similarly for areas 7, 8, and 11 in Bay 13 AmerGen states that the average of these three areas is 0.658 inches bounded by a 12" by 12" area. Therefore, this square foot area is greater than the local buckling criteria of 0.636 inches. First one should notice that the 1 square foot area has been bounded quite arbitrarily and could as well have been 24" by 24". Furthermore, the average of 658 mils for three measurements in reality is 658 +/- 52 mil such that the real value with 95% probability lies somewhere between 700 and 608 mils. We realize that this spread of the results and this uncertainty in the data is uncomfortable, however, it is based on AmerGen's data and classical statistical evaluation.

[1] Older instruments, such as were available in the late 1980's to early 1990's may have had a standard deviation more like 2% of wall thickness.

V. The Inherent Difficulties

The available models, which had been used to assess buckling (for instance), rely on uniform thinning over a large (or relatively small area as the case may be). Thus, a minimum wall thickness of 0.736 inches has been defined for the Dry Well Shell. This meant that if the Liner had been corroded down to a remaining wall thickness of 0.736 inches over an area embracing the height of the former sandbed and extending the length of one bay a real danger would exist that the Shell might "buckle". (For smaller areas the minimum wall thickness may be smaller as will be discussed below).

It is, however, well established, that corrosion did not occur in a uniform manner (see e.g. repeated references to the "golf ball like" aspects of the corroded surfaces). Additionally, the remaining wall thickness in the sandbed area was determined by ultrasonic "point measurements" at what appears to be random locations [2] below the vent pipes in each bay but not extending far into the respective bays.

As a consequence of this situation it became necessary to convert random point measurements of the wall thickness over a highly non-uniform surface to an average wall thickness for this same surface area. In principle this can only be done properly if the surface had been scanned. However, in view of the location and accessibility of "sand bed surfaces" ultra sonic scanning may not have been possible in 1992 after the removal of the sand.

In order to escape this dilemma AmerGen presented a model (**Ref. 3),** which essentially says that if the deepest pit (thinnest remaining wall thickness) had been located all other measurements would show larger wall thicknesses, and therefore an average wall thickness could be calculated between the thinnest and surrounding locations and this average could then be compared to the criteria. Clearly this is the only approach one can take, however, it also depends on how close together the point measurements are. AmerGen indicates that the point measurements cover an area with diameter of 2.5 inches. Hence, if point measurements are not further removed than 2.5 inches (center to center) from each other, the assumption is correct. If however the point-measurements are more than say 5 inches apart, there can be no assurance that not a deeper pit may exist between the two under consideration [3]. **The confidence one can have in AmerGen's assessment of the remaining wall thickness over the measured area depends on the density of the measurements.** We wish this "confidence" could be expressed in a number, but we think this is not

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[2] While the inside measurements were made with the help of a 6 inch by 6 inch template which could be placed in exactly the same position each time measurements were made, the outside measurement locations needed to be described with coordinates referenced to a specific point below the vent pipe for each bay. The exact location of this reference point relative to the centerline of the vent pipe may vary from bay to bay.

[3] AmerGen has given assurances that the inspector charged with making the measurements had selected the deepest corrosion features (thinnest wall thickness) by visual observation. We think that it would be quite difficult to discriminate between two corrosion features within +/- 0.05 inches. 0.05 inches, however, is of the order of the remaining margin in many areas.

possible. However, we can look at the situation and gain intuitive insight into this question. Figure 1, which is discussed in detail below, presents areas of equal wall thickness (contours) based on the measurements, shown as the points, performed on the outside of Bay 19 in 2006. Note the dark squares are 2.5 inch on each side (and drawn to scale with reference to the horizontal axis), hence cover the area of measurement claimed by AmerGen. It turns out that the measurements at the –20 (inch) vertical position are on average less than 0.725 inches. Since measurements had not been extended to higher elevations one has no assurance that there are no more seriously corroded areas either between those measured or further up in the sandbed.

A detailed explanation and discussion of these graphs will be offered below. At this point it must be pointed out that in general (with few exceptions) the locations chosen for UT measurements on the outside of the Dry Well Liner are few and far between, and that calculating averages between them cannot possibly lead to results with a high degree of confidence.

VI. The development of Contour Plots

Nevertheless, averages we must calculate or else we could not apply the wall thickness criteria, which have been established with considerable effort, and apply them to specified surface areas.

AmerGen went to considerable effort to attempt to demonstrate that essentially no corroded areas exceed the minimum wall thickness criteria. What AmerGen did essentially is to calculate averages from a limited set of measurements either in the y or x directions. Subsequently it estimated the surface area surrounding these points. Finally, average wall thickness and associated surface area were compared to the criteria. While AmerGen thus performed a one-dimensional analysis we propose here to perform a two dimensional analysis.

A simple statistical principle says there is "power in data" and the more data one can bring to bear on a statistical analysis, the more confidence one can have in the results. A typical example is the analysis of variance. Where experimental results have been obtained as a function of several parameters, one wants to evaluate the results using all the data over the entire parameter field, rather than studying each effect individually.

Similarly, in the present case where thickness data have been obtained as a function of horizontal and vertical distance from a reference point one wants to use all the data for an analysis rather than study variations along each axis individually, or specific arbitrarily chosen areas. Such a procedure is possible by using "triangulation" over the entire x - y field. Triangulation essentially calculates averages between all points instead of just some points. For example, take any point in Fig. 1 and connect it with any other point in its vicinity, then calculate the average between each pair and associate the coordinates to this average. Using all this data an algorithm now

calculates equal response lines in the two-dimensional x/y field, in this case, lines of equal wall thickness over the area, which comprises the measurements. The areas between the lines can be shaded. In this manner, Figure 1 shows the areas where it is estimated that the residual wall thickness is between 0.800 and 0.750 inches or less than 0.750 inches, etc. Lines of equal response can be spaced closer together (each 25 mils) or farther apart. In this case, because the inherent inaccuracy of the measurements themselves and the paucity of data it was judged that spacing the lines closer together would not contribute additional insight.

The advantage of this evaluation is that one can see all the available data in a quantitative presentation. Thus, one can see in Figure 1 that an area exists at elevation –20 (20 inches below the reference point) where the remaining wall thickness is less than 750 mils, or less than the criteria for general thinning at 95% confidence. This area extends from 20 inches on the left (-20 inches) to about 60 inches on the right (+60 inches), or about 7 feet. The width of this area in Fig. 1 is maybe 4 to 5 inches, however, because measurements were not extended toward lesser elevations (from the reference point) one simply cannot estimate how much further the serious the corrosion may extend in Bay 19.

In summary, the three-dimensional presentation of the UT wall thickness measurements does two important things for us:

- It presents all data as whole over the area that has been examined and where information exists
- It also indicates where information should have been gathered but wasn't. We therefore get a much better picture with respect to the confidence one may have in the results of the monitoring data.

VII. AmerGen's Treatment of the Raw UT Measurements

AmerGen perceived a difficulty with the UT measurements as far back as 1992 (Ref. 4) in that UT measurements on a "rough" corroded surface were judged inaccurate. In order to improve the accuracy, or, as the case may be, verify the UT measurements, the pit depths in the locations (areas) where UT measurements had been performed were measured by means of micrometers. However, the pit depths could not be referenced to the original surface because the surface from which the pit depth was measured was itself corroded. It was apparently felt that the micrometer measurements would need to be corrected themselves because of the corroded nature of the surface ("golf ball like pimples"). Therefore an imprint was made of the surface and the roughness assessed on the imprint by means of micrometers again. These measurements, about 40 randomly chosen over an area of 40" by 40" were averaged and the average plus one (1) standard deviation was used as a "conservative estimate of the roughness of the surface. Now raw UT measurements were corrected to account for the surface roughness and to yield a value called the "Evaluation Thickness" as follows:

$$T_{evaluation} = UT_{measurement} + (\text{AVG Micrometer readings}) - T_{roughness}$$

This algorithm appears to correct for the fact that due to the roughness the UT probe may not have "coupled" well with the metal surface and therefore detect less metal (thinner wall) than was actually there. This explanation had not been given in so much detail in the original calculation of 1993 and is in part our interpretation. It turned out that almost all UT measurements were reduced by this correction. However, when the average roughness plus two (2) standard deviations was used, the opposite was the case. Furthermore, we understand that the 2006 measurements were made with the epoxy coating in place. In this case the correction would not apply because the sensor would necessarily have coupled better with the smooth epoxy surface, and the instrument would have compensated for the thickness of the epoxy coat.

We can therefore not accept the evaluations done by AmerGen using the "evaluation thickness). Indeed, Mr. Tamburro himself commented in early 2006 that:

> *The calculation develops a term called "evaluation thickness" based on actual measured thicknesses. This value is then compared to the design basis minimum required uniform thickness for the sandbed region of 0.736 inches. The method in which "evaluation thickness" is developed is poorly explained. In addition the justification as to why it is acceptable to compare the evaluation thickness to the design basis required minimum uniform thickness of 0.736 inches is not documented in the calculation, nor is there a reference to an industry standard. (Ref.5)*

As it turns out, the procedure is used again in Ref. 3, page 23 without any further explanation or justification, other than that the evaluation thicknesses better fulfill the design basis criteria.

Another comment should be made at this point regarding the quality of the data used for the evaluation of fitness for purpose of the Dry Well Shell. Repeated reference is made to the fact that: *in 1992 inspections began with visual inspections to identify the thinnest areas in each bay. UT measurements were then performed on the thinnest points within each area (e.g. Ref.3, page 4 of 183).* One keeps wondering how it is possible to discern "the thinnest points" by visual inspection. No doubt the Dry Well Liner is not corroded uniformly in the former sand bed area. And certainly there are areas that are pitted more severely than others, which is totally consistent with the nature of this type of corrosion and the underlying corrosion mechanism. However, in view of the fact that the margins (difference between design basis thickness and actual UT measurements) are already very thin, one has to wonder how visual inspection can differentiate between areas that might differ by 50 to 75 mils in residual wall thickness. Case in point is repeat measurements in 2006. In Bay 15 for instance, area 1 was first measured as 0.779" residual thickness while repeat

measurements are shown to vary from 0.711" to 0.779 inches. Similar variations were found for a large number of the areas in Bay 15 as well as other Bays (Ref. 6).

The difference between the average of the first set of 2006 measurements in Bay 15 and the average of subsequent sets is statistically not significant. The standard deviation for repeat measurements, however, is of the order of 45 mils and the 95% confidence limits are of the order of +/- 90 mils.

AmerGen discusses the bathtub ring in Bay 1 (See also Figure 2) as one single area using 1992 and 2006 data for which the *evaluation thicknesses* had been determined (See discussion of evaluation thicknesses above). AmerGen finds that in this area the average of 11 data points, which is around 4 square feet in area, is 0.766 inches and 0.765 inches for the 1992 and 2006 measurements, respectively. Considering the uncertainty of the measurements, +/- 27 mils, there is at least a 5% probability that the remaining margin is of the order of 2 to 3 mils, assuming that areas larger than one square foot in extent must average 0.736 inches or more.

Even more seriously, if the original data as measured in 2006 had been used for this assessment, the average thickness from the 11 measurements would be 0.735. There would therefore be no margin left for corrosion for this particular area, not even taking into consideration that the 95% confidence limits are +/- 27 mils for the average of 735 mils.

At this point we should make a comment concerning the use of statistics. The statistical parameters for a set of data said to belong to the same population, such as the mean, the standard deviation, the 95% confidence limits, etc., are mathematically derived entities based on broadly accepted theory. The central limit theorem says that the standard deviation of the mean is smaller as more data is gathered. Thus, if a mean of 5 measurements is say 745 mils with a standard deviation for the individual measurements of 40 mils, then the 95% confidence limits are +/- (40/((5)^2))*2, or +/- 36 mils, ranging from 781 mils to 709 mils. The probability that this area does not meet design criteria then is of the order of 35 – 40 % (not rigorously determined), while the probability that it does meet it is of course the complement 60 to 65%.

One finds often in the practice of statistics a tendency to disregard statistical assessments in favor of intuitive approaches. For example, one way out of the dilemma is to use 1 sigma, but that would reduce the level of confidence, which is unacceptable here. Large variabilities are often in the nature of the phenomenon to be measured (corroded surfaces being a good example) or in the method of measuring. Only large data sets can overcome these difficulties. The table below may illustrate this situation.

Means, Variability, and Standard Deviation of UT Measurements on Corroded External Surfaces.

Bay	1993 Mean of all Measurements	1993 Variability 1 sigma	2006 Mean of all Measurements	2006 Variability 1 sigma	2006 Standard Deviation
5	0.993	0:053	0.960	0.039	0.033
7	1.005	0.043	1.007	0.028	0.023
15	0.816	0.054	0.810	0.053	0.050
19	0.889	0.077	0.848	0.083	0.043

The variability for the individual measurements reflects the irregularity of corrosion. One would not really expect the remaining wall thicknesses to be uniform over the corroded area. In that sense the spread of the data does not really reflect a standard deviation in the purest sense of the word. However, since a large number of repeat measurements had been carried out at the identical coordinates in Bays 5, 7, 15, and 19, it was possible to calculate a true standard deviation for these measurements. It turns out that this standard deviation is also a function of the degree of corrosion found on the varying surfaces.

VIII. Discussion of Contour Plots

The data used for the analysis are contained in Tables 1 and 2 for Bays 1 and 13 as extracted from AmerGen documents. Presumably, these were the most corroded Bays. Figure 2 shows a contour plot for Bay 1 obtained with the data from 1992. The dimensions of the points in the plot are 2.5 by 2.5 inches. Again, one needs to remember that the specific shape of the contours depends not only on the residual wall thickness measured at the locations indicated, but on the density of measurements as well. (For instance, an additional measurement at coordinates h (-20) v (-25) could completely alter the contours and in all likelihood extend the area of wall thickness below –750 mils [4]).

Nevertheless, it appears in Figure 2 that in the so called "bathtub ring" an extensive area exists with wall thicknesses between 700 and 750 mils (0.75 inches). This area extends well over 52 inches (4^+ feet) and is about 5 inches wide. In view of the fact that UT measurements are at best accurate with a standard deviation of about 45 mils, (95% confidence limits +/-90 mils), this area could well be more extensive.

Figure 3 shows the contours for Bay 1 obtained with the data from the 2006 inspection. The general shapes are the same as in Figure 2 except that here we have sizeable areas with residual wall thicknesses below 725 mils. The unexpected thing is

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[4] The spacing of the contours is chosen arbitrarily and lightly different results could be expected for alternate contours. In this case 25 to 50 mils was chosen because, as discussed above, there is essentially no difference, statistically significant, between the "criterion" or 736 mils and a measurement of 750 mil residual wall thickness.

that these areas seem to extend on the left beyond h –40 inches but no measurements are available to verify whether AmerGen did in fact manage to capture all of the most corroded areas as claimed.

Based on Figure 3, together with and assessment of the accuracy (reliability) of the data one must conclude that there is a good likelihood that the entire bathtub ring area extending from 40 to –40 inches on the horizontal axis and from about –30 to perhaps -20 inches on the vertical axis is below the 0.736 inch criteria for general thinning and is, much larger than the one square foot acceptance criterion. (Of course, since this area is the most corroded, it will taper off to higher wall thickness on both sides of the vertical axis). The corroded area is indeed shaped quite irregular, but one could venture a guess that the contoured areas below 750 mils are of the order of 4 to 7 square feet all together. This estimated area does not include the area to the left of -40, which probably contains additional area below 0.750 inches.

Figures 4 and 5 show the contours for Bay 13, 1992 and 2006 data, respectively. Here large areas exist with wall thicknesses below 700 mils and at least two seemingly unconnected areas where the residual wall thickness is less than 650 mils. It could be argued that those heavily corroded areas are less than 1 square foot and therefore are still acceptable according to the 636 mil criterion. However, the heavily corroded area on the left hand side (-20, -20) has not been further explored. One therefore does not know whether it might extend further. Similarly, the area on the right ((40, -7), clearly showing a fairly deep pit, was not further explored and was not even measured in 2006. While in Bay 1 the bathtub ring was at elevation –20 to –25 (from the reference point) in Bay 13 there is no clearly prominent bathtub ring. This may be because it was not there, but it may also be because the measurements were not extended toward elevation –15 and –10. We are therefore left with a great uncertainty as to the true extension of the damage in this Bay.

Figure 6 shows the contours for Bay 15. There is a heavily corroded area at elevation –10 with an extension of 1 ft by about 4.5 feet. However, this area was explored only with 2 measurements and was not extended beyond about 2 feet either side of the centerline. It appears that the majority of the measurements occurred in the non-corroded zones. Interestingly there appears some serious corrosion near the sandbed bottom, but the occurrence was not further explored either.

Figure 1 mentioned previously shows a heavily corroded area in Bay 19 at elevation –20. The extent of this area is highly uncertain because it was not further defined by additional UT measurements toward higher elevations (>-20). Indeed, one could find here an extended bathtub ring area.

Figure 7 shows the contours for Bay 11. Again there is a suggestion of severe corrosion at elevation –20 and no further exploration into the bathtub ring area. Once again, the extent of this area is highly uncertain because it was not further defined by additional UT measurements.

In summary, the contours for these various bays show a consistent but equally disturbing pattern. While AmerGen has consistently assured us that visual observation led to the selection of the locations to be evaluated by UT measurements we also find that assertion was not verified, once severe corrosion had been measured, by further exploring the surroundings. This omission greatly contributes to the uncertainty one must have regarding the integrity of the Dry Well Shell.

IX. Discussion of the Minimum Wall Thickness Criteria

Several minimum wall thickness criteria have been developed by means of a General Electric Company computational model. Of interest was the relationship between the degree of wall thinning and the area over which such thinning occurred. It stands to reason that the greater the thinning the smaller the thin area one could tolerate would have to be.

The first criterion so derived states that the limiting wall thickness in one bay was 736 mils in the case that the entire Dry Well Surface formerly in contact with the sandbed were uniformly corroded to that depth. This has been interpreted by AmerGen to apply to the mean of the measured thicknesses.

However, individual measurements less than 736 mil residual wall thickness have been observed. For this reason GE conducted a sensitivity analysis in order to determine the extent of corroded surface area still acceptable when the residual wall thickness was below 736 mils.

The analysis technique embedded in the GE Model the case of a local area of 12 inch by 12 inch having a residual wall thickness of 0.536 or 0.636 inches tapering back to 0.736 inches over a further foot. The theoretical load factor for this case was reduced by 9.5% for the 0.536 inches case and 3.9% for the 0.636 inches case. The safety factor in the first case of general wall thinning is 2 (as required by the ASME code). Therefore, allowable reductions in load factor should get less as the average thickness of the sand bed approaches the general wall criterion.

The following wall thickness acceptance criteria were derived from this model:

- If an area is less than 0.736 inches thick then that area shall be greater than 0.693 inches thick, and shall be no larger than 6 inches by 6 inches. C-1302-187-5320-024 has previously placed an area of this magnitude in Bay 13 **(Ref.2)** [5] Actually, as can be seen from Figure 4, there are two such areas in Bay 13.

- Most recently, the limiting wall thickness criterion was formulated as follows: *An evaluated area for local buckling shall not be greater than 36 inches by 36 inches wide. The center of the area shall be no larger than 12*

[5] please note that this reference is dated 12/15/06. This date is important, because it follows a detailed critique of the GE Model results by the same author dated 6/30/06.

inch by 12 inch and shall be on average 0.636 inch thick or thicker. The surrounding 36" by 36" area centered on the 12" by 12" area shall be on average thicker than the transition from 0.636" to 0.736".

This definition, most recently formulated (3/21/07) appears to be saying that the allowable area thinner than 0.736 inches is 9 square feet, but that no 12 inch by 12 inch area of 0.636 inch or less wall thickness should be present. However, it seems to us that this definition is in stark contrast to earlier more conservative interpretations, which limited the area thinner than 0.736 inches to one square foot or less.

An additional criterion relates to the pressure effect and essentially states that an area of 2.5 inch by 2.5 inch must have a wall thickness larger than 0.490 inches.

The real question then is this: If for general thinning of the wall in one bay the residual acceptable wall thickness is close to 0.736 inches how much additional reduction in load factor (or safety factor) can one tolerate if there are local areas with thinner, or much thinner wall thicknesses. We have not found an answer to this question.

X. General Questions and Reservations

For local areas corroded beyond the thickness of 0.736 inches the most stringent criterion derived from the GE calculations states that:

-if an area is less than 0.736 inches thick, then that area shall be greater than 0.693 inches and shall be no larger than 6 inch by 6 inch wide.

Such areas definitely exist in Bays 1 and 13. However, while apparently the criterion was derived for square areas, such areas do not exist in reality. Rather, the major area in Bay 1 which has wall thicknesses below 0.736 inches (and somewhere between 650 and 720 mils) is of the order of 80 inches by 5 inches. If total area rather than linear dimensions are important then the area in Bay 1 which is below 736 mils is 10 times larger than specified by the criteria (400 square inches vs. 36 square inches). There is another area in Bay 1 clearly below 725 mils about 10 inch by 10 in dimensions.

Finally, the acceptance criteria have been based on modeling of square areas of corrosion less than 0.736 inches. However, in Bays 1, 15 and 19 the most corroded areas are actually long grooves. It is likely that such grooves have more effect on the stability of the drywell shell than square areas because the stresses cannot easily distribute around such areas. In the absence of further modeling of the effect of these shapes on stability, it is prudent to use conservative acceptance criteria to review these grooves, based on the modeling conducted to date, especially in Bays 1 and 15 where the average thickness is, at best, very close to 0.736 inches. Thus, the area

below 0.736 inches should at least be smaller than one square foot, and thicker than 0.636 inches on average as it appears AmerGen also decided in 2006, after careful consideration.

References:

1. **Affidavit of Dr. Rudolf H. Hausler, April 25, 2007** (Memorandum to Richard Webster, Esq., *Update of Current knowledge regarding the state of integrity of OCNGS Drywell Liner and comments pertaining to the aging management thereof*)
2. **Sandbed Corrosion Rate Assessment,** Attachment 1, Calculation Sheet C-1302-187-E310-041, Preparer Pete Tamburro , 12/15/06, page 11 of 55, (also OCLR 00019286)
3. **CC-AA-309-1001 Rev.2** Calculation Sheet C-1302-187-5320-024, 3/28/07, page 7 of 183
4. **Calculation Sheet C-1302-187-5320-024, Rev. 0,** 04/16/93, page 5 of 54
5. **AR 00461639 Report:** Peter Tamburro, (*Calc C-1302-187-5320-024 is not clearly documented,)* 06/30/06, page 2 of 5, item 3
6. **AR A2152754 E09,** Passport 00546049 07 (Also OCLR 00018401 through 00018494)

Table 1

Bay 1 UT Measurements for External Corrosion.

Measurement ID	Vertical Position inches	Horizontal Position inches	Remaining Wall Thickness 1992 inches	Remaining Wall Thickness 2006 inches
1	-16	30	720	710
2	-22	17	716	690
3	-23	-3	705	665
4	-24	-33	760	738
5	-24	-45	710	680
6	-48	16	760	731
7	-39	5	700	669
8	-48	0	805	783
9	-36	-38	805	754
10	-16	23	839	824
11	-23	12	714	711
12	-24	-5	724	722
13	-24	-40	792	719
14	-2	35	1147	1151
15	-8	-51	1156	1160
16	-50	40	796	795
17	-48	16	860	846
18	-38	-2	917	899
19	-38	-24	890	856
20	-18	13	965	912
21	-24	15	726	712
22	-32	13	852	854
23	-48	15	850	828

Table 2

Bay 13 UT Measurements for External Corrosion.

Measurement ID	Vertical Position inches	Horizontal Position inches	Remaining Wall Thickness 1992 inches	Remaining Wall Thickness 2006 inches
1a	1	45	672	.
2a	1	38	725	.
3a	-21	48	941	932
1	-6	46	814	873
2	-6	38	615	.
3	-26	42	934	.
4	-12	36	914	873
5	-21	6	715	708
6	-24	-8	655	658
7	-17	-23	618	602
8	-24	-20	718	704
9	-28	4	924	915
10	-28	12	728	741
11	-28	-15	685	669
12	-28	-23	885	886
13	-18	40	932	814
14	-18	8	868	870
15	-20	-9	683	666
16	-20	-29	829	814
17	-9	38	807	.
18	-22	38	825	.
19	-37	38	912	960

Figure 1

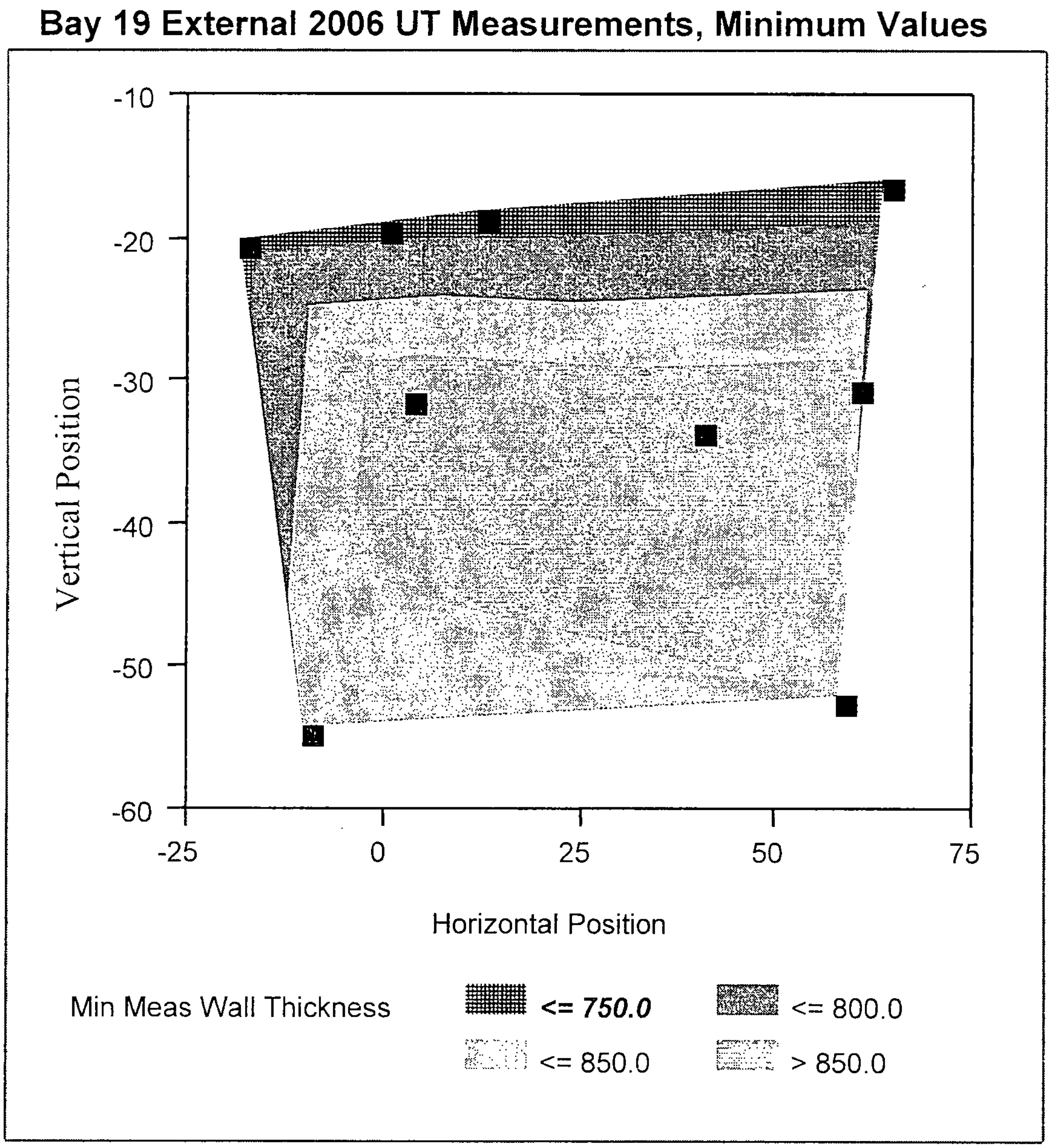

Bay 19 External 2006 UT Measurements, Minimum Values
-10
-20
-30
-40
-50
-60
Vertical Position
-25
0
25
50
75
Horizontal Position
Min Meas Wall Thickness
<= 750.0
<= 800.0
<= 850.0
> 850.0

