LBP-07-17

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

DOCKETED 12/18/07
SERVED 12/18/07

E. Roy Hawkens, Chairman
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of	Docket No. 50-0219-LR
AMERGEN ENERGY COMPANY, LLC	ASLBP No. 06-844-01-LR
(License Renewal for Oyster Creek Nuclear Generating Station)	December 18, 2007

INITIAL DECISION
(Rejecting Citizens' Challenge To AmerGen's Application To Renew
Its Operating License For The Oyster Creek Nuclear Generating Station)

I. INTRODUCTION

AmerGen Energy Company, LLC ("AmerGen") seeks a twenty-year renewal of its operating license for the Oyster Creek Nuclear Generating Station ("Oyster Creek"), which expires on April 9, 2009. The intervenors in this case – six organizations hereinafter referred to collectively as Citizens[1] – argue that AmerGen's license renewal request must be denied because its aging management program for corrosion of the drywell shell in the sand bed region is inadequate. More precisely, they argue that AmerGen's plan to take ultrasonic testing ("UT") measurements in the sand bed region every four years is not sufficiently frequent to ensure an adequate safety margin is maintained between measurements due to the uncertain condition of the drywell shell, the uncertain corrosive environment, and the uncertain corrosion rate. Having

[1] The six organizations are Nuclear Information and Resource Service; 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.

fully considered all the record evidence, including the testimony presented at the two-day hearing conducted on September 24 and 25, 2007, we find that AmerGen has demonstrated that the frequency of its planned UT measurements, in combination with the other elements of its aging management program, provides reasonable assurance that the sand bed region of the drywell shell will maintain the necessary safety margin during the period of extended operation.

II. BACKGROUND

A. The Drywell Shell

The drywell shell is a steel structure enclosing the Oyster Creek reactor plant. It is designed to withstand the potential pressures and temperatures associated with a break of any of the enclosed reactor cooling system pipes, thereby containing the release of fission products and ensuring that offsite radiation consequences do not exceed acceptable limits. See AmerGen's Exh. B, AmerGen's Pre-Filed Direct Testimony Parts 1-7 (July 20, 2007), Pt. 1, A.8.

The drywell shell is about 100 feet tall and shaped like an inverted light bulb. It measures about 70 feet in diameter at the spherical base. At a height of about 71 feet 6 inches, it transitions from a spherical shape to a cylindrical shape that is about 33 feet in diameter. See AmerGen Exh. B, Pt. 1, A.7; AmerGen Exh. 4, Schematic Drawing of the Cross-Section of the Drywell Shell.

The drywell shell – which is surrounded by a concrete shield wall – is set in and arises from a concrete pedestal atop the reactor building concrete foundation at an elevation of about 2 feet 3 inches relative to mean sea level. The shell is embedded in concrete on both sides from its bottom to a height of about 8 feet 11 inches, where the exterior drywell shell concrete floor is located. The interior of the shell remains embedded in concrete up to a height of about 11 feet (beneath the torus vent headers) and 12 feet 3 inches (areas between the torus vent headers). See AmerGen Exh. B, Pt. 1, A.7, A.9; AmerGen Exh. 4; AmerGen Exh. 5, Schematic Drawing of the Drywell Shell Exterior.[2]

The region of the shell known as the “sand bed” region begins at a shell height of 8 feet 11 inches (the level of the exterior concrete floor) and extends to 12 feet 3 inches. This region originally was constructed with a bed of sand on its exterior to structurally support the shell as it transitions from being embedded in concrete on both sides below 8 feet 11 inches to being embedded only on the interior. The sand bed region is divided into ten circumferential bays, each of which is designated with an odd number from one through nineteen, and each of which has an associated torus vent header. Five sand bed drains – equally spaced throughout the bays and located in the concrete floor of the external sand bed region – are designed to drain water that might reach the sand bed floor and flow into the torus room below. Water from these drains is diverted through plastic tubing where it can be collected in five-gallon plastic bottles. See AmerGen Exh. B, Pt. 1, A.9, A.10; AmerGen Exh. 5; AmerGen Exh. 6, Schematic Drawing Showing Top View of the Ten Bays in the Sand Bed Region; AmerGen Exh. 7, Schematic Drawing Showing Detail of the Lower Drywell/Sand Bed Region.

