October 10, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

NRC STAFF PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW, AND ORDER IN THE FORM OF AN INITIAL DECISION

I. INTRODUCTION

1. This initial decision rules on all outstanding issues in this 10 C.F.R. Part 2, Subpart L proceeding concerning the contention challenging the AmerGen Energy Company, LLC ("AmerGen" or "Applicant") application for renewal of the operating license for the Oyster Creek Nuclear Generating Station ("OCNGS" or "Oyster Creek"), in Ocean County, New Jersey. The proposed renewal would authorize the facility to operate 20 years beyond its current expiration date of April 9, 2009. Six organizations (collectively known as "Citizens")[1] sponsored a contention challenging AmerGen's aging management program for corrosion in the sand bed region of the Oyster Creek drywell shell, alleging that the frequency of ultrasonic testing (UT) monitoring in that region is insufficient to maintain an adequate safety margin during the period of extended operation because of the uncertain corrosive environment and uncertain corrosion rate in the sand bed region of the drywell shell during the proposed period of extended operation.

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[1] The six organizations are Nuclear Information and Resource Service (NIRS), Jersey Shore Nuclear Watch, Inc., Grandmothers, Mothers and More for Energy Safety, New Jersey Public Interest Research Group, New Jersey Sierra Club, and New Jersey Environmental Federation.

2. After considering all of the evidence in this proceeding, we find that the record shows that, contrary to Citizens' contention, AmerGen has met its burden of showing that the proposed monitoring frequency of four years (i.e., every other outage) is adequate to maintain the safety margin in the drywell shell during the proposed period of extended operation.

II. BACKGROUND

A. Procedural History

3. By letter dated July 22, 2005, AmerGen submitted to the U.S. Nuclear Regulatory Commission ("NRC" or "Commission") an application for a 20-year renewal,[2] pursuant to 10 C.F.R. Part 54, of Operating License No. DPR-16 for the Oyster Creek Nuclear Generating Station ("OCNGS" or "Oyster Creek"). The current license expires April 9, 2009.

4. The NRC published a notice of receipt of the application in the *Federal Register* on August 4, 2005 (70 Fed. Reg. 44,940). In response to a published notice of proposed issuance of the renewed license, 70 Fed. Reg. 54,585 (Sept. 15, 2005), Citizens filed a petition for leave to intervene on November 14, 2005. The New Jersey Department of Environmental Protection ("New Jersey") also filed an intervention petition on November 14, 2005.

5. In LBP-06-07, 63 NRC 188 (2006), the Board rejected the New Jersey petition,[3] but admitted Citizens' contention alleging that the license renewal application ("LRA") was deficient due to the failure to include periodic ultrasonic testing (UT) measurements of the sand bed region of the drywell shell in the aging management program, and rejecting Citizens'

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[2] Letter from C. N. Swenson, AmerGen, to NRC (July 22, 2005) (ML052080172). *See* Applicant Exh. 2.

[3] *See* LBP-06-07, 63 NRC, 199-201. New Jersey's appeal of this decision was also rejected. *See* CLI-06-24, 64 NRC 111 (2006).

attempt in its reply to expand the scope of the contention. [4]

6. In LBP-06-16, 63 NRC 737, 741 - 745 (2006), the Board ruled that Citizens' contention of omission was rendered moot by AmerGen's April 4, 2006, docketed commitment[5] to perform periodic UT measurements in the sand bed region of the drywell (*i.e.*, prior to entering the period of extended operation and every ten years thereafter), but gave Citizens the opportunity to file a new contention challenging AmerGen's new periodic UT program for the sand bed region as reflected in AmerGen's April 4th commitment.

7. In LBP-06-22, 64 NRC 229, 255-56 (2006), the Board admitted one of multiple challenges raised by Citizen's as the following contention:

> [I]n light of the uncertain corrosive environment and correlative uncertain corrosion rate in the sand bed region of the drywell shell, AmerGen's proposed plan to perform UT tests prior to the period of extended operations, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals is insufficient to maintain an adequate safety margin.

8. On March 30, 2007, AmerGen Energy Company, LLC (AmerGen) filed a "Motion for Summary Disposition of Citizens' Drywell Contention" ("SD Motion"). The Staff filed a response supporting the motion and Citizens opposed the motion. *See* NRC Staff Response to AmerGen's Motion for Summary Disposition (Apr. 26, 2007); Citizens' Answer Opposing AmerGen's Motion for Summary Disposition (Apr. 26, 2007).

9. In "Memorandum and Order (Denying AmerGen's Motion for Summary Disposition) (June 19, 2007) (unpublished) ("SD Order")," the Board denied summary

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[4] The admitted contention alleged that "AmerGen's corrosion management program . . . will not enable AmerGen to determine the amount of corrosion in that region and thereby maintain the safety margins during the term of the extended license." LBP-06-07, 63 NRC at 217.

[5] Letter from Michael P. Gallagher, AmerGen, to NRC (Apr. 4, 2006) (ML060970288).

disposition finding that a genuine dispute of material fact existed regarding (1) the remaining safety margins, (2) the potential for corrosion under the epoxy coating due to defect in and deterioration of the coating that is "past its useful life" and (3) future corrosion rates.[6] In the SD Order and a "Memorandum and Order (Clarifying Memorandum and Order Denying AmerGen's Motion for Summary Disposition)" (July 11, 2007) ("July 11 Order"), the Board noted that Citizens "may not challenge the derivation or validity of the established acceptance criteria or the methodology for analyzing UT results," (SD Order at 8) and Citizens may not "challenge any aspect of AmerGen's UT monitoring program that applies prior to the period of extended operation (*i.e.* prior to 2009)."[7] July 11 Order at 2.

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[6] The relevant factual issues for litigation following summary disposition were:

> (1) the amount by which the remaining thickness of the shell exceeds the established criteria in the sand bed region; (2) existence *vel non* of a corrosive environment, taking into account whether sources of water have been eliminated as well as whether, regardless of the potential existence of water, a corrosive environment can exist in the sand bed region after the sand was removed and the protective coating applied, particularly considering that the sand is no longer there to hold water in the previously corroded areas of the shell; and (3) the corrosion rate – including the uncertainties related to its determination [e.g., limited accuracy of the measurement method used, use of a limited number of data points, and the method use to analyze and interpret the data].

SD Order at 7.

[7] As noted in SD order at n.4, during the course of this proceeding, we have found that the following contentions proffered by Citizens were inadmissible: (1) Citizens' challenge to AmerGen's monitoring program for areas of the drywell shell below and above the sand bed region (LBP-06-11, 63 NRC 391, 396-400, *review denied on other grounds*, CLI-06-24, 64 NRC 111 (2006)); (2) Citizens challenge asserting that AmerGen be directed to conduct a root cause analysis of the corrosion problem (*id.* at 400-01); (3) Citizens' challenge to AmerGen's modeling for deriving acceptance criteria (LBP-06-22, 64 NRC at 237-40; Licensing Board Memorandum and Order at 6-12 (Apr. 10, 2007) (unpublished)); (4) Citizens' challenge to AmerGen's monitoring program in the sand bed region for moisture and coating integrity (LBP-06-22, 64 NRC at 244-48); (5) Citizens' challenge to AmerGen's program for responding to wet conditions and coating failure in the sand bed region (*id*. at 248-49); (6) Citizens' challenge to the scope of AmerGen's UT monitoring program in the sand bed region (*id.* at 249-51; Licensing Board Memorandum and Order at 7-19 (Feb. 9, 2007) (unpublished) ("Feb. 9 Order")); (7) Citizens' challenge to AmerGen's quality assurance program for measurements in the sand bed region (LBP-06-22, 64 NRC at 251-53); and (8) Citizens' challenge to AmerGen's methods for analyzing UT results in the sand bed region (*id*. at 254-55).

10. On July 20, August 17, and September 14, 2007, respectively, the parties filed initial,[8] rebuttal,[9] and sur-rebuttal[10] presentations and testimony. In addition, the parties filed motions in limine regarding prefiled testimony and responses to those motions.[11] In ruling on

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[8] *See:* AmerGen Energy Company, LLC Initial Statement of Position and attached AmerGen's Pre-filed Direct Testimony in seven parts: Part 1: Introduction, Drywell Physical Structure, History and Commitments ("Part 1"); AmerGen's Pre-filed Direct Testimony: Part 2: Acceptance Criteria ("Part 2"); AmerGen's Pre-filed Direct Testimony: Part 3: Available Margin ("Part 3"); AmerGen's; Pre-filed Direct Testimony: Part 4: Sources of Water("Part 4");AmerGen's Pre-filed Direct Testimony: Part 5: The Epoxy Coating ("Part 5");AmerGen's Pre-filed Direct Testimony: Part 6: Future Corrosion ("Part 6");AmerGen's Pre-filed Direct Testimony: Part 7: Conclusion ("Part 7"). Citizens' Initial Statement Regarding Relicensing of Oyster Creek Nuclear Generating Station and attached Initial Pre-Filed Written Testimony of Dr. Rudolf H. Hausler Regarding Citizens' Drywell Contention. NRC Staff Initial Statement of Position on the Drywell Contention.and attached NRC Staff Testimony of Hansraj G. Ashar, Dr. James A. Davis, Dr. Mark Hartzman, and Timothy L. O'Hara.

[9] AmerGen Energy Company, LLC Rebuttal Statement of Position and attached AmerGen's Pre-filed Rebuttal Testimony [Part 1];AmerGen's Pre-filed Rebuttal Testimony [Part 2];AmerGen's Pre-filed Rebuttal Testimony [Part 3];AmerGen's Pre-filed Rebuttal Testimony [Part 4];AmerGen's Pre-filed Rebuttal Testimony [Part 5];AmerGen's Pre-filed Rebuttal Testimony [Part 6]. Citizens' Rebuttal Regarding Relicensing of Oyster Creek Nuclear Generating Station and attached Citizens' Rebuttal Regarding Relicensing of Oyster Creek Nuclear Generating Station and attached Pre-Filed Rebuttal Written Testimony of Dr. Rudolf H. Hausler Regarding Citizens' Drywell Contention. NRC Staff Response to Initial Presentations and Response to Board Questions and attached NRC Staff Rebuttal Testimony Hansraj G. Ashar, Dr. James A. Davis, Dr. Mark Hartzman, Timothy L. O'Hara, and Arthur D. Salomon and Answer to Board Questions.

[10] AmerGen Energy Company, LLC SurRebuttal Statement of Position and attached AmerGen's Pre-filed SurRebuttal Testimony [Part 1]; AmerGen's Pre-filed SurRebuttal Testimony [Part 2];AmerGen's Pre-filed SurRebuttal Testimony [Part 3];AmerGen's Pre-filed SurRebuttal Testimony [Part 4];AmerGen's Pre-filed SurRebuttal Testimony [Part 5];AmerGen's Pre-filed SurRebuttal Testimony [Part 6]; AmerGen's Pre-filed SurRebuttal Testimony [Part 1]. Citizens' Reply to AmerGen and NRC Staff Rebuttal Testimony and attached Pre-Filed Sur-Rebuttal Written Testimony of Dr. Rudolf H. Hausler Regarding Citizens' Drywell Contention. NRC Staff Rebuttal Testimony NRC Staff Response to Rebuttal Presentations and attached NRC Staff Sur-Rebuttal Testimony Hansraj G. Ashar, Dr. James A. Davis, Dr. Mark Hartzman, Timothy L. O'Hara, and Arthur D. Salomon

[11] Motions and response to motion in limine on initial presentations: AmerGen's Motion in Limine to Exclude Portions of Citizens' Initial Written Submission (July 27, 2007); NRC Staff Motion in Limine Regarding Citizens' Presentation on Drywell Contention (July 27, 2007); Citizens' Motion for Clarification and Motion in Limine (July 27, 2007); AmerGen's Answer to Citizens' Motion for Clarification and Motion in Limine and Answer to Staff's Motion in Limine (Aug. 1, 2007); NRC Staff Answer to AmerGen's Motion in Limine Regarding Citizens' Initial Presentation (Aug. 1, 2007); NRC Staff Answer to Citizens' Motion for Clarification and Motion in Limine (Aug. 1, 2007); Citizens' Opposition to AmerGen and Staff Motions in Limine (Aug. 1, 2007). Motions and response to motions in limine on rebuttal testimony: AmerGen's Motion in Limine Regarding Portions of Citizens' Rebuttal (Aug. 27, 2007); NRC Staff Motion in Limine Regarding Citizens' Response to Board Question 12 (Aug. 27, 2007): Citizens' Opposition to AmerGen (continued. . .)

the parties' motions in limine on initial presentations, the Board stated that it would accord no weight to Citizens' arguments proposing the use of additional UT measurements from the outside of the reactor vessel, proposing alternative means for estimating the remaining thickness of the drywell shell, or suggesting that AmerGen's UT data is not sufficiently accurate. *See* Memorandum and Order (Ruling on Motions in Limine and Motion for Clarification) (Aug. 9, 2007) (unpublished) at 4. The Board reiterated that Citizens could not challenge the derivation of the acceptance criteria or the spatial scope of AmerGen's UT monitoring program. *Id.* at 6. The Board further stated that Citizens could not argue that in addition to or in lieu of periodic UT monitoring, AmerGen should be required to perform real-time corrosion monitoring. *Id.*

11. The Board denied motions in limine filed by AmerGen and the Staff on August 27 and September 18, as well as Citizens' "Motion to Cross-Examine Peter Tamburro and For Extension of Time Regarding NRC's Errata" (Aug. 24, 2007). *See* Memorandum and Order (Ruling on Motion to Conduct Cross-Examination and Motions in Limine) (Sept. 12, 2007);[12] Memorandum and Order (Ruling on Motions in Limine) (unpublished) (Sept. 21, 2007).