Figure 2
Bay 1 Remaining Wall thickness
External UT Measurements 1992/1993

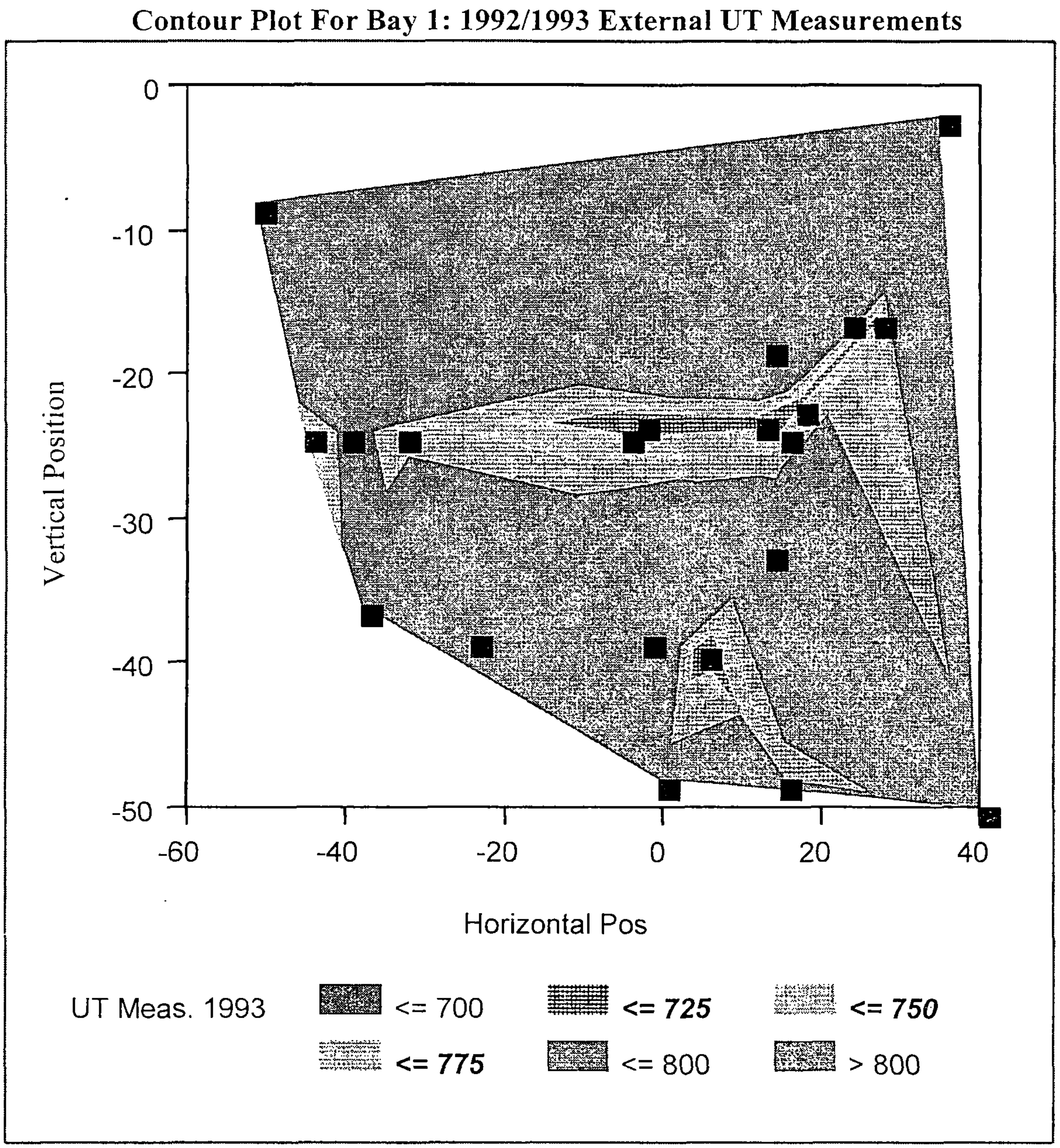


Figure 3

Bay 1 Remaining Wall thickness
External UT Measurements 2006

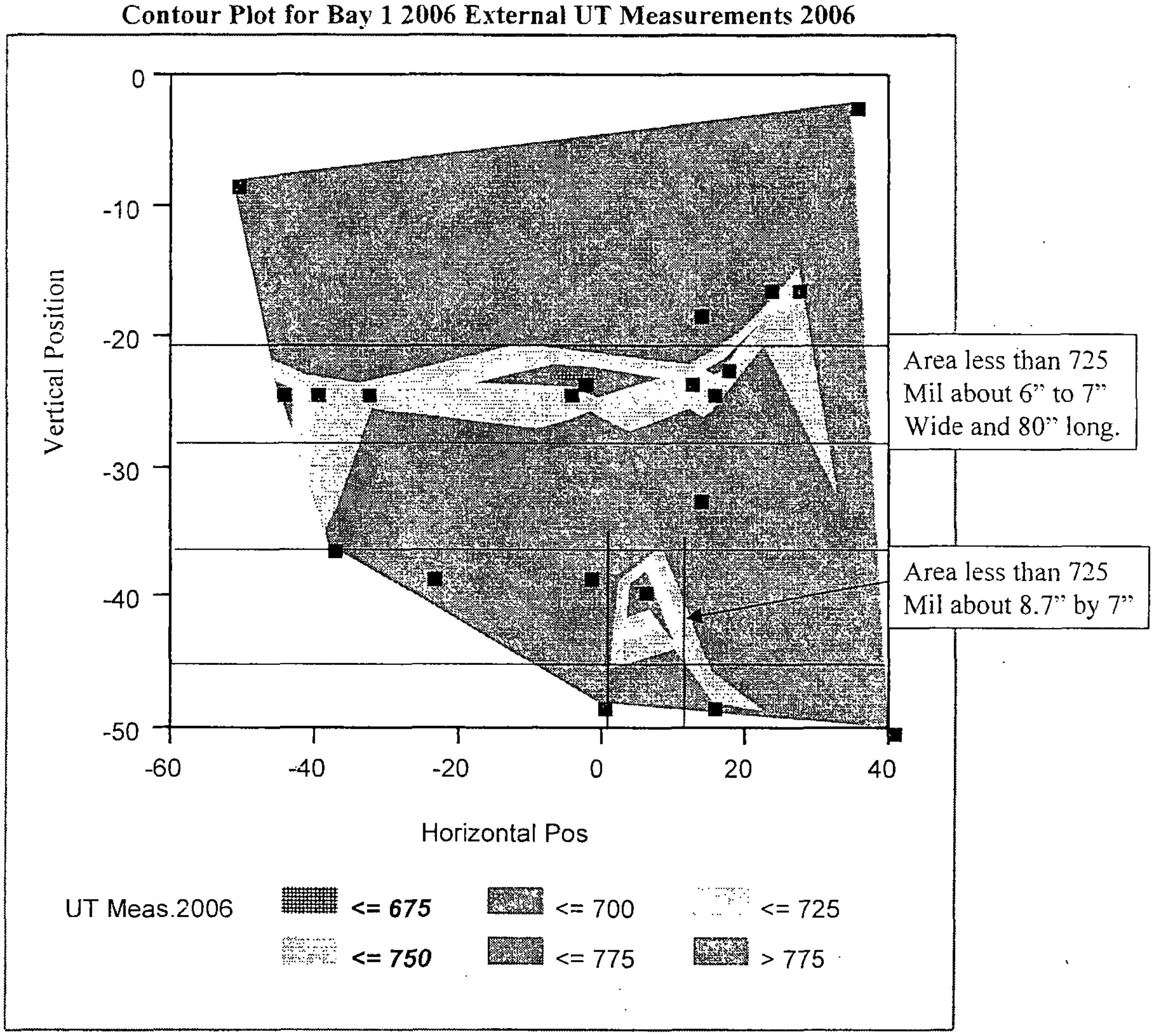


Figure 4

Bay 13 Remaining Wall Thickness
External UT Measurements 1992/1993

Contour Plot for Bay 13 19921993 External UT Data

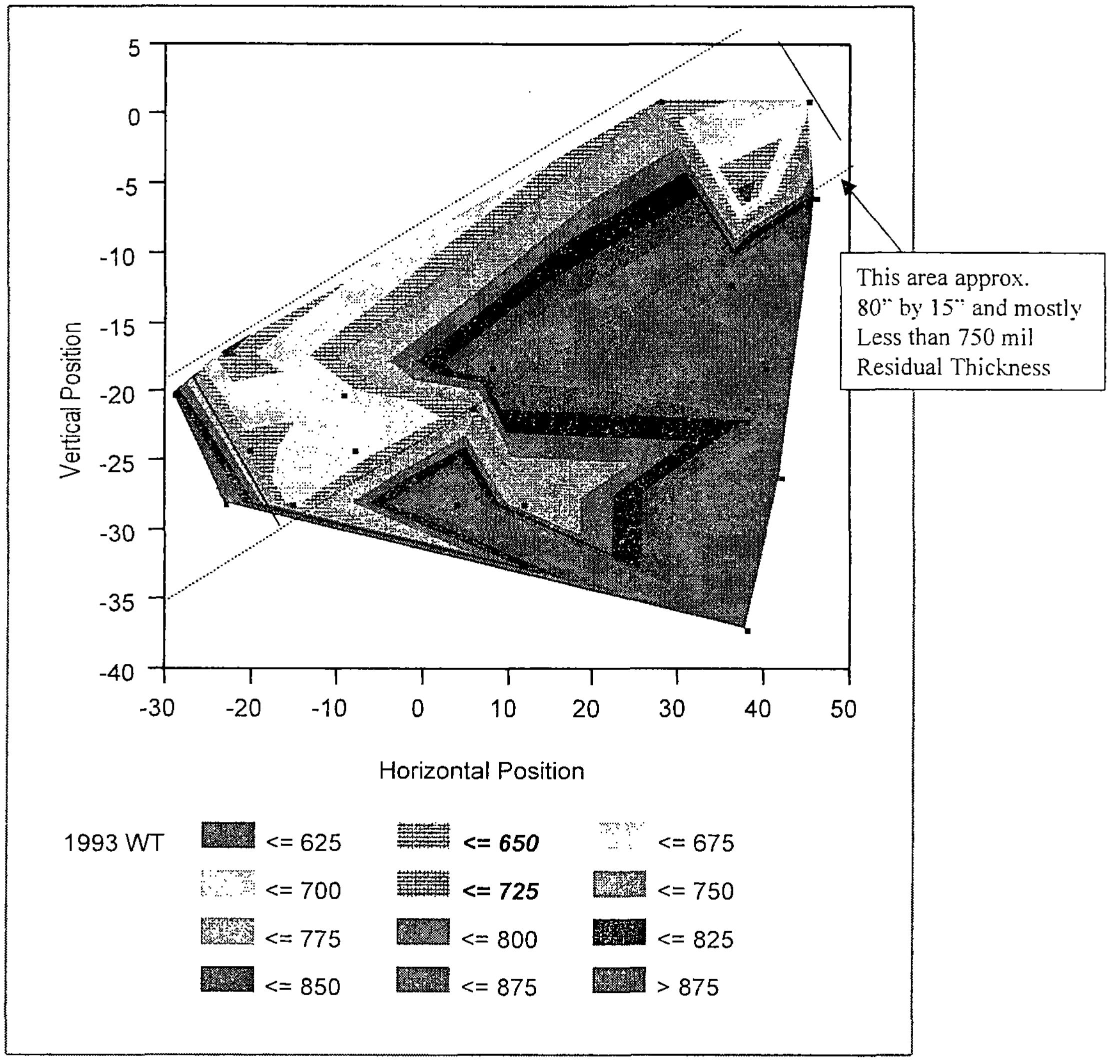
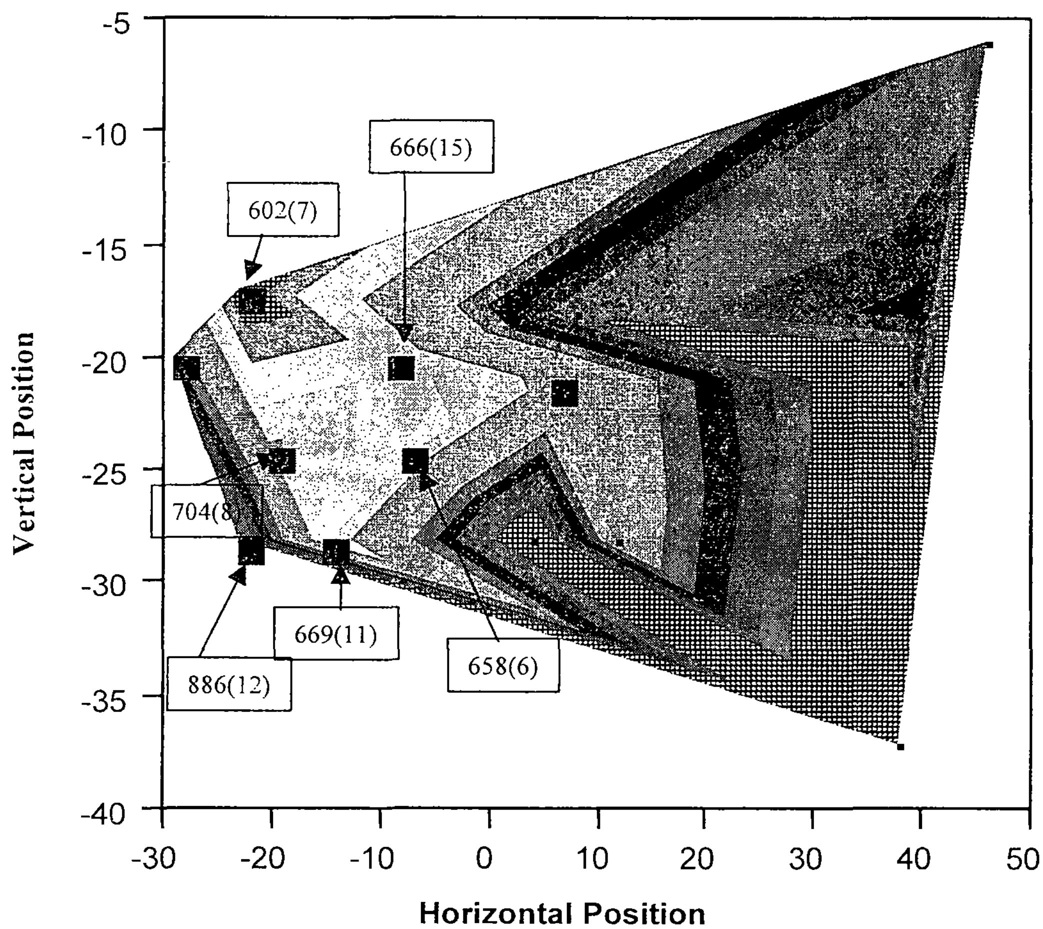


Figure 5

Bay 13 Remaining Wall Thickness
External UT Measurements 2006

Bay 13 Contour Plot 2006 UT Data



Numbers are residual wall thickness and (measurement ID)

Figure 6

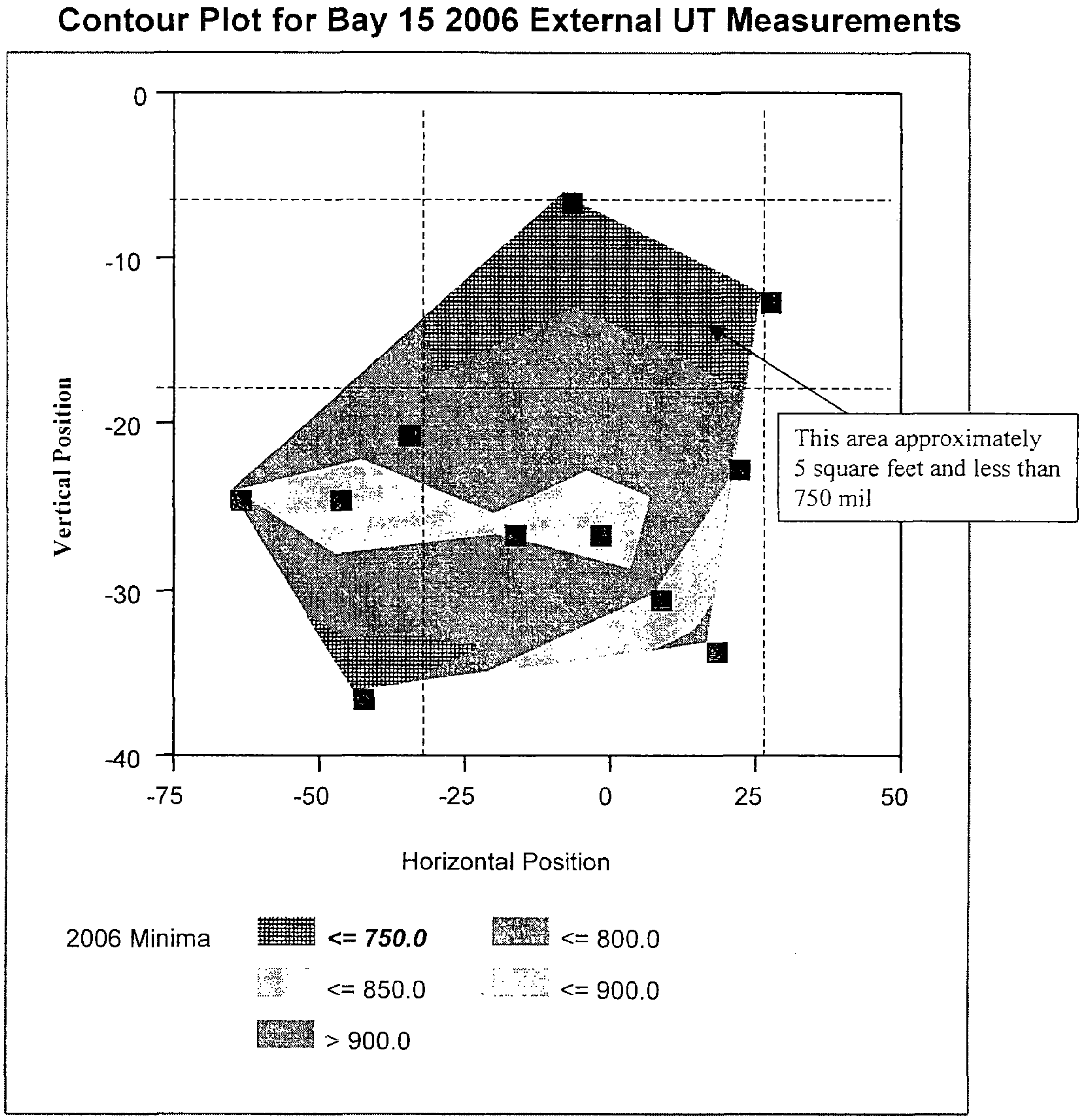
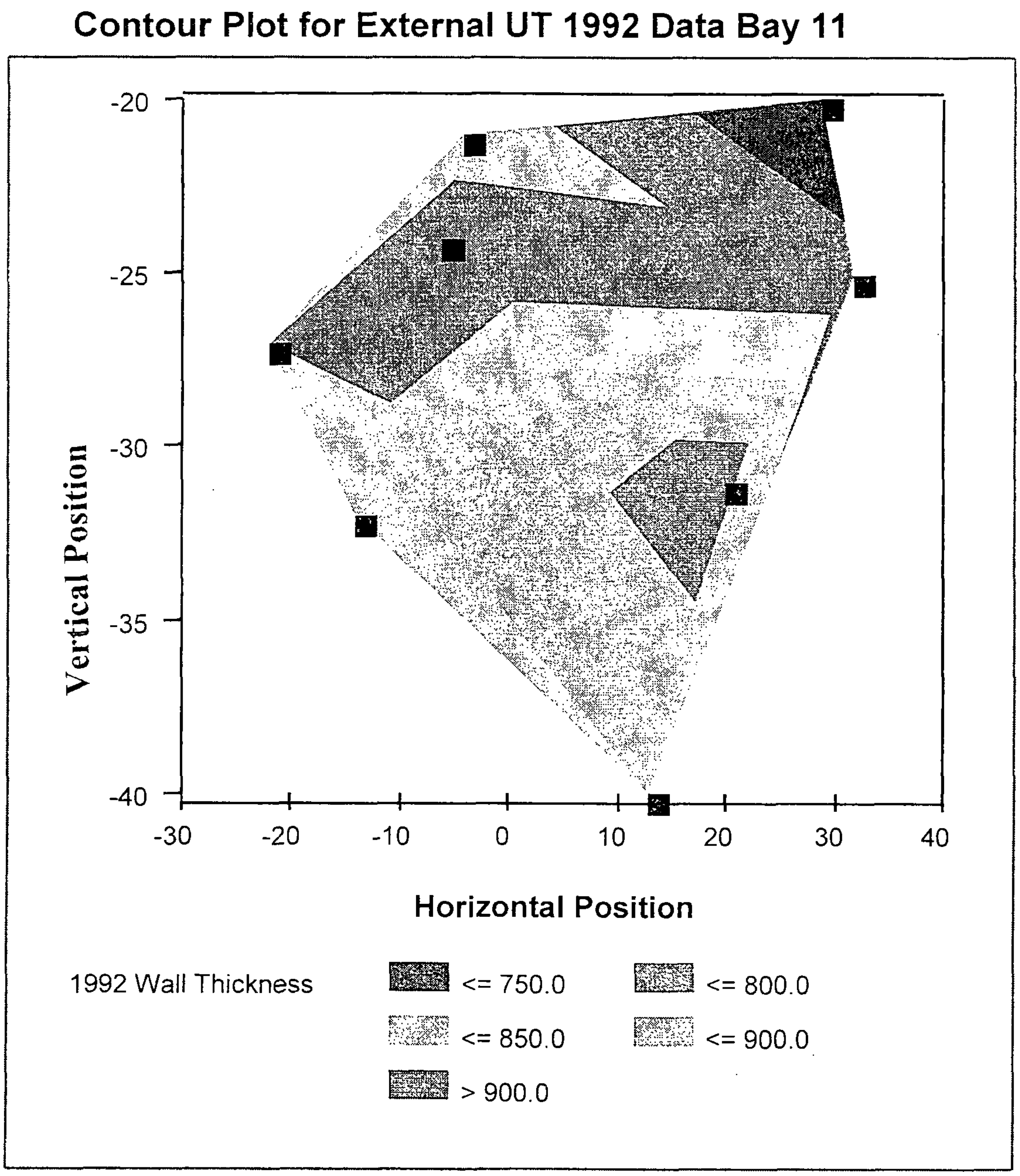

Contour Plot for Bay 15 2006 External UT Measurements
0
-10
-20
-30
-40
-75
-50
-25
0
25
50
Vertical Position
Horizontal Position
This area approximately 5 square feet and less than 750 mil
2006 Minima
<= 750.0
<= 800.0
<= 850.0
<= 900.0
> 900.0

Figure 7

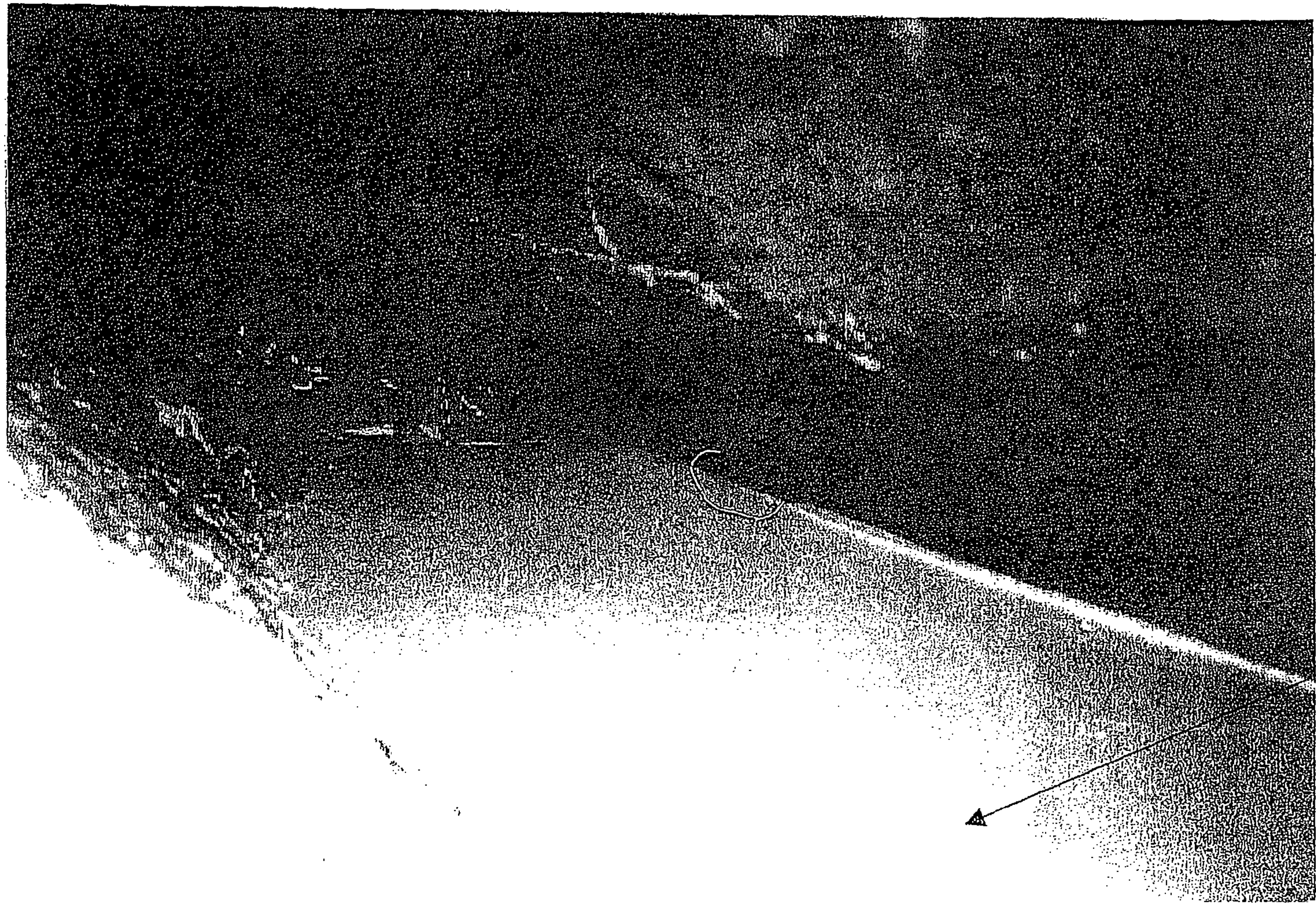


Contour Plot for External UT 1992 Data Bay 11
-20
-25
-30
-35
-40
Vertical Position
-30
-20
-10
0
10
20
30
40
Horizontal Position
1992 Wall Thickness
<= 750.0
<= 800.0
<= 850.0
<= 900.0
> 900.0

Exhibit 14

Sand Bed Region 1992

AmerGen
An Exelon Company



Bay 5 before shell coating

Exhibit 15

Official Transcript of Proceedings ACRS-337

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal

Docket Number: (not applicable)

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

SUNSI REVIEW COMPLETE

Location: Rockville, Maryland

Date: Thursday, January 18, 2007

Work Order No.: NRC-1398

Pages 1-371

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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

January 18, 2007

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on January 18, 2007, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

OYSTER CREEK GENERATING STATION

+ + + + +

THURSDAY,

JANUARY 18, 2007

+ + + + +

The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., DR. OTTO L. MAYNARD, Chairman, presiding.

MEMBERS PRESENT:

OTTO L. MAYNARD, Chairman

GRAHAM B. WALLIS, Vice-Chairman

WILLIAM J. SHACK, ACRS Member

MARIO V. BONACA, ACRS Member

DANA A. POWERS, ACRS Member

JOHN D. SIEBER, ACRS Member

SAID ABDEL-KHALIK, ACRS Member

J. SAM ARMIJO, ACRS Member

NRC STAFF PRESENT:

LOUISE LUND
DONNIE ASHLEY
MICHAEL JUNGE
BARRY GORDON
RICH CONTE
MICHAEL MODES
JIM DAVIS
NOEL DUDLEY
P. T. KUO
SUJIT SAMMADAR

ALSO PRESENT:

MIKE GALLAGHER
PETE TAMBURRO
FRED POLASKI
AHMED OUAOU
HARDIYAL MEHTA
HOWIE RAY
TOM QUINTENZE
JOHN O'ROURKE
TIM O'HARA
JON CAVALLO
MARTY McALLISTER
JASON PETTI

ALSO PRESENT (Continued):

MIKE HESSHEIMER

PAUL GUNTER

RICHARD WEBSTER

I-N-D-E-X

I-N-D-E-X (Continued)

P-R-O-C-E-E-D-I-N-G-S

(8:33 a.m.)

OPENING REMARKS

CHAIRMAN MAYNARD: This meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I am Otto Maynard, Chairman of the Plant License Renewal Subcommittee for the Oyster Creek license renewal application.

ACRS members in attendance are Jack Sieber, Said Abdel-Khalik, Sam Armijo, Dana Powers, Graham Wallis, Bill Shack, and Mario Bonaca. Michael Junge of the ACRS staff is the designated federal official for this meeting. He is to my right.

The purpose is this meeting is to review the license renewal application for the Oyster Creek generating station, the draft safety evaluation report and associated documents with focus on questions that were raised during the October 3rd, 2006 License Renewal Subcommittee meeting.

We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, Region I office, and AmerGen Energy Company. The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for

deliberation by the full Committee.

The rules for participation in today's meeting were announced as part of the notice for this meeting previously published in the Federal Register on January 25th, 2006. That's 71 FR 4177.

We have received requests for time to make oral statements from Paul Gunter of Nuclear Information Resource Service and from Richard Webster of the Rutgers Environmental Law Clinic. These statements will be considered as part of the Committee's information-gathering process. We have provided time on today's agenda for these oral statements.

Comments should be limited to the issues associated with the Oyster Creek generating station license renewal application or draft safety evaluation report with focus on questions that were raised during the October 3rd, 2006 License Renewal Subcommittee meeting.

We have received no written comments from members of the public regarding today's meeting. I will say that we did receive information from Mr. Webster in response to some questions that were at the last meeting and also copies of some of their proposed presentation material.

A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

It's going to be important to follow the agenda today. I am sure we will deviate some, but we do have important presentations from the license, from the NRC staff, and from members of the public. So I will be watching the time. And we all need to be paying attention to that, make sure we do focus on the right areas to get the right issues addressed in today's meeting.

I will now proceed with the meeting. And I call on Ms. Louise Lund of the Office of Nuclear Reactor Regulation to begin.

MS. LUND: Well, thank you.

STAFF INTRODUCTION

MS. LUND: And good morning. My name is Louise Lund. I am the Branch Chief of License Renewal Branch A in the Division of License Renewal. Beside me is Dr. P. T. Kuo, our Acting Director for the

Division of License Renewal.

The staff has continued their review of the Oyster Creek generating station license renewal application, which was submitted in July of 2005. Mr. Donnie Ashley, here to my right, is the project manager for this review. He will lead the staff's presentation in the afternoon.

In addition, we have several NRC members from Region I to discuss inspections that were held last October at Oyster Creek. We also have several members of the NRC technical staff in the audience to provide additional information and answer your questions.

As Dr. Maynard said at the last meeting in October last year, the ACRS Subcommittee had a number of questions. As a result of the meeting, the Committee requested additional information, specifically about the drywell shell, from the applicant, which they provided and included historical information and data as well as the results of the inspections that were held in October of 2006.

AmerGen has put together a comprehensive presentation to address the questions put forward by the Committee. In addition, the NRC staff provided a draft and final report of the analysis of a drywell

shell performed at Sandia to support the staff's review. We have representatives of Sandia here to answer any questions you may about their work.

Using insights from this work, the staff issued an update to the safety evaluation in December, which we provided to the Committee. You will be hearing about this information in more detail during the meeting today. In addition, you will be hearing from the regional inspectors that were present during the inspections in October 2006 and their observations of AmerGen's inspections.

With that, I would like to turn this presentation over to Mike Gallagher, who is the Vice President of Exelon's license renewal group, to begin the applicant's presentation.

AMERGEN - OYSTER CREEK PRESENTATION

MR. GALLAGHER: Good morning. My name is Mike Gallagher. And I'm Vice President of License Renewal Projects for AmerGen and Exelon. Also with me here from our management team is Tim Rausch -- he's our Site Vice President at Oyster Creek -- and Rich Lopriore. He's our Senior Vice President for Mid-Atlantic Operations.

On October 3rd, we last met and made a summary presentation on our license renewal

MR. O'HARA: We were looking at the coating on the drywell, but the general condition was looked at and noted. Any conditions that the licensee thought were not correct were put in their corrective action process and analyzed.

MR. GALLAGHER: And, remember, this picture is from 1992, Dr. Wallis.

MEMBER SHACK: I mean, I thought these floors were finished up to make them smooth, to make sure that you can drain the water. So, I mean, it presumably doesn't look like this anymore.

MR. GALLAGHER: Yes. These pictures are from 1992. That's correct.

MR. POLASKI: As we go on to the next several slides, we will show you what it looks like today or what it looked like in '92 after the --

MR. O'ROURKE: And slide 59 leads us into those photographs. We'll show you the condition of the drywell shell as repairs were in progress.

Slide 60 shows the photograph of the shell after cleaning and the corrosion products removed. It also shows the sand bed floor after the coating was applied. That's a partial answer to Dr. Shack's question.

The next photograph shows --

VICE-CHAIRMAN WALLIS: What's that thing in the background? It looks like a sheet of plastic or something. What is that?

MR. POLASKI: Yes. That very well could be plastic. You remember these pictures were taken during the actual application, repairs still in launch. So you will see plastic in that area.

VICE-CHAIRMAN WALLIS: Well, the sand bed floor needed quite a bit of repair it looks like.

MR. O'ROURKE: Slide 61 shows the shell as it's being coated with the primer coat and also again a view of the sand bed floor.

Slide 62 shows the shell after the epoxy coating was applied. It also shows the caulk seal that was applied to the interface between the external shell and the sand bed floor.

And I will note that there are some additional photos in your reference books.

MEMBER ARMIJO: Was that caulk sealing kind of pressurized to kind of get it into the gap or was it just kind of surface, like you do with a bathtub or something?

MR. O'ROURKE: Pete, do you have an answer to that question?

MR. TAMBURRO: The caulk ceiling was a

fairly viscous epoxy caulking. And it was forced into that gap with a trowel and pushed in there.

MR. GALLAGHER: Thanks, Pete.

VICE-CHAIRMAN WALLIS: So if there's no water there, it doesn't matter, does it?

MR. O'ROURKE: That's correct.

I'm looking at slide 63.

VICE-CHAIRMAN WALLIS: How about the draining of the sand bed floor? It presumably has to run around circumferentially to find a drain. Did you worry about leveling it off or putting a slope on it or it slopes to the drain or what? How did you do that?

MR. O'ROURKE: That is correct. The directions were to slope. When the floors were finished, the direction was to slope it away from the drywell and toward the drain.

VICE-CHAIRMAN WALLIS: All right.

MR. O'ROURKE: And remember Fred's earlier discussion that there are five sand bed drains, --

VICE-CHAIRMAN WALLIS: Right.

MR. O'ROURKE: -- as opposed to the one on the --

VICE-CHAIRMAN WALLIS: The one on the top, right.

MR. O'ROURKE: -- the unique trough up above. Continuing with the background and history for the sand bed region, the epoxy coating applied to the external shell was a three-part coating system designed for applications on corroded surfaces.

The first coat that I showed in a previous slide in the photograph was a rust-penetrating sealer designed to penetrate rusty surfaces, reinforce the rusty steel substrate, and ensure adhesion of the epoxy coating.

Two coats of epoxy coating were then applied. This coating is designed for more severe surfaces than we expect at Oyster Creek, a couple of which are noted on the slide.

Prior to application of the coating, it was tested in a mock-up for coating thickness and absence of holidays or pinholes. And we used two coats to minimize any chance of pinholes or holidays. And the coats are of a different color to facilitate future inspections.

Fred?

MR. POLASKI: Thank you, John.

I would now like to -- you have heard from Mr. O'Rourke about the corrective actions taken to stop the corrosion of the drywell shell in the sand

bed region. One of the key aspects of the corrective action was application of the epoxy coating to the exterior surface of the shell.

Our next presenter is Mr. Jon Cavallo, who will speak about the coating on the drywell shell. Mr. Cavallo is the Vice President of Corrosion Control Consultants Alliance Incorporated. He's a registered professional engineer in six states and holds a Bachelor's degree from Northeastern University in Boston, Massachusetts.

He also is a Certified society of Protective Coatings protective coatings specialist and holds registration as a certified protective coatings engineer from the National Board of Registration for Nuclear Safety-Related Coating Engineers and Specialists.

He is active in a number of technical societies, including ASTM, National Association of Corrosion Engineers, National Society of Professional Engineers, and the Society of Protective Coatings.

Mr. Cavallo served as the editor of the EPRI report "Guideline on Nuclear Safety-related Coatings Division I," assisted in development of and teaches EPRI code in his training courses. He's also the principal investigator of the EPRI report

"Analysis of Pressurized Water Reactor on Qualified Original Equipment Manufacturer Buildings" and since 2000 has been a member of the NEI PWR containment sump task force.

Mr. Cavallo?

MR. CAVALLO: Thanks, Fred. Good morning, gentlemen.

I was asked to take an independent look at the approach that Oyster Creek has taken to mitigating the corrosion on the exterior shell of the drywell in the sand bed region.

First off, I went back and looked at the background and history from a regulatory standpoint of good guidance that we received to approach this project.

The Oyster Creek protective coatings monitoring and maintenance program, aging management is consistent with NUREG-1801, which is a GALL report volume II, appendix XI.S8, which is the appendix devoted to coatings condition assessment. However, you should note that that appendix only covers coating service level I coatings, which is coatings inside of the primary pressure boundary inside the drywell.

Oyster Creek in my opinion wisely extended that requirement to the service level II coating,

which they applied to the exterior of the drywell using many of the same quality approaches that are used in containment coatings.

Next slide, please. The coatings applied to the exterior of the drywell, which we have seen some photographs of in the previous presentation, coating service level II, the evaluation and continued monitoring of those coatings are conducted in accordance with ASME section 11, subsection IWE by qualified VT inspectors. In other words, they are inspected the same way using the same techniques that are used inside the containment, both BWRs and PWRs.

The coated areas are examined at a minimum for visual anomalies, which includes flaking, blistering, peeling, discoloration, and other signs of distress. This approach is consistent again with the NUREG-1801 and its attendant ASTM standards.

The whole premise of ASME section 11, which is used for examination of the pressure boundaries in PWRs and BWRs, is the degradation of a vessel that's got a coating on it will be indicated by a visual precursor defect in the coating.

And, again, the ASME section 11, subsection IWE protocol is to remove that coating and examine the substrate. That way we have a consistent

manner to look for any continuing corrosion of the drywell shell on the exterior there, the sand bed region.

Now, I wanted to spend a little time discussing how barrier coatings such as the one that John described prevent corrosion of the scale substrates.

Basically we have four conditions necessary for metallic corrosion: an anode; a cathode; an electrical conductor; and some type of an electrolyte, which is a liquid that conducts electricity.

We as coatings engineers can only do one thing. We can't control the anodes. We can't control the cathodes. We can't control the electrical conductors because they were already inherently in the steel. So what we do is apply a barrier coating system, which isolates the moisture, the electrolyte, and breaks the corrosion cycle.

This is what has been done in the Oyster Creek sand bed region. Repeating what John told you, the Oyster Creek sand bed region coating system is really a three-step process.

First off, the surface preparation was done in accordance with SSPS SP2 hand tool cleaning,

which I think gets back to Dr. Wallis' question about what was done. That removes loose rust, loose mill scale, and loose coating. And loose is defined as determined by moderate pressure with a dull putty knife by code.

With that level of surface prep, which was appropriate, they then applied a pre-prime, which is an epoxy, which penetrates into the semi-irregular shape of the substrate, and then applied two coats --

VICE-CHAIRMAN WALLIS: About that pre-prime, it is a very key thing, isn't it? I mean, if you leave too much dry rust on, then it doesn't really adhere to the steel.

MR. CAVALLO: Exactly. I am going to in a little bit talk about how this was controlled as a special process similar to welding.

VICE-CHAIRMAN WALLIS: Okay. Okay.

MR. CAVALLO: I didn't mean to cut you off, sir.