On the exterior of the drywell shell, above the sand bed region and rising to the top of the shell, there is a gap of a few inches that separates the shell from the concrete shield wall. This small gap was filled during construction with a cement-composite product, which was subsequently compressed by heating, resulting in an air gap to allow expansion of the shell under design basis loads. See AmerGen Exh. B, Pt. 1, A.12; AmerGen Exhs. 4, 7.

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[2] The torus is a torroidal-shaped steel pressure vessel that encircles the base of the drywell shell and is partially filled with water to provide pressure suppression in the event of a loss-of-coolant accident. The shell is connected to the torus through ten cylindrical vent headers that protrude from the lower, spherical section of the shell. See AmerGen Exh. B, Pt. 1, A.10, A.11.

The refueling cavity[3] is located above the drywell shell at the top of the reactor building concrete shield wall. This cavity – which ordinarily is empty – is filled with water only during refueling outages,[4] or in the rare event of an outage when the reactor vessel must be opened for a purpose other than refueling. The refueling cavity drainage system has a concrete trough located below the cavity to collect water that might leak from the cavity when it is filled with water. The trough has a 2-inch drain line designed to direct leakage to the reactor building drain tank and prevent water from entering the gap between the drywell shell exterior and the concrete shield wall. See AmerGen Exh. B, Pt. 1, A.14; AmerGen Exh. 8, Schematic Drawing Showing Detail of the Reactor Cavity Seal and Trough Drain.

The average normal operating temperature inside the drywell shell is 139 degrees Fahrenheit. During reactor operations, maximum expected temperature outside the shell in the sand bed region is about 109.5 degrees Fahrenheit. During outages, the sand bed region temperatures range up to about 90 degrees Fahrenheit. See AmerGen Exh. B, Pt. 1, A.18; Tr. at 790, 794 (Hosterman).

Radiation levels inside the drywell shell in the sand bed region are about 4.7 to 5.6 rads per hour,[5] and consist primarily of gamma radiation. Radiation levels on the outside of the shell in the sand bed region are slightly lower. See AmerGen Exh. B, Pt. 1, A.19.

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[3] The refueling cavity is also known as the reactor cavity, but we will use the former name. See AmerGen Exh. B, Pt. 1, A.13.

[4] Oyster Creek operates on a two-year refueling cycle. During normal refueling outages, the refueling cavity is filled with water for less than 26 days once every two years. For instance, during the most recent refueling outage in 2006, the refueling cavity was filled with water for about 17 days. See AmerGen Exh. B, Pt. 1, A.13, A.16, A.17; Tr. at 689 (O'Rourke); Tr. at 692 (Ray).

[5] A "rad" is a measure of absorbed dose of ionizing radiation.

B. The Discovery In The 1980s Of Corrosion Of The Drywell Shell, And The Subsequent Corrective Actions

Oyster Creek began operation in 1969. In the late 1980s, the then-licensee[6] discovered water had leaked onto the outer wall of the drywell shell, causing significant corrosion predominantly in the top of the sand bed region. After extensive investigations, the then-licensee determined that the source of water was leakage through small cracks in the refueling cavity liner. See AmerGen Exh. B, Pt. 1, A.20, A.21; NRC Staff Exh. B, A.5; Tr. at 324 (Hausler).

The leakage from the liner – which occurred when the refueling cavity was filled with water – should have been collected by the concrete trough and directed by the drain line to the reactor building drain tank. The amount of leaking water, however, was greater than the capacity of the trough and drain pipe. Moreover, due to defects in the trough lip and a blocked drain, the trough did not contain the leaking water, which overflowed into the expansion gap (i.e., the gap between the exterior of the drywell shell and the concrete shield wall) and down into the sand bed region. See AmerGen Exh. B, Pt. 1, A.20; AmerGen Exhs. 7, 8; AmerGen Exh. 9, Schematic Drawing Showing Detail of the Reactor Cavity.

The water soaked into the sand, which kept moisture in direct and prolonged contact with the drywell shell, causing significant corrosion of the exterior shell before corrective actions were taken (AmerGen Exh. B, Pt. 1, A.20, A.21; Tr. at 323-24 (Hausler)). Also contributing to the prolonged corrosive condition were drywell shell drainage problems. Specifically, the sand bed drains were later discovered to be clogged, preventing proper drainage of water once it reached the bottom of the sand bed. Additionally, portions of the sand bed floor were not properly finished, hindering drainage toward the sand bed drains. See AmerGen Exh. B, Pt. 1, A.20, A.21.