12. In Memorandum and Order (Hearing Directives) (Sept. 12, 2007) ("Sept. 12 Order") at 2, Attachment A, the Board ordered Citizens to expunge portions of its prefiled direct testimony that exceeded the scope of the admitted contention.

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and NRC Motions in Lmine (Aug. 31, 2007); NRC Staff Answer to AmerGen Motion in Limine Regarding Citizens' Rebuttal (Aug. 31, 2007). Motions in limine and response on sur-rebuttal presentations: AmerGen's Motion to Exclude Portions of Citizens' Sur-Rebuttal (Sept. 18, 2007); NRC Staff Motion in Limine Regarding Citizens' Reply (Sept. 18, 2007); NRC Staff Response to AmerGen's Motion in Limine Regarding Citizens' Presentation on Drywell Contention (Sept. 19, 2007).

[12] Previously, the Board denied a Citizens' motion to apply formal 10 C.F.R. Part 2, Subpart G procedures to this proceeding. *See* Memorandum and Order (Denying NIRS's Motion to Apply Subpart G Procedures) (June 5, 2006) (unpublished).

13. The Board held two limited appearance sessions on May 31, 2007 in Toms River, NJ.[13] On September 20, 2007, the Board convened a brief evidentiary session on the admitted contention and received into evidence prefiled written direct, rebuttal and sur-rebutal testimony as exhibits, in accordance with 10 C.F.R. § 2.1207(b)(2), and other exhibits proffered by the parties. Tr. 199 (Applicant Exhs.); Tr. 232 (Citizens Exhs.); Tr. 247 (Staff Exhs.). In addition to testimony, the Board admitted 61 AmerGen exhibits, 62 Citizens exhibits and six Staff exhibits. *Id.*

14. An evidentiary hearing concerning the admitted contention was held in Toms River, New Jersey, on September 24-25, 2007, in accordance with the notice of hearing published in the *Federal Register*.[14] During the hearing, we also admitted additional exhibits from AmerGen and Citizens. Tr. 21, 16. The record for this proceeding was closed on September 25, 2007, subject only to transcript corrections. Tr. 603.

B. Witnesses

15. During the evidentiary hearing on Citizens' drywell shell monitoring contention, a total of 21 witnesses appeared on behalf of AmerGen, Citizens and the Staff.

16. AmerGen presented the testimony of 15 qualified witnesses, namely: 1) Julien D. Abramovici, Enercon Services, Inc.; 2) Jon Cavallo, Vice-President of Corrosion Control Consultants and Labs, Inc.; 3) Scott R. Erickson, NDE Level III Inspector; 4) Michael P. Gallagher, Vice President for License Renewal for Exelon; 5) Barry M. Gordon, Structural Integrity Associates; 6) Dr. David G. Harlow, Professor of Mechanical Engineering and

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[13] *See* Notice (Notice of Opportunity to Make Oral or Written Limited Appearance Statements) 72 Fed. Reg. 21,055 (Apr. 27, 2007) .

[14] Notice of Hearing (Application for 20-year License Renewal), 72 Fed. Reg. 48,694 (Aug. 24, 2007).

Mechanics, Lehigh University; 7) Jon C. Hawkins, NDE Level 3 Inspector; 8) Edwin W. Hosterman, Senior Staff Engineer, Corporate Engineering Programs Group, Exelon; 9) Martin McAllister, NDE Level III Inspector; 10) Ahmed M. Ouaou, contractor engineer for Exelon; 11) John F. O'Rourke, Senior Project Manager, License Renewal for Exelon; 12) Fred Polaski, Manager of License Renewal for Exelon; 13) Francis H. Ray, Engineering Programs Director at OCNGS; 14) Peter Tamburro, Senior Mechanical Engineer, OCNGS Engineering Department; and 15) Dr. Hardayal S. Mehta, Chief Consulting Engineer-Mechanics GE-Hitachi Nuclear Energy Co. Tr. 11-12. The professional qualifications of the each witness was appended to their prefiled testimony and separately admitted as AmerGen Exhibit D.

17. Citizens presented the testimony of Dr. Rudolph Hausler, a corrosion consultant with experience in oil industry, but not a structural engineer. Tr. 47. His qualifications were admitted as Citizens Exhibit D.

18. The Staff presented testimony of highly qualified witnesses, namely: 1) Hansraj G. Ashar, a Senior Structural Engineer in the Division of Engineering, Office of Nuclear Reactor Regulation (NRR); 2) Dr. James A. Davis, a Senior Materials Engineer in the NRR Division of License Renewal; 3) Dr. Mark Hartzman, a Senior Mechanical Engineer in the NRR Division of Engineering; 4) Timothy L. O'Hara, a Reactor Inspector in the Division of Reactor Safety, NRC Region I Office; and 5) Arthur D. Salomon, a Research (Mathematical) Statistician in the Office of Nuclear Regulatory Research. The professional qualifications of the each witness were appended to their prefiled testimony and separately admitted as NRC Staff Exhibit D.[15]

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[15] Staff Exh. D also included the professional qualifications of two witnesses that did not testify during the hearing. *See* Administrative Session, Tr. 241-42. Citizens argued that an additional session would be needed to rebut any testimony by the two witnesses. Tr. 259-60. Because the witnesses did not testify at the evidentiary hearing, in Toms River, New Jersey, the matter became moot.

19. All of the witnesses were found to be qualified to present testimony on the areas they addressed, however, the Board accorded greater weight to the testimony of AmerGen and Staff witnesses who (a) inspected, reviewed or physically observed the condition of the drywell shell and epoxy coating, (b) were experienced in performing or reviewing drywell buckling analyses, or (c) were familiar with nuclear standards. Each witness provided both written prefiled testimony and oral testimony in response to Board questioning during the evidentiary hearing.

III. LEGAL AND REGULATORY REQUIREMENTS

20. The scope of license renewal proceedings is limited.[16] The Commission's "[l]icense renewal reviews are not intended to 'duplicate the Commission's ongoing review of operating reactors.'" *Florida Power & Light Co.* (Turkey Point Nuclear Generating Plant, Units 3 & 4), CLI-01-17, 54 NRC 3, 7 (2001) (citing Final Rule, "Nuclear Power Plant License Renewal," 56 Fed. Reg. 64,943, 64,946 (Dec. 13, 1991)). The license renewal safety review process focuses on the "potential detrimental effects of aging that are not routinely addressed by ongoing regulatory oversight programs." *Id*. Consequently, "10 C.F.R. Part 54 requires renewal applicants to demonstrate how their programs will be effective in managing the effects of aging during the period of extended operation." *Id.* at 8 (citing 10 C.F.R. § 54.21(a)).

21. Applicants are required to "identify any additional actions, i.e., maintenance, replacement of parts, etc., that will need to be taken to manage adequately the detrimental effects of aging." *Id.* (citing Final Rule, "Nuclear Power Plant License Renewal: Revisions,"

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[16] The adequacy of the Staff's safety review is not subject to challenge in this proceeding. See Rules of Practice for Domestic Licensing Proceedings-Procedural Changes in the Hearing Process, Final Rule, 54 Fed Reg. 33168, 33171 (Aug. 11, 1989) (*citing Pacific Gas and Electric Co*. (Diablo Canyon Nuclear Power Plant, Units 1 and 2), ALAB-728, 17 NRC 777, 807, review declined, CLI-83-82, 18 NRC 1309 (1983)).

60 Fed. Reg. 22,461, 22,479 (May 8, 1995)). The Commission has recognized that these "adverse aging effects generally are gradual and thus can be detected by programs that ensure sufficient inspections and testing." *Id.* (citing 60 Fed. Reg. at 22,475). Therefore, license renewal proceedings are limited to a "review of the plant structures and components that will require an aging management review for the period of extended operation and the plant's systems, structures, and components that are subject to an evaluation of time-limited aging analyses." *Duke Energy Corp.* (McGuire Nuclear Station, Units 1 and 2; Catawba Nuclear Station, Units 1 and 2), CLI-01-20, 54 NRC 211, 212 (2001) (citing 10 C.F.R. §§ 54.21(a) and (c), 54.4; Nuclear Power Plant License Renewal: Revisions, Final Rule, 60 Fed. Reg. 22,461 (1995)).

22. Sections 54.21 and 54.29 of 10 C.F.R. Part 54 set forth the standards governing renewal of a plant's operating license. Pursuant to § 54.21, AmerGen must demonstrate that its UT monitoring program is adequate to manage the aging effects of corrosion on Oyster Creek's drywell so that the intended function of the drywell will be maintained during the period of extended operations consistent with the current licensing basis. Pursuant to § 54.29, one of the findings the Staff must make in order to renew the Oyster Creek license is that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis ("CLB").[17] Together, §§ 54.21 and

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[17] Current licensing basis is defined in 10 C.F.R. § 54.3 as:

> [T]he set of NRC requirements applicable to a specific plant and a licensee's written commitments ensuring compliance with and operation within the applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final

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54.29 require that AmerGen establish an aging management program that is adequate to provide reasonable assurance that the intended functions of the Oyster Creek drywell shell will be maintained in accordance with the CLB[18] during the period of extended operation.

23. Although reasonable assurance appears in many areas of the Commission case law and regulations, it is not specifically defined in either the Atomic Energy Act or the Commission's regulations. The courts, however, have stated that "reasonable assurance" does not mean zero risk or absolute certainty. *Nader v. Ray*, 363 F. Supp. 946, 954 (D.D.C. 1973); *Maine Yankee Atomic Power Co.* (Maine Yankee Atomic Power Station), ALAB-161, 6 AEC 1003, 1009 (1973). *See also North Anna Envl. Coalition v. NRC*, 533 F.2d 655, 667 (D.C. Cir. 1975) (rejecting argument that reasonable assurance requires proof beyond a reasonable doubt and noting that Licensing Board equated "reasonable assurance" with "a clear preponderance of the evidence"). Courts have also stated that, with respect to reasonable assurance of adequate protection of public health and safety, it is a determination to be made on a case-by-case basis.[19] *See Union of Concern Scientists v. NRC*, 880 F.2d 552, 558 (D.C. Cir. 1989) (stating

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> safety analysis report (FSAR) as required by 10 CFR 50.71; and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Oyster Creek's current licensing basis cannot be challenged in this proceeding. In establishing its license renewal process, the Commission determined that it was neither necessary nor appropriate to reanalyze a plant's current licensing basis during a license renewal review. *See Florida Power & Light Co.* (Turkey Point Nuclear Generating Plant, Units 3 & 4), CLI-01-17, 54 NRC 3, 6 (2001) (citing "Nuclear Power Plant License Renewal; Revisions," 60 Fed. Reg. 22,461, 22,473 (May 8, 1995)). In addition, whether Oyster Creek is presently in compliance with its current licensing basis ("CLB") is not an issue in this proceeding. *See* 60 Fed. Reg. at 22,473 (stating that the Commission's on-going regulatory process, which includes inspection and enforcement activities, ensures compliance with the CLB). Challenges to the adequacy of current operation may be raised separately via a 10 C.F.R. § 2.206 petition.