VICE-CHAIRMAN WALLIS: No, no. I just wanted to focus on that particular thing. The pre-prime is an important step in this.

MR. CAVALLO: Yes, sir, it is, absolutely. And, remember, our coating systems such as this one are actually designed. I mean, people think anybody

can paint. It's not true.

So we have selected a system with good history in this type of application. Then we applied two coats of the Devran 184 epoxy, which is a standard epoxy phenolic, which is used a lot for this region, which provides that barrier for moisture.

And, finally, we saw pictures of the Devmat 124S caulking, which was applied by troweling into the interface between the concrete floor and the steel substrate, again another moisture barrier.

MEMBER ARMIJO: Just to understand, the pre-prime, is it intended? Is it preferred that it be in contact with the metal or is it okay that it's in contact with a surface oxide that is adherent to the metal?

MR. CAVALLO: Both, actually. It's designed as an adhesion promoter. It soaks into any crevices in that remaining corrosion. And, remember, this is very tightly adherent corrosion and mill scale.

MEMBER ARMIJO: Right.

MR. CAVALLO: And also it's an epoxy polyamine. So it does bond to the steel substrate that may be exposed. So you have a combination of both conditions. And it is an adhesion promoter and

gives something for the next two coats to stick to.

VICE-CHAIRMAN WALLIS: You mean if you have a pit, it just bridges over the pit, does it?

MR. CAVALLO: No. It actually soaks in. It's a fairly slow-drying material. And it acts a lot like our old bridge paint did. It's to simulate that.

Now, my conclusion is in basically reviewing the approach and the engineering involved is that this coating system is appropriate for the intended service, which is to prevent further corrosion of the steel in the sand bed region drywell shell.

Some of the reasons I came to that conclusion are that we have created now a very benign corrosion environment. Before the sand was removed, we actually almost had an emergent condition. We had moisture trapped in there held against the surface by the sand. Now we have a dry --

CHAIRMAN MAYNARD: I'm sorry. Can you wait just a minute? We're trying to get this muted. We are getting some noise from one of the lines. So if the people on the telephone will be quiet, we'll go ahead and continue with the discussion. Go ahead, Jon.

MR. CAVALLO: All right. So, anyways, we

have removed all the sand. We removed the water. We have a benign environment, a fairly low radiation dose rate. So I don't worry about any sort of radiation damage. This coating typically good to 1 times 10^9 rads or more total lifetime dose. And we're never going to see anything like that.

Finally, it's an enclosed space. It's shielded from atmospheric moisture, shielded from the site environment. So we have now a very benign environment.

The coating system is compatible with that environment. Back to your question about the adhesion promoter, that adhesion promoter which is your penetrating sealer is designed to adhere to a minimally prepared surface is what we're talking about here, where we're leaving some corrosion product behind. And also the two-coat applied over top of that is used an awful lot in chemical tanks. So our environment is far less severe than that.

And, then finally, this coating system can be successfully applied by brush and roller. Because of their very tight environment, we couldn't get into very sophisticated spray equipment, such things like that. So this is appropriate to be applied that way.

Now, Oyster Creek also did something which

I think is quite noteworthy. They actually create a mock-up of the sand bed region with the drywell shell before they actually applied the coating in service. And they did surface preparation and coasting application using the same mechanics in this mock-up area with the restricted access.

This was a proof of principle on the coating system and also was used to train the mechanics who did the surface prep and the coating work. This includes the caulking also.

And then, finally, what they did was actually do a holiday test, which was an electrical test, to see whether or not they had pinholes on this mock-up. So this was treated very similar to a special process like we would have for welding. So it was well over and above what you normally see in an outside containment coating's work effort. So there was quite a bit put into that.

MEMBER SIEBER: So a holiday as referred to in your previous slide is a pinhole?

MR. CAVALLO: Yes, sir. And usually holidays are not visible. They're solvent blistering.

Now, I am going with periodic condition assessment maintenance if there is any required. And I am not sure there ever will be any. In my opinion,

The first slide.

The drywell shell is constructed first, and then on each side the interior and exterior concrete was poured in. When you have wet concrete in contact with steel, the concrete mixture is at very high pH, and this forms a passive film on the surface of the carbon steel, and it's a very resistent film.

And as the concrete hardens, even though it becomes very hard, it still contains pores in the concrete and the concrete contains it's called pour water, and this pour water is, again, very high pH and it mitigates corrosion.

So looking at the slide, again, the concrete. The shell is constructed first, covered both surfaces of the imbedded steel with concrete. The high pH is like 12.5 to 14 during the hydration of the cement, which is one of the mixtures in the composite concrete material. It forms a passive film on the surface which mitigates corrosion, and again, that's why this system is used for constructing buildings, tunnels, swimming pools, whatever.

Going to Slide 116, the reactor cavity water, looking at the exterior environment now. The reactor cavity water, which leaked down, went through sand bed, was certainly affected by the sand bed

region, and there may be some concern for that.

But a chemical analysis of this water, again, it's reactor cavity water which is very high purity to begin with, reveals that the pH is greater than seven. The fluoride content was 0.045 parts per million, and the sulfate concentration was 0.32 parts per million. That's very high purity.

And the next line I have there is an average of 3,600 waters, potable waters, natural waters around the United States, and it shows that the typical concentration is much higher, orders of magnitude higher in chloride and orders of magnitude higher in salts.

DR. WALLIS: So why was there so much corrosion on the outside originally?

MR. GORDON: It doesn't take -- in that particular area, in the sand region, there's no concrete there to protect it.

DR. WALLIS: But still why is it aggressive though? It should be neutral.

MR. GORDON: Oh, I mean, pure water will certainly corrode steel, but I'm talking about in the area where it is imbedded in concrete. It's a different environment.

Again, the American Concrete Institute has

rules on what kind of water is aggressive to concrete, and the GALL report and the EPRI studies have all supported the same level, and both these levels of the water obtained from the sand bed region is high purity and is not an aging concern.

Continuing with Slide 117, then the water would have been the same high quality as we saw as listed in the previous slide, but it would be interacted with the high pH pour water, concrete pour water, and it would provide a passive film for the carbon steel.

Again, per the GALL report and for the EPRI report, which is listed here, since the pH is greater than 5.5 and the chloride content is way below 500 ppm and the sulfate is below 1,500 ppm, there is not an aging concern for imbedded steel in concrete.

Now let's look at the surprise water that was found during the last inspection on the interior surface and see why that is also not a concern. A chemical analysis was performed on this water, and the next slide will actually show what this water looks like. Again, the pH of this water was 8.4 to 10.2, and this is even after it's exposed to the CO_2 in the air, which would lower the pH. So the pH is probably at least two points higher than this.

High pH, and that's what you want to maintain a passive film on carbon steel.

The chloride content, again, 13.6 to 14.6 ppm. It's way below the limit of 500 ppm.

Sulfate, again, 228 to 230, way below the 1,500.

The calcium content is just presented here as a point of interest, and we'll discuss that in the next slide. There's no GALL or EPRI concern with that.

So this water that you have looked at in the trench five is considered high purity concrete pour water, which mitigates corrosion of carbon steel. Again, this water that was found there complies with the GALL and EPRI and ACI recommendations.

The next slide shows the trench five, the water that was found in trench five, and the calcium content, which I illustrated on the previous slide indicates that the water was there for quite some time. Water leaches out calcium hydroxide first from concrete and it's an indication it took some time to get there and, again, it mitigates corrosion.

Any subsequent water that may be found in the interior of the drywell also will be affected by this concrete pour water, have a high pH, and will be

also high puree and will not lead to any degradation of the carbon steel.

MR. ARMIJO: Where did this water come from?

MR. GORDON: This is apparent during a maintenance.

MR. ARMIJO: It was a spill.

MR. GORDON: Yes, spills and things like that.

MR. GALLAGHER: As we mentioned in the beginning, it's equipment leakage. So the design of the drywell and the equipment leakage collection system, and so any leakage would come down, go in the sub pile room, go in a trough, and then goes into the sump. So it's designed that way to collect any leakage. That's where this leakage came from.

MR. ARMIJO: But did this water migrate through the concrete or did it just kind of flow over the top of something and just pour into this hole?

MR. POLASKI: It could have come from two sources. The investigation showed that the trough that we pointed out earlier in the sub pile room that all of the leakage is supposed to flow into and then drain to the sump did have some leakage in it. It was not in the condition it should have been, and that

some of that water did migrate through the concrete and showed up in these troughs.

The other thing is John mentioned earlier that we have now installed caulking at the edge of the curve, you know, against the scale of the drywell. Most other BWRs have that caulked. Oyster Creek did not. Oyster Creek is unique. It has a curve there, but if there was any leakage that got on the shell of the drywell and ran down, it could have gotten directly below the concrete. Either of those ways could have accounted for this.

MR. GORDON: And, again, this slide shows the water, and you can see the carbon steel there, the bare carbon steel. This has some superficial corrosion on it.

What happens to the steel that's not protected by the water, basically the side pH water.

MR. SHACK: Did you make inspections or, okay, there is inspections later.

PARTICIPANTS: Yes.

MR. GORDON: What happens to the steel that isn't protected by this high pH, high purity water? When the drywell is inerted, the cathodic reactant for the Trojan (phonetic) reaction oxygen is depleted and corrosion would basically stop at that

point.

Any possible subsequent steel corrosion would occur only during the brief outages, which are just a few, you know, ten days per year on average, and you wouldn't expect to see much atmospheric corrosion.

Finally, the transport of any oxygenated water that may come in from equipment manipulation would be affected by the high pH core water and also it would have to displace the oxygen depleted water before you'd see any corrosion.

So basically imbedded steel in concrete is not a concern on either the interior or the exterior of the drywell.

CHAIRMAN MAYNARD: Are you going to provide more justification for the superficial corrosion that you saw there or cover that in the inspection? I mean, you made a statement that there's some superficial rust there. I'd like to have a little bit more to go on than just that. How do you know it's superficial?

MR. GALLAGHER: Yes, Howie, answer that.

MR. RAY: Yes, so that's going to actually lead into the infraction to be performed.

CHAIRMAN MAYNARD: As long as it gets

covered there

MR. POLASKI: We will cover it in a couple of slides.

MR. GALLAGHER: And, Dr. Maynard, basically the bottom line is on the interior when we did UTs in the trench, and so you could easily wipe off the corrosion, and then we UTed the whole trench area and we have that data in here.

MR. POLASKI: So any other questions on --

DR. ABDEL-KHALIK: How much farther do you think beyond the trench that you dug in does the water extend or is the concrete in intimate contact with the steel along this entire bottom surface?

MR. POLASKI: The concrete that's on the inside --

DR. ABDEL-KHALIK: Right.

MR. POLASKI: -- as we said before, the concrete or the drywell shell was welded together and then the concrete was poured on the outside and then on the inside. So it is in intimate contact.

DR. ABDEL-KHALIK: So if it is in intimate contact, why is there water in the top part that you dug out?

MR. POLASKI: Well, even though it's in intimate contact, you can still get water into that.

There isn't really a gap there, but water can get in between, you know, soaked into the concrete along the steel.

MR. GALLAGHER: Yes, the concrete pour water throughout the concrete slab, and you know, so there's water there.

MR. RAY: Yes, the concrete is poured in different sections. So there's actually a pass where the water can get into the concrete or could migrate through the different paths and seek its elevation, to answer your question.

DR. ABDEL-KHALIK: Can you speak up a little bit louder?

MR. RAY: Yes. The concrete was poured in several different layers. So there are --

DR. ABDEL-KHALIK: Horizontal halves?

MR. RAY: Horizontal, yes.

DR. ABDEL-KHALIK: So, I mean, if I look at this picture, how much water is there and how much water don't I see?

MR. POLASKI: We believe based on what we found, when we found this water there was about five inches in the bottom of Trench 5. It was pumped out and then it filled back in again. So it was coming from, you know, underneath the concrete and other

areas.

We believe that the whole inside of the drywell below the floor has water in there.

MR. ARMIJO: So you think there's water in this lower part of the sphere --

MR. POLASKI: Yes.

MR. ARMIJO: -- between the concrete and the shell.

MR. POLASKI: Yes, that's correct.

MR. ARMIJO: And the source is the sump.

MR. POLASKI: Well, the source is equipment leakage. It wasn't from the sump itself, but from the troughs that then lead into the sump indicated there was leakage out of that trough. However, there would have been water in the past if there was a leakage in the drywell, and again, there was some small amount of leakage in the drywell; if it got on the drywell shelf, could have run down and gotten directly below. It could have been there for years.

MR. GALLAGHER: Let's be clear. The trough that we're talking about is this trough that goes 360 degrees on the interior of the sub pile room. That's designed to collect the water and then move it to the sump.

There were some defects in this trough so that some water could have got into the concrete. We don't know how far, you know, water is down there. We're assuming it's down there and that we've taken action to have an aging management program, assuming it's there to check, and that's what we've done.

MR. ARMIJO: Well, the water level, you know, if it's in direct contact, if it refills, the water level is coming from somewhere. That's at least that elevation or higher.

MR. GALLAGHER: Yes, and this elevation here is the highest at that point. It's higher than the bottom of the trench was. We've corrected this trough. So we wouldn't expect anymore water to get in there, but we added it to our aging management program to verify that, to verify if there's any ongoing effect.

But this trough elevation, see, right here, if you look at the side, that's the bottom of the trough, and then the bottom of the trench we're talking about is at the bottom of the sand bed floor.

So any water you have coming down here going into the trough, if the trough was not finished correctly, would have gone into the concrete. So we fixed that.

MR. ARMIJO: But it's feasible the whole bottom of that shell could have water in it.

MR. GALLAGHER: And that's what we're presuming. We haven't verified it, you know, because we only excavated down here.

MR. POLASKI: We're assuming there's water there, but Mr. Gordon's presentation is just addressing what would the conditions be, and once that water gets in there --

MR. GALLAGHER: It should be benign.

MR. POLASKI: -- it should be benign. A passive layer was there when the concrete was initially poured.

MR. SHACK: It would be better if it wasn't there.

MR. GALLAGHER: That's correct.

MR. GORDON: But you know, concrete, even if it's very well cured and very old, it still has this moisture in it. It's like a very hard sponge with this concrete pour with a high pH pure water. So it really is basically a hard sponge, and it works very successfully with steel.

DR. ABDEL-KHALIK: But that would not be the source of the water you're seeing. I mean, you pumped it out and the thing filled up again.

MR. RAY: The source of the water was coming through the trough. We paired a void there, and we won't have that source of water.

DR. ABDEL-KHALIK: Okay. If you went and looked at it today, it would be full of water again?

MR. RAY: We would not expect it. It still had a little moisture in the bottom Trench 5 when we started back up. With the operating cycle, we would expect that to evaporate off.

MR. SIEBER: Did you find cracks in the concrete?

MR. RAY: No, we've done structural monitoring, logged into the concrete, and had no significant cracks. The only void we found was in that trough, and we did verify there was leakage through there with a leak test.

MR. POLASKI: Any other questions? Okay.

MR. SHACK: It just seems like 40 years of operation to find a trough has a hole in it.

MR. POLASKI: Yes.

MR. ARMIJO: When the trough was first excavated, was there any data that showed that there was water in the trough when it was first built?

MR. GALLAGHER: The trench?

MR. ARMIJO: The trench, I mean, yeah, the

trench. When that was opened up the first time, did people find that full of water?

MR. GALLAGHER: When it was opened up the first time, I don't think there was any water in there, but we did find we did have some information that there was water there at one point, and in subsequent checks it wasn't there. So that's why we thought there was not a water environment in the lower elevation of the drywell, and that's why we hadn't included that as an environment in our LRA.

One thing we did though. We said, well, let's look at these trenches again, and that's when we identify this and put it in our corrective action system to update our LRA.

MR. ARMIJO: Have you ever experienced recirc water pump seal leak?

MR. GALLAGHER: Plant -- Tom Quintenze.

MR. QUINTENZE: I'm Tom Quintenze, AmerGen.

The question, I believe, was have you ever experienced recirc pump seal leaks.

MR. ARMIJO: Yes.

MR. QUINTENZE: And the answer to that is yes.

MR. ARMIJO: Would that be the source of

this water?

MR. QUINTENZE: It could be the source of water. In earlier years we did have some significant leak, but current history indicates that we've maintained our unidentified leak rate, which would be leakage from a recirc pump seal at a very low level, on the order of .1 to .2 gallons per minute.

MR. GALLAGHER: We know that we do have equipment leakage, like control rod drives. There's some leakage from them typically. They're right above the sub pile room, you know, right above this room here, and water drips down in all BWRs, and that's the case.

As Tom mentioned, there is an unidentified leakage criteria, no more than five gallons a minute unidentified leakage in your primary containment, and you know, we meet the technical specification limits by far. But this is designed to collect that leakage, any leakage like that and then take it away to the sump and then pump it out of containment.

MR. ARMIJO: Thank you.

MR. SIEBER: Given enough time though, that's a lot of water.

MR. GALLAGHER: Yes.

MR. POLASKI: All right. We've now heard

about the effect of water on carbon steel imbedded in concrete and how we expect minimal corrosion on the imbedded part of the drywell shell. I'd now like to have Mr. Howie Ray present the results of inspections that were performed during October 2006 refueling outage for the imbedded portion of the drywell shell.

MR. RAY: Thanks, Fred.

During the 2006 refuel outage, visual inspections of the surface of the trenches did show minor corrosion. It was easily removed with no material loss of metal or degradation of the surface, and the visual examinations were done satisfactorily at those surfaces.

And as we just discussed, you know, that superficial effect was what you would expect based on the technical (speaking from an unmiked location).

The UT measurements taken in trenches were used to compare the total corrosion on the inside and outside between 1986 and 2006. It is known that there was significant corrosion that was ongoing in the exterior surface that was not imbedded up to 1992 when the sand was removed.

The material loss identified was consistent with the corrosion rates on the outside of the drywell before the sand was removed in 1992.

So the next slide illustrates the 1986 readings versus the 2006 readings for both Trench 5 and Trench 17. This did not include the additional six inches of surface UTs that we exposed. We'll discuss that later.

What's critical here is there is a difference of 38 mils for both of those trenches, but that we would note that that occurred between the 1986 and 1992 time frame, before the san was removed, and you had significant corrosion going. So that would not be an unexpected corrosion rate.

CHAIRMAN MAYNARD: Okay. How do you know that that occurred over that time frame as opposed to something that has recently started? It's kind of hard to get a rate.

MR. RAY: Well, we're assuming that, but we know we had significant corrosion going on while the sand was there. We've shown that on the graphs with both of them. Bay 17 and Bay 5 both had significant corrosion rates going on.

So if you took that across those years that you had the sand installed with the water, we can assume it. We can't verify that, but you do have still good coating on the outside and you have a technical justification that says that water in this

area would not cause significant corrosion inside the drywell.

MR. GALLAGHER: And part of the basis is, when we get to the next slide, when we interrogated the six inches below the concrete floor, the corrosion rate -- Howie, why don't you go into that and you can show him that -- the corrosion rate which is really over the entire period of time since that shell was imbedded in concrete.

MR. ARMIJO: Before you go, did you find water to the same extent in Trench 17 as you did in Trench 5?

MR. RAY: No, we did not. The Trench 17 is about six inches shallower than the trench in Bay 5.

MR. GALLAGHER: So it's a higher elevation. There was a little moisture in there, but --

MR. ARMIJO: If there had been water there, it would have drained to a lower level?

MR. GALLAGHER: Yes.

MR. RAY: It was seeking its elevation. It was voiced in Bay 17, but there's no standing water.

DR. ABDEL-KHALIK: The statement that was

One of the things we need to be identifying is what specific information may be needed in the full committee presentation so that we can provide guidance to the staff and licensee on things that we want to specifically have in that.

We will not have as much time, and so we will need to focus on key areas.

So with that, let's take a ten minute break. Actually we'll come back at five o'clock and we'll do our round table discussion. That's closer to 12 minutes.

(Whereupon, the foregoing matter went off the record at 4:49 p.m. and went back on the record at 5:04 p.m.)

CHAIRMAN MAYNARD: All right. I'd like to bring the meeting back into session.

I'd like to just start briefly by saying I appreciate everyone's participation. We've had a lot of discussion today, had input from the licensee, had it from the NRC staff, had it from members of the public, and that's something for us to all take into account, think about.

We'll have another meeting on this subject at our full committee meeting, and so we'll have some time to look over this and maybe -- I don't know --

generate more questions of our own and we'll see where things go.

What I'd like to do now is to go around the table, get any thoughts that the members have and, again, one of the things is if there's any specific areas that they think we need to cover in the full committee meeting specifically, like the one that we talked about, we need to identify that so that the staff and the licensee can be prepared to address that.

So I'd like to start with Mario and just what comments you may have or discussion items.

DR. BONACA: My first comment is that we have a large amount of data. I certainly would want to review them before the full meeting just to digest some of the information

A couple of general comments I have. One, clearly we have been presented with an assertion that the corrosion has been stopped and then that the drywell, therefore, can operate until 2029. I have to reflect more about the inspections of the monitoring program that they're proposing, whether or not I think it's adequate.

At first glance I think that I would like to see certainly a more aggressive inspection program

in the short term, and I'm not sure about looking at it now and then in ten years doing inspections again.

So, I mean, the monitoring program is something I'll pay attention to, and I would like to see discussed definitely at the full committee meeting.

I have raised a number of times the issue of controlling sources of water. I mean, they may have done as much as they can to do that, but still during the refueling they have one gpm, water that comes down and will go down to the trough, and I'm sure of that.

But the question is have we done enough to control sources of water to assure that there is no further accumulation.

The other thing that, you know, is more like the issue of how the epoxy is doing, I mean, is there any corrosion taking place behind the epoxy? I don't know if the UT they're planning to do is going to tell us or is sufficient. I mean, maybe there should be some poking in some location to see if there is some weakness behind that.

But any, my attention is more focused on these programs that will give us some more comfort regarding the condition of the drywell and the ability

to go for additional 20 years.

Those are my comments.

CHAIRMAN MAYNARD: All right. Bill.

MR. SHACK: Well, the surprise for me today was the notion that we have water in the imbedded region. That concerns me a little bit. I mean, I fully agree with the argument that it's a fairly benign environment and the corrosion rates are low, and in a containment that didn't have the already substantial corrosion that this one does, I would sort of agree that its probably not a problem.

But this is a containment where there isn't a whole lot of margin, and you know, the estimate was you had 41 mils lost and that was less than one mil per year. Well, I do the arithmetic and I get more like tow mils per year, and you do have data on these 106 points.

Many of them are down in the region where you are looking through the thing at the imbedded region, and I think there's some data there that one could look at to try to really see just what you think the corrosion rates are in that imbedded area and understand that a little better.

I'm fairly comfortable with the notion that if the epoxy coating is in good condition, that

the corrosion on the OD is arrested, and that the visual examination is a good thing there. I'm a little less convinced with the small margins that we have that the corrosion in the imbedded region is as negligible.

Again, the buckling analysis, again, I think that we have to settle on both the legalistic requirements of who's analysis that you can accept, but it seems to me that perhaps it is time to take a more realistic -- you know, you haven't got enough margin to do the uniform thinning model anymore.

The Sandia one does seem to indicate that you have enough left. It makes it more difficult to assess just how much margin you have because it's difficult, but again, I'd like to hear more discussion over the kind of credit that should be given. Since there is no internal pressure, you know, whether the circumferential tension really does give you credit that you can account for, whether it's already built into the IGAN value analysis that you get out of the finite element model. I'm not 100 percent convinced that I'm not double counting here. You know, some more discussion of that would be helpful to me.

DR. BONACA: Yes, I had another comment I forgot to mention which was one of the assumed thinner

areas of one square foot. It would have been interesting to know how large an area you could tolerate, but that's a question I believe Sam raised, and I'm behind that.

CHAIRMAN MAYNARD: Okay. Dr. Wallis.

DR. WALLIS: Well, I think we got a lot more information than we got last time. I think that a lot of people made considerable effort to present things professionally.

The question for me is this buckling analysis and how good does it have to be. We got close enough to it could be a condition where you wouldn't accept the results. Do we have to -- I have to look at these things again in some detail to see whether I'm satisfied or whether I want to maybe even ask for some more analysis.

I think the buckling analysis is the most important issue here, and I'm not really sure whether it's adequate or not yet.

CHAIRMAN MAYNARD: Sam.

MR. ARMIJO: Okay. I was impressed, and I'd like to thank AmerGen and everybody who put this package together. It was exactly what we asked for. As far as the information, it was well presented, easy to read and that was very good.

Exhibit 16

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee
Docket Number:	(not applicable)
Location:	Rockville, Maryland
Date:	Tuesday, October 3, 2006
Work Order No.:	NRC-1271 Pages 1-232

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF PLANT LICENSE RENEWAL SUBCOMMITTEE

+ + + + +

TUESDAY,

OCTOBER 3, 2006

+ + + + +

The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 1:30 p.m., Dr. Otto Maynard, Chairman, presiding.

MEMBERS PRESENT:

OTTO MAYNARD	Chair
GRAHAM B. WALLIS	Member
WILLIAM J. SHACK	Member
SAID ABDEL-KHALIK	Member
J. SAM ARMIJO	Member
MARIO BONACA	Member
OTTO L. MAYNARD	Member
JOHN D. SIEBER	Member

ACRS STAFF PRESENT:

LOUISE LUND
FRANK GILLESPIE
HANS ASHER
RICK SKELSKEY
DONNIE ASHLEY
MICHAEL MODES
JIM DAVIS
KEN CHANG
MIKE HESSLER

ALSO PRESENT:

MIKE GALLAGHER
PETE TAMBURNO
AHMED OUAOU
TERRY SCHUSTER
FRED POLASKI
PAUL GUNTER
RICHARD WEBSTER

C-O-N-T-E-N-T-S

P-R-O-C-E-E-D-I-N-G-S

1:32 P.M.

CHAIRMAN MAYNARD: This meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Plant License Renewal Subcommittee. I am Otto Maynard, Chairman for this subcommittee meeting. ACRS members in attendance are Graham Wallis, William Schack, Mario Bonaca, Jack Sieber, Said Abdel-Khalik and Sam Armijo. Our ACRS consultant, John Barton is also present. Cayetano Santos with the ACRS staff, is a designated official for this meeting.

The purpose of this meeting is to discuss the license renewal application for the Oyster Creek Generating Station, the Associated Draft Safety Evaluation Report and other related documents. The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full committee. The rules for participation in today's meeting were announced in the Federal Register on October 2nd, 2006. ACRS meetings are conducted in accordance with the Federal Advisory Committee Act. They are normally open to the public and provide opportunities for oral or written statements from

members of the public to be considered as part of the Committee's information gathering process. I would like to emphasize that these comments should be limited to issues associated with the Oyster Creek Generating Station License Renewal Application.

We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, the Region 1 office, and the Amergen Energy Company. We have also received requests for time to make oral statements at today's meeting. Mr. Paul Gunter of the Nuclear Information Resource Service and Mr. Richard Webster of the Rutgers Environmental Law Clinic will make their statements following the formal presentation by the Applicant and staff.

If anyone else in the audience would like to make a statement, please notify Mr. Cayetano Santos during the break and we will try to accommodate your request during the public comment portion of the agenda. We have received one written comment from a member of the public regarding today's meeting. This comment was provided by e-mail from Mr. Bill Hering, dated October 3rd, 2006. Copies have been distributed to the subcommittee. A transcript of the meeting is being kept and will be made available as stated in the

Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee.

Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. Due to the number of people, we do have an overflow room next door. The audience can see the slides in that room. So if seating is not available in here, next door there should be some seating. Also due to a large number of people, I request to turn your cell phones off or at least put them on vibrate or your pagers on vibrate to minimize disturbance in the meeting.

I will now proceed with the meeting, and I call upon Ms. Louise Lund of the Office of Nuclear Reactor Regulation to begin.

MS. LUND: Okay, thank you. Good afternoon. My name is Louise Lund. I'm the Branch Chief of License Renewal Branch A in the Division of License Renewal. Beside me is also Frank Gillespie, our Director for the Division of License Renewal. The staff has conducted a very detailed and thorough review of the Oyster Creek Generating Station License Renewal Application which was submitted in July of

2005. Mr. Donnie Ashley, here to my right, is the Project Manager for this review. He will lead the staff's presentation this afternoon on the Draft Safety Evaluation Report. In addition, we have Mr. Michael Modes, who is our team leader for the Region 1 inspections that were conducted at Oyster Creek.

We also have several members of the NRR technical staff here in the audience to provide additional information and answer your questions. As a result of the review, five open items were identified which will be discussed in the presentation. This also resulted -- our review resulted in the issuance of 108 formal requests for additional information. I know the ACRS has been interested in the number of questions that have come out in the reviews in the past. We believe part of that reduction is as a result of the generic aging lessons learned report. This application was submitted using the draft GALL report that was issued back in January 2005. However, it was reconciled with a September 2005 version of the GALL report.

The GALL has certainly helped with the review by providing a roadmap. The staff at Oyster Creek provided excellent support for onsite audits and inspections that were conducted and also the

headquarters review through the conference calls and numerous meetings that we've had. And would you like to make some opening remarks?

MR. GILLESPIE: Only what we tried to do and you're going to see when Donnie comes on is we're going to try to conserve the Committee's time so that we can kind of focus on questions and answers. We do have a large number of slides but we're going to try to go through them on the staff presentation very quickly and not duplicate what you're going to hear from the licensee. So we'll make some adjustments because we know, at least in this case there's a number of technical issues. This is the one plant that's the first one to have us focus on this containment shell question which is also a topic of litigation.

So you'll also find the staff being very careful and trying to be careful of their words at his point relative to saying anything too definitive about specific findings because this is not the final SE. This is the SE with open items. So with that, I'm going to turn it over to Mike Gallagher from Exelon.

MR. GALLAGHER: Okay, good afternoon. My name is Mike Gallagher and I am the Vice President of License Renewal Projects for Amergen and Exelon. For

worst areas above it.

MEMBER WALLACE: That doesn't say very much.

MR. TAMBURNO: So it was no better.

MEMBER WALLACE: It was no better, right?

MR. GALLAGHER: Yeah, so it was the same. But there you would expect it to be similar because the sand, the wet sand -- there was sand throughout so the sand was contacting that. What we're saying is below that interface, it would be less -- the corrosion should be less significant because of the concrete that's embedded in it.

MEMBER ARMIJO: And that's a debate, right? That's an ongoing debate.

MR. GALLAGHER: Well, we think we're consistent with the guidance that's in the GALL and --

MEMBER WALLACE: You replaced the seal, did you?

MR. GALLAGHER: We put that seal in.

MEMBER WALLACE: You put it in afterwards.

MR. GALLAGHER: Yes, this is the corrective action.

MEMBER WALLACE: Okay.

CHAIRMAN MAYNARD: I'd like to move on with the presentation.

MR. GALLAGHER: Yes, sir.

MEMBER SIEBER: I'd like to ask, beyond, in our package the last slide you have is Slide 28. You're referring to backup slides which should be made part of the record. So -- okay.

MR. GALLAGHER: Yeah, any slide we show, we'll put in.

MEMBER SIEBER: Okay, we'll I'd like to have copies of this.

CHAIRMAN MAYNARD: Yeah, I want to remind everybody, we still have the staff's presentation after this and we also have public comment time. I want to make sure we get a chance to get through this and we'll see where we need to come back to.

MEMBER WALLACE: I'm sorry, Mr. Chairman, I'm responsible for this. I want to really know what's going on though, I'm afraid, so I have to ask these questions, because the presentation doesn't tell me unless I ask them, but I'll try to be brief.

MR. GALLAGHER: Okay, so leaving the embed, the drywell shell in the sandbed region was then coated. The coating that was applied was application of a three-coat epoxy coating system consisting of one coat of primer and two coats of epoxy coating. Each coat was visually examined and

dry film thickness measurements were taken to assure the proper coating thickness was achieved. The coating is a two-part 100 percent solid epoxy coating which is less susceptible to the degradation and moist environments. The coating was tested to qualify for emersion surface coating applications such as tank linings. The surrounding environment has stable temperature conditions resulting in lower thermal stresses being applied to the coating and therefore, provides close to an ideal service environment which will result if a very long service life.

MR. BARTON: Do you have any idea how long that coating would be good for, the epoxy coating?

MR. GALLAGHER: We can have Ahmed answer that question.

MR. OUAOU: There were some estimates done by our engineering and it varied from 10 years to 20 years. Recently we spent a lot of time talking to the vendor about the qualification of the coating and the feedback we're getting is that there is no guarantee for that coating, whether it is 20 years, 15 years, whatever. However, you can rely on your inspections to give you an indication whether you're approaching the end life of the coating. So the rigor inspection is the gauge as to when we think that coating is to

get replaced or repaired.

MR. BARTON: And the inspections are how frequent, every 10 years?

MR. OUAOU: The inspection, we inspect every fueling outage. We look at it basically every refueling outage.

MR. OUAOU: Every other refueling outage.

MR. GALLAGHER: Our current program, and I'll go into this, our current program which we do -- there's 10 bays. We do two of the 10 bays every other refueling outage and going forward, we're going to insure we do 100 percent of the bays every 10 years.

MEMBER SIEBER: And what's your cycle length, two years?

MR. GALLAGHER: Two-year refueling.

MEMBER ARMIJO: So it's every four years you inspect two out of 10 bays?

MR. GALLAGHER: That's the current program. Going forward, it will be a minimum of three every other outage to insure that we cover the you know, 10 bays.

CHAIRMAN MAYNARD: Do you have a criteria that when you find degradation that you expand or you increase your frequency or expand the number you look at?

MR. GALLAGHER: Yes, Ahmed?

MR. OUAOU: Yes, in the future, we'll be performing the ASME IEE inspections for the coating. Which requires that if you perform an automatic inspection, you look at the coating and you find defects, you have to assess the other areas that you looked at if you're doing a sampling. So if we do find degradations, we would look at other areas in accordance with our corrective action process.

CHAIRMAN MAYNARD: And you have a criteria as to what constitutes degradation?

MR. GALLAGHER: Yes, in the inspection program.

MR. OUAOU: This is Ahmed. We do have criteria. We're using the criteria right out of the WE that's looking for blistering and flaking and cracking, et cetera, degradation of the coating.

MEMBER WALLACE: This slide would benefit from numbers. If the first bullet said .74 and the second bullet said .69 or something, it would help.

MEMBER SIEBER: Yeah, it sure would.

MEMBER WALLACE: Can you tell us what those numbers are, what the shell thickness needs to be and what it is? Are you going to tell us the numbers?