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[6] In 2000, the NRC approved the transfer of the Oyster Creek license from the then-licensee, GPU Nuclear, Inc. and Jersey Central Power & Light Company, to AmerGen (65 Fed. Reg. 37,417 (June 14, 2000)).

The resulting corrosion in the sand bed region was unevenly distributed among or within the ten bays. However, in those bays where corrosion occurred, it was most significant near the top of the sand bed region where the sand retained moisture and the air/water interface existed. See AmerGen Exh. B, Pt. 1, A.22; Tr. at 324 (Hausler); Tr. at 344-45 (Gallagher). Additionally, corrosion generally was greatest in the vicinity of the torus vent headers, not between them. By way of reference, the design thickness of the drywell shell in the sand bed region is 1.154 inches. Although some bays exhibited almost no observable corrosion, some experienced considerable corrosion, with Bay 19 experiencing a maximum general average metal loss of about 0.35 inch over an area that is six inches by six inches. See AmerGen Exh. B, Pt. 1, A.22; Tr. at 472-73 (Tamburro).[7]

The then-licensee of Oyster Creek took multiple mitigating actions in the 1980s and early 1990s to address the corrosion problem. These actions included: (1) boring ten access holes through the concrete shield wall to access the ten bays to remove the sand from the sand bed region; (2) cleaning the exterior of the drywell shell; (3) applying a multi-layer epoxy coating on the drywell shell exterior in the sand bed region; (4) repairing the concrete sand bed floor to promote drainage in those bays where the floor was not properly finished; (5) clearing the sand bed drains; (6) applying epoxy caulk at the drywell shell/sand bed floor junction; (7) repairing the leakage collection trough in the refueling cavity and clearing the trough drain; (8) applying stainless steel tape and a strippable coating to the refueling cavity during refueling outages to seal cracks in the cavity liner and reduce leakage;[8] and (9) taking periodic UT measurements

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[7] The NRC Staff testified that about 50 percent of the sand bed region was not significantly degraded (i.e., the wall thickness in four bays is over an inch thick and the bays show no sign of degradation), and 80 percent of the sand bed region is 800 to 900 mils thick (i.e., 0.80 to 0.90 inch thick). See Tr. at 633-35 (Tamburro).

[8] Tape and strippable coating were not applied during the 1994 and 1996 refueling outages. See AmerGen Exh. B, Pt. 1, A.23.

from inside and outside the shell to ensure it maintained an adequate safety margin and was not experiencing further corrosion.[9] See AmerGen Exh. B, Pt. 1, A.23, A.24.

AmerGen concluded that, as a result of the corrective actions, the corrosion of the exterior drywell shell had been arrested. See AmerGen Exh. B, Pt. 1, A.24.

C. AmerGen's Commitments To Manage Corrosion Of The Drywell Shell During The Period Of Extended Operation

In support of its License Renewal Application, AmerGen made numerous commitments to the NRC Staff to demonstrate that its aging management program for the drywell shell provided reasonable assurance that the effects of aging (e.g., corrosion) will be adequately managed during the twenty-year renewal period such that the shell will perform its intended functions (i.e., structural integrity and pressure containment) consistent with the current licensing basis.[10] AmerGen's commitments include performing a full scope sand bed region inspection during the 2008 refueling outage and thereafter at every other refueling outage throughout the renewal period (i.e., every four years). A full scope sand bed region inspection consists of: (1) taking UT measurements using the same internal grids AmerGen previously has used, as well as over 100 external locations that were measured during the 2006 outage;[11] (2)

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[9] Two trenches were excavated in 1986 from the interior concrete floor in Bays 5 and 17 to permit UT measurements from inside the drywell shell. Bay 5 was selected because it was believed to have little external corrosion, and Bay 17 was selected because it was believed to have severe external corrosion. The Bay 17 trench has its base at a height of about 9 feet 3 inches, which is the lowest elevation from which AmerGen has UT grid data on severely corroded surfaces. The trench in Bay 5 is deeper than the trench in Bay 17, but Bay 5 has little corrosion. See AmerGen Exh. 40, AmerGen's Oyster Creek Generating Station License Renewal ACRS Presentation, at 53 (Jan. 18, 2007); Tr. at 343-44 (Gallagher); Tr. at 681-82 (Polaski).