[19] Reasonable assurance is a flexible standard and does not require focus on extreme values or (continued. . .)

that "adequate protection" may be given content through case-by-case applications of technical judgment and that Congress neither defined nor commanded the Commission to define adequate protection). *See also Revision of Backfitting Process for Power Reactors*, 53 Fed. Reg. 20,603, 20,605 (June 6, 1988) (stating that like "adequate protection," "reasonable assurance" is a determination based upon full consideration of all relevant information).

24. Reasonable assurance is based upon technical judgment, not application of a mechanical verbal formula, a set of objective standards, or specific confidence interval. *C.f. UCS*, 880 F.2d at 558. The Commission has explicitly stated that reasonable assurance does not denote a specific statistical parameter. *See* "Disposal of High-Level Radioactive Wastes in a Proposed Geological Repository at Yucca Mountain, Nevada," 66 Fed. Reg. 55,732, 55739-40 (Nov. 2, 2001). The touchstone of reasonable assurance of adequate protection of public health and safety is compliance with the Commission's regulations. *See Maine Yankee*, 6 AEC at 1009.

25. In the context of license renewal, an adequate aging management plan provides reasonable assurance. An adequate aging management program monitors the performance and condition of structures and components subject to aging mechanisms in a manner that allows for the timely identification and correction of degraded conditions. *See* 60 Fed. Reg. at 22,469.

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precise quantification of parameters to a high degree of confidence. *See* "Disposal of High-Level Radioactive Wastes in a Proposed Geological Repository at Yucca Mountain, Nevada," 66 Fed. Reg. 55,732, 55739-40 (Nov. 2, 2001).

IV. FINDINGS OF FACT

A. Statement of Issue

26. The issue before the Board in this proceeding is "whether, in light of uncertainty regarding the existence *vel non* of a corrosive environment in the sand bed region and the correlative uncertainty regarding corrosion rates in that region, [the frequency of] Amergen's UT monitoring plan is sufficient to ensure adequate safety margins" during the license renewal period. SD Order at 2; July 11 Order at 3. The overall burden of persuasion is on AmerGen to demonstrate that the frequency of the UT monitoring program is adequate to manage the aging effects of corrosion on Oyster Creek's drywell so that the intended function of the drywell will be maintained during the period of extended operations. *See* 10 C.F.R. § 2.325. Citizens, however, must come forward with evidence that AmerGen's aging management program is inadequate. *Louisiana Power & Light Co*. (Waterford Steam Electric Station, Unit 3), ALAB-732, 17 NRC 1076, 1093 (1983).

B. Drywell Corrosion, Commitments and Acceptance Criteria

1. Corrosion History

27. The Oyster Creek drywell shell is an approximately 100 ft. tall, plated carbon steel pressure vessel that is shaped like an inverted light bulb and is surrounded by a concrete shield wall. Applicant Exh. B, Part 1 at A.7; Applicant Exh. 3 (Letter from M. Gallagher, AmerGen to NRC (Dec. 8, 2006)); Applicants Exhs. 4 and 5. The spherical section at the bottom of the drywell is approximately 70 feet in diameter. Applicant Exh. B, Part 1 at A.7; Citizens Exh. B, Attachment 5 at 1. The reactor support structure (or pedestal) sits on the floor inside the drywell. Applicant Exh. 2 at 3-1. The drywell shell is embedded into a concrete pedestal on the Reactor Building concrete foundation. Applicant Exh. B, Part 1 at A.7; Applicant Exh. 1. The drywell shell was designed, fabricated, inspected and tested in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section VIII and Nuclear Code Cases

1270N-5, 1271N and 1272-N5. Applicant Exh. 2 at 3-1.

28. The drywell shell's function is to handle pressure and temperatures associated with a potential break of enclosed reactor pressure boundary piping and to provide structural support to the reactor pressure vessel, the reactor coolant systems and other systems, structures and components within the drywell. *Id.* at A.8; LRA § 2.4.1 (Applicant Exh. 2); Citizens Exh. B, Attachment 5 at 1. The temperature in the drywell is normally averages around 139° F. Applicant Exh. B, Part 1 at A18. During normal operation the drywell is closed and inerted with nitrogen. Applicant. Exh. B, Part 3 at A.8.

29. The drywell shell is connected to the torus[20] by ten cylindrical torus vent headers that protrude from the spherical section of the drywell. Applicant Exh. B, Part 1, at A7. Originally, there was a sand-filled sand bed region on the exterior of the drywell shell extending approximately from an elevation 8' 11" to 12' 3" to support the shell as it transitioned from being embedded in concrete on both sides below 8'11"— the elevation of the surface of the exterior drywell concrete floor — to being embedded on only the interior. Applicant Exh. B, Part 1 at A.9; Applicant Exhs. 4 and 7. The interior drywell has a curb around the perimeter of the drywell floor to prevent any water from collecting on the interior surface of the drywell shell. Applicant Exh. 3 at 3-1. Two trenches were excavated in the interior concrete floor of the drywell shell in the late 1980s to permit UT measurements from inside the drywell. Applicant Exh. B, Part 1, at A.9. Above the sand bed region, the drywell shell is situated within a few inches of the Reactor Building concrete shield wall. Applicant Exh. B, Part 1, at A.12.

30. The sand bed region of the drywell shell is spherical and has ten odd numbered

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[20] The torus, a steel pressure vessel that encircles the base of the drywell, is partially filled with water to provide suppression in the event of a loss-of-coolant accident. Applicant Exh. B, Part 1, A.11.

bays (from 1-19) and each bay has a vent. Applicant Exh. B, Part 1 at A.10; Applicant Exhs. 5, 6 and 7. There are five drains spaced around the drywell shell and in the sand bed region floor that are designed to drain water from the sand bed floor into the torus room below. Plastic tubing diverts water from the drains into five-gallon plastic bottles. Applicant Exh. B, Part 1 at A.10.

31. The reactor cavity (or refueling cavity), is located above the drywell and is filled with water only during refueling outages (which typically last 19-30 days every two years) or other outages when the reactor vessel needs to be opened. Applicant Exh. B, Part 1 at A.13, A.16. The next outage is scheduled for October 2008. *Id.* at A.16.

32. Corrosion of the sand bed region of the Oyster Creek drywell shell was identified in the late 1980s. Staff Exh. 1 (NUREG-1875, "Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station" (April 2007) ("SER")). at 4-42. The accumulation of water leaking from small cracks in the reactor cavity into the gap between the drywell shell and the shield wall concrete during refueling outages was retained in the wet sand due to improper drainage caused corrosion on the exterior of the drywell shell. Staff Exh. B at A5; Staff Exh. 1 at 4-42 to 4-43; Applicant Exh. B, Part 1 at A.20, A.22 .

33. Drywell shell corrosion occurred more near the top of the sand bed region than at the bottom. Dr. Hausler Tr. 50; Gallagher, Tr. 69-70. The original thickness of the drywell shell in the sand bed region was 1.154 inches. Applicant Exh. B, Part 1 at A.22. Staff Exh. C.1 at A47. About 50 percent of the sand bed region is not significantly degraded (*e.g.*, the wall thickness in four bays is over an inch thick and the bays show no degradation) and about 95 percent of the entire drywell shell is not degraded. Tamburro, Tr. 358-60. Eighty percent of the sand bed region is 800 to 900 mils thick. Tamburro, Tr. 360.

34. Corrective actions taken in the late 1980s and early 1990s to prevent additional corrosion of the exterior drywell shell in the sand bed region included removal of the sand from

the sand bed region, clearing of the sand bed drains, removal of corrosion products from the exterior of the drywell shell, application of a multi-layer epoxy coating on the shell exterior in 1992, repair of the concrete floor, application of caulk to seal the junction between the exterior drywell shell and concrete floor, and application of stainless steel tape and a strippable coating to the reactor cavity liner. Applicant Exh B, Part 1, A.23; Staff Exh. B at A12(b), A14; Staff Exh. 1 at 4-42 to 4-43; Staff Exh. C.1 at A45.

35. Prior to coating the shell, exterior thickness measurements taken in each of the 10 bays of the drywell identified that there was an average wall thickness generally greater than 0.800 inch and greater than the minimum average thickness of 0.736 inch specified in the structural analysis of the drywell shell using the provisions of ASME Section III, Code Case N-284. Staff Exh. B at A5.

36. AmerGen believes the corrective actions taken and UT testing show that the corrosion of the exterior drywell shell has been arrested. Appl. Exh. B, Part 1 at A.24; Staff Exh. B at A22; Staff Exh. 1 at 3-126.

2. Aging Management Program Commitments

37. The Staff reviewed AmerGen's drywell aging management program (ASME Section XI, Subsection IWE) and found it consistent with guidance for managing the effects of aging on the drywell. Staff Exh. B at A10, A24; Staff Exh. 1 at 3-143, 3-167, 4-75. The Staff also reviewed AmerGen's Protective Coating Monitoring and Maintenance Program (i.e. the program for monitoring the coating on the exterior of the drywell) and concluded that the program provided adequate guidance to ensure that the effects of aging on the drywell shell, including the sand bed regions, will be adequately managed. Staff Exh. B at A15, A18, A24; Staff Exh. 1 at 3-167.

38. During the Staff's review of the LRA, AmerGen committed to enhance its ASME Section XI, Subsection IWE Primary Containment Program with additional provisions. Applicant

Exh. B, Part 1 at A.25; Staff Exh. B at A15; Applicant Exh. 10 at Enclosure; Staff Exh. 1, Appendix A (Commitment 27 (21 Items)). The Staff relied on those commitments as part of its basis for concluding that AmerGen's aging management program provides reasonable assurance that the effects of aging will be adequately managed such that the drywell will perform its intended functions consistent with the CLB during the period of extended operation. Staff Exh. B at A15; Staff Exh. 1 at sections 3.0.3.2.23 and 3.0.3.2.27.[21]

39. AmerGen's commitments include performing a full scope UT measurement during the 2008 refueling outage and every other refueling outage (i.e., every four years) using the same internal grids and over 100 external locations that were measured during the 2006 outage. Staff Exh. B at A17, A18; Staff Exh. 1 at 1-16 to 1-17; Staff Exh. 1 at Appendix A, Commitment 27, Items 4, 9, 14, and 21; Applicant Exh. 10 at Enclosure.

40. To address certain leakages from components inside the drywell during outages, AmerGen committed to monitoring the two trenches inside the drywell for the presence of water until no water is identified for two consecutive outages. Staff Exh. B at A12(a).

41. To eliminate water on the drywell exterior, AmerGen has committed to monitor the sand bed region drains on a quarterly basis during the operating cycle and take corrective actions if water is found. Staff Exh. B at A12(b); Staff Exh 1 at 1-16, 1-17.

42. AmerGen also committed to use a strippable coating on the reactor cavity wall (during periods when the reactor cavity is flooded) during the proposed period of extended

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[21] The Staff found the frequency of inspections adequate because UT measurements taken during the 2006 outage confirmed that the epoxy coating in the sand bed area has been effective in reducing the potential for corrosion in this area since the changes in thicknesses were so small. Id. at A11. The Staff concluded that AmerGen's aging management program, as enhanced by Commitments 27 and Commitment 33, is consistent with GALL AMP XI.S1, ASME Section XI, Subsection IWE, such that the effects of aging will be adequately managed for the period of extended operation provided AmerGen effectively implements enhancements to its aging management program. Staff Exh B at A7; Staff Exh. 1 at 3-167, 4-72 to 4-75.

operation that has been shown to be effective in mitigating water intrusion into the annular space between the drywell shell and the shield wall. Staff Exh. B at A.12; Staff Exh. 1 at Appendix A, (Commitment 27, Item 2).

43. Commitment 27, Item 21 (Staff Exh. 1 at A-32), provides that AmerGen will perform a full scope drywell sand bed region inspection in 2008 (prior to the period of extended operation) and then every other refueling outage thereafter. The Staff (Exh. B at A10) explained that a full scope inspection is defined as:

- UT measurement from inside the drywell
- Visual inspections of the drywell external shell epoxy coating in all ten bays
- Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell, and
- UT measurements at the external areas inspected during the 2006 outage.

Any anomaly associated with inspections during the 2008 outage will be tracked prior to the start of license renewal period. *Id.*

44. AmerGen committed to conduct visual and UT inspection of the two trenches until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration. Staff Exh. 1 (SER) at A-31 to A-32.