Exhibit 17

From: Hutchins, Steven P <steven.hutchins@exeloncorp.com>
Sent: Monday, September 18, 2006 4:51 PM
To: Hufnagel Jr, John G <u000jgh@ucm.com>; O'Rourke, John F. <t925jfo@ucm.com>
Subject: FW: DW WHITE PAPERS
Attach: MAM writeup.doc; Drywell Corrosion Fact Sheet.pdf

-----Original Message-----
From: Tamburro, Peter
Sent: Tuesday, September 12, 2006 2:07 PM
To: Hutchins, Steven P
Subject: DW WHITE PAPERS

<<...>> <<...>>

1) Summary:

Beginning in 1980, conditions were identified at the Oyster Creek plant indicating episodic intrusion of water into spacing between the outer steel surface of the drywell portion of the primary containment and the surrounding reactor building concrete. The potential for corrosion of the outer surface of the drywell was recognized, with potential adverse effects on the ability of the drywell to perform its intended design functions. The presence of corrosion was subsequently confirmed and the degree and extent of the corrosion quantified through extensive inspection and testing. An initial assessment determined that the drywell structure remained capable of performing its design requirements.

Corrective actions were directed at assuring that the drywell would continue to satisfy its design requirements over the projected life of the plant. These have included but are not limited to: actions to minimize the potential for water intrusion into the affected area; actions to effect removal of any water that might intrude into the affected area; removal of material (sand) in the lower sand bed region external to the drywell shell that might contribute to drywell shell corrosion; application of a protective coating to the steel drywell external surface in the sand bed region; and determination of a plant specific drywell design pressure for Oyster Creek, establishing a conservative corrosion allowance for the upper region of the drywell. Corrective actions undertaken also include monitoring through periodic inspection activities of the condition of the drywell shell, assessment of the effectiveness of the various mitigating activities, and continuing assessment of the adequacy of the drywell to meet its design functions through the end of plant life.

Corrosion assessment results demonstrate that corrective actions taken at Oyster Creek have been effective in reducing the rate of corrosion in the upper regions of the drywell. The corrective actions also have been effective in arresting corrosion of the drywell shell in the sand bed region. Analysis performed following 2004 UT inspections show that the drywell shell will not corrode to less than minimum required thickness before the year 2029. UT measurements taken in 1992, 1994, and 1996 confirmed that the sandbed region coating has effectively mitigated corrosion of the drywell shell in the sand bed region. Continued implementation of corrective actions described below and as described in "ASME Section XI, Subsection IWE" program, "Protective Coating Monitoring and Maintenance Program", and in the "Drywell Corrosion" time-limited aging analyses, will provide reasonable assurance that loss of material of the drywell shell will be detected before a loss of the containment drywell intended function, assuring the capability of the drywell to perform its intended design functions throughout the License Renewal extended period of operation.

2) Background:

a) Containment Design

OCLR00013715

The Oyster Creek primary containment is a General Electric Mark I design and consists of a drywell, a pressure suppression chamber, and a vent system connecting the drywell and the suppression chamber. The primary containment is a safety related structure, required to control the release of fission products to the secondary containment in the event of a design basis loss-of-coolant accident (LOCA) so that off site consequences are within acceptable limits. The primary containment was originally rated for a maximum internal pressure of 62 psig, consistent with generic GE Mark I containment design.

The drywell houses the reactor vessel, the reactor coolant recirculation loops, and other components associated with the reactor system. The drywell structure is a steel pressure vessel in the shape of an inverted light bulb, consisting of a 70 ft diameter spherical lower section with a 33 ft diameter by 23 ft high upper cylindrical section, topped by a removable, semi-elliptical dome. The spherical section of the drywell is partially embedded in reinforced concrete, from a lower invert at elevation 2'-3" to elevation 8'-11 1/4", and transitions into the non-embedded section through a sand bed region extending to elevation 12'- 3". The non-embedded portion of the drywell is enclosed by a reinforced concrete shield wall, separated from the steel drywell structure by a nominal fifteen inch gap in the sand bed region and a nominal three inch gap above the sand bed region, designed to allow for expansion of the drywell shell (See Figure 1 detail "B").

DW.pdf

(Figure to be revised to show steel trough drain line and gasket)

The gap in the sand bed region was originally sand-filled with dry sand as specified in ASTM 633 to smooth the transition of the drywell shell from a condition of fully restrained in the embedded region to a free standing condition above the embedded region. Drains provided in the concrete surface beneath the sand bed were designed to remove any water that might intrude into the gap between the concrete shield wall and the drywell shell. The concrete surface beneath the sand bed was designed to be finished and shaped to direct any water intrusion to the sand bed drains.

The drywell shell is fabricated from ASTM A-212-61T Gr. B welded steel plates varying in nominal design thickness:

- Embedded shell below the sand bed region	: 0.676 inches
- Sand bed region shell	: 1.154 inches
- Spherical region El 23' to El. 51'	: 0.770 inches
- Spherical region El. 51' to El. 65'	: 0.722 inches
- Transition from spherical to cylindrical region	: 2.625 inches
- Cylindrical region	: 0.640 inches

The internal surface of the drywell steel shell is coated with Carboline Carbo-Zinc 11 paint. The external surface of the drywell steel shell above the embedded region was originally coated with red lead base paint identified as TT-P-86C Type I. Internally, the bottom of the drywell is filled with concrete to a nominal elevation of 10'-3".

b) Cause of Corrosion

The potential for corrosion of the drywell vessel was first recognized when water was noticed coming from the sandbed drains in 1980. Water leakage from the sandbed drains created the potential for a moist environment to exist in contact with the exterior surface of the drywell shell. Extensive investigations to identify the source of water and the leakage path were undertaken during the 1980, 1983, and 1986 refueling outages. Results of the investigations indicated that:

- Leakage was observed during refueling outages;

- Leakage was not attributed to the reactor cavity steel trough drain line gasket or the refueling bellows seal (See Figure 1 detail "A").

  The reactor cavity steel trough drain line gasket leak was ruled out as the primary source of water observed in the sand bed drains because there was no clear leakage path to the seismic gap. Minor gasket leakage would be collected in the concrete trough below the gasket. 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.

  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 the 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.

- Leakage was attributed to through wall cracks in the reactor cavity liner; and

- The leakage path was through the seismic/expansion gap between the drywell and the reactor building, down to the sandbed region within the reactor building.

OCLR00013717

c) Initial Corrosion Monitoring

To determine if water leakage had an adverse effect on the drywell shell, a series of ultrasonic thickness (UT) measurements of the drywell shell were taken during refueling outages and outages of opportunity between 1986 and 1989 to establish and characterize the extent of corrosion of the drywell shell. Approximately 1000 UT measurements were taken to identify the thinnest areas. In addition, core samples of the drywell shell were taken at seven locations, believed to be representative of general wastage, to confirm the UT results. Results of the UT measurements confirmed that:

- Corrosion was occurring in the sandbed region and, to a lesser extent, in the upper regions of the drywell;
- The most severe corrosion rate found in the sandbed region was 39.1±3.4 mils/year; and
- The highest corrosion rate above the sandbed region was 4.6±1.6 mils/year.

As a result of these inspections, it was concluded that a long term monitoring program would be established. This program included periodic UT inspections at critical locations, the performance of calculations to track corrosion rates, and the projection of vessel thickness based on conservative corrosion rates to demonstrate that the minimum required vessel thickness is maintained. The continued presence of water in the sandbed region raised concerns about corrosion at higher elevations and, consequently, periodic UT measurements in the upper spherical region (elevation 50'-2" and 51'-10") and in the cylindrical region (elevation 87'-5") were eventually added to the long term monitoring program.

Based upon the differing drywell shell plate thicknesses in the different regions of the drywell, coupled with the different observed corrosion rates and postulated corrosion mechanisms for these regions, different mitigative actions were undertaken for the upper regions of the drywell and the sand bed region, as discussed below.

3) Mitigative Actions:

a) Strippable Coating:

A strippable coating was applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

b) Sandbed Region:

i) Sand Bed Region Drains

The sand bed region drains were cleared to improve drainage.

ii) Modifications:

(1) Cathodic Protection System:

In 1988, based upon assessment that the higher observed rate of corrosion in the sand bed region was largely galvanic in nature, the first extensive corrective action, i.e., the installation of a cathodic protection system, was taken. The cathodic protection system was comprised of rectifiers, anodes, reference electrodes and system performance monitoring equipment. The cathodic protection system was an impressed current system, which relied on an electrolyte to pass current from the anodes to the "protected" structure. The design of the cathodic protection system assumed that the pre-existing leakage of moisture into the sandbed region would not be abated and would provide an adequate electrolyte for the impressed current system. However, several modifications and/or maintenance activities were performed that eliminated or reduced the leakage into the sandbed, including, the application of a strippable coating to the reactor cavity liner during refueling outages (subsequently made a commitment for the extended period of operation) and the monitoring of leakage from the sandbed region drains. The "drying" of the sandbed reduced the systems performance and the cathodic protection system was subsequently deemed ineffective. The system was removed in 1992.

(2) Sand Removal:

In 1992, a modification was implemented to remove the sand from the sandbed region. Modification activities in the sandbed region also included the removal of rust and old paint from the drywell exterior and the application of a protective epoxy coating on the drywell exterior surface. The concrete surface below the sand was intended to be shaped to promote flow toward each of the five sand bed drains. However once the sand was removed it was discovered that the floor was not properly finished and shaped as required to permit proper drainage. There were low points, craters, and rough surfaces that could allow moisture to pool instead of flowing smoothly toward the drains. These concrete surfaces were refurbished to fill in low areas, smooth rough surfaces, and coated with an epoxy coating to promote improved drainage. The drywell

shell at the juncture of the concrete floor was sealed with an elastomer to prevent water intrusion into the embedded drywell shell.

(3) Protective Coating:

The coating of the exterior surface of the drywell in the sandbed region is considered to be a non-safety-related Service Level II application, as defined by ANSI N101.4. The coating procedure invoked surface preparation in accordance with Steel Structures Painting Council standards SSPC SP-2, Hand Tool Cleaning, and SP-3, Power Tool Cleaning. It also provided requirements for the application of a three-coat Devoe epoxy coating system, consisting of one coat of Preprime 167 and two coats of Devran 184 epoxy coating. Devmat 142S caulk was specified to seal crevices, and the new coatings were required to overlap the existing sound coatings, which permitted a continuous film to be established in the recoated area. Each coat was visually examined and dry film thickness measurements were taken to assure proper coating thickness was achieved. Devran 184 is a two-part, 100 percent solids epoxy coating, which is less susceptible to degradation in moist environments than solvent-based coatings because there are no microscopic pores remaining as a result of solvent release to serve as entry points for moisture intrusion. Instead, the two components cross-link chemically to form a dense solid film. The primer assures that good bonding is achieved with the substrate, and the application of two coats assures that full coverage is attained. Therefore, this coating system was an excellent choice for this application.

The coatings system was qualified inside a sandbed mockup with lighting conditions and space constraints similar to those in the actual sandbed region to assure that the specified coating application methods and thickness requirements were adequate to produce a sound coating film over the rough surface. Personnel performing the qualification tests wore anti-contamination clothing and respirators to simulate working conditions in the actual sandbed region. Representative coating qualification test panels were prepared and coated in accordance with the coating procedure and were visually examined and inspected using a low-voltage wet sponge holiday test in accordance with ASTM G62 to detect any pinholes or discontinuities. This type of testing is normally specified to qualify immersion service coating applications, such as tank linings.

Following the application of the coating system in the sandbed region, the coating in all ten bays (the ten bays are numbered only using odd numbers from 1 – 19) was visually examined to the same visual standards used for the procedure qualification and coating thickness was measured. Since the initial coating application and inspection in 1992, the coating applied to the sandbed region of the drywell shell exterior has been visually examined for chips/scratches, rust spots, blisters, spalling, peeling, cracking, delamination, flaking and any other types of visible coating defects or distress in the coatings. These examinations have been performed on a sample basis during refueling outages, with two bays being examined every other refueling outage. A total of five of the ten bays have been inspected to-date, in the following sequence: 1994 – Bays 11 and 3; 1996 – Bays 11 and 17; 2000 – Bays 1 and 13; 2004 Bays 1 and 13. All coating inspection results to-date have been satisfactory, with no deficiencies noted in any of these inspections. The five remaining bays (5, 7, 9, 15, and 19) have not been re-inspected since the original coating application inspection. Prior to the period of extended operation, Oyster Creek will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Protective Coating Monitoring and Maintenance program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage.

Visual inspection of the containment drywell shell, conducted in accordance with ASME Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containments is considered inaccessible by ASME Section XI, Subsection IWE, thus visual inspection of the sand bed region was not possible at Oyster Creek before the sand was removed. After removal of the sand, the region was made accessible during refueling outages for periodic inspection of the coating. Subsequently, Oyster Creek performed periodic visual inspection of the coating in accordance with an NRC current licensing basis commitment. This commitment was implemented prior to implementation of ASME Section XI, Subsection IWE. For the period of extended operation, Oyster Creek has committed to monitor the protective coating on the exterior surfaces of the

drywell in the sand bed region in accordance with the requirements of ASME Section XI, Subsection IWE through the implementation of the Protective Coating Monitoring and Maintenance Program. Sand bed Region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1.

- The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

- Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

- Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation."

c) Drywell Upper Elevation:

i) Revised Drywell Design Pressure:

The upper regions of the drywell vessel, above the sandbed, were handled separately from the sandbed region because of the significant difference in corrosion rate and physical difference in design. As part of the overall mitigation strategy addressing Oyster Creek drywell corrosion, a decision was made to establish a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. The original primary containment design pressure of 62 psig was generic to GE Mark I containment design and was based upon simulation tests to confirm the design adequacy of the Bodega Bay Plant. The value was established by adding 10 psig to the estimated 52 psig peak containment pressure for Bodega Bay. The 10 psig was added for margin and conservatism. The resulting generic value was considered bounding for the Oyster Creek containment design. A comparison of the Oyster Creek and Bodega Bay containment design features indicated that the Oyster Creek drywell pressure would be significantly less than that for Bodega bay.

Analyses were performed to reevaluate the drywell design pressure and to establish an appropriate plant specific design pressure and corresponding temperature for the Oyster Creek drywell. Analysis demonstrated that following a worst-case design basis loss of coolant accident (DBLOCA), the peak drywell pressure will not

exceed 38.1 psig, with a corresponding saturation temperature of 285° F. Applying a 15% (nominal) margin establishes an appropriate design pressure for the Oyster Creek drywell of 44 psig at a corresponding saturation pressure of 292° F. In accordance with the provisions of 10CFR50.90, Oyster Creek requested a change to Appendix A of the Facility Operating License, reducing the drywell design pressure from 62 psig to 44 psig at a corresponding coincident drywell temperature of 292° F. These changes were approved as Amendment 165 to the Oyster Creek Technical Specifications.

Establishment of an appropriate, plant specific design pressure for the Oyster Creek drywell and subsequent evaluation of observed drywell shell thickness in the upper drywell region demonstrates adequate existing and projected wall thickness for this, the thinnest portion of the drywell shell.

Given that 1) mitigation measures for the sand bed region (including application of a protective coating to the outer drywell shell in the region) have resulted in arresting the corrosion that was occurring in the sand bed area, and 2) the metal in the upper drywell is directly exposed to any potential water spillage into the expansion gap, while wetting of the metal in the sand bed region is precluded by the applied protective coating, monitoring the condition of the upper drywell shell is considered a conservative means of assessing corrosion effects on the overall drywell structure. Periodic UT measurements in the sand bed region were discontinued for a time, with upper drywell UT measurements combined with periodic inspection of the sand bed region protective coating providing adequate drywell shell corrosion monitoring. Periodic UT measurements in the sand bed region will be reinstituted, however, to provide additional assurance that drywell corrosion effects are adequately monitored during the period of extended operation.

4) Corrosion Monitoring:

a) Sand Bed Region

After the sand was removed in 1992, and prior to coating the shell, thickness measurements were taken in each of the 10 bays, from outside the drywell, to establish the minimum general and local thickness of the thinned shell. The measurements from inside the drywell showed that the minimum general thickness of the sand bed region was 0.800 inches, and the minimum local thickness was 0.618 inches. The measurements from outside the drywell in the sand bed region showed that the minimum general thickness was generally greater

Exhibit 18

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF JON R. CAVALLO

City of Portsmouth)
)
State of New Hampshire)

Jon R. Cavallo, being duly sworn, states as follows:

INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station operating license, and admitted by the Licensing Board on October 10, 2006. Citizens' contention as admitted by the Licensing Board is: "AmerGen's scheduled [ultrasonic testing ("UT")] monitoring frequency in the sand bed region is insufficient to maintain an adequate safety margin." The purpose of my Affidavit is provide

information regarding the multi-layer epoxy coating used on the exterior of the Oyster Creek drywell shell in the sand bed region, in order to address Citizens' contention.

2. It is my expert opinion that Citizens' allegations have no technical merit because they are based on a misunderstanding of the nature of the epoxy coating, and of the inspections performed on that coating.

EDUCATION AND EXPERIENCE

3. I am Vice President of Corrosion Control Consultants & Labs, Inc., and in this capacity I provide corrosion mitigation professional engineering services in surface preparation, protective coatings and linings. I have held this position since 1998. I am also Vice-Chairman of Sponge-Jet, Inc., located in Portsmouth, New Hampshire, a company I helped found which designs and manufactures state-of-the-art surface preparation and decontamination systems.

4. I served as Editor of Electric Power Research Institute (EPRI) Report 1003120 (formerly TR-109937), Revision 1, "Guideline on Nuclear Safety-Related Coatings." I also teach and assisted developing the EPRI protective coatings course. I am also the Principal Investigator of EPRI Report 1009750, "Analysis of Pressurized Water Reactor Unqualified Original Equipment Manufacturer Coatings," (Final Report, March 2005).

5. I have worked on coatings and corrosion control at nuclear power facilities for over 35 years. Specifically:

   - From 1971 to 1983, I was employed by Stone & Webster Engineering Corporation in both the Boston and Denver offices. During this period, I specified coating systems for a number of new nuclear generating facilities as

well as performed coating system failure analysis and attendant repair plans for operating nuclear generating facilities.

- After leaving Stone & Webster, I worked with Metalweld, Inc. until 1986 as its Northeastern United States regional manager. I was the project manager for all of the protective coatings work for the Seabrook Nuclear Plant.
- From 1986 to 1991, I was a Senior Associate in the consulting engineering firm of S.G. Pinney & Associates, Inc. During my employment with the firm, I performed protective coating and lining work at a number of nuclear generating facilities. I was the Professional Engineer assigned to all underwater protective lining work conducted by the firm.
- From 1991 to 1998, I was an independent professional engineer performing corrosion engineering consulting services.
- From 1998 to the present, I have worked in my current capacity as Vice President of Corrosion Control Consultants & Labs, Inc.

6. I received my B.S. degree in Engineering Technology, *cum laude*, from Northeastern University in Boston, Massachusetts, in 1979. I have completed a variety of engineering and engineering management study programs, including U.S. Naval Nuclear Power Training, the University of Colorado (engineering project management), and NACE International (corrosion prevention in oil and gas production). I am a Registered Professional Engineer in six states, President of the Maine Society of Professional Engineers, and an SSPC-Society for Protective Coatings certified Protective Coating Specialist.

7. I am active on a number of national technical societies including SSPC, NACE and ASTM. I have served as Chairman of the Northern New England Chapter of SSPC from 1991 to 1998, Chairman of the New England Chapter of SSPC from 2000 to the present, and was a member of the SSPC National Strategic Planning Committee. I was elected Chairman of ASTM Committee D-33 (Protective Coating and Lining Work for Power Generation Facilities) for the period 2004 through 2008. I have also served as Chairman of the Industry Coating Phenomena Identification and Ranking Table (PIRT) Panel reviewing the work of Savannah River Technical Center on the USNRC Containment Coatings Research Project (Generic Safety Issue -191).
8. Based on my review of the relevant historical documentation, I am familiar with the historical corrosion of the OCNGS drywell shell, and the actions taken to control corrosion.
9. I have also reviewed the relevant portions of the OCNGS License Renewal Application ("LRA") submitted to the NRC on July 22, 2005, and the LRA supplement submitted to the NRC on December 3, 2006.
10. Finally, I testified before the Advisory Committee on Reactor Safeguards (ACRS) license renewal subcommittee on January 18, 2007, on the topic of the Oyster Creek drywell shell epoxy coating.

OPINIONS OF JON R. CAVALLO

11. Citizens have asserted that under corrosive conditions, long-term corrosion rates of more than 0.017 inches per year have been observed in the sand bed region of the Oyster Creek drywell shell. This assertion is based on public documents estimating

long term corrosion rates in the period before the application of the epoxy coating to the drywell shell.

12. The historic corrosion occurred because, among other things, the drywell shell in the sand bed region was not coated. The exterior shell is now protected by a three-layer (pre-prime and two coats) epoxy coating system. This coating system was designed for submerged applications, such as tank bottoms, so even if water was always present in the sand bed region, it would have no effect on the coated steel shell. This coating was applied in the following manner:

   - Prior to application, Oyster Creek personnel created a mock-up of the sand bed region. Using the same mechanics, and with the same restricted access, personnel prepared the surface and applied to the coating to this mock-up. Through this process, Oyster Creek personnel qualified the surface preparation, coating application, and inspection techniques for use on the drywell shell.
   - Following surface preparation of the drywell shell by SSPC-SP 2 hand tool cleaning that removed loose rust, loose mill scale, and loose coating, the pre-prime was applied.
   - The pre-prime is a red epoxy coating that soaks and penetrates into the semi-irregular shape of the substrate metal.
   - Then two coats of the whitish-gray Devran-184 epoxy were applied with a brush and roller.
   - Finally, a Devmat 124S caulking was used to seal the interface between the concrete floor and the steel substrate.

13. Citizens speculate that there might be tiny holes in the epoxy coating - "pinholes" or "holidays" - which would allow water to get behind the coating, causing corrosion of the underlying drywell shell. Dr. Hausler has suggested that such holidays would be so small that they could not be detected with the naked eye during a visual inspection. By definition, a pinhole or holiday is a very localized defect in the coating that occurs during the application and cure of the coating. Thus, these localized defects could only be caused by a defect in the original application of the coating, and cannot be caused by degradation over time.
14. As would be expected, the possibility of a pinhole or holiday decreases with each layer of coating that is applied. As I noted, the epoxy protecting the exterior of the drywell shell is comprised of a three layer (a pre-prime and two coats) coating system.
15. AmerGen's protective coating monitoring program includes VT-1 visual inspections of the epoxy coating by qualified inspectors in accordance with NUREG-1801 and ASME Section 11, Subsection IWE. Under the VT-1 method, trained and qualified individuals inspect surfaces such as the drywell shell for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation. The VT-1 technique is a proven method, used throughout the industry, on both boiling water reactors and pressurized water reactors. If a corrosion rate of 0.017" per year had occurred between 1992 and 2006, then it would have been readily detected by the VT-1 inspections performed during the 2006 refueling outage. Future corrosion would also be detectable in a VT-1 inspection.

16. This is because as carbon steel corrodes, the reaction between oxygen and the iron in the steel results in an iron oxide byproduct. The epoxy coating would not allow the corrosion byproducts to migrate from the site of the corrosion, so these byproducts would either accumulate as a blister at the corrosion site, or they would seep out through the postulated pinhole or holiday in the coating onto the otherwise whitish-gray epoxy coating. In either case, the corrosion byproducts would be clearly visible in a VT-1 inspection.

17. It is well accepted corrosion science that corrosion byproduct occupies a volume seven to ten times greater than the underlying corroding steel. For example, if 0.017" of steel corrodes in a year under an epoxy coating, then between 0.119" and 0.170" of byproduct would result. Four years of corrosion at that rate—the interval that AmerGen will perform UT in the sand bed region—would result in between 0.476" and 0.680" of corrosion byproduct. Thus, the amount of corrosion that Citizens postulate would, in a four-year period, generate a blister under the epoxy coating of around ½-inch thickness. Such a blister would be clearly visible to an inspector qualified to perform VT-1 inspections.

18. Therefore, a corrosion rate of 0.017" occurring in a pinhole since 1996 (the last time that strippable coating was not used during a refueling outage), would result in a 1.2" to 1.7" blister in the epoxy coating. Even if significant corrosion could occur behind a pinhole or holiday in the epoxy coating, corrosion at a rate of 0.017" per year would be visible through the VT-1 inspections performed every four years.

19. In fact, Citizens' argument that such local defects have existed since 1992 is inconsistent with their argument that the air in the sand bed region is moist and

capable of corrosion. If a moist environment and pinholes coexisted for the past 14 years (1992 to 2006), then the resulting corrosion would be easily visible during the VT-1 inspections.

20. The VT-1 inspections would also detect the corrosion products caused by much lower corrosion rates. Even a corrosion rate of 0.002 inches per year would yield corrosion products that would cause a blister of between 0.056" and 0.080" in the four year interval between inspections. Such a blister would also be visible in a VT-1 inspection performed by a qualified inspector.

21. The VT-1 Inspection is designed to be used on any type of steel or concrete surface, including textured concrete and irregular surfaces such as welds. Therefore, the techniques used in this inspection would be adequate to use on surfaces such as the Oyster Creek drywell shell.

22. Also, the eight to ten year rated lifetime discussed in Citizens' Exhibit 6 to their original contention (this exhibit is a letter submitted to the NRC in 1995 by the previous owner of Oyster Creek Nuclear Generating Station) is simply incorrect. The multilayer epoxy coating is designed to withstand a submerged environment and to last for the life of the plant, including the extended period of operation, provided that proper VT-1 inspections are conducted and necessary corrective maintenance is performed to address any discrepancies found. This type of coating is commonly used throughout the nuclear industry, and there is no such limitation in life span.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Jon R Cavallo

Jon R. Cavallo
235 Heritage Avenue, Suite 2
Portsmouth, NH 03801

Subscribed and sworn before me this 26th day of March, 2007.

Joyce L. Goodwin

Notary Public

My Commission Expires: JOYCE L. GOODWIN, Notary Public
My Commission Expires January 15, 2008

Exhibit 19

*** ACTION REQUEST ***

A/R TYPE : CM ECR
REQUEST ORG : OED
REQUEST DATE: 21OCT06
REQUESTED BY: TAMBURRO

A/R NUMBER : A2152754
A/R STATUS : ASIGND
STATUS DATE: 23OCT06
LAST UPDATE: 25OCT06
PRINT DATE : 25OCT06

==

EVALUATION NBR: 01
EVALUATING ORG: OEDM
EVAL ASIGND TO: TAMBURRO, PETE
EVAL REQUEST ORG: OEDM
EVAL REQUESTOR: RAY, H
EVAL RETURNED BY: HUTCHINS, SP

ORIG DATE ASSIGNED:
EVAL DUE DATE: 23OCT06
DATE ASSIGNED: 22OCT06
EVAL STATUS : RETURN

IMPORTANCE CODE: OEAP: SCHEDULE CODE: DATE FIXED:

EVAL DESC: DETERMINE PROPER SEALANT FOR DW SANDBED FLOOR VOIDS

**	TANO 23OCT06
DETERMINE/EVALUATE THE PROPER FILLER (SEALER, CAULK, ETC)	TANO 23OCT06
MATERIAL TO USE ON THE VOIDS/SEAMS IN THE DW SANDBED BAYS	TANO 23OCT06
AS DESCRIBED IN IR/AR # 00546932.	TANO 23OCT06
**	TANO 23OCT06
.	TANO 23OCT06
THE SUBJECT EVALUATION (QUESTION) REQUIRES TECHNICAL	PXTO 23OCT06
(DIRECTION, GUIDANCE, INTERPRETATION, EVALUATION) TO BE	PXTO 23OCT06
GIVEN TO THE REQUESTOR (MAINTENANCE). AS SUCH, THE	PXTO 23OCT06
RESPONSE WILL BE TREATED AS A TECHNICAL EVALUATION IAW	PXTO 23OCT06
PROCEDURE CC-AA-309-101.	PXTO 23OCT06
.	PXTO 23OCT06
THE RESOLUTION OF THIS TECH EVAL WAS REVIEWED IN	TANO 23OCT06
ACCORDANCE WITH HU-AA-1212 AND FOUND TO HAVE A RISK	PXTO 23OCT06
RANK OF 3. THEREFORE A THIRD PARTY REVIEW BY AN	PXTO 23OCT06
INDUSTRY COATING EXPERT IS RECOMMENDED.	PXTO 23OCT06
.	PXTO 23OCT06
A. REASON FOR EVALUATION / SCOPE:	PXTO 23OCT06
.	PXTO 23OCT06
DURING VISUAL INSPECTIONS OF THE DRYWELL VESSEL	PXTO 23OCT06
EXTERIOR COATING IN THE SANDBED REGIONS (BAYS 1,7,9 &15)	TANO 23OCT06
AREAS WERE OBSERVED TO HAVE SEAMS/VOIDS. SPECIFICALLY,	PXTO 23OCT06
THE AREAS WHERE THE EPOXY COATING REPAIRS WERE APPLIED	PXTO 23OCT06
TO THE ORIGINAL CONCRETE FLOOR OR THE SIDE OF THE	PXTO 23OCT06
BIOSHIELD HAVE SEPARATED IN SPOTS. TO PREVENT WATER	PXTO 23OCT06
FROM SEEPING UNDER THE EPOXY, AN EXPANDABLE FILLER	PXTO 23OCT06
MATERIAL IS REQUIRED FOR THE SEAMS/VOIDS.	PXTO 23OCT06
.	PXTO 23OCT06
THE SCOPE OF THIS TECH EVAL IS TO PROVIDE GUIDANCE ON	PXTO 23OCT06
FILLING THE SUBJECT SEAMS/VOIDS.	PXTO 23OCT06
.	PXTO 23OCT06
B. DETAILED EVALUATION:	PXTO 23OCT06
.	PXTO 23OCT06
IN 1992, THE EPOXY COATING WAS APPLIED TO THE FLOOR IN	PXTO 23OCT06
AREAS WHERE IT WAS UNEVEN, SO THAT ANY WATER ENTERING	PXTO 23OCT06
THE SANDBED WOULD FLOW AWAY FROM THE VESSEL AND BE	PXTO 23OCT06
ROUTED TO THE DRAINS. SINCE 1996, INSPECTIONS HAVE	PXTO 23OCT06
FOUND INDICATIONS OF THE EPOXY SEPARATING FROM THE	PXTO 23OCT06
CONCRETE. THIS SEPARATION COULD BE CAUSED BY THE	PXTO 23OCT06
CONCRETE SWELLING (EXPANDING AND CONTRACTING) OVER	PXTO 23OCT06
TIME.	PXTO 23OCT06
.	PXTO 23OCT06

*** ACTION REQUEST ***

A/R TYPE : CM ECR
REQUEST ORG : OED
REQUEST DATE: 21OCT06
REQUESTED BY: TAMBURRO

A/R NUMBER : A2152754
A/R STATUS : ASIGND
STATUS DATE: 23OCT06
LAST UPDATE: 25OCT06
PRINT DATE : 25OCT06

THE DRYWELL IS CLASSIFIED Q (SAFETY RELATED). THE	PXT0	23OCT06
CONCRETE FLOOR IN QUESTION DOES NOT HAVE A SAFETY RELATED	TAN0	23OCT06
FUNCTION. THE FUNCTION OF THE FLOOR IS TO ROUTE WATER	PXT0	23OCT06
THAT MAY ENTER THE SANDBED TO THE FIVE EQUALLY SPACED	PXT0	23OCT06
DRAIN LINES AND KEEP THE WATER AWAY FROM THE DRYWELL	PXT0	23OCT06
VESSEL.	TAN0	23OCT06
.	PXT0	23OCT06
THE SEPARATED SEAMS COULD POTENTIALLY ALLOW SOME WATER	PXT0	23OCT06
TO GET UNDER THE EPOXY COATING REPAIR. PLEASE NOTE	PXT0	23OCT06
INSPECTION OF THESE BAYS SHOWS NO DEGRADATION DRYWELL	PXT0	23OCT06
VESSEL COATING OR THE CAULKING BETWEEN THE VESSEL	PXT0	23OCT06
COATING AND THE FLOOR. SEPARATED SEAMS ARE LOCATED	PXT0	23OCT06
AWAY FROM THE DRYWELL VESSEL AND ARE LOCATED NEAR	PXT0	23OCT06
CONCRETE BIO SHIELD.	PXT0	23OCT06
.	TAN0	23OCT06
THE EPOXY THAT WAS USED IN THE EARLIER REPAIR IS DEVRON	PXT0	23OCT06
184 EPOXY COATING WITH A	PXT0	23OCT06
DEVOE PREPRIME 167 SEALER.	PXT0	23OCT06
.	PXT0	23OCT06
BASED ON THE CONDITIONS AND MATERIALS, THE	TAN0	23OCT06
RECOMMENDED FILLER SEALANT TO USE IS SIKAFLEX -	PXT0	23OCT06
TEXTURED SEALANT. THIS PRODUCT IS RECOMMENDED BY THE	PXT0	23OCT06
WILLIAM COATINGS GROUP AND IS TYPICALLY USED TO SEAL	PXT0	23OCT06
CONCRETE TO EPOXY JOINTS.	PXT0	23OCT06
.	PXT0	23OCT06
THE SEALANT SHALL BE APPLIED PER THE MANUFACTURERS	PXT0	23OCT06
INSTRUCTIONS. ATTACHED IS THE TECHNICAL DATA SHEET FOR	PXT0	23OCT06
THE PRODUCT (SEE EVAL ATTACHMENT 1).	TAN0	23OCT06
ALSO ATTACHMENT 2 PROVIDES THE MSDS SHEET FOR THE	PXT0	23OCT06
PRODUCT.	PXT0	23OCT06
.	TAN0	23OCT06
AS PER ENGINEERING STANDARD ES-027, THE ENVIRONMENTAL	PXT0	23OCT06
PARAMETERS OF THE DRYWELL (ZONE 1) ARE AS FOLLOWS:	PXT0	23OCT06
.	PXT0	23OCT06
1) NORMAL PLANT OPERATING;	PXT0	23OCT06
AGING TEMP = 139 DEG F	PXT0	23OCT06
RADIATION = 20 E06 RADS	PXT0	23OCT06
HUMIDITY = 50 %	PXT0	23OCT06
PRESSURE = 16 PSIA	PXT0	23OCT06
.	PXT0	23OCT06
2) DESIGN BASIS ACCIDENT;	PXT0	23OCT06
AGING TEMP = 317 DEG F	PXT0	23OCT06
RADIATION = 32 E06 RADS	PXT0	23OCT06
HUMIDITY = SUBMERGENCE	PXT0	23OCT06
PRESSURE = 53.1 PSIA	PXT0	23OCT06
.	PXT0	23OCT06
THE TECHNICAL DATA SHEET (ATTACHMENT 1) INDICATES THAT	PXT0	23OCT06
SEALANT IS ACCEPTABLE FOR A SERVICE RANGE OF -40F TO	PXT0	23OCT06
170F AND IS WHETHER RESISTANT. THEREFORE THE SEALANT	PXT0	23OCT06
WILL NOT DEGRADE OVER TIME DUE TO TEMPERATURE AND	TAN0	23OCT06
HUMIDITY. THE SEALANT IS NOT REQUIRED TO PERFORM ITS	PXT0	23OCT06
FUNCTION DURING THE DESIGN BASIS ACCIDENT. THEREFORE	PXT0	23OCT06