[10] The "current licensing basis" is the "set of NRC requirements applicable to a specific plant and a licensee's written commitments . . . 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" (10 C.F.R. § 54.3). The full definition is provided infra note 17.

[11] Any significant deviations of UT results will require corrective action prior to any (continued...)

making visual inspections of the external shell epoxy coating in all ten bays; and (3) inspecting the seal at the junction between the sand bed region concrete and the embedded drywell shell. See AmerGen Exh. B, Pt. 1, A.27.

To address leakage from components inside the drywell, AmerGen committed to monitoring the two trenches inside the drywell shell (in Bays 5 and 17) for the presence of water until no water is identified for two consecutive outages (NRC Staff Exh. B, A.12(a); NRC Staff Exh. 1, Excerpts from Safety Evaluation Report, at A-31 to A-32 (Apr. 2007)). To eliminate water on the drywell shell exterior, AmerGen committed to monitoring the sand bed region drain for water on a daily basis during outages when the refueling cavity is filled with water (AmerGen Exh. B, Pt.4, A.4), as well as on a quarterly basis during the operating cycle when the cavity is not filled with water (ibid.), and to take corrective action if water is found (AmerGen Exh. B, Pt. 1, A.27).[12] AmerGen also committed to using a strippable coating on the refueling cavity wall during periods when the cavity is flooded, which has been shown to be effective in mitigating water intrusion into the gap between the exterior drywell shell and the concrete shield wall (ibid.).

Finally, AmerGen committed to inspecting the multi-layer epoxy coating on the exterior wall of the shell in the sand bed region in accordance with American Society of Mechanical Engineers ("ASME") Code Section XI, Subsection IWE, and to performing repairs, as necessary, to manage corrosion. This inspection commitment provides that: (1) the areas will be

[11](...continued)
restart. Such corrective action includes promptly notifying the NRC Staff, performing confirmatory UT measurements, performing an engineering evaluation to assess the extent of the condition and to determine whether additional inspections are required to assure drywell shell integrity, and performing an operability determination and justification for operation until the next inspection (AmerGen Exh. B, Pt. 1, A.27).

[12] At the evidentiary hearing, AmerGen also agreed – as a condition of the renewed license – to inspect the sand bed drains for blockage at intervals consistent with its existing internal procedures (Tr. at 793, 843-44) (Tamburro, Gallagher). We understand that the NRC Staff will coordinate with AmerGen to ensure the frequency of such inspections are adequate (Tr. at 800) (Ashar).

visually examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress; (2) areas that are suspect will be subjected to engineering evaluation or correction by repair or replacement in accordance with IWE-3122; and (3) supplemental examinations in IWE-3200 will be performed when specified as a result of the engineering evaluation. See AmerGen Exh. B, Pt. 1, A.27; NRC Staff Exh. B, A.15.

D. The Litigative History Of AmerGen's License Renewal Application

By letter dated July 22, 2005, AmerGen submitted an application to renew its operating license for Oyster Creek for a twenty-year period pursuant to 10 C.F.R. Part 54. The current license will expire on April 9, 2009.

Citizens filed a petition for a hearing in response to the NRC's publication of a notice of opportunity for hearing in the Federal Register (70 Fed. Reg. 54,585 (Sept. 15, 2005)). As relevant here, in LBP-06-07, 63 NRC 188, 194 (2006), this Board granted Citizens' hearing request, concluding that Citizens had standing and had submitted an admissible contention. The admitted contention alleged that AmerGen's License Renewal Application ("LRA") was deficient due to the failure to include periodic UT measurements in the sand bed region of the drywell shell in the aging management program.[13]

In LBP-06-16, 63 NRC 737, 741-45 (2006), this Board ruled that Citizens' contention was rendered moot by AmerGen's April 4, 2006 docketed commitment to perform periodic UT