45. AmerGen committed to conduct inspections of the multi-layer epoxy coating in the sand bed region in accordance with ASME Code Section XI, Subsection IWE (Commitment 27, Items 4 and 21, and Commitment 33) and to perform repairs, as necessary, to manage corrosion. Staff Exh. B at A13; Staff Exh. 1, Appendix A; Applicant Exh.10. AmerGen's coating inspection commitments provide that the area will be inspected by VT-1 visual examinations and (a) the area will be examined for evidence of flaking, blistering, peeling, discoloration, and other

signs of distress, (b) areas that are suspect will be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122 (Staff Exh. 2), and (c) supplemental examinations in IWE-3200 (Staff Exh. 2) will be performed when specified as a result of the engineering evaluation. Staff Exh. 1 at 3-120, A-18 to A-23, A-32 to A-33.

46. Consistent with a recommendation made by the Advisory Committee for Reactor Safeguards ("ACRS"), the renewed license will include a condition that requires AmerGen to perform full scope inspections of the drywell every other refueling outage during the proposed renewal period. Staff Exh. B at A10; Staff Exh. 3 (Letter from W. Shack to Dale Klein, "Report on the Safety Aspects of the License Renewal Application for the Oyster Creek Generating Station" (Feb. 8, 2007) ("ACRS Report")); Staff Exh. 1 at 1-18.

47. The Board finds that the commitments regarding the drywell shell in the sand region are as described above, in AmerGen Exhibit 10 and the Staff's SER (Staff Exh. 1, Appendix A, Commitments 27 and 33). The remainder of the decision examines Citizens' disputes related to the frequency of UT monitoring under AmerGen's aging management program.

3. Acceptance Criteria

a. Evidence

48. The current licensing basis for buckling of the Oyster Creek drywell shell (designed to ASME Code Section VIII) is based on General Electric (GE) analyses performed in 1991-1992. Staff Exh. B at A7; Applicant Exh. B, Part 2, at A.13, A.14. After degradation of the drywell shell was discovered, the structural stability of the shell was evaluated using ASME Code Case N-284 (see Applicant Exhibit 42), to demonstrate whether buckling would occur after removal of the sand in the sand bed region. Applicant Exh. C.1, Part 2, at A.4, A.5; Staff Exh B at A.7. The objective of the analyses was to provide reasonable assurance that the structural integrity of the as-built shell (and with degraded wall thickness in the sandbed region) would be

maintained under refueling conditions, by showing that the stresses do not exceed ASME Section III, Subsection NE, provisions.[22] Staff Exh. B at A7.

49. The term "buckling" refers to "linear bifurcation buckling," which is the state where adjacent equilibrium configurations of the shell may exist under the same loading condition. Staff Exh. B at A7.

50. The Oyster Creek drywell accommodates the loads (refueling pool water weight, external pressure, dead weight and potential earthquake loading equivalent to a safe shutdown earthquake) acting during the refueling loading condition, which was found to be the limiting condition. Staff Exh. C.1 at A53; Staff Exh. B at A7. The governing failure mode of the as-built (and degraded)drywell shell was determined as elastic buckling in the sand bed region. Staff Exh. C1 at A53.

51. The GE analysis included a buckling analysis of Oyster Creek's drywell shell, considering a uniform reduction in the sand bed region wall thickness due to corrosion to 0.736 inch and later modeled locally thinned areas in the sand bed region. Staff Exh. B at A7; Staff Exh. C.1 at A54; Applicant Exh. C, Part 2, at A.6; Applicant Exh. C.1, Part 2 at A.3.

52. A GE analysis (AmerGen 39) of local thin areas assumed wall thicknesses of 0.536 inch and 0.636 inch, extending over a square foot area tapering to 0.736 inches over a 9 square foot area. Staff Exh. B at A7; Applicant Exh. C.1, Part 2, at A.3. The area most susceptible to buckling was found to be between bays and away from the stiffening effect of the vent headers. Applicant Exh. C, Part 2 at A.4; Dr. Mehta, Tr. 207-08.

53. GE's analysis showed that the postulated wall thinning did not have a significant

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[22] Due to its vintage, Oyster Creek is not required to adhere to ASME Code Section III under 10 C.F.R. § 50.55a. In addition, the provisions of ASME Code Section III, Subsection NE are not incorporated

effect on the allowable buckling loads. Staff Exh. B at A7. GE analyzed the shell using three-inch by three-inch finite element mesh. Applicant Exh. C, Part 2 at A.4; Mehta, Tr. 199; Staff Exh. C at Response A12(a). A 3 foot by 3 foot tray area with a bottom wall thickness of 636 mils would reduce the safety factor 3.5 percent. Mehta, Tr. 206-07; Hartzman, Tr. 246. A reduction in thickness to 536 mils reduces the safety factor about 9 percent. Mehta, Tr. 245; Hartzman, Tr. 246.

54. The general buckling criterion (a uniform thickness of 0.736 inch in the drywell sand bed region) became part of the licensing basis for Oyster Creek when the GE analysis was docketed and the Staff issued its April 1992, "Safety Evaluation of the Office of Nuclear Reactor Regulation: Drywell Structural Integrity Oyster Creek Nuclear Generating Station" (Applicant Exh. 37). Applicant Exh. C.1, Part 2, at A.3; Staff Exh. B at A7. The local buckling criterion of 0.536 inch in a tray configuration transitioning to 0.736 inch and the pressure criterion of 0.49 inch in circular areas with diameters up to 2.5 inches became part of the licensing basis through updates to Oyster Creek Updated Final Safety Analysis Report (UFSAR) that referenced a December 1992 GE Letter Report, "Sandbed Local Thinning and Raising the Fixity Height Analysis (Line Items 1 and 2 In Contract #PC-0391407)" (Dec. 11, 1992) (AmerGen Exhibit 39). GE's evaluation of locally thin areas was used to derive the criteria. Applicant Exh. C. 1, Part 2, at A.3, A.4; Staff Exh. B at A7; Staff Exh. C.1 at A42.

55. Based on information received from the 2006 outage inspection, the Staff's LRA review concluded that overall changes in the extent of drywell shell corrosion since 1992 are relatively small and are bounded by GE's analyses for the period of extended operation. Staff Exh. B at A7.[23]

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[23] To provide added assurance that the degraded shell could perform its function during the (continued. . .)

56. Citizens alleged that AmerGen has inconsistently applied the local wall buckling criterion because calculations performed by AmerGen after 1993 also evaluate thin areas using a 0.636 inch and 0.693 inch criteria in Calculation 24, Revs. 1 and 2. (Applicant Exhs. 16 and 18.) Citizens Exh. B, Attachment 5, at 2-5. Citizens also claimed that the local wall thickness criterion was not always applied to a 12 inch by 12 inch area transitioning to a 3 foot by 3 foot area. Citizens Exh. B, Attachment 5 at 4-5.

57. AmerGen testified, and the Staff agreed, that AmerGen's current licensing basis includes a general wall thickness acceptance criterion of 0.736 inch and a local area acceptance criterion of 0.536 in a one square foot area tapering to 0.736 inch. Ashar Tr. 146-47; Gallagher, Tr. 147-48. Calculations using other thicknesses, i.e. using 0.636 inch instead of 0.536 inch, do not form part of Oyster Creek's CLB. Tr. 145.

58. Dr. Hausler also questioned whether GE analyzed a 3 foot by 3 foot area and improperly listed only half the dimensions of the tray configuration. Citizens Exh. C at A6; Tr. 153, 150. The Staff testified that because Dr. Hausler was not a structural engineer, he did not understand that because of symmetry, the 6 inch by 12 inch and 1.5 feet by 3 feet areas modeled by GE actually analyze a 12 inch by 12 inch and 3 foot by 3 foot areas, respectively. Staff Exh. C.1 at A48.

(. . .continued)

renewal period, he Staff asked Sandia National Laboratory to perform a confirmatory analysis of the drywell's stability for the renewal period. Staff Exh. B at A7. Sandia analyzed degraded ("as-built") drywell shell using advanced modeling techniques to determine the controlling loads. Id.; Staff Exh. 6 (Sandia Report, SAND2007-00055, "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station" (Jan. 2007)) at 66, 76. Sandia used shell thickness from exterior UT measurements, evaluated two locally thin areas (18" by 30") in Bays 1 and 13 using the lowest thickness in those bays and determined that the degraded shell can withstand the postulated load conditions without exceeding the provisions of ASME Section III, Subsection NE, stress allowables. Staff Exh. 6 at 47-50, 67; Staff Exh. C.1 at A44.

59. GE performed analyses where a portion of the uniformly thinned drywell shell in the sand bed region is less than 0.736 inch, *i.e.*, the idealized "tray" configuration. Staff Exh. C.1 at A49. AmerGen and the Staff testified that the criteria for the drywell shell acceptance are (1) a general minimum average required thickness of 0.736 inch, (2) a minimum locally thin thickness of 0.536 inch, in an area of one square foot, with a surrounding one foot transition area to 0.736 inch, and (3) the minimum thickness of 0.49 inch in an isolated area not exceeding a circle having a diameter of two and one-half inches. AmerGen Exh B, Part 2 at A.14; Staff Exh B. at A.9. The LRA included the criteria. Applicant Exh. B, Part 2, at A.16; Applicant Exh. 12.[24]

60. AmerGen explained that it used thicker or more conservative "administrative limits'' of 0.636 inch and 0.693 inch in evaluations of locally thin areas. AmerGen Exh. B, Part 2, at A.18 to A.20 (discussing Calc-24, Rev.0 (1993) (Applicant Exh. 17), Calc-24, Rev. 1 (2006) (Applicant Exh. 18), Calc-24, Rev. 2 (2007) (Applicant Exh. 16), Tech Eval E09 (Applicant Exh. 19) and Calc-41 (2006) (Applicant Exh. 20)). AmerGen testified that the calculations using the thicker administrative limits were not part of its licensing basis. *E.g.*, Applicant Exh. B, Part 3, at A.19 to A.20; Tamburo, Tr. 150. The Staff agreed that the calculations were not part of the licensing basis or relied on during the review of the application. Staff Exh. B at A9.

61. Citizens also asserted that the Staff's acceptance of AmerGen's local acceptance

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[24] Oyster Creek's updated final safety analysis report (UFSAR) was submitted as part of its license renewal application and discusses the design of Oyster Creek's drywell and references GPU Technical Data Report, TDR No. 1108, "Summary of Corrective Actions Taken from Operating Cycle 12 through 14R" (Apr. 29, 1993) (AmerGen Exhibit 27), which describes the local wall thickness acceptance criterion of 0.536 inch in a 12 inch by 12 inch area tapering to 0.736 inch over an additional 12 inches. See Sur-Rebuttal Testimony at A42. Thus, the local wall thickness acceptance criterion of 0.536 inch in a one square foot area with a one square foot transition area on all sides to 0.736 inch is part of Oyster Creek's current licensing basis and cannot be challenged in this proceeding. See, e.g., August 9 Order at 5-6.

criterion for areas less than 0.736 inch thick was based on an assumption that only 0.68 square feet of the total area of the drywell was less than 0.736 inch. Citizens Exh. B, Attachment 5 at 2. The Staff stated that although the total area of all measured locations thinner than 0.736 inch was 0.68 sq. ft. of the over 700 sq. ft. sand bed surface of the drywell shell, the Staff found the criterion acceptable based on the buckling analysis that showed the effect of a nine square foot, degraded tray area with a 12 inch x 12 inch bottom 0.536 inch criterion would not be significant. Staff Exh. C at A38.

b. Board Findings

62. The Board has considered the evidence presented by the parties and concludes that the acceptance criteria are 0.736 inch general average wall thickness, 0.536 inch (with a surrounding one foot transition to 0.736 inch in a 3 foot by 3 foot tray area) and 0.49 inch as discussed above. We also find that the testimony shows that the three criteria were considered by the Staff during its review of the LRA[25] and the AmerGen calculations that analyze thicker areas have not been incorporated into Oyster Creek's licensing basis. Contrary to Citizens' assertion, see Citizens' Rebuttal Regarding Relicensing of Oyster Creek Nuclear Generating Station (August 17, 2007) (Citizens' Rebuttal) at 5-9, Oyster Creek's local thickness acceptance criterion of 0.536 inch in a 12 inch by 12 inch area transitioning to a 3 foot by 3 foot 0.736 inch area is part of Oyster Creek's CLB. The CLB, as defined in 10 C.F.R. § 54.3, includes "plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71 and licensee commitments documented in NRC safety evaluations"

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[25] The Staff's statement of the 0.536 inch criteria discussed in the SER at 4-55 to 4-61 did not include the transition area, but the Staff understood based on the GE local thinning analysis that there was a surrounding one foot transition area. *See*, e.g., Staff Exh. B at A9.