*** ACTION REQUEST *** PAGE: 06

A/R TYPE : CM ECR
REQUEST ORG : OED
REQUEST DATE: 21OCT06
REQUESTED BY: TAMBURRO

A/R NUMBER : A2152754
A/R STATUS : ASIGND
STATUS DATE: 23OCT06
LAST UPDATE: 25OCT06
PRINT DATE : 25OCT06

THE DESIGN BASIS ACCIDENT PARAMETERS IN ES-027 ARE NOT	PXT0	23OCT06
APPLICABLE.	PXT0	23OCT06
.	PXT0	23OCT06
THE MATERIAL IS A POLYURETHANE BASED PRODUCT MATERIAL	PXT0	23OCT06
AND IS EXPECTED TO HOLD UP WELL UNDER ABOVE NORMAL	PXT0	23OCT06
OPERATING RADIATION EXPOSURE.	PXT0	23OCT06
.	TAN0	23OCT06
C. CONCLUSION / FINDINGS:	PXT0	23OCT06
.	PXT0	23OCT06
BASED ON THE ABOVE EVALUATION, SIKAFLEX - TEXTURED	PXT0	23OCT06
SEALANT IS AN ACCEPTABLE FILLER MATERIAL FOR THE	PXT0	23OCT06
SEPARATIONS/VOIDS IN THE BAYS.	PXT0	23OCT06
.	TAN0	23OCT06
IT IS NOTED THAT THE SIKAFLEX TEXTURED SEALANT IS	TAN0	23OCT06
DESIGNED FOR ALL TYPES OF JOINTS, WHERE THE MAX AND MIN	TAN0	23OCT06
DEPTHS DO NOT EXCEED 1/2" OR 1/4" RESPECTIVELY. ANYTHING	TAN0	23OCT06
BEYOND THESE VALUES HAS THE POTENTIAL OF DEGRADING.	TAN0	23OCT06
.	PXT0	23OCT06
LIMITATIONS ARE AS FOLLOWS:	PXT0	23OCT06
.	TAN0	23OCT06
1) AFFECTED AREAS ARE PROPERLY PREPPED AS STATED ABOVE.	PXT0	23OCT06
2) APPROPRIATE CURE TIMES ARE ADHERED TO.	PXT0	23OCT06
3) THE SEALANT IS APPLIED PER THE MANUFACTURERS	PXT0	23OCT06
INSTRUCTIONS.	TAN0	23OCT06
.	PXT0	23OCT06
NOTE: A REVIEW OF CC-AA-102 DETERMINED THAT THE	PXT0	23OCT06
ACTIVITY DOES NOT IMPACT THE CONFIGURATION OF THE	PXT0	23OCT06
SANDBED. THE APPLICATION OF THE SEALANT IS A PREVENTIVE	PXT0	23OCT06
MAINTENANCE MEASURE TO ENSURE THE EPOXY GROUT WILL NOT	PXT0	23OCT06
DEGRADE OVER TIME.	PXT0	23OCT06
.	PXT0	23OCT06
D. REFERENCES:	PXT0	23OCT06
.	PXT0	23OCT06
1) IR/CR # 00546932	PXT0	23OCT06
2) ENG STD ES-027 REV.4	PXT0	23OCT06
3) SPECIFICATION # SP-1302-32-035 REV. 0	PXT0	23OCT06
.	PXT0	23OCT06
E. LIST OF ATTACHMENTS (TO BE CMT'D WITH EVAL TO RM):	TAN0	23OCT06
.	PXT0	23OCT06
1) SIKAFLEX PRODUCT DATA SHEET (2 PAGES)	PXT0	23OCT06
2) SIKAFLEX MSDS SHEET (5 PAGES)	PXT0	23OCT06
.	PXT0	23OCT06
RESPONSE PREPARED BY: PETE TAMBURRO	PXT0	23OCT06
CO-PREPARED BY: TEDD NICKERSON 10/23/06	TAN0	23OCT06
.	TAN0	23OCT06
**	TAN0	23OCT06
INDEPENDENT REVIEWER BY : HOAT HO (TMI) 10/23/06	HDH0	24OCT06
.	HDH0	24OCT06
THE TECH. EVAL WAS REVIEWED TO DETERMINE WAS	HDH0	24OCT06
CORRECT INPUT USED. THE RESULTS ARE REASONABLE.	HDH0	24OCT06
ANY CONCERNS WERE DISCUSSED WITH CO-ORIGINATOR OF THIS	HDH0	24OCT06
TECH. EVAL AND RESOLUTIONS HAVE BEEN INCORPORATED.	HDH0	24OCT06

*** ACTION REQUEST ***

A/R TYPE : CM ECR	A/R NUMBER : A2152754
REQUEST ORG : OED	A/R STATUS : ASIGND
REQUEST DATE: 21OCT06	STATUS DATE: 23OCT06
REQUESTED BY: TAMBURRO	LAST UPDATE: 25OCT06
	PRINT DATE : 25OCT06

VERIFIER CONCURS WITH ORIGINATOR.	HDH0	24OCT06
BASED ON THIS EVALUATION, THE TECH.EVAL. IS VERIFIED TO	HDH0	24OCT06
BE ACCEPTABLE.	HDH0	24OCT06
**	HDH0	24OCT06
THIS TECH EVAL WAS REVIEWED BY JON CAVALLO (THIRD	PXT0	24OCT06
PARTY REVIEW) AND FOUND TO BE ACCEPTABLE. ATTACHMENT	PXT0	24OCT06
3 PROVIDES AN EMAIL DOCUMENTING HIS REVIEW.	PXT0	24OCT06
.	SPH1	25OCT06
THIS TECHNCIAL EVALUATION HAS BEEN REVIEWED AND APPROVED	SPH1	25OCT06
BY ENGINEERING MANAGEMENT. IT MEETS THE REQUIREMENTS OF	SPH1	25OCT06
CC-AA-309-101 AND HU-AA-1212. S. HUTCHINS (10/25/06)	SPH1	25OCT06

Exhibit 20

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

November 9, 2006

Mr. Richard Webster
Staff Attorney
Rutgers Environmental Law Clinic
123 Washington Street
Newark, NJ 07102

Dear Mr. Webster:

In an e-mail dated September 26, 2006, addressed to Michael Modes, Team Lead for the Oyster Creek License Renewal Inspection, you posed a number of questions about the integrity of the former sandbed area of the Oyster Creek drywell. Information related to this subject can be found in NRC Inspection Report 05000219/2006007, dated September 21, 2006 (ADAMS Accession No. ML062650059) and the NRC "Safety Evaluation Report With Open Items Related to the License Renewal of Oyster Creek Generating Station" issued in August 2006 (ADAMS Accession No. ML062300330). In addition, you were present at the public exit meeting concerning this inspection, which was held on September 13, 2006, in Lacey Township, NJ, during which this subject was discussed and you asked numerous questions. The following responds to your September 26 e-mail.

The subject of emptying of the sandbed drain collection bottles (i.e., 5 gallon poly bottles or jugs) during the March 2006 license renewal inspection was discussed in the September 21, 2006 Inspection Report, on pages 23-24. During the inspection, the NRC inspection team overheard an Amergen technician talking about clearing the torus room for the NRC walkdown and emptying some bottles of water he found. Amergen told the NRC that a member of Amergen's staff was sent into the torus room, on the day before the NRC inspection team entered, in order to make sure the area was safe for the NRC team inspection walkdown. The Amergen staff took it upon themselves to empty the collection bottles into the floor drains provided for the purpose of catching water overflow, before the team entered the torus room. The overflow drains route liquid to the sump where it is then processed.

Because the bottles were emptied prior to any sampling or analysis, the source of the water was not determined and there was no determination about whether the water contained any radioactivity. The team inspected the bottles during their walkdown and noted there was no evidence of overflow from the bottles because there were no water stains or residue on the floors around the bottles. The technician responsible for emptying the bottles was asked about over-flow and indicated that only two of the five bottles were filled with water, and that no water was flowing out of the filled bottles.

During the NRC walkdown of the torus room, the NRC determined there was no discernable residue that could be analyzed. The NRC examined the bottles and concluded the high heat in the room dried the water bottles such that no usable residue was present. In addition, during the torus room walkdown, the NRC noted that, in one location, water was leaking from the

ceiling onto the torus. Amergen indicated that this leak was from a known condenser leak in the room above.

As noted in our inspection report, Amergen indicated that the bottles were improperly emptied without measurement or analysis and that it was unable to locate any documentation that showed prior surveillance of the water drains had been completed. Amergen also took corrective actions to ensure that, in the future, the drains would be monitored.

The NRC did evaluate the incident for enforcement action based on the commitment made by the licensee in 1996 to monitor leakage from the former sandbed drains. Using the guidance contained in NRC Manual Chapter 612 "Significance Determination Process," Appendix A (www.nrc.gov/reading-rm/doc-collections/insp-manual/manual-chapter/index.html), we determined this was a performance deficiency of minor significance because the performance deficiency had no impact on the safe operation of the plant. The failure to fulfill a commitment is not, by itself, a violation of our regulations. As noted in our inspection report, the performance deficiency related to the monitoring of leakage from the former sand bed region of the drywell was deemed not to be safety significant and was entered into the applicant's ongoing corrective action system.

Ten bays in the former sand bed region of the drywell were excavated and coated with an epoxy paint in 1992. Although Amergen has been performing regular visual inspections, prior to October 2006, five of the bays had not been visually inspected, but were inspected during the October 2006 outage. Each inspection is performed by an individual trained and qualified for visual inspection who enters the sand bed cavity. This individual inspects all accessible areas of the surface and documents the results of the survey. The NRC does not have a schedule of the inspections performed by Amergen prior to October of 2006 and has not received any Amergen reports or data related to these prior inspections.

As noted in our report, the NRC inspection of Amergen's aging management programs, including for the sand bed region, was conducted in accordance with NRC Manual Chapter 2516 and NRC Inspection Procedure 71002. The results of that team inspection are documented in Inspection Report 05000219/2006007, and are not based on the expertise of one individual.

The NRC continues to evaluate Amergen's proposed aging management programs related to the sand bed, including the embedded region. NRC staff conclusions about Amergen's aging management programs for the drywell shell will be included in the Safety Evaluation Report that is scheduled to issue in December 2006.

I trust that you will find this information responsive.

Sincerely,

Richard J. Conte

Richard J. Conte, Chief
Engineering Branch 1

Exhibit 21

Nuclear

GPU Nuclear Corporation
One Upper Pond Road
Parsippany, New Jersey 07054
201-316-7000
TELEX 136-482
Writer's Direct Dial Number:

December 5, 1990
5000-90-1995
C320-90-302

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

Gentlemen:

Subject: Oyster Creek Nuclear Generating Station (OCNGS)
Docket No. 50-219
License No. DPR-16
Oyster Creek Drywell Containment

References: (1) NRC Letter dated October 16, 1990 - Requested Clarifications.
(2) GPUN Letter dated November 26, 1990 - Drywell Inspection/Sampling Plan.

This letter, together with the Reference (2) submittal, completes the response to the Reference (1) request for clarifications on the drywell corrosion issue.

The attachments to this letter address Reference (1), Items ii to iv, which correspond to Reference (2), Items (2) to (4).

Attachment I to this letter provides the information requested by the NRC for Item (2). This attachment consists of GE/Teledyne Report TR-7377-1 "Justification for Use of Section III Subsection NE Guidance in Evaluating the Oyster Creek Drywell." This report provides the technical justification for using ASME Section III NE guidance for the evaluation of membrane stress intensities which are between 1.0Smc and 1.1Smc.

Attachment II to this letter provides the information requested by the NRC for Item (3). This attachment consists of GE Reports Index No. 9-1 and 9-2, "An ASME Section VIII Evaluation of the Oyster Creek Drywell Stress and Stability Analysis." This two part report covers the structural analysis of the Oyster Creek drywell through the 14R outage with the current sand-in-place configuration and the sandbed portion of the drywell conservatively assumed corroded to 0.700". This report confirms the adequacy of the Oyster Creek drywell shell utilizing ASME Section III guidance to demonstrate ASME Section VIII Code compliance.

Attachment III to this letter provides the information requested by the NRC for Item (4). This attachment consists of a detailed summary of the actions GPUN has undertaken to identify and prevent water intrusion into the drywell gap and addresses the effects of leakage on structures and equipment other than the drywell.

In addition to providing the requested Reference (1) clarification documentation, GPUN is proceeding with the analysis, engineering and planning to support removal of sand from the drywell sandbed region. Since our meeting with you on September 19, 1990, corrosion testing studies have reinforced our conviction that this will be a key step in arresting corrosion in that region. The technical evaluation supporting sand removal is well underway and the structural calculations are expected to be completed in December. Assuming satisfactory results, we plan to submit this structural analysis to you by December 31, 1990.

If you have any questions on this submittal or the overall drywell corrosion program, please contact Mr. Michael Laggart, Manager, Corporate Nuclear Licensing at (201) 316-7968.

Very truly yours,

J. C. DeVine, Jr.
Vice President, Technical Functions

JCD/RZ/plp
Attachments

cc: Administrator, Region I
NRC Resident Inspector
Mr. Alex Dromerick, Jr.

C320302

ATTACHMENT III

GPUN Detailed Summary Addressing Water Intrusion
and Leakage Effects Related to the Oyster Creek Drywell

C320302

WATER INTRUSION

The following describes GPUN past actions to investigate, identify, and correct leak paths into the drywell gap, as well as our planned future actions to prevent and surveil potential leakage. The issues discussed below occurred from 1985 to date. Actions taken to address the impact of leakage on other structures and equipment are also described.

1. REFUELING CAVITY

a) Liner

Cracks caused by mech. Damage or heat.

The stainless steel liner was inspected both by visual and dye penetrant methods. A significant number of cracks were found as well as some through-wall damage, most probably caused by mechanical impact. As a result, an analysis was performed for determining the failure mechanism (i.e., IGSCC, fatigue, etc.) and it was determined that the cracking was mechanically induced and not IGSCC induced. The most probable cause was thermal fatigue. (A sample was removed from the liner and metallurgically examined.)

- Tape
- Strippable coating
remove after outage

To prevent leakage through these cracks during refueling, we install an adhesive type stainless steel tape to bridge any large cracks observed, and subsequently, apply a strippable coating. Both the tape and the coating have been qualified by GPUN and vendor for use in the environment that they normally see. This method of repair is temporary (refueling only) and both the tape and coating are removed prior to the end of the outage. No leakage concerns exist at any other times since the cavity is dry.

b) Bellows

No leaks from the bellows

The bellows allow for expansion between the drywell and the refueling cavity and are made of stainless steel. They were repeatedly tested using helium (external) and air (internal) without any indication of leakage. Any leaks from the refueling bellows would wind up in the concrete trough, which has a leakage detection/collection system. No leakage has been observed for the last two refuelings.

c) Piping Drains

No leak from drains

There are two drain lines from the cavity that allow for water removal from the cavity and trough. They have been pressure tested with no evidence of leakage.

d) Metal Trough

The metal trough is located between the drywell and the reactor building. It was tested visually and with helium without any positive leaks identified.

A gasket at the drain line from the trough was replaced. However, no clear leakage path was identified from this source. This portion of the cavity is coated during refueling with strippable coating.

e) Concrete Trough

The concrete trough is located under the metal trough and is designed to collect any leakage from the bellow area and direct it to a drain. This area was inspected by removing the drain plate attachment to the metal trough and visually inspected, using remote video. An area where concrete was found to be chipped was repaired and the drainage capability restored. No further problems are known to exist.

f) Steps (Stainless Steel Liner)

These are the steps that receive the shield plugs and plugs from the fuel pool to the cavity and cavity to equipment pool gates. These steps were examined visually and by PT with no indications of cracking. These steps will also be periodically coated during refueling.

g) Skimmer

The skimmer system is designed to maintain water clarity in the cavity. It consists of ducts and piping connected to the liner with most of the ducting and piping encased in concrete. A pressure test was performed in the skimmer system and as a result, some skimmers are removed from service by plugging them prior to each refueling.

In conclusion, we believe that all potential water leakage pathways from the refueling cavity into the drywell gap have been thoroughly checked and the continuation of our current tape/strippable coating method during future refueling outages is adequate for prevention of leakage from this source.

2. EQUIPMENT POOL

a) Liner

The liner was inspected both visually and dye penetrant tested, with any PT indications vacuum box checked. No through wall leakage was found. Additionally, the equipment pool has a leak detection system under the welds in the plate which is routed to drains. Any leaks into the collection system would not reach the drywell. While the leak detection system indicated leakage, no liner leaks were found.

Preventively, the equipment pool will be taped using the SS tape and then coated with a strippable coating prior to the refueling outage, further reducing the probability of leakage.

b) Drain

The drain was checked for leaks via pressure test and found to be leak free.

c) Support Pad

Concerns with the pad to liner welds arose. As a result, the pad was removed and the liner weld area checked prior to replacing the pad. No leakage was identified.

In conclusion, no leaks have been found related to the equipment pool. Preventively, the equipment pool will be protectively coated similar to the refueling cavity. Drains from the leak detection system are monitored on a periodic basis to detect any changes.

3. FUEL POOL

The fuel pool has a leak detection system similar to the equipment pool. The leak detection is for all welded joints in the stainless steel liner. Minor leakage (dripping) has been noted over the years at infrequent intervals, even though the pool is continuously flooded. Leakage or condensation has been postulated as the source. Additionally, in 1985 while reracking the pool, a leak was found. As a result, vacuum testing was performed to find the leak and underwater divers were used to confirm the leak location and to repair the leak. No further problems were encountered. Ongoing monitoring of the leak detection ensures early leakage detection.

4. PIPING PENETRATIONS

Piping that is buried in concrete and whose leakage could become a leak path to the drywell gap was investigated. The piping penetrating the drywell was not investigated since it was either tested as part of 10 CFR 50 Appendix J or any significant leakage would be detected as part of operability/system operation.

Other piping such as the drains from the cavity and equipment pool are discussed above.

In conclusion, no leakage is expected from the buried piping or piping penetrating the drywell.

5. WALKDOWNS FOR VISUAL LEAKAGE

Walkdowns are periodically conducted to identify any leakage in the Reactor Building wall, under the two pools, and on the drywell wall. While minor staining can be seen, samples of water were obtained (sand bed, drywell wall, etc.) and analyzed without being conclusive as being reactor refueling water.

6. SAND BED DRAINS

In the sand bed region of the drywell, there are five sand bed drains equally spaced around the drywell. Some of these drains were known to drip/leak. When cathodic protection was installed, water was observed coming out of the CP holes. As a result, every effort to remove any water entrapped in the sand bed was initiated. The five drains were cleared using a "roto-rooter" approach and approximately 500 gallons of water were removed. Presently, the drains are not leaking and preventive maintenance to clear the drains periodically has been initiated. A routine walkdown to identify changes in leakage is in place.

In conclusion, while the sand was retaining water due to blockage of the drains, after clearing the drains, the sand bed area appears to be free of water.

As a result of the above described approach to identify and correct potential water source leak paths and our ongoing program for surveillance for water intrusions, as discussed in the presentations made to the NRC on September 19, 1990 and the NRC site visit and inspection on October 29-31, 1990, we believe we have a thorough program for managing leakage that could affect drywell integrity.

In addition to the efforts described above, actions have also been taken to address the potential impact of leakage on other structures and equipment. These actions are described below.

??

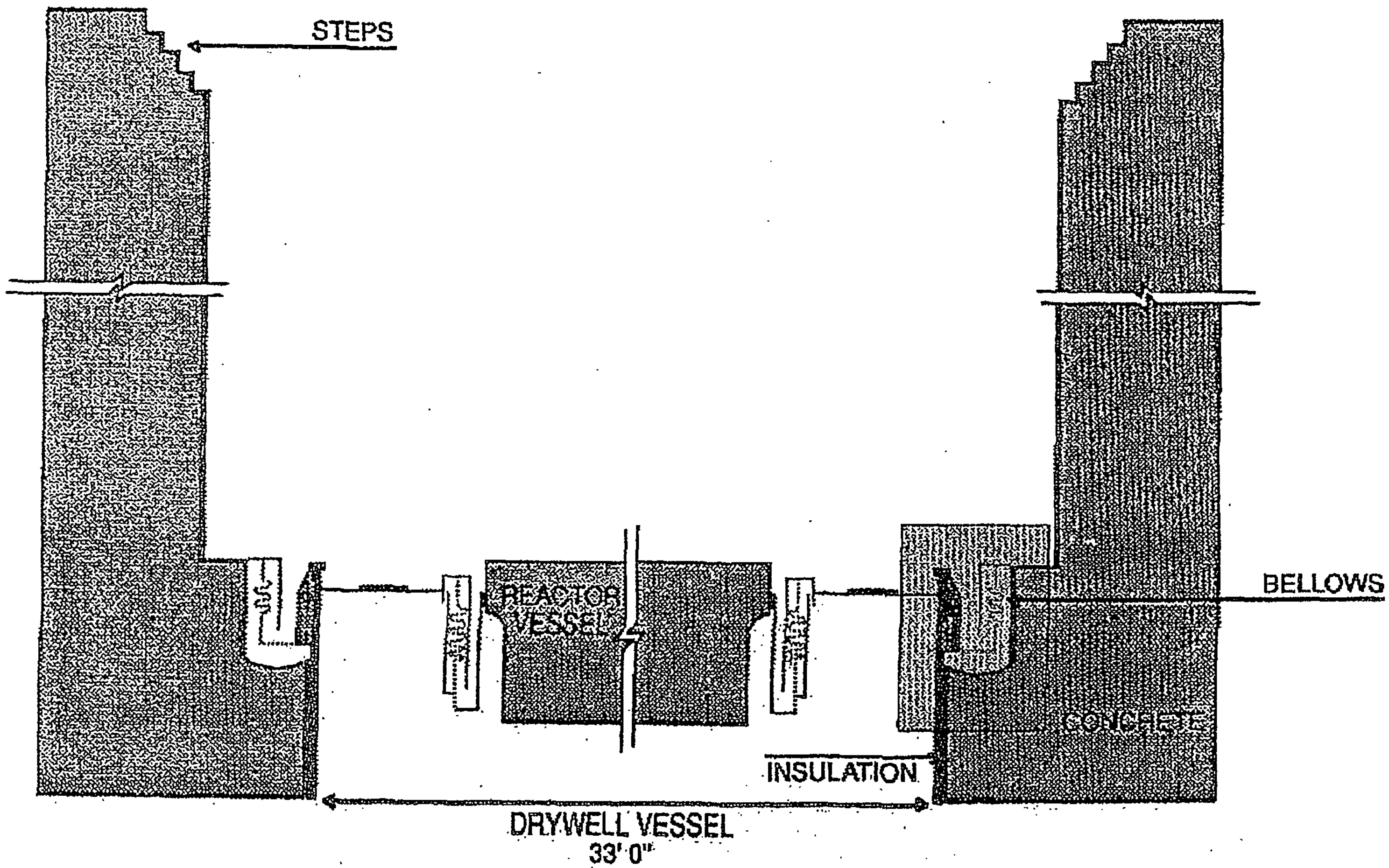
Cracks have been identified in the concrete walls and floor of the spent fuel pool and equipment pool. These cracks are routinely inspected and monitored for changes in size and condition. Numerous analyses have been performed which conclude that the identified cracking does not degrade the ability of the building to perform its intended function.

- Cracks
- leaks under equipment pit
- rust

Inspections of these cracks indicate no evidence of leakage around or under the spent fuel pool. Evidence of leakage has been observed in both the floor and wall of the equipment pool and in the reactor cavity wall above elevation 95'-0". Based on visual inspections, this leakage has not affected any equipment. The water stains observed on the underside of the equipment pool contain no evidence which would indicate reinforcing bar corrosion. In addition, visual inspections indicate no general concrete degradation associated with these cracks.

Stains on the equipment pool and reactor cavity walls above elevation 95'-0" do indicate slight corrosion of the reinforcing bar. To determine the potential effect of this corrosion, a compositional analysis of a representative concrete core sample was performed in October, 1988. This analysis indicates that the diameter of a typical reinforcing bar could be expected to be reduced by 0.002 inch/year. The walls in question are reinforced with #8 and #11 reinforcing bar. Therefore, if the corrosion continues, the diameter of the reinforcing bar would be reduced by 8% and 6% respectively over a 40-year period. Since the corrosion is localized, this reduction has no impact on concrete integrity.

TOP OF REACTOR VESSEL



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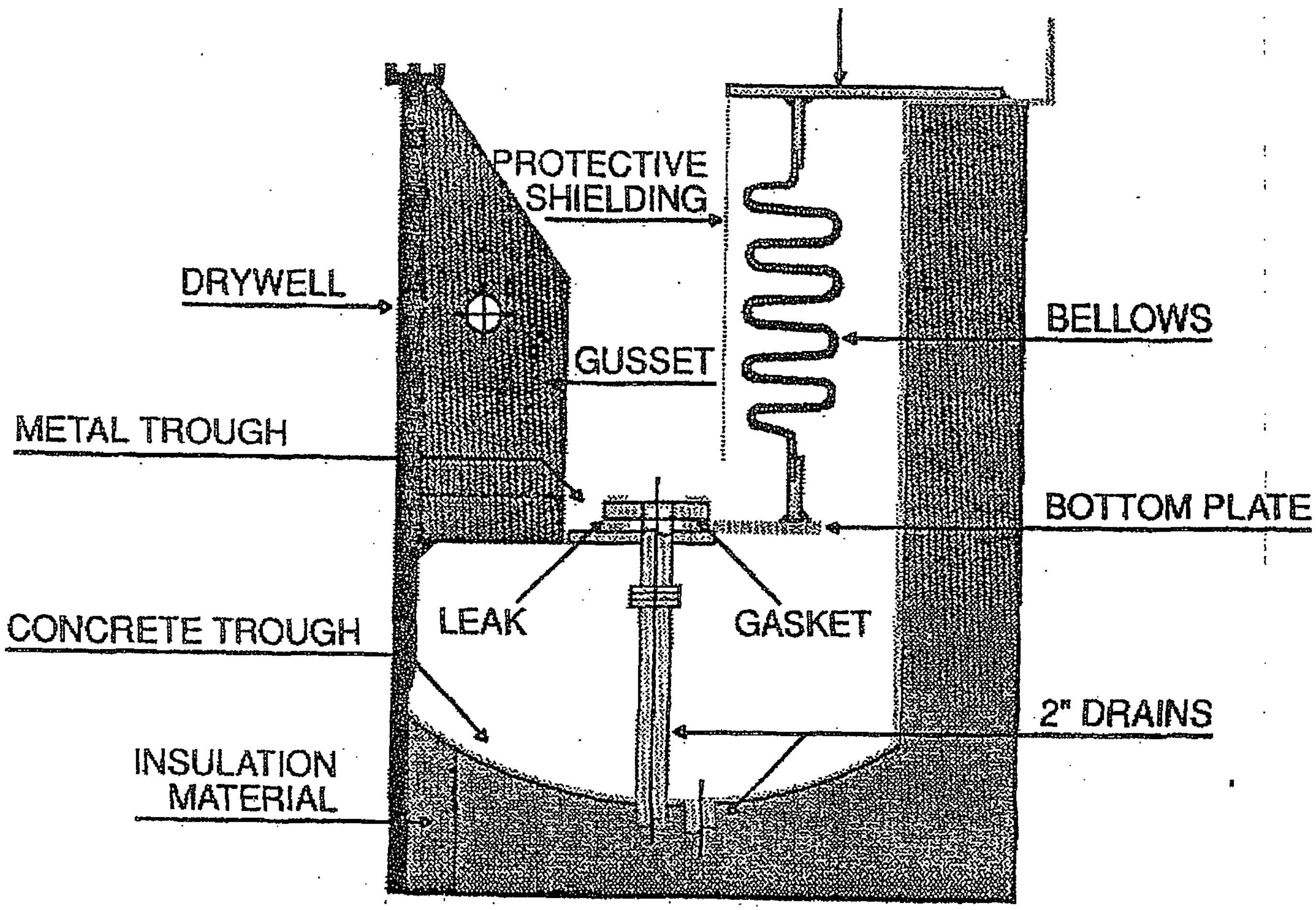
DRYWELL TO CAVITY SEAL



OCLR00029280

Exhibit 22

GPU Nuclear Technical Data Report	TDR No. 964	Revision No. 0
	Budget Activity No. 402873 Page 1 of 6	
Project: DRYWELL SAND BED DRAIN LEAKAGE	Department/Section E&D Mech. Components	
	Release Date ______	Revision Date ______

Document Title: CLEARING OF THE OYSTER CREEK DRYWELL SAND BED DRAINS

Originator Signature	Date	Approval(s) Signature	Date
John A Martin	2/15/89	[signature]	3/3/89

Does this TDR include recommendation(s)? [X] Yes [ ] No If yes, TFWR/TR# AT-5691, AT-5692 Mech

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Statement of Problem

On October 26, 1988 during the drywell cathodic protection core bore installation (B/A 402873) standing water was found in the drywell sand bed cushion. Inspection of the sand bed drains disclosed that a small drip was present at four of the five bay drains (3, 11, 15, & 19). Since dripping is not considered representative of drainage, it was considered prudent to "clear the sand bed drains".

Summary

The sand bed drains and sand beds were cleared and agitated. This resulted in collection of 514 gallon of water over a span of 4 weeks (11/16/88 to 12/16/88).

Although each of sand beds have been agitated, water is still dripping from the drain pipes. (Feb. 2, 1989)

(For Additional Space Use Side 2)

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* Abstract Only

Abstract Continuation TDR No. 897 Revision No. 0

Conclusion

Sand bed drains from elbow to sand bed were agglomerated thus preventing water from draining and have been cleared.

Recommendation

1. Install a catch basin under each sand bed drain and route poly tubing to individual 5 gallon poly containers at respective bays at the perimeter of the torus. This container should be monitored and reported to Technical Functions on a weekly basis by plant operations. This is being accomplished by Reference 1.

2. Place sand bed drains on planned maintenance schedule to be accessed and agitated at the next planned outage(13R). TR AT-5691

3. Review recommendations made in TDR 831 and assess if further drying of the sand can be effectively accomplished. TR AT-5692

TABLE OF CONTENTS

1.0 INTRODUCTION

On Oct 26, 1988 during the cathodic protection core bore operation (B/A 402873) it was noted that hole 2 in bay 11 was filled with standing water. This water when tested by O.C. chemistry was found not to be core bore water used during the drilling operation but rather it had characteristics of "old" fuel pool water.

Since the reactor cavity had not been filled with fuel pool water for the "upcoming refueling" it was postulated that this entrapped water could be "old" fuel pool water.

It was estimated that a quantity of 400 to 550 gallons was present in the sand bed region.

An inspection of the five(5) sand bed drains disclosed that only a small drip was present at four of the drains(3, 11, 15, & 19).

Since the level of this water in the core hole of bay 11 did not decrease and the dripping was not considered representative of drainage, it was considered prudent to "clear the sand drains".

Consequently, a work order was issued to "clear the sand bed drains".

1.1 Background

There are drainage channels in the bottom of the 35 foot dia sand bed that slope toward five 4" Sch 40 sand filled drain lines. The five drain lines are located beneath every other downcomer nozzle in bays 3, 7, 11, 15 and 19. Each of the drain line runs vertically (approximately 15 inches) from the sand area to a 90° elbow and down a slopped pipe (1" per foot) for approximately 9 feet 6 inches through the concrete foundation before penetrating into the torus room.

Each pipe drain has a 100 mesh S.S. screen to retain the sand in the line.

Removing the screen and examining each of the pipes revealed that only one drain pipe(bay 11) had sand in the pipe. The remainder of the drain pipes were partially empty of sand.

2.0 METHODS

Scaffolding had to be built in each bay to access the drain pipes. In addition each of the five 4" sch 40 drain pipes were cut back to gain access to the end of the pipe.

As a precaution to a sudden discharge of water or sand, a specially designed 4" test plug with a 2" threaded connection was installed in the end of each of the 5 pipes. To this connection a 2" tee was assembled so that a machine driven 3/4" dia snake (Attachment 1) could be inserted into the pipe. A 1/2" ball valve along with a poly catch funnel was installed under this assembly to collect any water resulting from the cleared sand bed. Both the 2" ball valve and catch basin were manifolded together to a 1/2" poly tubing which was then routed under the torus to a 55 gal drum. This arrangement was made to each of the five sand bed drains.

The machine driven 3/4" reinforced snake was fitted with various cutting accessories (Attachment 1) to clear the sand packed drains. Specifically a spear head was used to open the way followed by progressively changing to larger cutters (2-1/2" dia).

A wet vacuum was also used to assist in the clearing and collecting of sand and water samples.

3.0 RESULTS

Although problems kept cropping up to delay the goal of clearing the water from the sand beds, the clearing of each of the drains was finally completed on December 9, 1988.

The total water collected as of Dec. 16, 1988 amounted to 514 gallons. Graph (Attachment 2) shows the total water collected and a bar chart (Attachment 3) shows the progression of clearing of each drain.

Bay 11 was chosen as the first drain to clear because of the water found in core hole 2 of the drywell cathodic protection program (B/A 402873).

Using a hand held drain cleaner with 1/2" cable and various cutting tools proved to be unsuccessful after many configuration changes.

Consequently, it was decided to move to bay 15. Upon removing the screen at the end of the pipe a second screen(original screen) started to discharge water at a very fast rate. In the course of seven days 192 gallons of water was collected.