C. Available Margin and Future Corrosion

63. Citizens assert that there is uncertainty regarding the existence of a corrosive environment in the sand bed region of the drywell shell and correlative uncertainty regarding corrosion rates. *See* LBP-06-22, 64 NRC 229, at 240.

1. Available Margin

a. Remaining Thickness

i. Evidence

64. Dr. Hausler testified that the available margin above the general local acceptance criterion of 0.736 inch is 0.034 inch (based on the lower 95% confidence limit of the lowest average grid measurement), not the 0.064 inch as AmerGen claims and that AmerGen must demonstrate wall thickness acceptance criteria are met with a 95% confidence. Citizens Exh. B at A14, A16. Dr. Hausler testified that his contour plots were generated using exterior UT measurements because the internal UT measurements "are not representative" of the degradation in each bay, and are topographical maps of the degradation of the drywell shell, which illustrate the uncertainty about the extent of the corrosion of the drywell shell in the sand bed region. Citizens Exh. B at A14; Citizens Exh. C.1, Attachment 1; Tr. 248, 218.

65. AmerGen testified that the available thickness margin of the drywell in the sand bed region is 0.064 inch based on a comparison of the lowest average measurement of the UT grid measurements from the interior of the drywell of 0.800 inch and the general buckling criterion of 0.736 inch. Applicant Exh. B, Part 3 at A5; Applicant Exh. 16 at 5 of 183. The local buckling criterion of 0.536 inch and the pressure criterion of 0.490 inch are easily satisfied because the lowest single UT measurement obtained since 1992 is 0.602 inch. Applicant Exh B, Part 3, at A5, A31. Citizens improperly derived a 0.034 inch margin value by subtracting 0.030 inches from the lowest average grid measurement. Applicant Exh. C, Part 3, at A.27. AmerGen noted that Dr. Hausler did not explain the 0.030, but apparently derived a 0.034 inch

margin based upon AmerGen's statement to the NRC that it would take action if, in the future, the average of any internal grid data collected during an outage was +/- 0.021 inch from previous readings. Applicant Exh. C Part 3, at A.27; Staff Exh. 1 at 3-121. The 0.021 inch number is based on the standard deviation of internal UT data of 0.011 inch plus uncertainty to account for instrument inaccuracy of 0.010 inch. Applicant Exh. B, Part 3, at A27. *See* Staff Exh. 1 at 3-121. AmerGen testified that Citizens claim that 0.011 inch is only one standard deviation and two standard deviations are required for 95% confidence. Applicant Exh. B, Part 3, at A27. If one standard deviation is 0.011 inch, then two standard deviations is about .030 inch. Applicant Exh. B, Part 3, at A27. Thus, AmerGen testified, Citizens derive an available margin of 0.034 inch by subtracting the local buckling criterion of 0.736 inch from the lowest average grid measurement of 0.800 inch, and then subtracting 0.030 from the result, i.e., (0.800 inch – 0.736 inch – 0.030 = 0.034 inch.) Applicant Exh. C, Part 3, at A27.[26]

66. AmerGen's experts testified that the +/- 0.021 inch is an action limit. Applicant Exh. C, Part 3, at A28. If AmerGen used two standard deviations as Citizens recommend, AmerGen would not take action until the average of any internal grid data collected during an outage was +/- 0.030 inch from previous readings. AmerGen also testified that Citizens' approach focuses on the thinnest points in the grid and ignores thicker points. Applicant Exh. C,

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[26] AmerGen challenged Dr. Hausler's qualifications as a statistician. *See* AmerGen's Motion to Exclude Portions of Citizens' Initial Written Submission (July 27, 2007) at 3-4. Dr. Hausler states that "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)." Citizens Exh. 12 (Citizens Exh. B Attachment 2) at 7. According to AmerGen's Dr. Hausler performed the calculation incorrectly by failing to divide by $\sqrt{10}$. Applicant Exh. C, Part 3 at A31. Assuming this is the case, if 0.03 is the standard deviation — i.e., the sample standard deviation — of the 10 measurements, then one must divide this by the square root of the sample size (i.e., divide by $\sqrt{10}$). This results in $0.03/\sqrt{10}$ (= .0095). Then the lower confidence limit would be approximately 0.731 inches [0.75 – 2(.0095) = 0.75 – 0.019 = 0.731], a number substantially different and larger than that suggested by Dr. Hausler.

Mr. Salomon, the Staff's statistical expert, noted other errors in Dr. Hausler's testimony regarding statistics. *See* Staff Exh. C at A32-A34.

Part 3, at A29.

67. Citizens' asserted that 95% confidence in the available margin should be required. Citizens Exh. B at A12, A14. AmerGen experts testified that neither its acceptance criteria nor the ASME Code require that it bound the condition of the drywell shell with 95% confidence. Applicant Exh. C, Part 3, at A29.

68. During an aging management inspection in March 2006 (see Staff Exh. 5, "NRC Inspection Report No. 0500219/2006007"), NRC inspectors reviewed the historical evolution of the drywell corrosion issue and inquired about Oyster Creek's past UT data and data collection procedures. Staff Exh. B at A18. The NRC inspectors concluded that Oyster Creek has completed a well-documented baseline inspection on the internal and external drywell condition, which will be reinspected, at appropriate intervals based upon recently-measured corrosion rates, to ensure that the drywell wall thicknesses remain adequate. Staff Exh. B at A18.

69. During the 2006 outage, Reactor Inspector O'Hara observed the use of a qualified UT procedure, performed by qualified technicians. Staff Exh. B at A17. AmerGen was able to obtain comparison readings for 106 of 115 points. Staff Exh. B at A17. AmerGen employed a UT measurement technique (automatic nullification of the epoxy coating thickness) that eliminates an additional measurement step that was required by previous UT measurement techniques. Staff Exh. B at A19. This new technique provides more consistent and accurate measurements than the technique used prior to 2006. Staff Exh. B at A19. Mr. O'Hara concluded that based upon his observation the measurement uncertainty in the 2006 UT measurements was very low. Staff Exh. B at A19

70. The Staff evaluated the process used by AmerGen related to UT measurements taken after the epoxy coating was applied. Staff Exh. B at A22; Staff Exh. 1 at 4-59 to 4-60. The Staff reviewed AmerGen's quasi-statistical approach for the evaluation of the grid data taken from inside the sand bed, to determine the corrosion rate. Staff Exh. 1 at 4-59 to 4-60;

Staff Exh. C at Response A11. The Staff accepted trending of the grid UT measurements taken from inside of the drywell shell, as noted in the SER (Staff Exhibit 1 at 4-59 to 4-60), at 95% confidence level *only* for assessing the future corrosion. Staff Exh. C.1 at A43. Dr. Davis noted, for example, for flow-accelerated corrosion (where grids are used to take repeated UT measurements) Electric Power Research Institute (EPRI) guidelines specify the use of average measurements, not 95 percent confidence levels. Tr. 287. Averages are also used for measuring the thickness of paint in containment. Davis, Tr. 287.

71. The Staff testified there is generally no requirement or industry practice to perform mean or extreme value analysis of UT data. Staff Exh. C at Response A10. The ASME Code does not contain provisions requiring thickness gauging (wall thicknesses measurements) and does not specify statistical treatment of UT data. Staff Exh. C at Response A10. Although NACE recommends practices, and certifies coating inspectors in the processes needed for measuring ambient conditions and surface temperature, measuring surface profile depth, assessing surface cleanliness, sampling and testing for soluble salt contamination, calculating and measuring wet film thickness, measuring coating thickness, testing of coating adhesion, and detecting pinholes and holidays in coatings and linings, NACE does not address the determination of wall thickness and corrosion loss by ultrasonic testing and does not have a report or specification related to this subject. Staff Exh. C at Response A10.

72. AmerGen's experts addressed the spatial relationship between the external single-point UT measurements and the internal grid measurements. Messrs. Tamburro, Gallagher, and Polaski testified that the spatial correlation between the exterior UT measurements and the internal grid measurements is depicted in Applicant Exh. 28; Tr 87-95. Applicant Exh. 28 shows only one exterior UT measurement in 2006 that was less than .636 inch. Gallagher, Tr. 91. Messrs. Polanski and Tamburro also explained that Applicant Exh. 44, maps the relationship between internal and external UT measurements for Bays 1, 13,

17, and 19 – the bays that have experienced the most corrosion. Tr. 195-98. Applicant Exh. 44 shows that there is thicker material between thin exterior UT measurements. Tr. 272-274. Mr. Tamburro testified that Applicant Exh. 16 at 30-32 (Figs. 1-3, 1-4, and 1-5) shows reading in a 36 inch by 36 inch tray area), Tr. 193, and that the tray was manipulated to capture the thinnest measured points. Tr. 194. He explained that the tray criteria are met because the points are greater or above the tray. Tr. 194.

73. The accuracy of Dr. Hausler's multi-color contour plots of depicting "corrosion" (Citizen Exhs. B, Attachment 4, at 17-23, C, Attachment 3, at 21-22, C.1., Attachment 1 at 14-17), which were generated based on exterior UT measurements in the sand bed region of the drywell shell was disputed. *See e.g.*, AmerGen's Motion in Limine to Exclude Portions of Citizens' Initial Written Submission (July 27, 2007). Both AmerGen and Staff experts testified that Dr. Hausler's plots were not consistent with available data and that the plots appeared to overestimate the extent of corrosion. *See, e.g.*, Applicant Exh. C, Part 2, at A7; *id.* Part 3, at A40; Staff Exh. C at A26-27; Response 12(d). Another limitation of Dr. Haulser's contour plots is that they do not show the exact boundary of the area where the thickness is below the general thickness acceptance criteria of 0.736 inch. Staff Exh. B at A27.

74. Dr. Hausler testified that the software used to generate his contour plots utilizes triangulation to calculate averages between all points to predict thicknesses beyond known points. Tr. 250-53, 256-258; Citizens Exh. B, Attachment 4, at 5-6. The program basically applies an interpolation scheme to the limited exterior data. Haulser, Tr. 218. Dr. Hausler did not know how the software code was written or the equations used for extrapolations, Tr. 258, but he believed that the software allows "the experimenter to speculate outside the experimental areas," Tr. 259, and that about 80% of the area depicted as less than 0.625 in contour plot in Citizens Exh. C.1, Attachment 1, Figure 4, was speculation, Tr. 260. Dr. Hausler admitted that his contour plots did not demonstrate that AmerGen's local buckling acceptance criteria were

not met, but noted that they were useful to make projections from limited data. Tr. 263. He also admitted that a valid criticism regarding the contours was that averaging may not accurately represent thicknesses between the points averaged. Tr. 256-57.

75. AmerGen and the Staff questioned the reliability of data used to create the contour plots in Citizens Exh. C.1, Attachment 1. Tr. 263-267. Because AmerGen was unable to find and remeasure nine of the 115 points measured in 1992, Applicant Exh. B, Part 3, at A.21, Dr. Hausler testified that he "calculated" the nine missing points by subtracting 20 mils from the 1992 measurements to avoid a portion of the plot from being "grossly and erroneously distorted." Tr. 265-66.

76. AmerGen's experts testified that use of exterior data to generate thickness contours is not appropriate because there are too few data points in the sand bed region and the exterior UT measurements were specifically selected to be "biased thin". Applicant Exh. C, Part 3 at A10, A40; Polaski, Tr. 268. Technical Data Report (TDR) 1108 (Applicant Exh. 27), which was developed and approved by the team that took corrective actions regarding drywell corrosion, describes the removal of corrosion byproducts from the shell, the selection of thin external UT measurement locations, the preparation of those selected locations for UT inspection by grinding, and the UT measurements. Tamburro, Tr. 271-72.

77. AmerGen's experts also described photographs (Applicant Exh. 40 at 91) of the exterior of the drywell shell in the sand bed region depicting visibly thin exterior points. Tr. 278. Both Mr. Tamburro and NRC Inspector O'Hara, who have entered the sand bed region of the drywell, testified that the exterior points are clearly thinner than the surrounding areas. Tamburro Tr. 280, O'Hara Tr. 285. Overlays of interior UT readings also show that there are thicker areas between thin exterior UT points. Applicant Exh. C, Part 3 at A42: Applicant Exh. 42.

78. At hearing the Board sought additional testimony from the parties about

uncertainty in UT measurements. Dr. Hausler asserted that his contour plots were a way to illustrate the uncertainty in AmerGen's UT measurements. Tr. 249, 289-89, 294, Citizens Exh. C, Attachment 2, at 10 (Table 1). Dr. Hausler indicated that there is a certain variability associated with the repeatability of the exterior UT measurements. Tr at 291-301.

79. AmerGen identified ten sources of systematic error in UT measurements: 1) UT instrumentation uncertainties (approximately +/-0.010 inch, which is not significant when grid data is averaged over multiple samples); 2) actual drywell surface roughness and UT probe location repeatability; 3) actual drywell source roughness and UT probe rotation; 4) temperature effects' 5) Batteries: 6) NDE technician; 7) calibration block; 8) internal surface cleanliness; 9) UT unit settings; and 10) identification of the physical inspection location. Staff Exh. 1 at 4-53 to 4-55; Applicant Exh. C, Part 3, at A6. AmerGen testified that systematic error UT measurements is negligible and many of these uncertainties were not significant. Applicant Exh. C, Part 3, at A7.

80. The Staff testified that Amergen took steps in its 2006 UT inspections to minimize and control potential sources of systematic error in their collection of the UT and visual inspection data, including: 1) use of procedures qualified to industry standards and AmerGen approved data collection procedures; 2) use of qualified technicians specifically trained to perform these data collection activities; 3) use of additional dedicated NDE Level 3 qualified personnel to supervise the data collection technicians in the drywell, providing continual NDE supervision to ensure that the procedure and the data collection were performed correctly and consistently in the field; and 4) use of an external drywell thickness measurement technique (wave-skip methodology) to calibrate the UT instrument and to record the UT data, thus eliminating the need to manually measure the epoxy coating thickness separately. Staff Exh. C at Response A7.

81. Mr. Hawkins, an ASME Non-Destructive Examination NDE Level III Inspector,

who actually took some of exterior drywell shell measurements, testified that because the ground areas are two to three inches in diameter, 2006 measurements might not have been taken in exactly the same place as the 1992 measurements. Tr. 305. Most external data points are in either bowl- or plate-shaped areas. Tr. 306. If the area around the point is plate shaped, it is possible to scan anywhere on the plate and get similar readings, but if the area is bowl shaped, it is necessary to scan around the area in order to find the bottom of the bowl. Tr. 306. Mr. Hawkins testified that only the lowest reading at each location was recorded. Tr. 307.

82. AmerGen's experts testified that they did not know whether written procedure was used in 1992 by the plant's former owner, a written procedure was used in 2006. Tr. 309-310. Mr. O'Hara, an NRC inspector, observed the 2006 UT inspections and found them to be done by qualified personnel (per Exelon Procedure TQ-AA-122, Rev. 3 Qualifications of Nondestructive (NDE) Personnel (Staff Exh. 4)) and in accordance with written procedures. Tr. 310-11; Staff Exh. B at A17.

83. Dr. Hausler asserted that although there is uncertainty in the external UT measurements, Tr. 249, 289-89, 294; Citizens Exh. C, Attachment 2, at 10 (Table 1), he used the external data because he "thinks" that the internal grids are not representative of condition of the drywell shell in the sand bed region at lower elevations. Tr. 315. Dr. Hausler opined that thin areas cannot be selected simply by looking at the surface and therefore the exterior points are not biased thin. Tr. 318.

84. AmerGen responded that with regard to the internal UT measurements, the internal UT measurements locations were not selected at random. Tamburro, Tr. 325. In the mid 1980s, before the exterior was accessible, extensive UT inspections of over 1,000 UT readings in the accessible areas on the interior of the shell were performed on the inside of the drywell shell before the UT grid locations were selected. Tr. 326, 325. Mr. Polaski testified that the investigations performed in the 1980s when the corrosion was discovered indicated that

most of the corrosion was at the higher elevations of the sand bed region, as confirmed by inspections of the exterior after removal of the sand. Tr. 326-27. If AmerGen did not identify the absolutely thinnest locations on the exterior, enough locations were selected to be representative of the thinnest areas. Tr. 328. Most of the thin areas were then ground to permit UT measurements, removing, based on depth micrometer readings, 100 to 200 mils of additional material. Tr. 329-330; Applicant Exh. 16.

85. Dr. Harlow, AmerGen's statistical expert, addressed Citizens' assertion that statistical analyses of whether the drywell shell meets the buckling acceptance criteria should use the external UT measurements. Citizens Exh. C at A12, A16. Dr. Harlow testified that a statistical analysis of the external UT measurements would not provide meaningful results about uncertainty in the UT measurements or the remaining thickness of the drywell shell in the sand bed region. Tr. 368, 373, 375-76. If 106 external points are representative of the areas that are biased thin, the distribution would be a conditional distribution that is not representative of the entire sand bed region in any bay. Dr. Harlow, Tr. 363. Because of the variability in exterior data that may have been caused by grinding, internal grid measurements should be used to understand the error in exterior data for corrosion trending. Harlow, Tr. 374-76.

86. Dr. Harlow also addressed Citizens' use of "extreme value statistics" as the basis for Citizens' assertion that there may be an exterior point thinner than the pressure criterion of 0.490 inch. Citizens Exh. C at A17. Dr. Harlow indicated that Dr. Hausler's testimony lacked detail sufficient for him to review Dr. Hausler's work or to confirm that extreme value statistics were used because underlying calculations were not included, and none of the three classical distributions for maxima and three classical distributions for minima, were stated in Citizens' written testimony. Tr. 399, 390-92. Dr. Harlow further testified that, with respect to the graph on page 12 of Citizens' Exhibit 38, that neither the vertical or horizontal axis was labeled. Tr. 393. At least one square regression line was went through some points but there is no indication

where the points came from. Tr. 393. Based on his 25-years of experience using the Weibell distribution, Mr. Salomon of the NRC Staff agreed with Dr. Harlow that, it did not appear that Dr. Hausler used the Weibull distribution. Tr. 394-95, 397-98.

87. AmerGen's experts testified that neither the ASME code nor the National Association of Corrosion Engineers prescribe UT data evaluation methodology, including whether to evaluate the data using the mean, extreme value, or analysis of the variance. Applicant Exh. C, Part 3, at A54. Rather, ASME and NACE only prescribe inspection methodology. Applicant Exh. C, Part 3, at A54

2. Board Findings

88. Based on its review of the testimony and exhibits presented, the Board finds the evidence shows that internal grid measurements are representative and that the external measurements are biased thin. Based on AmerGen's 2006 ultrasonic data, which averaged UT grid data, the lowest margin to the general buckling/acceptance criterion exists in Bay 19 and is 0.064 inch. All other bays show greater margin to the thickness acceptance criterion.

89. The Board finds that Citizens did not provide a technical basis for the accuracy of the contour plots. The Board's questioning revealed that the plots are speculative extrapolations that are not reliable and should be accorded no weight. Citizens failed to provide any technical basis for its assertions that the external measurements are more representative of the condition of the drywell shell and its assertion that the exterior UT measurements are not biased thin.

90. The Board finds that Dr. Hausler failed to provide sufficient detail for comprehension and confirmation by another expert of the specific data and analyses underlying his conclusions based on extreme value statistics. Therefore, the Board gives no weight to Dr. Hausler's conclusions based on extreme value statistics.

91. The Board finds that Citizens' statistical analyses of the external UT

measurements does not provide reliable information about the uncertainty in the UT measurements or the remaining thickness of the drywell shell in the sand bed region because the evidence shows 100-200 mils of material was removed when exterior points were ground smooth to allow for UT measurements and because the measurements themselves were specifically selected as thin. The Board finds that there is no industry requirement to perform statistical analysis of UT data and, based on the evidence, there is no basis to impose the statistical methods suggested by Citizens, *e.g.* extreme value statistics, analysis of variance or 95% confidence. A 95 percent confidence level in UT measurement is not required by NRC regulation or applicable industry guidance. The Board concludes that averaging UT grid data is acceptable practice for reasonable assurance for the renewal period.

c. Buckling

1. Evidence

92. Dr. Hausler testified that the thickness of the drywell shell is likely insufficient to meet AmerGen's acceptance criteria and that the effective factor of safety is probably less than 2.0. *See,* e.g., Citizens Exh. B at A13; Citizens Exh. C at A6; Citizens Exh. C.1 at A2. He acknowledged that the sand bed is not uniformly corroded to 0.736 inch, Tr. 181, and admitted that he was unable to respond to testimony regarding buckling analysis or the effective factor of safety of the drywell shell because he is not a structural engineer. *See* Tr. 171, 204.

93. Dr. Mehta testified that there are important conservatisms in the GE analysis. Applicant Exh. C, Part 2, A6, Tr. 163. First, the GE analysis assumed that the thinnest areas were in the highest stress areas. Exh. C, Part 2, A6; Tr. 130, 163. The thinnest areas of the Oyster Creek drywell shell, however, are not in the highest stress areas. Exh. C, Part 2, A6; Tr. 163. Second, the GE buckling load analysis assumed that the entire shell in the sand bed region was reduced to a uniform thickness of 0.736 inch and concluded that the factor of safety was 2.0. Exh. C, Part 2, A6; Tr. 118-119, 164.

94. When modeling a shell, it is appropriate to average material properties over an area so long as the area is less than the square root of radius times thickness. Dr. Mehta, Tr. 200. For Oyster Creek's drywell, it was the square root of 402 inches times 0.736 inch which is 18 inches. Mehta, Tr. 201. Thus, property variations over areas smaller than 18 inches will not materially affect the structural analysis results and small thickness variations over a small area will not affect the factor of safety against buckling. Tr. 201-202.

95. Dr. Hartzman, an NRC structural engineer, testified that a "factor of safety" is the ratio of the calculated loads acting on a structure which could cause failure to the calculated loads that could be imposed on the structure under postulated loading conditions. Staff Exh. C.1 at A51. Staff Exh. C.1 at A51. For the drywell shell, the *effective* factor of safety is the calculated reduced buckling stress or load divided by the calculated actual stress or load acting on the shell. Staff Exh. C.1 at A53.

96. Dr. Hartzman and Dr. Mehta agreed that the actual effective factor of safety for the Oyster Creek drywell shell is most likely greater than 2.0 because the Oyster Creek drywell shell is not, as the GE analysis assumed, uniformly thinned to 0.736 inch in the sand bed region. Staff Exh. C.1 at A47; Hartzman, Tr. 166; Mehta, 178-79.

97. Dr. Hartzman further testified that even if the effective factor of safety was less than 2.0, physical local buckling of the sand bed shell may occur only when the effective factor of safety for sand bed shell approaches 1.0 without uncertainties. Staff Exh. C at A28. See Hartzman; Tr. 172. Assuming that the corrosion is as extensive and severe as Dr. Hausler's contour plots in Citizens Exh. 13, he estimated that the effective factor of safety in the sand bed shell would be 1.9, but there would still be margin to the point where buckling would occur. Staff Exh. C at A28. However, since the actual thicknesses of the shell in the sand bed region are greater than 0.736 inch, the effective factor of safety is 2.0 or greater. Staff Exh. C.1 at A54. The Sandia analysis used 1992 UT data and calculated a factor of safety 2.15 for the degraded

sand bed region. Staff Exh. B at A8.

2. Board Findings

98. Board finds that Citizens have not provided reliable evidence that the drywell shell does not meet AmerGen's acceptance criteria. GE assumed a drywell shell uniformly degraded to 0.736 inch in the sand bed region and concluded that the effective factor of safety against buckling of such as shell is 2.0. AmerGen demonstrated that the drywell shell in the sand bed region is not uniformly degraded to 0.736 inch using the average of internal grid measurements consistent with industry standards for similar parameters. The Board finds, based on the evidence and testimony presented that the effective factor of safety of Oyster Creek's drywell shell based on current data is 2.0 or greater, and that margin exists consistent with the analysis using ASME Section III.