Since bay 15 was draining on its own, a decision was made to proceed to bay 3. Using a 1/2" dull drill point on the hand held "Super Vee" drain cleaner (Attachment 1) a break was made in the hard sand packed area beyond the 90° elbow. Water poured out of this drain at a very fast rate. In the course of two days 82 gallons were collected.

Because of the difficulty encountered using the hand held drain cleaner a larger capacity, heavy duty machine was obtained (Attachment 1).

Setting up the heavy duty machine in bay 7 resulted in accessing the sand bed and agitating the sand to a distance of six feet beyond the 90° elbow. Water came out of this drain in a small stream.

The amount collected in four days amounted to 28 gallons. On December 14, 1988 the total collected amounted to 42.3 gallons. This drain had never been recorded as "dripping".

The drain pipe in bay 19 was then accessed and the machine driven 3/4" cable and 2-1/2" dia cutter was moved in and out to agitate the sand bed six feet beyond the 90° elbow. No excessive water appeared from this exercize however the cable and cutter showed evidence of damp sand. A total of 2.6 gallons was collected as of December 14, 1988.

The drain pipe in bay 11 was then accessed using a small 1/2" spade type cutter. However, enlarging the hole proved to be difficult and time consuming until a specifically designed auger was used. Specifically, the sand was packed tightly and gaining access to the sand bed was slow and tedious. Finally after much persistence and "elbow grease" the sand bed was accessed. The sand bed was accessed 28" beyond the 90° elbow and the 3/4" cable with a 2-1/2'cutter was moved in and out of the sand bed to agitate the sand bed. It was decided to "hold up" completely accessing the sand bed because the cathodic protection anodes were already installed in this bay. A small amount of water was found in this bay as evidensed by the damp sand on the cable and cutter.

Although bay 15 and bay 3 were draining it was decided to go into the drains and subsequent sand beds to agitate the sand beds. This was accomplished in both bays and the 3/4" cable with associated 2-1/2" dia end piece was moved in and out of the beds at a distance of six feet from the 90° elbow.

A graphic representation of access to each of the sand bed drains is shown by Attachment 4.

4.0 CONCLUSIONS

It was difficult to access the drywell sand beds from each of the sand bed drains. However, it was finally accomplished and a total of 514 gallons of water was collected as of December 16, 1988 (Attachment 2). The water had all but stopped from each of the drains.

Water samples were collected from each bay drain and analysis proved to be inconclusive (Attachment 5 and Reference 2).

Sand samples were collected from several bays and analyzed as to why the sand was impervious to draining of water from the sand bed (Attachment 6 and Reference 3 and 4).

5.0 RECOMMENDATION

1. Install a catch basin under each sand bed drain and route poly tubing to individual 5 gallon poly containers at respective bays at the perimeter of the torus. This container should be monitored and reported to Tech Functions on a weekly basis by plant operations. This is being accomplished by Reference 1.
2. Place sand bed drains on planned maintenance schedule to be accessed and agitated at the next planned outage(13R).
3. Review recommendations made in TDR 831 and assess if further drying of the sand can be effectively accomplished.

6.0 REFERENCES

Reference 1 Memo 5310-89-001 "Surveillance of the Oyster Creek Drywell Sand Bed Drains in the Torus Room" dated 1/4/89 from J.A. Marting to K. Mulligan.

Reference 2 Memo 2210-89-020 "Drywell Leak off Samples" dated 1/16/89 from W. dunphy to G. R. Taylor.

Reference 3 Memo 5390-89-0002 "Drywell Sand and Water Analysis" dated 1/3/89 from P. R. Walton to G.R. Taylor.

Reference 4 Report 5393-89-0116 "Drywell Sand and Water Analysis" Oyster Creek from M. J. Chelius to G.R. Taylor.

Exhibit 23

The following plan is in place for inspecting for leakage around the Drywell:

Prior to Refueling Outage

- A camera inspection is performed to ensure the cavity trough drain line is free of any debris that could cause the trough to overflow and run down the drywell shell. (PM 18703M)

During Refueling Outage

- Strippable Coating is applied to the Reactor Cavity and Equipment Pool to minimize leakage.

- A camera inspection is performed while the cavity is flooded to ensure debris has not clogged the drain. (PM 18703M)

- After flood-up, inspections commence to determine if leakage is occurring, and to quantify the amount of leakage. The frequency of inspections is a minimum of once per day. The inspections will continue while the cavity is flooded. After drain-down, the inspections will continue until leakage has stopped. Inspection locations include poly bottles in the Torus room, concrete around vent pipes as viewed from the top of the Torus, Cavity and equipment pool drains, and electrical penetrations on 23' & 51' elevations. (PM 18704M)

During Run Cycle

- Inspections are performed on a quarterly basis to check for water in the Torus room poly bottles and leakage from the cavity trough drain. (PM 18705M)

Note: Water was found in 3 poly bottles in March 2006. This water was believed to be from past refueling outages. A sample of the water was taken in April 2006 and was found to have no activity. The bottles have been inspected twice since March (The latest inspection was May 26, 2006), with no water found.

Exhibit 24

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee on Reactor Safeguards 539th Meeting
Docket Number:	(not applicable)
Location:	Rockville, Maryland
Date:	Wednesday, February 1, 2007
Work Order No.:	NRC-1422

Pages 1-342

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

539TH MEETING

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WEDNESDAY, FEBRUARY 1, 2007

VOLUME I

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., DR. WILLIAM J. SHACK, Chairman, presiding.

MEMBERS PRESENT:

WILLIAM J. SHACK, Chairman

JOHN D. SIEBER, Vice Chairman

SAID ABDEL-KHALIK, Member

GEORGE E. APOSTOLAKIS, Member

J. SAM ARMIJO, Member

SANJOY BANERJEE, Member

MARIO V. BONACA, Member

MICHAEL L. CORRADINI, Member

THOMAS S. KRESS, Member

OTTO L. MAYNARD, Member

DANA A. POWERS, Member

GRAHAM B. WALLIS, Member

STAFF PRESENT:

ZENA ABDUALLY
WILLIAM H. BATEMAN
GARY HAMMER
CORNELIUS HOLDEN
MICHAEL JUNGE
RALPH LANDRY
TIMOTHY R. LUPOLD
RALPH MEYER
BOB RADLINSKI
TANEY SANTOS
TED SULLIVAN
JENNIFER L. UHLE
SUNIL WEERAKKODY

ALSO PRESENT:

JOHN ALVIS
MICHAEL C. BILLONE
BERTRAND DUNNE
NAYEM JAHINGIR
CHRISTINE KING
ALEX MARION
ODELLI OZER
JIM RILEY
MIKE ROBINSON
GLENN WHITE

A-G-E-N-D-A

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

1:18 p.m.

CHAIRMAN SHACK: On the record. I'd like to come back into session now. We're going to be discussing the final review of the license renewal application for Oyster Creek Generating Station and Otto Maynard will lead us through that. Thank you.

MEMBER MAYNARD: Thank you, Mr. Chairman. As many of you know, we've had two subcommittee meetings on this subject, one in fact last October. The other was January of this year. During those meetings, a number of questions have been asked, raised, answered, developed. We've had the benefit of looking at a lot of data. A lot of information has been provided to the ACRS members to review. Some of that has answered questions. Some of it generates questions and that's the purpose of this meeting.

We've also received input from the public and we've received some letters from the Congressional representatives from New Jersey. We've also received a letter, actually I think the Commissioners did, from the governor inviting us if we needed to to come to Oyster Creek for a meeting there and discuss information further. So getting a lot of interest.

We also have some people on the telephone

listening today. We need to make sure that everybody does speak up so the people on the phone can hear us. We'll do our best to keep that going.

The presentation today, we're going to be going over some of the material in the beginning just to bring everybody up to speed and I would caution the members. If there's something from clarity from the beginning of that on the history, that's fine. But we're going to be getting a number of the specific details of certain issues after the Licensee, the Applicant, has gone through some of those. So we'll keep an eye on that so we don't spend too much time on history that's already been gone over in some of the various meetings there.

After all of our discussion, there are two key areas that have still generated a lot of questions and interest. One is the continued leakage that is seen for refueling outage and stuff, although it's put in the drain capacity, I think there's still some interest in discussing that. The other gets into the analysis done for the containment shell, the drywell shell and the use of certain code cases, the applicability of that, and I understand we're going to have some good discussion on that as well as some other things. So there is a number of key issues that

are going to be addressed.

With that, I'd like to turn it over to Bob Schaff of the staff just to get us started with the staff and then I think turn it over to the Applicant.

MR. SCHAFF: Thank you, Mr. Maynard. My name is Bob Schaff. I'm the Acting Branch Chief for License Renewal Branch A in the Division of License Renewal. To my left is Pat Hiland who is the Director of NRR Division of Engineering. To his left is Louise Lund who is Acting Deputy Director for the Division of License Renewal. To my right is Donnie Ashley. He is the Project Manager for the review of AmerGen's application for the renewal of the Oyster Creek operating license. We also have a number of members of NRR's Technical Staff in the audience who are available to provide additional information and answer any questions that the Committee may have today.

As Mr. Maynard noted, several questions regarding the Oyster Creek drywell shell remain the following last license renewal subcommittee meeting held last month. Today's meeting will allow the Applicant and the NRC staff an opportunity to respond to those questions as part of their presentations.

With that, I'd like to turn the meeting over to Mike Gallagher, Vice President of Exelon's

license renewal group to begin the Applicant's presentation.

MR. GALLAGHER: Okay. Thank you, Bob. Good afternoon. My name is Mike Gallagher and I'm the Vice President of License Renewal Projects for AmerGen and Exelon. Also with me here today from our senior management team is Rich Lopriore, our Senior Vice President of MidAtlantic Operations and Mirshak Rame, our Senior Vice President for Engineering and Technical Services.

On January 18th, we presented to the subcommittee the details and basis for our overall conclusions on the Oyster Creek drywell corrosion issue and just to recap, our overall conclusions are the corrective actions to mitigate drywell shell corrosion have been effective; drywell shell corrosion has been arrested in the sand bed region and continues to be very low in the upper drywell elevations; and the service life of the drywell shell extends beyond 20.29 with margin. The corrosion on the embedded portion of the drywell shell is not significant due to the environment of embedded steel and concrete. The drywell shell meets code safety margins and we have an effective aging management program in place to ensure continued safe operation of Oyster Creek.

For today's presentation, we will provide a summary of the drywell shell corrosion issue. Can we go to the agenda? However, we can go into any level of detail that you desire.

We also will have discussed five issues that the subcommittee had from our last meeting and our proposed resolution and you mentioned two specifically, Mr. Maynard. We have those covered. We will also provide an overall summary of our license renewal application at the end of the meeting.

Our handouts today are we have the presentation. We have the reference material booklet which is the same reference material booklet we provided last time. It has the pictures and the detailed graphs of the entire drywell and we also are providing to you today this table which is a summary of all our drywell inspections and that's one of the five issues we want to talk to you about later in our presentation.

Also this week, I did send in a letter, Subcommittee Chair Maynard, with AmerGen's response to issues presented to the subcommittee during the public comments session of the subcommittee meeting just for your consideration.

Presenting for AmerGen today will be Fred

Polaski, John O'Rourke and Ahmed Ouaou from our License Renewal group. We also have with us here today Dr. Hardiyal Mehta from General Electric for our presentation on the capacity reduction factor which is in our buckling analysis and we also have Dr. Clarence Miller, the author of Code case N-284 which relates to the capacity reduction factor. And both Dr. Mehta and Dr. Miller will be making a presentation later on in our presentation.

I'll now turn the presentation over to Fred Polaski who will go through some background and then the drywell corrosion issue.

MEMBER MAYNARD: Before you, since you brought up your letter, I need to mention that at the beginning of the full Committee meeting this morning we acknowledged letters that we had received. But some of the people may not have been in the room at the time and in addition to your letter, we also received a letter from Mr. Webster and others mentioned earlier from Congressmen and the Governor. So there is other correspondence and I believe Mr. Webster also is going to be making comments at the end of the meeting today. So just to put that on the record, although it was stated this morning also.

Go ahead, Mr. Polaski.

CHAIRMAN SHACK: That was very helpful.

MR. POLASKI: The second issue that the subcommittee raised was that the thickness margin may be better understood with a modern three-dimensional finite element model with various thickness and thickness configurations in the sand bed region could be evaluated. And our response is that (1) our current licensing basis analysis demonstrated that the Code requirements were made and that's what we've just been discussing; (2)because the GE model used a uniform thickness corresponding to the lowest average thickness measured, we agree that use of a modern modeling technique inputting actual shell thicknesses should demonstrate more thickness margin and a larger safety factor; and lastly, in order to better understand the margin that is available for the Oyster Creek drywell shell, AmerGen will be performing a 3-D finite element analysis of the Oyster Creek drywell. This analysis will be completed prior to entering the period of extended operation.

MEMBER MAYNARD: Just to make sure I understand because I believe that Item 3 is a new commitment that we had not discussed or talked about.

MR. GALLAGHER: Yes, that's correct, Mr. Maynard, but we're trying to address the issues that

you all brought up and this is a new commitment. It is a significant commitment on our part and we will do that.

MEMBER MAYNARD: Okay. And I wanted to make sure that your position, you would be willing -- you would be making this as a commitment to be done, not just something that you're thinking about doing.

MR. GALLAGHER: That's correct and we will send in a letter with this commitment following the meeting.

MEMBER MAYNARD: Okay. I don't think any of the members would tell you not to do that.

(Laughter.)

MR. GALLAGHER: We didn't think so.

MR. POLASKI: Mr. John O'Rourke will now present the other three subcommittee issues, those being the issue with the reactor cavity liner leakage, future monitoring programs and the interior surface of the embedded drywell shell. John.

MR. O'ROURKE: The next issue from the January 18th subcommittee meeting was that the leakage through the reactor cavity liner should be eliminated. We agree that eliminating the liner leakage would be desirable. Our current program is designed to control this leakage to ensure that no water gets into the

sand bed region and it was proven successful during the 2006 refueling outage. However, based on the subcommittee's input, we have decided to perform an engineering study prior to the period of extended operation to investigate cost effective replacement or repair options to eliminate this leakage.

MEMBER MAYNARD: This one when I read this the first time, I was more excited than after the second time.

(Laughter.)

MEMBER MAYNARD: I see a commitment to do an engineering study, but the way I read this that's not necessarily a commitment to actually --

MR. SIEBER: Do anything.

MEMBER MAYNARD: -- do anything. Would you clarify that?

MR. GALLAGHER: I will clarify that. I mean our intent is to find a solution here. As we talked about last time to the subcommittee and Dr. Bonaca, this is a difficult repair situation. So we want to find a solution. We want to implement a solution and that's what this is about. Will we find a solution that's cost effective? I hope so and that's what we're trying to do.

MR. SIEBER: And right now, you're using

duct tape and paint, right?

MR. GALLAGHER: We're using strippable coating and metallic tape. That's correct.

MEMBER MAYNARD: I'll tell you. My issue is I understand that right now the leakage is within the capacity of the drain. However, the drain is there as a backup in case there's a failure of some components, some leakage, unexpected leakage or whatever. So by counting on that as part of normal operations, you've reduced your margin to any additional leakage or whatever.

The system, the design intent, is to not have any leakage and it is bothersome to still have some leakage and be willing to live with that. I know that you would like to fix it. I'm just not sure that -- We'll have to see how others feel about how strongly the stuff is here. I appreciate what you're doing here.

MR. GALLAGHER: We believe the feedback we did get from Dr. Bonaca was that cost effective could come into it. I do have our Senior VP here, Rich Lopriore, who he is behind this 100 percent and wants to make sure we find a solution.

MR. LOPRIORE: Yes. I'm not as tall as the other guy.

MR. GALLAGHER: This is Rich Lopriore, our Senior VP.

MR. LOPRIORE: I'm Rich Lopriore, the Senior VP from Mid Atlantic Operations. I am responsible for Oyster Creek in my area of responsibility. We agreed. We certainly want zero leakage and that is fundamentally what these studies are going to do.

But we want to make sure we know what is the right approach to this. I think at this point without studying this further, we don't know exactly what that is. It could be a membrane. It could be welding a new skin, but there are complications with all of that.

So it's not for not wanting to put investment into the plant. We clearly want to invest in the plant and we share the Committee's concern about wanting to achieve zero leakage. We will pursue that very vigorously and come up with the right answer. In the meantime, we do agree that we have a way to manage and by no means does that mean it's going to stop us from trying to get zero leakage.

MEMBER MAYNARD: I understand and I appreciate that and I can understand the difficulty in making a commitment doing something that you don't

know what the answer is. So I understand that, too.

MR. SIEBER: The problem is not as simple as it may first appear because of the stresses. You can't weld on that very well. This isn't the only one that leaks. That's exactly what we've said. This is not a unique problem. On the other hand --

CHAIRMAN SHACK: You've got to permit it after it's fixed.

MR. SIEBER: Yes.

MEMBER MAYNARD: It's a building where you're relying just one drain, too.

CHAIRMAN SHACK: That's the other thing. I was going to ask if anybody put a ball bearing on that lip up there just to see how well it rolls around. One drain?

MR. POLASKI: The design -- This is Fred Polaski. The design of that is about a two inch drop away from the side 180 degree away from the drain to the drain. The design, I can't guarantee that it's two inches, whatever the design was. So that built into the design.

MEMBER MAYNARD: And it should be higher on the side that doesn't have the drain.

(Laughter.)

CHAIRMAN SHACK: I hope it's better than

my gutters.

MR. SIEBER: Yes. In any event, I consider this a challenge to you and I'm interested in it. So I will follow what it is you do to solve the problem.

MR. GALLAGHER: Okay. We understand.

MEMBER ABDEL-KHALIK: Is that area of the damaged lip accessible?

MR. POLASKI: The area of the damaged lip when they did the repairs, they had to cut actually holes in the, I call it, the floor in the reactive cavity to gain access to that. It's not readily accessible. The way they do the visual is through four scope of fiber optics up through the drain line to see in that area. Difficult to get to.

MEMBER ABDEL-KHALIK: Have you considered increasing the height of that lip?

MR. GALLAGHER: We repaired the lip is what we did and as we said in this outage, we showed that all the leakage was controlled and not going into the sand bed region. So we think we have that lip fixed. This is really get back up -- You know, the feedback we got from you all was getting back up to stop it from getting there in the first place and that's what we're going to focus on in this study.

MEMBER ABDEL-KHALIK: Thank you.

MR. O'ROURKE: Moving on. Slide 33. The next subcommittee comment that I will address is the monitoring of the drywell shell thickness should be more aggressive in the short term. At the subcommittee meeting on January 18th, we did not adequately explain the breadth and frequency of our monitoring activities. We prepared a summary of these activities and provided them to the Committee as a handout and that's the 11" X 17" that I referred to earlier. I'll discuss the monitoring in detail using your handout and the next slide.

This slide summarizes the monitoring activities for the drywell shell beginning with the activities performed during the most recent outage through the period of extended operation. The table is divided up into four major areas. The first area contains the activities we used to verify that there is no water leakage into the sand bed region.

The second area identifies the upper drywell shell monitoring. As we had previously described to the ACRS subcommittee, the monitoring locations for Item 2 were established based on extensive examinations performed over several years. Once the monitoring locations were established,

Exhibit 25

January 17, 2007

Mr. Christopher M. Crane
President and CEO
AmerGen Energy Company, LLC
200 Exelon Way, KSA 3-E
Kennett Square, PA 19348

SUBJECT: OYSTER CREEK GENERATING STATION - NRC IN-SERVICE INSPECTION AND LICENSE RENEWAL COMMITMENT FOLLOWUP INSPECTION REPORT 05000219/2006013

Dear Mr. Crane:

On December 6, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Oyster Creek Generating Station. The inspection was a review of AmerGen's in-service inspections, including a followup inspection of your license renewal commitments relevant to the Fall 2006 outage related to the drywell shell and torus. The enclosed report documents the inspection results, which were discussed on November 16, 2006, and again on January 16, 2007, with Mr. T. Rausch, Senior Vice President, Oyster Creek, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. In addition, this inspection also examined the plant activities and documents that supported license renewal commitments of Oyster Creek Generating Station drywell shell and torus. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, no findings of significance were identified. Also, the NRC staff determined that there were no safety significant conditions with respect to the primary containment that would prohibit plant startup and there was reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle.

For the license renewal commitments reviewed during this inspection, the inspectors determined that AmerGen was adequately implementing those commitments. This inspection report does not provide an overall NRC conclusion about acceptability of programs for license renewal; final technical conclusions will be provided by the NRC Office of Nuclear Reactor Regulation.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web Site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Richard J. Conte, Chief
Engineering Branch 1
Division of Reactor Safety

Docket No. 50-219
License No. DPR-16

Enclosure: Inspection Report 05000219/2006013
w/Attachment: Supplemental Information

cc w/encl:
Chief Operating Officer, AmerGen
Site Vice President, Oyster Creek Nuclear Generating Station, AmerGen
Plant Manager, Oyster Creek Generating Station, AmerGen
Regulatory Assurance Manager, Oyster Creek, AmerGen
Senior Vice President - Nuclear Services, AmerGen
Vice President - Mid-Atlantic Operations, AmerGen
Vice President - Operations Support, AmerGen
Vice President - Licensing and Regulatory Affairs, AmerGen
Director Licensing, AmerGen
Manager Licensing - Oyster Creek, AmerGen
Vice President, General Counsel and Secretary, AmerGen
T. O'Neill, Associate General Counsel, Exelon Generation Company
J. Fewell, Assistant General Counsel, Exelon Nuclear
Correspondence Control Desk, AmerGen
J. Matthews, Esquire, Morgan, Lewis & Bockius LLP
Mayor of Lacey Township
K. Tosch, Chief, Bureau of Nuclear Engineering, NJ Dept of Environmental Protection
R. Shadis, New England Coalition Staff
N. Cohen, Coordinator - Unplug Salem Campaign
E. Gbur, Chairwoman - Jersey Shore Nuclear Watch
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance
P. Baldauf, Assistant Director, Radiation Protection and Release Prevention, State of NJ

SUMMARY OF FINDINGS

IR 05000219/2006013; 10/16/2006 - 12/6/2006, Oyster Creek Generating Station; In-service Inspection, including License Renewal Commitment Followup inspection activity.

This inspection of in-service inspection activities, including license renewal commitment followup activities, was performed by four regional office inspectors and one resident inspector. There were no safety significant conditions with respect to the primary containment that would prohibit plant startup and there is reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

No findings of significance were identified.

B. Licensee-Identified Violations

None.

Executive Summary

The NRC staff conducted a baseline inspection of in-service inspection (ISI) activities, as well as an extensive onsite review of AmerGen's actions to evaluate: (1) the structural integrity of the primary containment relative to the existing licensing basis in consideration of any actual or potential corrosion, and (2) the significance of water that was identified in two trenches located inside the drywell during the October 2006 outage at the Oyster Creek Nuclear Generating Station (OCNGS). The NRC review involved a multi-week inspection of AmerGen's ISI program, and included an assessment of license renewal commitments for the outage and AmerGen's technical evaluation and structural integrity reports associated with the design basis for the primary containment (drywell). In accordance with the NRC's agreement with the State of New Jersey, state engineers observed portions of the NRC's staff review. Based on the results of the NRC's inspection activities, the NRC concluded that: (1) ISI activities were adequately performed, (2) there were no safety significant conditions with respect to the primary containment that would prohibit plant startup, and (3) there is reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle. The following provided additional background and details pertaining to the primary containment.

In the mid-1980s, GPU Nuclear (as licensee) identified corrosion of the shell of the OCNGS containment drywell in the sandbed region. Initial licensee actions were not effective in arresting corrosion, and in 1992, all sand was removed from the sandbed region and the accessible exterior surfaces of the drywell shell were cleaned and coated with an epoxy paint. Ultrasonic test (UT) measurements of the drywell shell thickness were taken in 1992 and 1996. UT results indicated that the corrosion had been effectively arrested.

On October 16, 2006, OCNGS shut down for a refueling and maintenance outage. Scheduled outage work included expanded in-service inspection of the drywell shell thickness (through UT testing) and material condition of accessible internal and external portions of the drywell (via visual testing).

During the Fall 2006 outage, AmerGen Energy, LLC (the current licensee) obtained UT measurements of drywell shell thickness at many of the same locations as previously examined in the 1990s. UT measurements were taken in the former sandbed region, both inside and outside the drywell, and in two trenches cut into the concrete floor in two bays inside the drywell. These trenches permit access to the embedded portion of the drywell shell below the sandbed region. In addition, UT measurements were taken at various levels of the drywell shell from the inside (the upper drywell shell is not accessible in these areas from the outside due to the concrete shield building).

The NRC staff inspection throughout the outage focused on:

1) Non-destructive examination results of the drywell shell and torus and related AmerGen evaluations.
2) AmerGen's efforts to identify and mitigate the source of water which accumulated in the trenches in the concrete floor inside the drywell. These efforts included tracer dye testing of the drywell leakage collection trough inside the reactor pedestal, inspection of the drywell sump, inspection and repair of the leakage collection trough, and caulking of the joint between the concrete drywell floor and the steel drywell shell.
3) Structural integrity of the concrete drywell floor and the condition of the embedded portion of the drywell shell.
4) The potential impact from various repairs to the containment on the design and licensing bases of the drywell.

The overall results of the staff's observations and review were:

1) All UT results were greater than the AmerGen calculated minimum ASME code required thickness for various plates that form the drywell shell.
2) There were no adverse conditions associated with the epoxy coating on the outside of the drywell shell in the former sandbed region.
3) Repairs performed by Amergen in and around the trough within the reactor vessel pedestal area did not result in any adverse conditions.
4) The water discovered in the drywell trenches had no adverse impact on the structural integrity of the concrete floor or the potential for corrosion of the embedded portion of the drywell shell. AmerGen has taken actions to prevent further accumulation of water in this area.
5) There were no adverse conditions with respect to the drywell or torus structural integrity that would preclude restart.

Based on a review of the technical information, the NRC staff determined that AmerGen had sufficient justification to restart OCNGS.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R08 In-service Inspection Activities (71111.08G - 1 Sample)

a. Inspection Scope

The inspectors observed non-destructive examination (NDE) activities and reviewed documentation of NDE and repair activities. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation could result in a significant increase in the risk of core damage. The direct observations and documentation reviews were performed to verify that NDE activities were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1995 Edition, with the 1996 Addenda, 10CFR 50.55a, Codes and Standards, Boiling Water Reactor Vessel Internals Program recommendations, and station implementing procedures. The inspectors reviewed a sample of NDE reports initiated to document the performance and record results of in-service inspection (ISI) examinations completed during the current refueling outage 1R21 as well as those since the last refueling outage 1R20. The inspectors also evaluated the licensee's effectiveness in resolving relevant indications identified during ISI activities. Documents reviewed for this inspection are listed in the attachment.

The inspectors reviewed several NDE examinations, including liquid penetrant (PT), UT, and radiographic (RT) examination data records, to verify the effectiveness of the licensee's program for monitoring degradation of risk-significant piping structures, systems, and components. The inspectors examined the licensee's evaluation and disposition for continued operation, without repair or rework, of non-conforming conditions identified during ISI activities by review of AR 547617 and General Electric INR 01R21 IVVI-06-08, which documented some indications during IVVI examinations on the inside diameter surface of core shroud vertical weld SHD V-09. The indications are horizontal (transverse to the SHD V-09 weld). These indications had previously been identified and documented in 1996. Measurements were taken to evaluate the condition observed this outage (1R21) to those identified in 1996. The inspector verified that the licensee comparison of the indications found during 2006 correlated closely with the indications identified and documented in 1996. The indications meet the requirement of the program.

The inspectors reviewed one ASME Section XI code repair and its associated NDE from the 1R21 refueling cycle. Specifically, the inspectors reviewed the NDE associated with the welding repair activities performed per work order C2013778 on 3-inch control rod drive return line weld NC-2-2, which is a ferritic steel to austenitic steel joint with austenitic weld material. This categorizes the weld as a dissimilar metal weld. The weld is located between valve V-15-28 and V-15-29 inside the drywell. AmerGen selected

this weld for UT examination to support license renewal. The inspectors reviewed initial UT data examination report number 1R21-217, data sheet number D-218 of weld NC-2-2, which documented a recordable axial indication during a 45° RL scan in the circumferential direction during the current 1R21 refueling outage. The indication started adjacent to the root on the ferritic side of the weld and had an estimated through-wall height of 50 percent. The inspectors verified that AmerGen implemented corrective actions to replace a section of the piping between the two valves and sent the pipe section with the weld flaw indication for failure analysis to determine the failure mechanism. After the section of piping was replaced and repairs completed, the inspectors reviewed the liquid penetrant examination and radiographic records of the new welds NC-2-2A and NC-2-2B. This review was performed to verify that the activities associated with welding on ASME Class I or II components were in accordance with applicable ASME code requirements.

The inspectors performed direct field observations of UT examination of "B" Isolation Condenser 12-inch pipe welds NE-1-220 and NE-1-221 per work order C2012158, UT examination of N8 closure head nozzle reactor head vent to shell NR02 5-576 weld per work order C2012402, documented in UT examination report number 1R21-166, sheet D-107 and PT examination of N8 nozzle to flange reactor head NR02 6-576 weld, documented in examination report number 1R21-163, sheet PT-004. The review was performed to evaluate examiner skills and performance; examination technique; assess contractor oversight activities; and to verify licensee and contractor ability to identify and characterize observed indications.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Other - License Renewal Commitment Followup (71003)

.1 License Renewal Commitment Followup Inspections

a. Inspection Scope

The license renewal portion of this inspection was performed in accordance with the guidance in IP 71003, which is a part of the NRC Inspection Manual Chapter 2516, License Renewal Program. The inspectors verified that the license renewal commitments contained in AmerGen Letters 2130-06-20284 (4/4/06), 2130-06-20358 (7/7/06) and 2130-06-20414 (10/20/06) were met. All of the commitments dealt with inspections and actions necessary to ensure structural integrity of the primary containment (drywell and torus) at Oyster Creek.

The following commitments were verified to be completed during the October 2006 1R21 refueling outage:

(1) Visual inspection of the epoxy coating on the exterior of the drywell in the former sandbed region.
(2) UT thickness measurements (internal and external) of the drywell shell in the sandbed region.
(3) The application of a strippable coating to the reactor cavity liner before beginning refueling operations during the October 2006 1R21 refueling outage.
(4) The reactor cavity seal drains and the drywell sand bed region drains were monitored for water leakage during the October 2006 1R21 refueling outage.
(5) Visual inspection of the drywell shell in the access trenches. Upon noting water in the trenches, AmerGen completed a technical evaluation of the unexpected condition. AmerGen determined that structural integrity was not affected by the presence of this water.
(6) Visual inspection of the coating on the inside of the torus. A number of shallow pits were noted in the metal and many were repaired in accordance with plant specifications and repair procedures.
(7) Conducted UT thickness measurements at the 23'6" and 71'6" elevations of the drywell at the same locations which had been previously measured.

The inspectors completed confined space training and sandbed bay mock-up training in preparation for observing the licensee's inspections in the drywell shell sandbed bays (Bays 1, 11, and 13). Additionally, the inspectors reviewed inspection data sheets and video records of the inspections of all 10 sandbed bays. The inspectors verified that the sandbed bay external conditions were accurately described and measured on the AmerGen data sheets in the context of the Aging Management Program for the drywell and torus (see below ASME, Section XI, Subsection IWE and Protective Coating Monitoring and Maintenance).

ASME, Section XI, Subsection IWE Program

Monitoring of the condition of the primary containment drywell is accomplished through the licensee's ASME Section XI, Subsection IWE monitoring program. Additionally, if the plant obtains a renewed license, the Aging Management Program (AMP) for the primary containment drywell and torus will use the same program.

The ASME, Section XI, Subsection IWE Program is an existing program modified for the purpose of managing the aging effects in the drywell containment system at Oyster Creek. ASME Section XI, Subsection IWE provides for inspection of primary containment components, including steel containment shells. The aging effects are managed by periodic visual inspections and periodic ultrasonic testing wall thickness measurements. Additionally, AmerGen will conduct monitoring of leakage from the drywell sand bed region drains as an additional method to detect conditions which indicate further corrosion may occur. Analysis and evaluation of the visual and ultrasonic examinations are given credit for managing the effects of aging.

The inspectors reviewed supporting documentation and interviewed AmerGen personnel to confirm the adequacy of the license renewal conclusions of this program.

The inspectors reviewed the licensee's UT inspection procedures, interviewed NDE supervisors and observed field collection and recording of UT data in accordance with the approved procedures. The inspectors also reviewed the UT qualifications of selected data collection technicians.

Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program is an existing program credited with managing the aging effects on the internal and external surfaces of the torus and the condition of the drywell in the sandbed region. The aging effects are managed by visual inspections of the protective coatings on each component, and examination, evaluation and repair of all coating defects observed.

The inspectors reviewed supporting documentation and interviewed applicant personnel to confirm the adequacy of the license renewal conclusions from the visual inspections conducted in the drywell and torus.

The inspectors reviewed the licensee's VT inspection procedures, interviewed NDE supervisors and observed field collection and recording of VT data in accordance with the approved procedures. The inspectors also reviewed the VT qualifications of selected data collection technicians.

The inspectors reviewed the VT inspection data sheets for the drywell shell and torus inspections conducted during the October 2006, 1R21 refueling outage. The inspectors reviewed the VT inspection data sheets for the torus internal coating inspections conducted during the October 2006, 1R21 refueling outage. The inspectors verified that the VT results for the drywell sandbed regions indicated no degradation of the epoxy coating.

The inspectors reviewed documented evidence that strippable coating of the refueling channel had been applied during October 2006 1R21 refueling outage. This strippable coating is used as a measure to limit or prevent water leakage during refueling operations.

Structural Review

During the planned structural review, AmerGen removed the temporary grout in the trenches inside the drywell which were previously dug out to expose the shell in the sandbed region. The structural review was expanded when water was unexpectedly discovered in the trenches. Accordingly, the inspectors monitored licensee actions and reviewed drawings, visually examined the condition of concrete in the drywell floor slab, and reviewed chemical analysis of the water sampled from one of the trenches. The inspectors reviewed the 50.59 screen associated with repairs to the drywell floor, trough, and curb (interface between the concrete floor slab and the drywell shell) and performed a walkdown of the drywell to ensure that the repairs were made in accordance with written instructions. The inspectors attended the Station Onsite Review Committee meeting on November 4, 2006, that discussed AmerGen's technical evaluation of the

drywell issue. The inspectors performed inspections of the water collection bottles associated with the sandbed drains on October 19, 23, 27, and November 1, 2006, to ensure no water was being detected.

b. Findings and Observations

No findings of significance were identified.