2. Sources of Water

a. Evidence

99. Dr. Hausler testified that AmerGen had not shown that water cannot be present in the exterior of the drywell shell. *See* Citizens Exh. C at A20. *See* also Citizens Exh. B at A17. Dr. Hausler noted that AmerGen might not apply the strippable coating prior to flooding the refueling cavity during a forced outage, Citizens Exh. B at A17; Citizens Exh. C at 9, and opined that water could leak from the refueling cavity even if the strippable coating is used. Citizens Exh. C at A20. Dr. Hausler testified that water that enters the sand bed region will not drain properly because of blocked drains, Citizens Exh. B at A18, and opined that there could be condensation of water on the surface of the drywell in the sand bed region. Citizens Exh. C at A20; Citizens Exh. B at A18. At hearing, Dr. Hausler conceded that condensation on the exterior of the drywell shell was not "a real problem." Tr. 412. Rather, the source of water on the exterior of the drywell shell is the reactor cavity. *Id.* Dr. Hausler admitted that Citizens could provide no evidence that water on the exterior of the drywell comes from a source other than the

water-filled reactor cavity. Tr. 423.

100. AmerGen's experts testified that the only known source of water on the exterior of the drywell shell in the sand bed region, as confirmed by quarterly inspections during operation and daily inspections during outages, is leakage from the reactor cavity. Applicant Exh. B, Part 4 at A.4; Applicant Exh. C at Part 4, A.4, A.6. During the 2006 outage, the use of the strippable coating eliminated leakage from the reactor cavity because no water was found in the various bays of the drywell shell. Applicant Exh. B., Part 4 at A.11. Thus these corrective actions are enough to prevent a continuous source of water in sand bed region of the drywell shell. Tr. 112.

101. AmerGen's experts also testified that AmerGen's commitment to apply a strippable coating prior to flooding the reactor cavity applies not only to planned refueling outages, but forced outages as well. O'Rouke Tr. 421-22. Refueling outages last about 26 to 30 days, but that the reactor cavity it not flooded during the entire outage. Applicant Exh. B, Part 1, at A16, O'Rouke, Tr. 414. In 2006, the cavity was flooded from October 18 to November 3. Ray, Tr. 417.

102. The Staff testified that AmerGen has committed to monitor the sand bed region drains quarterly during the operating cycle and take corrective actions if water is found. Staff Exh. B at A12(b); Staff Exh. 1 at Appendix A, Commitment 27 (Item 3). AmerGen has committed to using a strippable coating during the proposed period of extended operation that has been shown to be effective in mitigating water intrusion into the annular space between the drywell shell and the shield wall. Staff Exh. B at A12(b); Staff Exh. 1 at Appendix A, Commitment 27 (item 2). The Staff agreed that AmerGen's commitment to use the strippable coating would also apply to forced outages. Ashar, Tr. 422. Based on this and other AmerGen commitments, listed in the SER, Appendix A, the Staff concluded that the effects of aging will be adequately managed and the drywell shell will be able to perform its intended functions during

the period of extended operation. In addition, an NRC inspector who entered Bays 11 and 13 in the sand bed region of the drywell shell during the 2006 outage, testified that he did not observe any moisture. Staff Exh. B. at A20; Staff Exh. C at A40.

b. Board Findings

103. The Board finds that AmerGen has shown that the only credible source of water on the outside of the drywell is leakage from the reactor cavity. AmerGen's commitment to apply a strippable coating prior to flooding the reactor cavity whenever the reactor cavity is flooded has been shown to prevent leakage in the sand bed and applies to regular and forced outages. AmerGen's commitment (Staff Exh. 1 at Appendix A, Commitment 27 (Item 2, 3)), to monitor the sand bed drains for leakage during refueling outages daily and quarterly during operations, and to take corrective actions if leakage is detected, provide assurance that the potential for corrosion of the drywell shell will due to the presence of water be adequately managed during the period of extended operations. Citizens have not presented evidence that refutes the technical basis for the AmerGen position and the adequacy of proposed future corrective actions actions.

3. Epoxy Coating

a. Evidence

104. Dr. Hausler testified that it was not reasonable to assume that the three-layer epoxy coating on the exterior of the Oyster Creek drywell shell in the sand bed region would not fail during the period of extended operation and visual inspection of the epoxy coating could detect early signs of coating failure, Citizens Exh. B at A21. Coatings are never "100% perfect" because pin holes or holidays are always present and can allow corrosion to occur and corrosion. Citizens Exh. B, Attachment 3 at 8. Although there are methods to detect holidays or pin holes, such methods were not used at Oyster Creek. Citizens Exh. B, Attachment 3 at 8. Dr. Hausler testified that blistering and cracking due to corrosion under the epoxy coating might

not be visually detected and/or might occur between inspections, Citizens Exh. B, Attachment 3 at 8-9, and that based on the cracked coating found on the floor of some bays, the coating applied to the shell might similarly crack and fail. Citizens Exh. B, Attachment 3 at 8. He testified that the epoxy might spontaneously crack and that the slow diffusion of water and oxygen through the epoxy coating could cause formation of a thin layer of oxide on the surface of the metal, destroying the coating's adherence properties. Citizens' Exhibit 38 at 17-18. He opined that the corrosion rate (rate of deterioration) in pitting situations as well as on coated materials, increases exponentially with time. Citizens Exh. B at A21. Dr. Hausler asserted that some areas of the drywell shell in the sand bed region were not coated with epoxy because they are inaccessible. Citizens Exh. C.1 at A21. Dr. Hausler also testified that elevated temperatures around 150 degrees could cause hardening. Tr. 458.

105. At hearing, Dr. Hausler admitted that it was Citizens' theory that there are holidays or pin holes in the epoxy coating, but that there is no available evidence that pin holes or holidays actually exist. Tr. 447. He said he was not familiar with the specific composition of the epoxy used at Oyster Creek (Tr. 459-60).

106. AmerGen's Expert, Jon Cavallo, testified that the epoxy used at Oyster Creek is designed for and is appropriate for this application. Applicant Exh. B, Part 5 at A.5, A.7. The epoxy coating applied to the drywell shell in the sand bed region is 100% solids. Applicant Exh. B, Part 5 at A.5. The three-layer system includes on pre-prime and two additional coats. Applicant Exh. B, Part 5 at A.6. The pre-prime is clear while the middle and top coats have contrasting pigments to ensure continuous coverage and that signs deterioration visible to an inspector, particularly a trained VT-1 inspector. Applicant Exh. B, Part 5 at A.6; Cavallo, Tr. 450. The coating is designed for underwater conditions and can withstand temperatures in excess of normal operating temperatures and the radiation levels in the drywell. Applicant Exh. B, Part 5 at A7.

107. Mr. Cavallo testified that the epoxy coating should continue to perform its intended function during the period of extended operation. Applicant Exh. B, Part 5 at A.8 to A.9. The epoxy coating is designed for immersion service, is rated for up to 250 degrees Fahrenheit (i.e. much hotter than the normal 139°F operating temperatures in the drywell, Applicant Exh. B, Part 1 at A18.), and can withstand radiation up to $1x10^9$ rads, (which is much higher than that expected for service in the drywell shell). Applicant Exh. B, Part 5 at A.7 Cavallo, Tr. 460.. The estimated dose to the epoxy during operation is 5.6 rads per hour and would only receive a total dose of 1.8×10^6 rads through the end of the period of extended operations. Applicant Exh. B, Part 5 at A.7. The Oyster Creek epoxy is in a relatively benign environment in terms of exposure to elevated temperature, mechanical damage, immersion in water, radiation, and UV light. *Id.* at A.9. The 2006 outage found the epoxy coating in an excellent condition. Applicant Exh. B, Part 5 at A.8, A.23. In his opinion, a coating that does not fail soon after application should last for decades. Applicant Exh. B, Part 5 at A9. Signs of embrittlement or cracking are possible at the end of a coating's life, but would develop over a long period of time. Applicant Exh. B, Part 5 at A9. Similar coating systems that have been in use for 30 years at other U.S. nuclear power plants show no signs of end of life deterioration. Applicant Exh. B, Part 5 at A9. Mr. Cavallo testified that, in his experience, a properly applied coating, such as Oyster Creek's, should not rapidly deteriorate due to age. Tr. 457.

108. Mr. Cavallo testified that the three-layer epoxy coating used at Oyster Creek is not susceptible to pin holes or shrinkage because it is solvent free. Applicant Exh. B, Part 5 at A14; Tr. 449, 475. Pin holes develop either when the epoxy is applied or when it cures and the solvent evaporates leaving small holes or pin holes. Applicant Exh. B, Part 5 at A13; Tr. 449. Pinholes are not the result of degradation of a coating over time. Applicant Exh. B,

Part 5 at A13; Tr. 449.[27] There is no evidence of pinholes because no visible rust stains at Oyster Creek. Cavallo, Tr. 447-48.

109. It has been Mr. Cavallo's experience at over 50 nuclear power plants in the United States and abroad that when a pin hole and moisture are present, the first sign of corrosion is rust bleeding through the pin hole or holiday, Tr. 447-48, and that such a defect would visible during VT-1 inspection. Applicant Exh. B at A22. Based on his review of the epoxy coating inspections at Oyster Creek, there are no pinholes in the 15 year-old epoxy coating applied on the exterior of the Oyster Creek drywell shell in the sand bed region. Tr. 448;

110. Messrs. McAllister, Erickson, and Hawkins testified that in 2006, VT-1 visual examinations of all 10 bays were performed by qualified inspectors in accordance with ASME Section XI, Subsection IWE criteria. Applicant Exh. B, Part 5 at A.22. Messrs. Erickson and Hawkins, who actually performed the inspection of the epoxy coating in 2006, testified that they saw no peeling, blistering, cracking, flaking, discoloration, or sign of rust bleeding through the epoxy. Applicant Exh. B, Part 5 at A23; Hawkins, Tr. 448; Erikson, Tr. 448-49. Mr. Ouauo testified that the "epoxy" on the concrete floors of the bays is a putty. Tr. 470. The coating on the floor has no connection to the corrosion-preventing epoxy on the steel drywell, *.i.e*, the two coatings are made of different materials and serve different purposes. Cavallo, Tr. 471[28].

111. Dr. Davis of the NRC Staff testified that corrosion (not visible to an inspector) will not occur in pinholes or holidays in the epoxy coating on the external surface of the drywell.

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[27] Although he was not familiar with the epoxy used at Oyster Creek, upon learning that the epoxy used on the drywell was solvent free, Dr. Hausler speculated that solvent free epoxy is much more viscous, making it hard for air bubbles to escape and necessitating good quality control. Tr. 473. Citizens provided no information that would lead the Board to question the opinions of Mr. Cavallo and Dr. Davis regarding the robust nature of the epoxy coating at Oyster Creek.

[28] Dr. Hausler did not previously know that the coating applied to the floor of the sand bed was entirely different from the epoxy coating applied to the dry well shell. Tr. 472.

Staff Exh. B at A13. First, the application of a multi-layer epoxy coating (i.e. one pre-primer, and two top coats) to the exterior of Oyster Creek's drywell shell in the sand bed region results in an extremely low probability that pinholes or holidays will line-up in the three-layer coating. Staff Exh. B at A14. Second, AmerGen has committed to conducting inspections of the coatings in the sand bed region in accordance with ASME Code Section XI, Subsection IWE (Commitment 27 Items 4 and 21 and Commitment 33) to provide assurance that degradation, if any, is detected. Staff Exh. B at A13. The Staff testified that performance of ASME Section XI, Subsection IWE, visual inspections of the drywell in all ten bays of the sand bed region every other refuelling outage, and AmerGen taking appropriate actions when significant corrosion is detected, provides assurance that effects of aging will be adequately managed so that intended functions will be maintained throughout the renewal period. Staff Exh. B at A15; Staff Exhibit 1, Sections 3.0.3.2.23 and 3.0.3.2.27.