Observations

The inspectors noted that AmerGen commitments for the drywell and torus were met; a more detailed listing of observations (factual details) are noted below. With respect to the water in the trenches, the most likely source was found and conditions inside the drywell as a result of the issue were appropriately evaluated by AmerGen (additional factual details are noted in Commitment No. (5) below). Overall, the team determined that there were no safety significant conditions with respect to the primary containment that would prohibit plant startup and that there is reasonable assurance that the primary containment is capable of performing its design function throughout the upcoming operating cycle.

Also, during this inspection, the inspectors noted improvement in AmerGen's procedure controls governing VT and UT inspections and data analysis. The documentation of inspection results, the presence of acceptance criteria, and the disposition and analysis of the data were significantly improved over past inspections.

Commitments (1), (2) and (7) (Commitment numbers related to the listing at the start of this report section)

The inspectors reviewed the UT wall thickness data sheets for the drywell shell from 1R21 refueling outage which documented shell thickness measurements. The UT results indicate that the shell thickness was accurately reported by the licensee. The inspection procedures contained appropriate criteria for reporting nonconforming conditions and that all nonconforming data were reported and evaluated by cognizant engineering personnel. AmerGen subsequently verified that design minimum wall thicknesses, required for pressure loads and for buckling loads, remain valid until the next refueling outage in 2008.

The inspectors noted that coating inspections performed on the outside surface of the drywell shell during 1R21 in 2006 did not identify any blistering or degradation of the coating. The inspectors determined that AmerGen will perform an inspection of the drywell shell during the 1R22 Oyster Creek refueling outage scheduled for 2008 based on review of AmerGen letter 2103-06-20426, dated December 3, 2006.

The AmerGen aging management program, which includes both the ASME Section XI, Subsection IWE program and the Protective Coatings Monitoring and Maintenance, will address structural integrity beyond 2008, subject to NRC staff safety evaluation review.

Commitment (3)

The inspectors reviewed documented evidence that strippable coating of the refueling channel had been applied during October 2006 1R21 refueling outage.

Commitment (4)

The inspectors reviewed the licensee's procedure for inspections of the sandbed drains and the reactor cavity seal drains. The inspectors also reviewed and verified records which showed that the licensee inspected the sandbed drains and the reactor cavity seal drains throughout the outage. The inspectors also performed independent inspections of the water collection bottles associated with the sandbed drains on October 19, 23, 27, and November 1, 2006, to ensure no water was being detected.

Commitment (5)

Presence of Water in the Drywell Concrete Slab

Water was discovered in the drywell trenches of bay 5 and bay 17 after removal of the grout by AmerGen during the current 1R21 refueling outage. The grout was being removed in order to perform a license renewal commitment inspection. The presence of the water was not expected by AmerGen. The condition was entered in the corrective action process and AmerGen carried out the following actions:

(1) Conducted walkdowns of the structure and examined drawings to determine the source of the water. The actual source of the water was not positively determined.
(2) Sampled the water and performed dye tracer testing to determine the source of the water.
(3) Removed the water from the trenches and conducted the planned UT thickness measurements of the drywell shell in the trenches.
(4) Conducted technical engineering evaluations by an industry corrosion expert and AmerGen engineering personnel to assess the structural integrity of the drywell concrete slab given the presence of the water.
(5) Installed a seal between the concrete curb and the drywell shell to prevent water from entering the drywell shell-to-concrete gap.
(6) Made a repair to the drywell trough drain, which eliminated leakage path into the concrete/drywell liner gap.
(7) Removed an additional 5" of concrete from the trench in Bay 5 and collected more UT thickness data in a previously unmeasured area.
(8) Performed and documented a VT inspection of the drywell shell in the trenches.

Clearing of the trough drain and repair of the trough routed some leakage away from the drywell shell. AmerGen's root cause evaluation did not determine the exact source of the water in the drywell trenches. Operational leakage via the unsealed concrete to drywell shell interface or control rod drive leakage could not be ruled out. AmerGen had a technically justifiable logic as to why the major source of the water was the trough with

concrete flaws, but the associated technical evaluation lacked details with respect to the basis and elimination of other potential sources of water.

Drywell Concrete Floor

The inspectors observed that the condition of the concrete outside the reactor pedestal was in good condition, there was no obvious indication of concrete deterioration, e.g., disintegration, spalling, chipping and/or erosion.

The floor within the reactor pedestal annulus is overlaid by approximately 7-inch thick wearing surface to provide a crown for drainage towards the drainage trough around the pedestal. This wearing slab is textured with exposed rounded gravel which is generally used to protect surfaces from damaging effects of long time/sustained drip and/or flow of any liquid/water on structural surfaces. There was a visible crack in this overlay that appeared to extend the full depth of the overlay; however, the crack did not appear to be active, and was filled with fine granular material. Such loose, fine materials are not uncommon and/or unusual in textured finish surfaces. Also, the overlay is not reinforced, and does not have any structural significance.

Based on observation of the concrete floor, the structural integrity of the concrete is not impaired or negatively affected by the construction joint in the concrete overlay inside the pedestal annulus.

During cleaning of the troughs, a glass bottle was found imbedded in the side of the trough near the drywell sump pumps. The object was removed in pieces from the concrete. There appeared to be a leakage path from where the bottle was removed. Based on NRC staff review, the effect of this small void on the strength, durability, and functionality of slab is negligible.

Drywell Steel Shell Corrosion

The drywell steel shell is embedded between the structural reinforced concrete base and the drywell floor, which also is reinforced structural concrete. Therefore, the service environment of the steel liner is similar to embedded rebar or any other carbon steel embedment.

There is sufficient technical literature and public domain studies available to support a conclusion that carbon steel embedded in highly alkaline material does not corrode in general service, unless the alkaline environment is radically altered and a sustained acidic environment is created. Availability of chloride ions also affects and accelerates corrosion.

With available information, it appears that the drywell shell is not in a corrosive environment, thus active corrosion is unlikely. The most likely source of water inside the drywell during operation is condensate water, which does not contain corrosive materials.

Overall, the inspection team did not disagree with AmerGen's conclusion and reasons that no significant corrosion of the embedded drywell shell was evident or anticipated:

(1) The water in contact with the drywell shell had a high pH as a result of being in contact with the adjacent concrete.
(2) Water entering the slab-to-shell area will have to migrate through concrete and will also become high pH water; corrosion is minimal in high pH conditions.
(3) Any exposure of the drywell to an oxygen-rich environment will be limited due to containment inerting with nitrogen during operations.

Commitment (6)

The VT inspection procedures contained appropriate criteria for reporting nonconforming conditions and for dispositioning nonconforming conditions. The VT results for the torus internal coating indicate continuing degradation of the coating. Of the 959 coating blisters identified by AmerGen, they repaired 881 coating blisters that exceeded the administrative repair criteria and the others were evaluated as satisfactory. AmerGen then conducted a structural integrity verification calculation of the observed conditions, which demonstrated structural integrity until the next refueling outage in 2008. The AmerGen aging management program will address structural integrity beyond 2008, subject to NRC staff safety evaluation review.

4OA2 Other - Identification and Resolution of Problems

.2 Identification and Resolution of Problems - In-service Inspection and License Renewal Commitment Followup (71111.08 & 71003)

a. Inspection Scope

The inspectors reviewed the Issue Reports listed in Attachment 1 associated with ISI, including license renewal commitment followup inspection activities. The inspectors verified that problems identified by these documents were properly characterized in AmerGen's corrective action reporting system, and that applicable causes and corrective actions were identified commensurate with the safety significance of the in-service inspection deficiency.

b. Findings

No findings of significance were identified.

Observations

During the inspectors' review of Issue Reports (IRs) written during this inspection, the inspectors noted that, on several occasions, inspectors questioned AmerGen personnel on the need to enter specific conditions in the AmerGen corrective action process. Subsequently, all important conditions were entered into the corrective action process.

Also, the inspectors provided several technical comments and corrections on the draft technical evaluations AR A2152754-06 and AR A2152754-09, which evaluated the unexpected water in the drywell trenches. As a result of these comments provided by the inspector, AmerGen made substantive changes to the evaluations. This indicated some missed opportunities for AmerGen supervisory review to impart attention to detail.

The inspectors noted that the presence of water in the bay 5 and bay 17 trenches inside the drywell had been reported in Structural Inspection Reports in 1992 and 1994. The Structural Inspection Report from 1994 (dated January 3, 1995) indicates that the rectification of the situation will require prevention of water from reaching the trenches with proven material(s). However, this condition and the evaluation were not addressed by the corrective action process in effect at the time. More importantly, during the October 2006 1R21 refueling outage, the issue was entered into the IR process using the current standards for timeliness of identification. The AmerGen resultant evaluation in 2006 determined no significant effect on primary containment.

Further, AmerGen review of inspection results performed during the October 2006 refueling outage of the internal surface of the drywell shell caused a re-evaluation of the license renewal application with respect to water in the trenches excavated in the concrete floor. AmerGen determined that an environment/material/aging effect combination exists that had not been previously included in the Oyster Creek license renewal application. AmerGen's letter to the NRC (2103-06-20426), dated December 3, 2006, addresses this issue along with the results of an extent-of-condition review. Also, AmerGen has identified additional aging management activities that will be included in the aging management programs associated with the drywell. This additional information provided by AmerGen is being reviewed by the NRC Office of Nuclear Reactor Regulation staff similar to additional information provided by applicants when the NRC staff issues requests for additional information, that is, subject to review in a final safety evaluation report.

4OA6 Meetings, including Exit

The inspectors met with Mr. T. Rausch, Oyster Creek Generating Station Vice President and other members of the licensee's staff at the conclusion of the onsite inspection on November 16, 2006, and again on January 16, 2007, to summarize the inspection results. The end of the inspection was extended to December 6, 2006, to include a review of AmerGen's letter to the NRC (203-06-20426), dated December 3, 2006. Proprietary information was provided to the inspectors during this inspection, but licensee representatives indicated that it may be released.

Exhibit 26

From: Dunsmuir, Steven P <Steven.Dunsmuir@exeloncorp.com>
Sent: Sunday, October 22, 2006 4:52 AM
To: Ray, Howie <u001fhr@ucm.com>; Krejsa, John <u999j5k@ucm.com>; O'Rourke, John F. <t925jfo@ucm.com>
Subject: Trench prep, test, and 1-8 sump report.

10/21/06
Preparing Drywell liner surface for UT thickness reading.
5 (under ladder)
Surface had traces of a red primer and gray sealant layer. Bare metal had a light oxide layer and areas of light to moderate pitting. 80 grit "tiger paw" discs and angle grinder were used to remove paint and oxide layers. In areas of pitting no attempt was made to clean out or "chase the pits". Areas were left in a condition suitable for UT testing.

17D
Upper surface near "plug weld" was prepared to white metal prior to our arrival.
Under this area is the area we were tasked to prep. The first foot or so had a simple grey epoxy type paint coating and seam to be relatively fresh. This area was cleaned to white metal in less than five minutes. Below this area was a baked on two layer coating. This section was very tough to clean and took over one hour to prep.

Photographed prepped area .
K:\Drywell\1R21 Drywell Pictures\DW 13 ft Core Bore Preps
Prep time approx 3:15 and 80 mr per worker.

10/22/06
HEPA Vacuum test

Entered drywell to continue HEPA Vacuum timed test.
Found test was invalid HEPA unit top was not placed back on unit properly. Vacuum was not functioning. Measured level in vacuum tank at 2 5/8" emptied vacuum tank.

Water level in test trench (core bore) was 18 ½ measured from top surface of the concrete. Over a 40 min period there was no change in this level.

Placed top back on empty vacuum unit. Place hose back in trench restarted vacuum and stopwatch also marked time with phone system time at 10:56 pm

Trough Levels:
Marked 4 test points around trench A, B, C, D clockwise from door way with C being to the left of 1-8 sump. A Dry, B 1/16", C ½", D Dry.

Dose 22mr

Test 2
Entered Drywell Checked Trench (core bore) Dry and Vacuum still running.
Shutdown vacuum and stop watch 3:23:13. Measured water in vacuum tank 1 ¼"
After 15 min checked trench level was at 20" a thumb sized puddle of approx 2 or 3 oz.

Restarted vacuum and stopwatch, vacuum tank was NOT emptied.
1-8 Sump level was measured @ 13" deep.

Trough levels:
A Dry, B 1/16, C 2", D 1/16

Photos of feeder holes to the 1-8 sump are at:
K:\Drywell\1R21 Drywell Pictures\1R21 DW 1-8 Sump
In the photos you can see the holes thru the trough into 1-8 sump. What appears to be gaps between concrete and drain to sump can be seen.

Point of interest:
In the trough to the very right of data point C (to the left of the sump) a area of loose aggregate was noticed. When probed with the ruler, the loose material is about 2" deep. I tested the right side of the sump and found a matching hole / pit. This could be from original construction chipped out and not refilled when fitting the sump liner.

Dose 20 mr

Vacuum information:
Minuteman 85 Model 801085 Serial # W8010850829 Rad con # V-29 inside diameter
15 3/8"

Steve Dunsmuir
FIN/Operations RO

Exhibit 27

From: Quintenz, Tom <u777teq@ucm.com>
Sent: Wednesday, February 1, 2006 5:02 PM
To: Muggleston, Kevin <u999kpm@ucm.com>; Beck, George <u998g0b@ucm.com>
Cc: Polaski, Frederick W <u000fwp@ucm.com>; Warfel Sr, Donald B <u001dbw@ucm.com>; Fuhrer, Edwin C <n5917@ucm.com>; Miller, Mark A. - PE <u001mam@ucm.com>
Subject: RE: RAI regarding corrosion of carbon steel mechanical components in containment atmosphere

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At this time the monitoring and limits for Oxygen are dictated by Technical Specifications, and Operating Procedures. Technical Specifications would limit Oxygen Levels to less than 5%.

-----Original Message-----
From: Muggleston, Kevin
Sent: Tuesday, January 31, 2006 4:35 PM
To: Beck, George
Cc: Polaski, Frederick W; Warfel Sr, Donald B; Quintenz, Tom; Fuhrer, Edwin C; Miller, Mark A. -PE
Subject: RAI regarding corrosion of carbon steel mechanical components in containment atmosphere

Action Required: Yes
Recommendation: Meeting prior to NRC call

Draft RAI D-RAI 3.4-4 challenges our position regarding corrosion of carbon steel surfaces of mechanical components inside containment subject to the inert environment. The staff acknowledges the cited past precedence, but requests additional justification, such as "monitored data from the Oyster Creek containment nitrogen environment to indicate that the free oxygen levels have been continuously maintained below threshold levels and would continue to be maintained during the period of extended operation." I am not aware of any "threshold levels" for oxidation. NRC is requesting additional justification, or a commitment for a one-time inspection.

Ed Fuhrer has identified several instances of carbon steel-surface corrosion in the RBCCW system inside containment. It may be appropriate to respond based on OE, and offer a one-time inspection of RBCCW system components.

In any event, we need to discuss as a group before the NRC call, as I need direction on how we want to respond to this question.

Exhibit 28

GPU Nuclear

Technical Data Report

TDR No. 1011		Revision No. 0
	Budget Activity No. ________	Page 1 of 18
Project: OYSTER CREEK	Department/Section E&D/Mechanical Systems	
	Revision Date ____________	

Document Title: EVALUATION OF FEBRUARY 1990 DRYWELL UT EXAMINATION DATA

Originator Signature	Date	Approval(s) Signature	Date
Peter Tamburro	3/8/90	Fred P. Barbieri	4-18-90
		Approval for External Distribution	Date

Does this TDR include recommendation(s)? X Yes ___No If yes, TFWR/TR# ____ see next page

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Summary and Purpose

The purpose of this report is to document the preliminary evaluation of the February 1990 Drywell UT Examination Data as well as document the possible reasons for why corrosion has not significantly abated.

Results of UT examination data obtained February 9, 1990 indicated that some locations of the drywell vessel may be experiencing corrosion rates greater than recently projected.

Conclusions

Although a more detailed review is currently underway (to be documented by revision to References 7.6 and 7.8), this report is intended to document preliminary analysis which determined that the drywell would be serviceable up to the 13R outage.

Based on a preliminary analysis of the February, 1990 data, this evaluation projects the most limiting drywell vessel region to be Bay 5 at the 51 foot elevation. The most conservative rates project that this area will not reach minimum thickness until the 13R outage scheduled in January 1991.

(For Additional Space Use Side 2)

This is a report of work conducted by an individual(s) for use by GPU Nuclear Corporation. Neither GPU Nuclear Corporation nor the authors of the report warrant that the report is complete or accurate. Nothing contained in the report establishes company policy or constitutes a commitment by GPU Nuclear Corporation.

* Abstract Only

Recommendations:

1. SE 000243-002 Rev. 3 needs to be revised to indicate the new corrosion rates and projections.

2. The use of actual material properties (CMTR) should be pursued for the 50'2" elevation.

3. The drywell design pressure of the drywell should be lowered.

4. Operation of the Cathodic Protection system needs to be verified and corrected as necessary.

5. Means of abating-corrosion at the upper drywell elevations must be evaluated.

NOTE: All recommendations are being performed through ongoing activities.

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Background Information

GPUN has established a drywell corrosion abatement and monitoring program. (References 7.1, 7.2, 7.3, 7.4, 7.5, 7.6 and 7.7.) This program includes: the installation and operation of the cathodic protection system in the sand bed region (3/89); reduction of water inleakage sources (10-12/88), mechanical agitating and draining water from the sand bed region (10-11/88), monitoring the most limiting areas (ongoing), and continued analysis of the situation (ongoing).

The most limiting areas are listed in the table below:

PRIORITY	UT INSPECTION ELEVATION	AREA
1	11'-3"	Eleven 6" x 6" grids in Bays 9, 11, 13, 15, 17, 19 and frame 17/19
1	50'-2"	One 6" x 6" grid above Bays 5
2	87'-5"	Three 6" x 6" grid above Bays 11 & 15
2	11'-3"	Eight strips (1" x 6" reading 1" apart) in Bays 1, 3, 5, 7, 9, 13

Priority 1 areas are inspected at each outage of opportunity but not more frequently than once every three (3) months. Priority 2 areas are inspected in an outage of opportunity if the previous set of data was taken eighteen months (18) or more before the outage.

Review of UT data up to October 1988 (References 7.6 and 7.7) indicated that the most limiting area (sand bed bay 17D) would not corrode below the minimum thickness before June of 1992. The installation of cathodic protection and sand bed draining were intended to significantly abate corrosion and allow extension of the projected date. Interim data taken in September 1989 indicated that corrosion rates in the sand bed regions had been reduced. On February 9, 1990 UT examinations were performed on all Priority 1 locations. Results from this data suggests corrosion rates in some areas may be greater than projected in October 1988 and September 1989. This report documents the assumptions, methods, results of the preliminary analysis, and engineering judgement used to evaluate the corrosion rates in each region.

2.0 METHODOLOGY

In order to understand the results from the February 1990 data the following were evaluated and reviewed:

2.1 A preliminary review of the data was performed to determine the data's validity and calculate new conservative corrosion rates.

2.2 A review of the UT measuring device was performed, in addition to a review of the physical application of the device in the field.

2.3 A review of GPUN's understanding of the perceived corrosion mechanism was performed.

2.4 A review of the Cathodic Protection System operation since installation was conducted to identify any operational changes which may have affected the corrosion mechanism in the sand bed region. As part of this effort, a meeting was held with a cathodic protection expert, Mr. Ian Munroe of Corrosion Services, who designed the present system at OC.

2.5 A review of the existing Safety Evaluation (Reference 7.7) which justified continued operation through June 1992 was performed to determine if the conclusions of the SE were still valid.

3.0 RESULTS

3.1 Results of February 1990 UT Examination

Although the February 1990 UT examination data is not completely understood, the data seems to be valid. To ensure a completely thorough and conservative approach, this data was used in establishing new corrosion rates.

3.1.1 Mean Thickness Values

Each priority 1 inspection location consists of an 6" x 6" area. Measurements were made using the template with 49 holes (7 x 7) laid out on a 6" x 6" grid with 1" between centers.

A mean of all points in each grid was calculated. This approach is consistent with earlier mean thicknesses calculations as is documented in Reference 7.5.

Table 1 presents the calculated mean thickness values derived from February 1990 and October 1988 examinations.

TABLE #1

Area	Bay	Mean Thickness as of 10/88 (mils)	Mean Thickness as of 2/90 (mils)	Difference (mils)
Protected Sand Bed Regions	11A	908.6	880.4	-28.2
	11C Top 3	916.6	978.4	-
	Bottom 4		869.0	-
	17D	864.8	839.1	-25.7
	19A	837.9	807.8	-30.1
	19B	856.5	840.7	-15.8
	19C	860.9	830.5	-30.4
	17/19 Frame	981.7	994.4	-
Unprotected Sand Bed Region	9D	1021.4	1010.0	-11.4
	13A	905.3	859.0	-46.3
	15D	1056.0	1057.3	-
	17A Top 3	957.4	1120.2	-
	Bottom 4		937.5	-
50'2" Elevation	5	750.0	739.6	-10.4

Note: After October 1988, Bays 11C and 17A were split into two regions (the top three rows and bottom four rows). This is because these bays showed regions which were corroding at different rates. The February 1990 data show these differences while the October 1988 data presents a mean for the entire grid.

TABLE 2 - ESTIMATED CORROSION RATES - SAND BED REGION

BAY	(1) CORROSION RATE UP TO 10/88 (MPY)	(2) CORROSION RATE FROM 6/89-2/90 (POST CP & H20 DRAIN) (MPY)	(3) CORROSION RATE FROM 10/88 - (2/90 PRE-CP & POST H20 DRAIN) (MPY)	(4) CORROSION RATE TO 2/90 ALL DATA (MPY)	(5) FEB. 1990 THICKNESS (MILS)	(6) REQ. MIN. THICK. (MILS)	(7) DATE WHICH MINIMUM THICK IS REACHED (COL. 2)	(8) DATE WHICH MINIMUM THICK IS REACHED (COL. 3)	(9) DATE WHICH MINIMUM THICK IS REACHED (COL.4)
11A	NOT SIGNIFICANT	-5.0 ±19.5 (128.1)	-4.1 ±6.3 (-22.5)	(3) -12.4 ±3.0 (-18.1)	880.4±	700	5/91	6/97	3/99
11C TOP 3	INDETERMINABLE	(3) -62.0 ±3.8 (-86.4)	-20.3 ±15.2 (-64.7)	(3) -35.0 ±8.5 (-51.5)	978.4±	700	1/93	1/94	1/95
11C BOTTOM 4	INDETERMINABLE	-18.3 ±30.4 (-210.2)	-13.4 ±10.0 (-42.6)	(3) -22.1 ±5.3 (-32.4)	869.0±	700	10-11/90	9/93	11/94
17D (2)	(3) -27.6 ±6.1 (-41.)	-27.8 ±6.6 (-69.5)	-17.7 ±4.3 (-30.25)	(3) -24.0 ±2.4 (-28.5)	839.1±	700	12/91	4/94	7/94
19A	(3) -23.7 ±4.3 (-32.9)	-35.7 ±7.0 (-79.9)	(3) -20.7 ±5.96 (-38.1)	(3) -21.8 ±1.8 (-25.2)	807.8±	700	5/91	9/92	1/94
19B	(3) -29.2 ±0.5 (-30.4)	-21.6 +11.7 (-95.5)	-10.2 ±5.6 (-26.6)	(3) -19.6 ±2.1 (-23.7)	840.7±	700	6/91	12/95	7/95
19C	(3) -25.9 ±4.1 (-35.5)	-25.3 ±8.6 (-79.6)	(3) -18.4 ±3.8 (-29.5)	(3) -23.9 ±1.5 (-26.8)	830.5±	700	8/91	2/94	7/94
17/19	INDETERMINABLE	(3) -13.0 ±0.9 (-18.7)	-	-2.8 ±8.2 (-26.7)	994.4±	700	2004	-	2000
9D	INDETERMINABLE	-69.0 ±41.4 (-330.)	-11.1 ±28.0 (-92.8)	-16.4 ±7.5 (-34.0)	1010.0±	700	12/90	2/93	5/98

NOTE: 1) RATES IN PARENTHESIS REPRESENT MOST CONSERVATIVE RATES WHICH CAPTURES 95% CERTAINTY.

2) BAY 17D WAS THE MOST LIMITING BAY AFTER OCTOBER 1988 UT RESULTS

3) STATISTICAL REGRESSION MODELING MORE APPROPRIATE THAN MEAN MODEL.

OCLR00001675

TABLE 2 - ESTIMATED CORROSION RATES - SAND BED REGION

BAY	(1) CORROSION RATE UP TO 10/88 (MPY)	(2) CORROSION RATE FROM 6/89-2/90 (POST CP & H20 DRAIN)	(3) CORROSION RATE FROM 10/88 - (2/90 PRE-CP & POST H20 DRAIN)	(4) CORROSION RATE TO 2/90 ALL DATA	(5) FEB. 1990 THICKNESS	(6) REQ. MIN. THICK. (MILS)	(7) DATE WHICH MINIMUM THICK IS REACHED (COL. 2)	(8) DATE WHICH MINIMUM THICK IS REACHED (COL. 3)	(9) DATE WHICH MINIMUM THICK IS REACHED (COL.4)
13A	INDETERMINABLE	-41.8 ±15.4 (-139.)	(3) -39.3 ±6.0 (-56.8)	(3) -16.3 ±4.8 (-27.6)	859.0±	700	2/91	8/92	5/95
15D	NOT SIGNIFICANT	-5.2 ±3.2 (-25.4)	-	-1.54 ±3.4 (-11.5)	1057.7±	700	2002	-	2018
17A TOP 3	INDETERMINABLE	+17.4 ±7.6 (-65.4)	-	-10.9 ±4.3 (-23.5)	1120.2±	700	12/95	-	2006
17B BOTTOM 4		(3) -44.3 ±.01 (-44.4)	-	-18.1 ±12.3 (-54.)	937.5±	700	12/94	-	2/94

NOTE: 1) RATES IN PARENTHESIS REPRESENT MOST CONSERVATIVE RATES WHICH CAPTURES 95% CERTAINTY.
2) BAY 17D WAS THE MOST LIMITING BAY AFTER OCTOBER 1988 UT RESULTS.
3) STATISTICAL REGRESSION MODELING MORE APPROPRIATE THAN MEAN MODEL.

OCLR00001676

TABLE 3- ESTIMATED CORROSION RATES - UPPER ELEVATIONS

BAY	(1) CORROSION RATE UP TO 10/88 (MPY)	(2) CORROSION RATE BASED ON SECTION 3.3	(3) CORROSION RATE BASED ON STRAIGHT AVG. 6/89 - 2/90	(4) CORROSION RATE TO 2/90 ALL DATA	(5) FEB. 1990 THICKNESS	(6) REQ. MIN. THICK. (MILS)	(7) DATE WHICH MINIMUM THICK IS REACHED (COL. 2)	(8) DATE WHICH MINIMUM THICK IS REACHED (COL. 3)	(9) DATE WHICH MINIMUM THICK IS REACHED (COL. 4)
51' (ALL DATA)	− 4.3 ±0.03[3] (−4.5)	16	15	−3.6 ±2.9 (−9.8)	739.6±	725	1/91	2/91	6/91
51' (9/89 DELETED)	N/A	N/A	N/A	−5.6 ±1.6[3] (−9.5)	739.6±	725	N/A	N/A	7/91
51' (USING CMTRs)	N/A	16	15	−3.6 ±2.9 (−9.8)	739.6±	671	5/94	7/94	6/96
86' 9	NOT SIGNIFICANT	16	N/A	USING (−9.8)	(AS OF 6/26/89) 619.1	591	3/91	N/A	1/92

NOTE: 1) RATES IN PARENTHESIS REPRESENT MOST CONSERVATIVE RATES WHICH CAPTURES 95% CERTAINTY.

3) STATISTICAL REGRESSION MODELING MORE APPROPRIATE THAN MEAN MODEL.

OCLR00001677

In addition the NDE/ISI group at Oyster Creek performed an equipment functional check on the UT meter (D-meter) and probe used to record the data. Different D-meter and probe combinations were used on various thickness. The results were generally identical with variances of only several thousands on an inch.

3.3 Existing Corrosion Mechanism

3.3.1 Corrosion Mechanism in Sand Bed Region

Per Reference 7.2, the cause of the corrosion in the sand bed region is the result of water trapped in the sand bed. The water which may have leaked into the sand bed during construction and/or outages in 1980, 1983 and 1986 was contaminated with chlorides, sulfates and numerous other metal ions. Per Reference 7.2, a likely corrosion rate (based on plug samples, analysis of inleakage water, laboratory testing, and literature research of related phenomena) is 17 mils/year. However, to ensure conservatism, Reference 7.8 arrived at a conservative rate assuming all material loss observed in 1986 had occurred in the six year period of water intrusion since 1980. The resulting rate -48 MPY was used to justify continued plant operation to June 1992.

3.3.2 Corrosion Mechanism in Upper Elevation

Per reference 7.3 the cause of the corrosion in the upper elevation was the result of the drywell steel exposed to the "firebar" insulation laden with chloride containing water. This was based on analysis of drywell vessel plug samples, analysis of inleakage water, laboratory testing, and literature research of related phenomena. Reference 7.3 concludes that the most conservative corrosion rate (based on plug samples, analysis of inleakage water, laboratory testing, and literature research of related phenomena) is 16 mils per year.

3.4 Review of Cathodic Protection System Operation Since Installation

A review was performed on the Drywell Cathodic Protection System (CPS). This review included verification of the electrical installation and system operating parameters. According to the design documentation, the system is configured correctly. Review of system electrical potential data has shown that since the initial draining of water from the sand bed, generally there has been a steady reduction of current as a function of time.

The data indicates that since June of 1989, many of the cathodic protection system probes have experienced zero current. There are several possible reasons for this occurrence.

1) The sand bed could have become uniformly dry, including the sand in contact with the vessel wall. With the sand bed completely dry, the corrosion mechanism and subsequent rate were expected to halt.

2) Only the sand in areas close to and around the CPS probes has completely dried. The remaining sand bed region, including the sand in contact with the vessel wall, is still wet and the corrosion mechanism is still in place. The locally dry sand around the probes may be developing very high resistivity factors which have resulted in low and/or zero currents. Per discussions with Ian Munroe, of Corrosion Services, this is thought to be unlikely because the current density of the system is not high enough for this kind of phenomena.

3) The current provided initially is too low. Per discussing with Ian Munroe, of Corrosion Services, the electrical power supplied to the system may need to be increased. This may be required due to the grade positioning being different than the conceptual layout of grades.

3.5 Review of Safety Evaluation 000243-002, Rev. 3 (Reference 7.7)

3.5.1 Sand Bed Region

The above referenced Safety Evaluation projects Bay 17D in the sand bed region as the most limiting of all monitored locations. Mean thickness was expected to reach the minimum allowable mean thickness of .700 inches by June 1992.

3.5.2 Elevation 50'-2"

The above referenced Safety Evaluation projects mean thickness on EL. 50'-2" as .730 inch by June 1992 which is above the minimum mean thickness of .725 inches. Note that this value does not take credit for the actual material properties of the steel plate (CMTRs). Minimum allowable thickness using actual stress values from CMTRs is .671 inches (Ref. 7.4).

3.5.3 Elevation 87 Foot

The above referenced Safety Evaluation does not project mean thickness on Elevation 86-'5" as no corrosion was ongoing at this elevation. However, the minimum allowable mean thickness at this elevation is .591. Note that this value is derived from actual material properties of the steel (CMTRs).

The minimum allowable thickness for localized areas at this elevation is .425 inches.

4.0 EVALUATION

4.1 Evaluation Approach

This evaluation documents and illustrates the preliminary approach used to estimate corrosion rates, identify the limiting bay and project the date at which minimum shell thickness is reached. The statistical appropriateness of these analyses is to be verified by revision to Reference 7.5. Reference 7.5 will be updated to provide statistically appropriate corrosion rates.

4.1.1 Sand Bed Region

A logical approach based on an understanding of the corrosion phenomena, a vigorous application of statistics, and sound engineering judgement was necessary to develop appropriate conservative corrosion rates.

Rates based on data from June 1989 to February 1990 were intended to capture a rate post cathodic protection installation and sand bed draining. These rates may have indicated the most recent changes in corrosion. However, these rates are based on only three observations (6/89, 9/89 and 2/90 data) which generally resulted in statistically inappropriate rates.

Corrosion rates based on all data up to February 1990 would capture an overall rate and would statistically be more accurate (Table 2, Column 4). However, these rates may not capture possible recent increases in corrosion rates. Therefore, this approach may not be the most conservative.

Rates were also calculated based on data from 10/88 to 2/90. Although these rates are based on only four observations, the time period is almost doubled (compared to the 6/88 to 2/90 period).

Table 2 shows which of the rates are based on data which fit the regression model more appropriately than the mean model (indicated by Note #3). (This will be referred to as "statistical appropriateness" throughout this report.) However, the most "statistically appropriate" rate may not be the most conservative. Therefore, to take a consistently conservative approach, the greatest rate must be chosen, unless that value can be discounted (based on sound engineering judgement coupled with an understanding of the corrosion phenomena).

The evaluation approach was to find the date in columns 7, 8 and 9 which would occur soonest in time. The rate used in projecting this date was then evaluated to see if it was based on a statistically appropriate curve fit and if the rate could be realistically expected (i.e. $\leq$ 60 MPY). If the rate was not realistic and not statistically appropriate, then it would be disregarded and the next date in time in column 7, 8 and 9 would be chosen.

The date which occurs soonest in time is Bay 11C (bottom four rows) which projects a 10-11/90 date (in column 7). The corresponding corrosion rate is -18.3 $\pm$ 30.4 (column 2). This suggests a standard error which is almost twice as much as the rate. As a result of this uncertainty, and the small number of observations, the 95% confidence rate is -210.4 MPY. This type of corrosion rate is considered unrealistic (see Section 3.3). Therefore, this rate and the projected date based on this rate must be disregarded.

For the next, Bay 9D, the column 2 rate is -69 $\pm$ 41.4 MPY. This results in a 95% confidence rate of -330.0 MPY. This rate is considered unrealistic and is not based on a statistically appropriate model. Again, this rate and the projected date are disregarded. Bays 11A, 11C (top 3 rows), 13A, 17D, 19A, 19B and 19C showed similar unrealistic results in column 2. In general, all column 2 results and projected dates (column 7) were not considered reasonable.