112. Dr. Davis testified that because visual inspections of the epoxy coating indicate that the epoxy coating is in good condition after 15 years, it is evident that the surface was properly prepared and the coating properly applied. Staff Exh. C at A35. Improperly and poorly applied coatings usually fail within the first few years. Staff Exh. C at A35, Tr. 458. Once the coating gets beyond the first few years, rapid failure is much less likely. Tr. 458. In addition, the fact Oyster Creek's epoxy coating, which was designed for immersion service (i.e., under water), is not subject to stressors such as ultraviolet light, high temperatures, mechanical damage, or high radiation, that could shorten its life provides assurance that it will have a prolonged service life. Staff Exh. C at A35. Dr. Davis further testified that visual inspection of the epoxy coating will detect the early stages of coating failure, Staff Exh. C at A36, because when steel surfaces corrode the resulting oxide film is higher in volume than the original steel and different in color. Staff Exh. B at A15. Any oxide film will be obvious against the gray color epoxy coating, especially to qualified inspectors performing VT-1 inspections in accordance with

AMSE Code Section XI, Subsection IWE. Staff Exh. B at A15. *See also* Staff Exhibit 4 (Exelon Procedure TQ-AA-122, Rev 3;"Qualification and Certification of Nondestructive (NDE) Personnel).

113. Dr. Davis further testified that Dr. Hausler's assertion that the epoxy could spontaneously fail is without basis and his assertion that a slow diffusion of water and oxygen through the epoxy could cause formation of a thin film of oxide on the surface of the metal and destroying the epoxy's adherence properties is incorrect. Staff Exh. C.1 at A56-57. Fillers in epoxy can block the permeation of moisture through immersion service coatings and eliminate the disbonding of coatings.. Staff Exh. C.1 at A57. In addition, Dr. Davis testified that there was no basis for Dr. Hausler's conclusion that the corrosion rate (rate of deterioration) in pitting situations as well as on coated surfaces increased exponentially because pitting is a different corrosion mechanism than experienced in the shell and the rate of corrosion does not increase exponentially overtime, it *decreases* over time. Staff Exh. C at A37. Corrosion occurs when iron reacts with water to create ferrous hydroxide (rust). Staff Exh. C at A37. The rust that forms is larger than the original iron, and as more rust is generated, it becomes more and more difficult for water molecules and oxygen atoms to reach the iron surface and for the freed hydrogen atoms to escape. Staff Exh. C at A37. Also, as the drywell heats up during operations, the solubility of oxygen in water decreases which reduces the rate of corrosion. Staff Exh. C. at A37.

114. Reactor Inspector, Timothy O'Hara, who physically entered Bays 11 and 13 during the 2006 outage, testified that he observed that the coating in both bays was grayish-white in color, that the coating appeared to be in excellent condition with no visible evidence of cracking, peeling, or blistering, and that there was no visible moisture. Staff Exh. B at A20. Mr. O'Hara did not see any sign that corrosion had disturbed the epoxy coating and saw no evidence that corrosion was occurring under the coating. Staff Exh. B at A20. Mr. O'Hara

testified that he also reviewed videos of inspections of all the Bays and saw no evidence of moisture, a corrosive environment, or deterioration of the epoxy coating. Staff Exh. B at A20.

b. Board Findings

115. Based upon the evidence presented, the Board finds that the three-layer coating, which was applied to all accessible exterior areas of the Oyster Creek drywell shell in the sand bed region in 1992, will inhibit future corrosion. The robust coating is designed for immersion service and more demanding service conditions than at Oyster Creek. Inspection of the epoxy by qualified inspectors shows no visible signs of deterioration. Expert testimony shows that coating failures normally occur early in the service life of the coating and a properly applied coating can last for decades at nuclear plants. Contrary to Citizens' assertion, the Board concludes that it is reasonable to assume that visual inspection of the epoxy coating will detect the early stages of coating failure and that AmerGen's commitments to inspect the epoxy coating every four years and take corrective actions if any degradation is observed provide assurance the potential for corrosion of the drywell shell will be adequately managed during the period of extended operations. In reaching this conclusion, the Board gave greater weight to the testimony of AmerGen and Staff witnesses, who demonstrated expertise experience with coatings widely used in nuclear power plants.

4. Future Corrosion

a. Evidence

116. Dr. Hausler testified that taking UT measurements every four years is inadequate because overall corrosion rates could be .041 or 0.049 inch per year. Citizens Exh. B. at A16; Citizens Exh. C at A2. However, Dr. Hausler admitted that before the sand was removed, most of the corrosion was near the top of the shell in the sand bed region, but that any future corrosion will most likely to occur at or near the bottom of the sand bed region, where the shell is thicker. Tr 49-50.

117. AmerGen experts testified that no significant corrosion of the drywell is occurring now and no corrosion can occur in the future unless the epoxy coating fails in some way. Applicant Exh. B, Part 6, at A11. Corrosion will not occur even if the epoxy coating fails in some way unless water is present and that water goes undetected. *Id.* at A12; A16. If water were present, it would only be present for a short period of time, *i.e.* during refueling outages, and AmerGen has made commitments to use a strippable coating to prevent leakage from the reactor cavity, and to monitor drains in the sand bed region daily during outages and quarterly during operations. *Id.* at A13; Applicant Exh. C.1, Part 6, at A3. AmerGen experts testified that Dr. Hausler's postulated corrosion rates of 0.041 and 0.049 are unrealistic because, if the epoxy coating were to fail and water to come in contact with the drywell shell, the water would be present for a limited period of time and there is no longer sand present to retain water against the shell. Applicant Exh. C at A14-15.

118. Mr. Tamburro testified that using a conservative rate of 6.9 mils per year (the amount that would have been observable with only four measurements from 1992 to 2006), it was estimated at a lower 95% confidence that the 0.736 thickness criterion would not be violated until 2014. Tr. 349-51. Mr. Polaski added that there was a radical reduction in corrosion rate after removal of the sand from the sand bed region in 1992. Polaski, Tr. 352. As noted in AmerGen Exh. 40, at 86, if the hypothetical, minimum observable corrosion rate of 6.9 mils per year is projected (using Monte Carlo sampling from the distribution of the mean of each data point) from 2006 into the future, a thickness of .736 would not be reached until 2016. Tamburro, Tr. 352-53.

119. The Staff testified that that the results of the 2006 UT measurements do not indicate any significant corrosion that would challenge the integrity of the drywell shell is occurring. Staff Exh. B at A21, A24. The 2006 measurements confirm that the epoxy coating in the sand bed area has been effective in reducing the potential for corrosion in this area since

the change in thicknesses were small. Staff Exh. B at A11. The Staff estimates that, based on a linear interpolation of the reduction in the thickness of the drywell, the rate of corrosion on the exterior surface of the drywell shell in the sand bed region between 1986 and 2006 was approximately 0.002 inch per year. Staff Exh. C.1 at A45. However, most of the corrosion probably occurred between 1986 and 1992, before the sand was removed and the epoxy coating applied. Staff Exh. C.1 at A45. Therefore, the corrosion rate between 1992 and 2006 is probably significantly less than 0.002 inch per year. Staff Exh. C.1 at A45.

120. The Staff testified that based 2006 UT results and AmerGen's Aging Management Program, which includes commitments listed in (Staff Exh. 1, pages A-18 to 33) to periodically monitor corrosion in the sand bed region of the drywell shell, identify the extent of additional degradation, perform additional UT measurements and compare thickness differentials, report statistically significant corrosion to the NRC, and perform an operability determination and justification for operation until the next inspection, there is reasonable assurance that drywell shell integrity (and the intended function of the drywell) will be maintained during the period of extended operation. Staff Exh. B at A24; Staff Exh. C.1 at A59. The Staff testified that its conclusion regarding the frequency of UT inspections was based on available information about the condition of the Oyster Creek drywell shell, the predicted corrosion and AmerGen's Aging Management Program that includes, monitoring of the sand bed drains, the epoxy coatings on the drywell exterior, and periodic monitoring of the sand bed region for water, as well as precautions (use of strippable coatings) during refueling outages to prevent leakage from the refueling cavity. Staff Exh. C.1 at A59.

b. Board Findings

121. The Board finds that the evidence presented shows that currently there is no significant corrosion that would challenge the integrity of the drywell shell. AmerGen's corrective actions (removal of sand and application of the epoxy coating) have been effective

and future corrosion will be minimal. The epoxy coating applied to the exterior of the drywell in the former sand bed region has been effective in keeping water from contacting the steel surface of the drywell. Corrosion, if any, will minimal because of the epoxy coating and AmerGen's Aging Management Program commitments, which include monitoring the condition of the epoxy and repairing of any defects.

122. The Board finds that the future corrosion can be conservatively estimated to be 2 mils per year and that the general wall thickness criteria of 0.736 inch and local thickness criteria of 0.536 and 0.49 inch will not be exceeded between scheduled inspections at a frequency of every other outage. The Board finds that AmerGen's commitments to apply a strippable coating on the inside of the refueling pool during all refueling outages, and to monitor the sand bed drains for evidence of leakage during refueling outage and during normal operation will prevent water from entering the sand bed region of the drywell shell assure that water will minimize the potential for a corrosive environment. Thus, based on the available information regarding the condition of Oyster Creek's drywell shell, AmerGen's corrective actions, the predicted corrosion rate, and the corrosion monitoring interval under AmerGen's enhanced aging management plan, the Board concludes that there is reasonable assurance that corrosion of the drywell shell will be managed such that the drywell can perform its intended functions during the period of extended operations.

123. The Staff's testified that the AmerGen Aging Management Program will adequately manage the condition of the drywell shell during the license renewal period. Staff Exh. B at at A24. Based on the condition of the Oyster Creek drywell shell in the sand bed region during the 2006 outage, the AmerGen Aging Management Program, as enhanced by commitments to perform UT inspections every other outage (as required by proposed license condition), provides reasonable assurance that drywell shell integrity (and the intended function of the drywell) will be maintained during the period of extended operation. *Id.*

124. The Staff's reasonable assurance finding with respect to aging management of corrosion of the drywell shell is based upon consideration of potential corrosive conditions, corrective actions taken by AmerGen to prevent corrosion (removal of sand from sand bed, application of multi-layer epoxy coating, and use of strippable coatings to prevent leaks during refueling), the condition of the Oyster Creek drywell shell in the sand bed region during the 2006 outage inspections, and the AmerGen Aging Management Program, as enhanced by commitments to perform UT inspections every other outage (as required by proposed license condition) in making its reasonable assurance determination. *See* Staff Exh. C at A39, Response 11; Staff Exh. B at A12(b).

III. CONCLUSIONS OF LAW

125. The Licensing Board has considered all of the evidence presented by the parties on the drywell contention and the hearing record, consisting of the filings of the parties in this proceeding, the orders issued by this Board, the exhibits received in evidence and the transcript of the proceeding. Based on a review of the entire record in this proceeding, consideration of the proposed findings of fact and conclusions of law submitted by the parties, and based upon the findings of fact set forth above, which are supported by reliable, probative and substantial evidence in the record, the Board has decided all matters in controversy concerning this contention in favor of AmerGen and reaches the following conclusions.

126. Pursuant to 10 C.F.R. § 54.21(a)(3), AmerGen is required to demonstrate that for the drywell shell, a structure that performs a safety function (i.e., maintains the integrity of reactor coolant pressure boundary as defined in § 54.4), it has an aging management program that demonstrates the effects of aging (i.e., corrosion) will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation.

127. Pursuant to 10 C.F.R. § 54.29, as pertinent here, a renewed license may not be

issued unless actions have been identified or have been taken with respect to the drywell shell, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB.

128. AmerGen's UT monitoring frequency (full scope monitoring every four years) under its aging management program enhanced by commitments that include monitoring for moisture, is adequate to maintain a safety margin against buckling in accordance with 10 C.F.R. Part 54 requirements during the period of extended operation. Thus, the contention is resolved in favor of AmerGen.

129. All issues, motions, arguments, or proposed findings presented by the parties, but not addressed herein have been found to be without merit or unnecessary for this decision.

ORDER

130. For the foregoing reasons, it is hereby ordered that Citizens contention is resolved in favor of the Applicant, AmerGen. This initial decision shall constitutes the final decision of the Commission forty (40) days from the date of its issuance, unless , within fifteen (15) days of its service, a petition for review is filed in accordance with 10 C.F.R. § 2.341(b)(1). It is so ORDERED.

Respectfully submitted,

/RA/

Mitzi A. Young
Counsel for NRC Staff

/RA/

Mary C. Baty
Counsel for NRC Staff

Dated at Rockville, Maryland
this 10th day of October, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the "NRC STAFF PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW IN THE FORM OF A INITIAL DECISION" in the above-captioned proceeding have been served on the following by electronic mail with copies by deposit in the NRC's internal mail system or as indicated by an asterisk, by electronic mail, with copies by U.S mail, first class, this 10th day of October, 2007.

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