4.1.2 Upper Elevations

Table #3 presents 3 rows for Bay 5 at the 51 foot elevation. The first row presents an overall rate up to October 1988 (column 1), a rate based on section 3.3 (column 2), a rate based on straight line average from June 1989 to February 1990 (column 3), and an overall rate up to February 1990 (column 4).

Since it appears that a significant amount of material was lost from June 1989 to February 1990 (see Table #4) a straight average using mean thicknesses on these two dates was developed.

TABLE 4

Bay 5 Elevation 51 Mean Thickness

Date of UT	Mean Thickness
11/1/87	753.8
7/12/88	750.0
10/8/88	750.2
6/26/89	749.6
9/13/89	755.6
2/9/90	739.6

The second row presents a rate with the September 1989 data disregarded. Review of the September 1989 mean thickness value shows an increase over the June 1989 mean thickness (by approximately 6 mils). This increase, coupled with a resulting overall rate which is based on a curve fit which is not statistically appropriate, prompted an analysis of the data with the September 1989 observation deleted. The resulting rate of -5.6 $\pm$ 1.6 is based on a curve fit which is statistically appropriate.

Regardless, the more conservative of either resulting 95% confidence rate (with or without the September 1989 data) was chosen as the most conservative projection (-9.8 MPY).

The third row for the 51 foot elevation presents the same rates as in the first, except a CMTR based minimum mean thickness is applied. Resulting projections are presented in column 7, 8 and 9.

4.2 Sand Bed Region

4.2.1 Most Limiting Bay In The Sand Bed Region

The October 1988 Safety Evaluation (Reference 7.11) projected Bay 17D (in the sand bed region) has the most limiting of all monitored locations. Based on a rate of -27.6 $\pm$ 6.1 MPY and a 95% confidence conservative rate of -41 MPY, mean thickness was projected to reach the minimum allowable mean thickness of 0.700 inch by June 1992.

Results from February 1990 data now suggests that a conservative rate of -17.7 ± 4.3 MPY and a 95% confidence conservative rate of -30.25 MPY can be applied, and that this bay is projected to reach a mean thickness of 700 mils by April of 1994.

The February data now indicates that Bay 19A is the most limiting bay of all monitored locations in the sand bed region. Based on a new conservative rate of -20.7 ± 5.6 MPY and 95% confidence rate of -38.1 MPY, it is projected that this bay may reach a mean thickness of 700 mils by September 1992. The conservative rate is both realistic and is based on a statistically appropriate curve fit. Note, this rate is based on data recorded from October 1988 through February 1990 (column 4).

4.2.2 Protected Bays

Interim data recorded in September 1989 indicated that corrosion rates in the protected sand bed region had generally decreased, yet the February 1990 data indicates that corrosion rates generally increased almost to former levels before cathodic protection installation.

A possible explanation for this may be the reduced or zero probe current rates which has occurred since June 1989 (Section 3.4).

Up to June 1989 the sand bed region may have been uniformly wet and Cathodic Protection System may have performed its intended purpose by inducing a current throughout the sand bed. Then in June the sand close to and around the probes may have completely dried with the remaining sand (including the sand in contact with the vessel wall) remaining wet. The locally dried sand around the probe may have developed very high resistivity factors resulting in very low and zero currents.

The lack of impressed current prevents the cathodic protection system from performing it's function. This may explain the increased corrosion rates observed in February 1990.

4.3 50"-2" Elevation

The most limiting bay at the 50 feet elevation is Bay 5. October 1988 data had resulted in a mean thickness of approximately .75 inches. October 1988 data indicated an on-going rate of -4.3 ± .03 MPY.

February 1990 data indicates a loss of material resulting in a mean thickness of .7396 inches. Although the February 1990 data is not been thoroughly understood an overall rate of -3.6 ± 2.9 MPY and a 95% confidence conservative rate of -9.8 MPY has been calculated. Based on this rate, it is projected that this area may reach a minimum mean thickness of .725 inches by June 1991. This thickness is based on code allowable stress values for the steel and not CMTR results.

The minimum mean thickness at this elevation based on measured stress values (per vendor CMTRs) is .671 inch (Reference 7.7). Use of this minimum (instead of a minimum based on code allowable stress values) and the -9.8 MPY rate allow a projection for serviceability to June 1996.

The more conservative rates of 16 and 15 MPY were also considered. The most limiting projection based on these rates (without CMTR stress values) resulted in a January 1991 date. Use of CMTR stress values and resulting minimum mean thickness result in a May 1994 date.

4.4 86 Foot Elevation

The most limiting bay at the 86 foot elevation is bay 9. June 1989 data indicates that this bay had a mean thickness of .6191 inches. As of June 1989 this bay was considered to be experiencing a rate of 0 MPY.

UT examination was not performed at this elevation in February 1990. Although it is very likely that this area is continuing to experience rates close to zero MPY, the conservative rate calculated at the 51 foot elevation applied to the June 1989 mean thickness at Bay 9 on the 86 foot elevation projects that this bay may reach the minimum mean thickness of .591 inches by January of 1992.

A more conservative rate of 16 mils/year based on the original safety evaluation (Section 3.3) was considered. Projection based on this rate resulted in a March 1991 date.

If CMTR stress values are applied to the 51 foot elevation projection, then bay 9 on the 86 foot elevation becomes the most limiting bay with a serviceability date of March 1991.

5.0 CONCLUSION

5.1 Based on this evaluation, the sand bed region is no longer the limiting elevation for drywell vessel service. Bay 5 at the 51 foot elevation is now the most limiting. Based on February 1990 mean thickness of .7396 inches and a conservative rate of 16 MPY (Sec. 3.3), this area is projected to reach the minimum mean thickness of .725 inch by January 1991. This projection is based

on a theoretical rate of 16 MPY. The detailed review currently underway may determine a different projection which is based on a statistically derived rate from the data. However, this conservative projection does show that the drywell will be serviceable until January 1991.

5.2 Use of CMTR stress values applied to bay 5 at the 51 foot elevation projects this area to reach the minimum mean thickness of .671 inch by May 1994.

5.3 Although no data was taken in February 1990 at the 86 foot elevation and it is likely that corrosion rates remain at zero MPY, the conservative rate of 16 MPY (Sec. 3.3) projects bay 9 on the 86 foot elevation to reach the minimum mean thickness by March 1991.

5.4 February 1990 data now indicates that Bay 17D in the sand bed is no longer the most limiting bay. Results from the February 1990 data projects the most limiting bay in the sand bed is 19A. It is conservatively projected that this area will reach the minimum mean thickness by September 1992.

Based on these results in the sand bed region, it is concluded that cathodic protection is currently producing very limited positive results in abating corrosion in the sand bed region.

6.0 RECOMMENDATIONS

6.1 Safety Evaluation 000243-002 Rev. 3 (Reference 7.6) which projects drywell service life up to June 1992 must be revised to reflect the new rate and a new date of January 1991. This is ongoing.

6.2 The minimum mean thickness at the 50'2" elevation is .725 inches. This value is based on code requirements. It is recommended that GPUN pursue using CMTR results to calculate a reduced minimum mean thickness value of .671 inches. This would result in projected serviceability date (at this elevation only) of June 1996. This is ongoing.

6.3 It is recommended that GPUN pursue lowering the design pressure of the drywell. This would further reduce the minimum mean thickness value in the upper elevation and provide more margin. This is ongoing.

6.4 Current cathodic protection system potential data indicates a postulated mechanism which may be defeating cathodic protection. The proper operation of this system needs to be verified and corrected as necessary. This is ongoing.

6.5 Evaluate methods for abating corrosion in the upper elevations. This is ongoing.

7.0 REFERENCES

7.1 TDR 851 Assessment of Oyster Creek Drywell Shell.

7.2 TDR 854 Drywell Sand Bed Region Corrosion Assessment.

7.3 TDR 922 Drywell Upper Elevation, Wall Thinning Evaluation.

7.4 TDR 926 OC Drywell Structural Evaluations.

7.5 TDR 948, Statistical Analysis of Drywell Thickness Data.

7.6 Calculation C-1302-187-5360-006 Projection of Drywell Mean Thickness through October, 1992.

7.7 Safety Evaluation SE 000243-002, Rev. 3.

7.8 Safety Evaluation SE 000243-002, Rev. 1.

Exhibit 29

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	
AmerGen Energy Company, LLC	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	

AFFIDAVIT OF BARRY GORDON

City of San Jose)
)
State of California)

Barry Gordon, being duly sworn, states as follows:

INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station ("OCNGS") operating license, and admitted by the Licensing Board on October 10, 2006. That contention challenges the frequency of AmerGen's UT measurements of the drywell shell in the sand bed region. In part of their contention, Citizens speculate that significant corrosion of the exterior of the OCNGS drywell shell in the sand bed region could occur through tiny defects (called "pinholes" or holidays") in

the three-layer epoxy coating system: "corrosion may occur under the epoxy coating in the absence of visible deterioration due to non-visable holidays, or pinholes."

2. As I discuss below, it is my expert opinion that these allegations have no technical merit because: (a) significant corrosion is not possible with an epoxy-coated drywell shell; and (b) even if such a corrosion rate was possible, AmerGen's committed frequency of UT measurements is more than adequate to detect such corrosion (even under unrealistic assumptions), before the ASME Code-specified margins are exceeded. Accordingly, Citizens' argument is not only factually irrelevant but simply immaterial to the integrity of the drywell shell during the proposed period of extended operation.

EDUCATION AND EXPERIENCE

3. For the past 38 years, I have been an engineer focusing on corrosion and material issues in light-water reactors, with special emphasis on stress corrosion cracking (SCC). I have addressed numerous materials and corrosion issues in the nuclear industry in a wide range of contexts including reactor internals, piping, fuel hardware, water chemistry transient and core flow issues, weld overlays and repairs, crack growth rate modeling, alloy selection, failure analysis, license renewal, NRC inspection relief, dry fuel storage, and decontamination.

4. I received my B.S. and M.S. degrees in Metallurgy and Material Science from Carnegie Mellon University in 1969 and 1971, respectively. Since then, I have completed additional courses from M.I.T., the University of Pittsburgh and the National Association of Corrosion Engineers (NACE) in Corrosion Science.

5. I am a Registered Professional Engineer in Corrosion Engineering in the State of California (#208), a Registered Corrosion Specialist with NACE International (#1986) and a Member of the International Cooperative Group on Environmentally Assisted Cracking (ICG-EAC).
6. I was certified as an Instructor for the International Atomic Energy Agency (IAEA) on February 2001 and am an Adjunct Professor at the Colorado School of Mines, in Golden, Colorado where I currently supervise one Ph.D candidate. I teach the following course: "Corrosion and Corrosion Control in LWRs" for Structural Integrity Associates, Inc. and have taught "Corrosion and Corrosion Control in BWRs" for GE Nuclear Energy (GENE). I have held instructor credentials for Engineering in California Community Colleges since 1986.
7. From 1969 to 1975, I was employed as a materials engineer by Westinghouse Electric at the Bettis Atomic Power Laboratory, located in West Mifflin, Pennsylvania.
8. From 1975 to 1998, I was employed by GE Nuclear Energy, located in San José, California. While at GE Nuclear Energy, I was a technical expert in corrosion engineering, a project manager in corrosion technology, and a program manager in stress corrosion cracking.
9. Since 1998, I have been employed by Structural Integrity Associates, Inc., also located in San José, California, as an Associate.
10. I am familiar with the historical corrosion of the OCNGS drywell shell because I started working on that issue in 1986 as the OCNGS drywell project manager when I was employed by GENE.

11. More recently, I prepared an evaluation report on the corrosion of steel embedded in concrete on the exterior of the drywell (June 5, 2006) and on effects of water on corrosion propensities of concrete embedded steel identified in the interior of the drywell (November 3, 2006). I also testified before the Advisory Committee on Reactor Safeguards (ACRS) on both subjects on January 18, 2007.

OPINIONS OF BARRY GORDON

12. In his June 23, 2006, memorandum, Dr. Rudolf Hausler suggests that a future corrosion rate of 0.017" per year is possible for the external surface of the drywell shell in the sand bed region at OCNGS. He correctly asserts that this corrosion rate was observed by the former owner of the OCNGS in certain areas of the sand bed region prior to 1992 (after which the external surface of the drywell shell was protected from further corrosion by a sand bed removal and the installation of a multi-layer epoxy coating system). As I demonstrate below, however, this corrosion rate is not possible with an epoxy-coated drywell shell. Moreover, even if this or a significantly higher corrosion rate was possible, AmerGen's committed frequency of UT measurements is more than adequate to detect such corrosion before the ASME Code-specified margins are exceeded.

13. Part of the reason why the corrosion rate was historically as high as 0.017" per year in certain bays of the drywell shell sand bed region is because there was a medium (*i.e.*, sand) to physically hold water against the drywell shell. Specifically, the sand bed region got its name from the sand that was placed there as part of the original design. Once water entered this area, the sand physically held the water against the shell, ensuring a constant source of water to facilitate corrosion of the metal drywell shell.

This sand, however, was removed as part of the corrective actions completed in 1992 to prevent additional corrosion in the sand bed region. So there is no water-retaining media to facilitate future corrosion.

14. Of course, such a corrosion rate of 0.017" per year is unrealistic because the drywell shell is protected from further corrosion by a multi-layer epoxy coating system. AmerGen has demonstrated that corrosion of the external surface of the drywell shell has been arrested, and no additional corrosion is possible unless there is a defect in the coating and water is able to come into contact with the metal drywell shell through that defect. Accordingly, it is my opinion that no corrosion is possible beneath an intact epoxy coating system, such as the one applied on the exterior of the OCNGS. This is because corrosion of a kind significant enough to affect the integrity of the drywell shell requires the presence of water and oxygen, and there is no water or oxygen adjacent to the metal surface of the drywell shell to initiate, let alone sustain, the corrosion process.

15. Dr. Hausler, however, has speculated that there could be tiny defects in the coating, referred to as "pinholes" or "holidays." He essentially argues that water could get to the metal surface of the underlying drywell shell through these hypothetical, tiny defects. It is my opinion that even if there were such defects, they would not allow sufficient oxygenated water to reach the underlying drywell shell for corrosion to exceed ASME Code-specified margins before AmerGen would detect it through its committed inspections (*i.e.*, every four years). Accordingly, this argument is simply not relevant to the long-term integrity of the drywell shell. The support for my opinion is presented in the next paragraphs.

16. We know that the maximum measured historical corrosion rate was not 0.017" per year, but was more than twice that at 0.039" per year (in location Bay 13A).[1] So we know that with the presence of water, wetted sand holding that water adjacent to the uncoated shell, blocked drains preventing that water from being drained out of the sand bed region, and the temperature specific to the exterior of the drywell shell in the sand bed region during operations, that loss of metal at a rate of 0.039" per year is possible.

17. To show how absurd Citizens' argument is—that corrosion significant enough to affect the integrity of the drywell shell could occur through a pinhole or holiday in the epoxy coating—I have made the following assumptions in my calculation, some of which are unrealistic and overly conservative:

- AmerGen performs the visual and UT inspections of the sand bed region in 2008 that it has already committed to;
- AmerGen does not perform inspections of the sand bed region in 2010, also consistent with its commitments (inspections are to be performed every four years after 2008);
- The drywell shell is exposed to water during the 2010 scheduled refueling outage. The source of the water is minor leakage from the refueling cavity, which only contains water during refueling outages, so the shell could not get wet prior to a refueling outage;

[1] Citizens' Petition states that a "reasonable estimate of the worst case potential corrosion rate that may occur could be obtained by analyzing the pre-1992 data [*i.e.*, before the sand was removed from the sand bed region].... Observed corrosion rates to 1990 ranged up to 0.035 inches per year and were very uncertain." While it is my understanding that AmerGen is not required to perform "worst case" analyses, the corrosion rates that occurred prior to removal of the sand from the sand bed region simply are not representative of the potential corrosion rates after removal of the sand. As I demonstrate in this Affidavit, even this order of magnitude corrosion does not challenge the integrity of the drywell shell.

- This water is not detected. This is conservative because AmerGen's commitments include monitoring the refueling cavity liner drain during outages, as well as the five sand bed region drains both quarterly and daily during outages;
- The water enters Dr. Hausler's hypothetical pinhole or holiday on the first day of the 2010 refueling outage. This is conservative because the refueling cavity is not even flooded on the first day of the outage;
- The pinhole or holiday is located within the region that has the least remaining margin (*i.e.*, Bay 13). This is conservative because it is statistically unlikely that the thinnest area of the shell also has the defect in the coating;
- Corrosion at the maximum historical rate of 0.039" per year instantly begins as water enters the pinhole or holiday;
- Oxygen's contact with the metal surface is not mitigated by the presence of corrosion products. This is conservative because corrosion tends to be self-limiting when corrosion films are produced on the metal surface and corrosion byproducts (*i.e.*, rust) create a diffusion barrier that reduces the amount of subsequent corrosion of the shell;
- The refueling outage takes four weeks to complete, and the cavity is filled with water during the entire refueling outage;
- The water stays in the pinhole during the entire four-week outage; and
- The water in the pinhole or holiday does not evaporate until a year after the refueling outage is over, and the 0.039" per year corrosion rate continues for the entire year after the outage, for a total of 56 weeks of new corrosion. This

is extremely conservative because the temperature in the sand bed region of the drywell is about 130°F during operations, which would result in the evaporation of the small amount of water in the pinhole or holiday in significantly less time. For example, at 130°F, a drying out rate of about 0.3 pounds per hour, per square foot, is reasonable for a sand bed region with no sand.[2] This would result in evaporation of water in the pinhole or holiday in less than one day. There are many factors involved in the calculation of water evaporation rates. One of the most important factors is the air or wind velocity across the water surface. I derived the 0.3 pounds per hour, per square foot value from the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) equation for evaporation from ponds or pools: $W = [A + (B)(V)](Pw - Pa)/Hv$ (where: W = water evaporation rate, (lb/hr) per sq.ft. of the water's surface area; A = a constant = 95; B = a constant = 37.4; V = air velocity over the pond surface, miles/hr (which I assumed was zero); Pw = vapor pressure of water at the water temperature, inches of Hg; Pa = vapor pressure of water at the air dewpoint temperature, inches of Hg; and Hv = heat of vaporization of water at the pond water temperature, Btu/lb).

18. In summary, therefore, I have assumed that the drywell shell behind the pinhole or holiday will experience the maximum historical corrosion rate of 0.039" per year, for 56 weeks. This results in a total loss of metal of about 0.042", which is well within: (a) the margin of 0.064" remaining in Bay 19 (thickness of 0.800"), when measured

2 This is around 2.4 ounces per hour, per square foot.

against the general average thickness criterion of 0.736"; and (b) the margin of 0.128" remaining in Bay 13A, when measured against the very local area average thickness of 0.490".

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Barry Gordon
Structural Integrity Associates, Inc.
3315 Almaden Expressway, Suite 24
San Jose, CA 95118-1557

Subscribed and sworn before me this 26 day of March 2007.

PAULA RODGERS
Commission # 1540492
Notary Public - California
Santa Clara County
My Comm. Expires Jan 1, 2009

Notary Public

My Commission Expires: Jan. 1, 2009

Exhibit 30

DESH 301
BNE

State of New Jersey

DEPARTMENT OF ENVIRONMENTAL PROTECTION

JON S. CORZINE
Governor

LISA P. JACKSON
Commissioner

Division of Environmental Safety and Health
P.O. Box 424
Trenton, New Jersey 08625-0424
Phone: (609) 633-7964
Fax: (609) 777-1330

April 26, 2007

Dr. Pao-Tsin Kuo
Director Division of License Renewal
U. S. Nuclear Regulatory Commission
One White Flint North
Mail Stop O-11 F1
11555 Rockville Pike
Rockville, MD 20852

Subject: Oyster Creek Drywell Corrosion - Expert Review Findings

Dear Dr. Kuo:

As you are aware, by letter dated January 17, 2007, I informed you of the State of New Jersey Bureau of Nuclear Engineering 's (BNE) intention to hire an independent expert in the field of corrosion mechanisms to review and comment on the Oyster Creek Engineering Evaluation performed for AmerGen, by Structural Integrity Associates, on the potential corrosion consequences of the water unexpectedly discovered inside the drywell during the 2006 refueling outage. Oyster Creek's Engineering Evaluation supported AmerGen's conclusion that Oyster Creek could restart from the last refueling outage and continue to operate for an extended license renewal period.

Additionally, as part of this independent review, BNE requested comments on three memorandums, previously submitted to the NRC as part of the currently open license renewal citizen's coalition contention relating to the serviceability of the Oyster Creek drywell, prepared by Rutgers Environmental Law Clinic's corrosion expert, Mr. Rudolph Hausler.

Enclosed with this letter is a copy of the BNE sponsored independent review, dated March 26, 2007, conducted by Dr. Ronald M. Latanision, Principal and Director, Mechanics and Materials Practice, Exponent, Inc. Dr. Latanision is a recognized expert in corrosion mechanisms with an extensive and noteworthy resume of accomplishments in this field.

In general, Dr. Latanision's findings where in agreement with the Stuctural Integrity Associates report. He did provide precautionary comments in four areas.

First, if voids in the concrete exist in which water could accumulate at the concrete/steel interface, this could compromise the conditions which are necessary to support the premise that the embedded steel is in a passive condition. He notes that no such voided condition at the concrete/steel interface has been identified at Oyster Creek but offers that corrosion of embedded steel could be probed using reference electrodes.

Second, any subsequent water ingress should remain low in impurities such as chlorides, sulfates and other aggressive anions.

Third, nitrogen inerting during plant operation would not mitigate corrosion inside the drywell if water exposed to the atmosphere is being continuously transported into the concrete thereby allowing the pore water to remain saturated with oxygen.

Fourth, the position that negligible corrosion occurs when the inside of the drywell is not nitrogen inerted since the oxygen in the water is consumed by corrosion of the steel can be questioned if the water inside the drywell is being refreshed by atmospheric exposure.

Dr. Latanision further suggests that drywell thickness be monitored in real time using corrosion monitoring devices at locations known to be troublesome since the thickness margins that exist in some places of the drywell are small and given that unexpected changes to the corrosion "system", such as the introduction of aggressive impurities to the pore water chemistry, could result in accelerated corrosion.

Finally, Dr. Latanision's review of the Hausler memos indicates that the epoxy coating in the sandbed region could be assessed in ways other than visual but the coating does seem to be working, Hausler's water chemistry concerns seem speculative and inconsistent, and a chloride environment would not subject carbon steel to stress corrosion cracking.

Should you have any questions or need additional information, please contact me directly at (609) 633-7964 or Mr. Kent Tosch, Manager of the Bureau of Nuclear Engineering, at (609) 984-7700.

Sincerely yours,

Jill Lipoti

Jill Lipoti, Ph.D.
Director

Enclosure

Timothy Rausch, Oyster Creek Site Vice President
Graham B. Wallis, Chairman, ACRS
R. DeGregorio, Exelon
Samuel Collins, Regional Administrator, NRC Region I
Marsh Gamberoni, Director, Division of Reactor Safety, NRC Region I
Richard Conte, Chief, Engineering Branch, NRC Region I
Nancy MacNamara, State Liaison Officer

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March 26, 2007

Mr. Ron Zak
NJDEP-Bureau of Nuclear Engineering
33 Arctic Parkway
PO Box 415
Trenton, New Jersey 08625

Subject: Oyster Creek Review
Exponent Project No. BN64124

Dear Mr. Zak,

This report is in response to my review of Attachment 7.5 of the Oyster Creek Engineering Evaluation, which is the Structural Integrity Associates report concerning a corrosion evaluation of the Oyster Creek drywell steel shell. In particular, I have focused on the question of whether the water discovered during the 2006 refueling outage in two trenches that had been excavated earlier in order to permit inspection of the inside of the shell would lead to future corrosion problems. This question is central to the Structural Integrity report.

I am, in general, in agreement with the findings of the Structural Integrity report, but I would add the following commentary. Structural Integrity concludes that no significant corrosion of the inside surface of the drywell steel shell will occur as long as the current environmental conditions inside the drywell are maintained for the following reasons:

(1) The concrete floor pore water inside the drywell is such that embedded steel is in a passive condition and thereby protected from corrosion. I would add that passive does not mean that oxidation (corrosion) is entirely inhibited, but, rather, that the rate of oxidation is sufficiently slow that corrosion is not significant. The low impurity content of the pore water limits the otherwise potential breakdown of the passive film, which could under different circumstances give rise to corrosion at significant rates. The above applies to the case of steel that is well embedded in concrete. If voids are present at the concrete/steel interface and the steel is thereby poorly embedded, water may accumulate. In such instances oxygen and carbon dioxide may be transported through the porous concrete, dissolve in the accumulated water and increase the corrosion rate of the steel. Corrosion of embedded steel which has the above origin may be probed remotely using reference electrodes, a common practice in the case of concrete deck slabs, for example. It is important to note that there is no indication in the documents that I have seen that the latter is of concern at Oyster Creek.

(2) Any subsequent water ingress will take on the chemistry of concrete pore water. I would agree provided that the source of the water remains low in impurities such as chlorides, sulfates and otherwise aggressive anions.

(3) Corrosion of the steel shell that is not wetted by the concrete pore water will be mitigated by the inerting of the inside of the drywell with nitrogen during plant operation. I agree that the use of nitrogen for this purpose is helpful in that this will minimize the presence of oxygen, but it will not eliminate it. This is a positive step. However, one must consider the source of the water that is of potential concern. If that water is exposed to the atmosphere and is continuously transported into the concrete, then the pore water is likely to remain saturated with oxygen.

(4) Negligible corrosion would occur during outages when the nitrogen inerting is not present. I agree that this calculation shows that if all of the dissolved oxygen initially present in the water were consumed by corrosion of the steel, the steel lost as a consequence would be insignificant. However, this calculation refers to a non-refreshed system and, as pointed out in (3) above, if the source of the transported water is such that the oxygen is refreshed by atmospheric exposure, then the metal loss may be somewhat larger.

It was of value in the context of the above review to examine the presentation material from the January 18, 2007 *Oyster Creek License Renewal Presentation to the ACRS Subcommittee*. In the AmerGen presentation, it was noted that following the October 2006 outage the drywell shell current condition in the sand bed region is such that a 64 mil available thickness margin is present (i.e., the minimum measured wall thickness exceeded the code required average thickness by 64 mils). The thinned areas are typically near and below vent headers. While it appears that corrosion is under control, given the UT wall thickness data that were collected during the 2006 inspection and that no degradation was noted in the visual inspection of the external shell coating, I fully support the apparent plan to repeat UT measurements in both trenches during the 2008 outage. The corrosion rate appears to be low at the moment, but any upset to the system that might, for example, introduce aggressive anionic impurities into the concrete pore water could change that markedly. On this point, the drywell steel shell thickness could in principle be monitored with corrosion monitoring devices in real time and at locations that are known to be troublesome. These areas could be identified by mapping wall thinning data on a drywell steel shell model. Such monitors are used for continuous monitoring of uniform corrosion in various industrial circumstances. I am not aware of commercial experience with comparable equipment for the present purpose, but this seems tractable to me.

I have additionally reviewed documents which you had provided to me from the Rutgers Environmental Law Clinic. My review of those documents is appended to this letter.

Please do call me if you would like to discuss any of the above.

Sincerely,

R.M. Latanision

R.M. Latanision
Principal and Director
Mechanics and Materials Practice

Appendix: Review of Documents from the Rutgers Environmental Law Clinic

I have reviewed the following documents:

(1) January 16, 2007 letter to ACNS from Richard Webster which includes a Memorandum from Rudolph Hausler to Mr. Webster
(2) July 26, 2006 Memorandum from Rudolph Hausler to Paul Gunter
(3) December 19, 2006 Memorandum from Rudolph Hausler to Richard Webster.

These documents are directed toward a number of issues related to the serviceability of the Oyster Creek drywell. Mr. Webster represents a citizen's coalition that has expressed concern regarding drywell corrosion. Mr. Hausler consults with Mr. Webster. These documents are in general critical of AmerGen. As an objective observer, I find some points associated with technical questions with which I agree, some which I do not share, and others that I believe to be incorrect. The language is clearly adversarial as might be expected. The following is an example of each of the above.

(a) On the subject of the inspection of the epoxy coating that has been applied in the former sandbed area, I do agree that there are techniques other than visual that could be used to assess the condition of the coating. I note in this regard that the reported absence of coating degradation during the 2006 inspection was the result of a visual inspection. On the other hand, the fact that UT data indicated that corrosion had been arrested provides a confirmation, when coupled with the visual observation of the coating condition, that is indicative of a protective coating and is in that context reassuring.

(b) On the subject of the chemistry of the water draining from the sandbed, Mr. Hausler speculates that the water should contain chlorides in the ppm range if not in the hundreds of ppm (page 5 of the December 19 letter), despite evidence to the contrary. I would agree that a repeat of the water analysis would have been useful. However, the facts are that in the reported analysis the chloride content was relatively low and, thus, not of concern from the point of view of the passivity of the embedded steel. I do not share this willingness to speculate on such matters.

(c) Mr. Hausler speculates further as to the conductivity of the water on page 6 of the December 19 letter and on page 11 of the July 26 letter, in both cases in the context of the operation of differential aeration cells. In short, my understanding is that he argues that the low conductivity of the water that is present would confine the differential aeration cell to the top of the sandbed in order to account for the observations related to the "bathtub ring" corrosion. The low conductivity of the water seems contrary to the speculation in (b), above, that the chloride content was much higher than the reported values. There is a seeming disconnect in these two arguments since the presence of a large chloride concentration would surely increase the water conductivity.

(d) Reference is made in the January 16 letter by Mr. Webster to chloride stress corrosion cracking of carbon steels (page 4). Mr. Hausler, in the Memorandum attached to Mr. Webster's letter, appears on page 2 to come to the same conclusion: although he does not explicitly argue that chlorides induce stress corrosion cracking of carbon steels, he observes that chlorides have been identified in the corrosion products and in the water present in the sandbed and concludes that in principle all the conditions for stress corrosion cracking are present. Carbon steels are subject to stress corrosion cracking in certain environments, as is true of virtually all engineering alloys, but chlorides are not among those environments.

Exhibit 35

AmerGen

Michael P. Gallagher, PE
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License Renewal Projects

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10 CFR 50
10 CFR 51
10 CFR 54

2130-06-20426
December 3, 2006

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

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

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

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

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

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

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

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

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

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

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

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

Respectfully,

Executed on 12/03/2006

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

Enclosure: LRA Supplemental Information, Post-2006 Refueling Outage

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

Enclosure

License Renewal Application
Supplemental Information
Post-2006 Refueling Outage

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

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

Summary of Post-2006 Refueling Outage Supplement

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

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

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

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

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

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

Enclosure Contents

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

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

Exhibit 36

From:	Barry Gordon
Sent:	Thursday, November 2, 2006 1:52 PM
To:	Ray, Howie; Knepper, Dave P.; Fiorello, Daniel J; Lambert, Craig; Kettering, David B.; Tamburro, Peter
Subject:	RE: Privileged & Confidential--ITPR of DW water evaluation--2 main concerns/comments

Howie, et al,

I just wanted to let you know that although the requested calculation is rather straight forward it is going to introduce additional chemistry terms such as moles (and people had trouble with ug/l, ppb and ppm), have several equations and add a couple of references and perhaps a figure.

Barry

-----Original Message-----
From: howie.ray@exeloncorp.com [mailto:howie.ray@exeloncorp.com]
Sent: Thursday, November 02, 2006 10:10 AM
To: dave.knepper@exeloncorp.com; daniel.fiorello@exeloncorp.com; Craig.Lambert@exeloncorp.com; david.kettering@exeloncorp.com; Barry Gordon; Peter.Tamburro@exeloncorp.com
Subject: FW: Privileged & Confidential--ITPR of DW water evaluation--2 main concerns/comments
Importance: High

the following are the two pressing questions that MPR has at this time. I believe they are easily answered but we need to enhance the documents to make it obvious.

Pete, please address question 1.
Barry please work on addressing question 2.

MPR will provide additional comments as they move on.

-----Original Message-----
From: Schlaseman, Caroline [mailto:cschlaseman@mpr.com]
Sent: Thursday, November 02, 2006 12:09 PM
To: Ray, Howie
Cc: Nestell, Jim
Subject: Privileged & Confidential--ITPR of DW water evaluation--2 main concerns/comments
Importance: High

Howie--

Jim has 2 significant concerns that your team should start working on

ASAP:

1. Structural Integrity--The Tech Eval A2152754 E09 identifies UT measurements that are less than 0.736" and accepts them based on local acceptance criteria of 0.49" wall loss in an area 2" or less in diameter. Attachment 1, pages 4 & 5, of the Tech Eval identify 2 adjacent UT readings less than 0.736". The UT readings below and on one side of the low readings are above 0.736", but there are no readings above and to the other side. Therefore, it is unknown whether the area that does not meet global wall thickness requirements does or does not meet the local thickness requirements because the thinned area could extend beyond a 2" diameter circle. Although this area is above the 10'-3" water level which is the focus of this evaluation, there is a potential design basis compliance issue at this location. [Also, note that the white paper Section 2.9, "NDE inspections," does not discuss structural margins or impact of the UT measurements in the original area of the trenches in Bays 5 and 17. Additionally there should be a separate section that discusses structural margins.]

2. Chemistry (SIA report conclusion)--The SIA conclusion depends in part on the high pH of concrete pore water in contact with the DW shell. Although SIA addresses the issue of higher corrosion rates during outages when oxygen is present, chemistry data from samples reported in Section 7.3 show that the pH decreases rapidly during CRD rebuild operations, and in fact the protective pH cannot be assumed to exist during outages anywhere below the 10'-3" level in the DW. SIA should evaluate the effect of combined oxygen and lower pH on corrosion during outages to estimate how much corrosion will occur during each outage, and show by calculation that it is insignificant. This is a loose end, more than a "show-stopper". [Note that the Tech Eval, Section 2.5 "Water Samples," reports that pH measurements were taken on "initial water samples" (plural). Only one pH measurement is reported from the initial samples in the supporting documentation. If more than one measurement was made, this should be documented. Also, the water chemistry report, Attachment 7.3, should include a discussion of all water samples, including the initial ones, and pH results for all should be included.]

Please call me or Jim (703-519-0421) if you have any questions about these comments.

--Caroline

Caroline S. Schlaseman, PE

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