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[13] When Citizens submitted their petition, AmerGen's LRA contained no provision for future UT measurements in the sand bed region of the drywell shell based on its conclusion that corrosion in that region had been arrested and that the planned visual inspections of the multi-layered epoxy coating in that region would be sufficient to manage any unexpected corrosion problems during the renewal period. During the pendency of the license renewal review process, AmerGen docketed several commitments that progressively enhanced its aging management program for the sand bed region of the drywell shell, resulting ultimately in the current commitment at issue in this proceeding; namely, the commitment to perform UT measurements every four years. See AmerGen Exh. 10, Letter from Michael P. Gallagher, AmerGen, to U.S. NRC (Feb. 15, 2007), Enclosing Additional Commitments Related to the Aging Management Program for the Oyster Creek Drywell Shell Associated with AmerGen's License Renewal Application, Commitment 27(1).

measurements in the sand bed region of the drywell shell. However, we gave Citizens the opportunity to file a new contention challenging the new periodic UT program embodied in AmerGen's April 2006 commitment.

In LBP-06-22, 64 NRC 229, 255-56 (2006), this Board admitted the following contention that underlies the present proceeding:

> [I]n light of the uncertain corrosive environment and the correlative uncertain corrosion rate in the sand bed region of the drywell shell, AmerGen's proposed [UT monitoring] plan . . . is insufficient to maintain an adequate safety margin.[14]

On September 20, 2007, this Board convened an evidentiary session to (1) determine whether the witnesses proffered by the parties were qualified to present testimony in their putative areas of expertise, and (2) receive into evidence their pre-filed written direct, rebuttal, and sur-rebuttal testimony as exhibits (10 C.F.R. § 2.1207(b)(2)), as well as the parties' other exhibits. See Tr. at 199-200 (AmerGen Exhs. A-D and 1-61); Tr. at 231-32 (Citizens Exhs. A-D and 1-62); Tr. at 247 (NRC Staff Exhs. A-D and 1-6). The Board found all the witnesses to be qualified to present testimony in the areas they addressed. See Tr. at 250, 255, 258.

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[14] During the course of this proceeding, this Board concluded that the following contentions proffered by Citizens were *not* admissible because they were nontimely, or failed to satisfy admissibility standards, or both: (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 (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); (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). See Licensing Board Memorandum and Order at 2 n.4 (June 19, 2007) (unpublished).

AmerGen presented, and this Board accepted into evidence as exhibits, the pre-filed written testimony of the following fifteen witnesses: (1) Julien D. Abramovici, Enercon Services, Inc.; (2) Jon R. 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, Inc.; (6) Dr. David G. Harlow, Professor of Mechanical Engineering and Mechanics, Lehigh University; (7) Jon C. Hawkins, NDE Level III Inspector; (8) Edwin W. Hosterman, Senior Staff Engineer, Corporate Engineering Programs Group, Exelon; (9) Martin McAllister, NDE Level III Inspector; (10) Dr. Hardayal S. Mehta, Chief Consulting Engineer, Mechanics GE-Hitachi Nuclear Energy Co.; (11) Ahmed M. Ouaou, contractor engineer for Exelon; (12) John F. O'Rourke, Senior Project Manager, License Renewal for Exelon; (13) Frederick W. Polaski, Manager of License Renewal for Exelon; (14) Francis H. Ray, Engineering Programs Director at OCNGS; and (15) Peter Tamburro, Senior Mechanical Engineer, OCNGS Engineering Department. See AmerGen Exh. D, Professional Qualifications of AmerGen Witnesses; AmerGen Exh. B, Pts. 1-7; AmerGen Exh. C, AmerGen's Pre-Filed Rebuttal Testimony Parts 1-6 (Aug. 17, 2007); AmerGen Exh. C.1, AmerGen's Pre-Filed Surrebuttal Testimony Parts 1-6 (Sept. 14, 2007).

The NRC Staff presented, and this Board accepted into evidence as exhibits, the pre-filed written testimony of the following five witnesses: (1) Hansraj G. Ashar, Senior Structural Engineer, Division of Engineering, Office of Nuclear Reactor Regulation ("NRR"); (2) Dr. James A. Davis, Senior Materials Engineer, NRR Division of License Renewal; (3) Dr. Mark Hartzman, Senior Mechanical Engineer, NRR Division of Engineering; (4) Timothy L. O'Hara, Reactor Inspector, Division of Reactor Safety, NRC Region I Office; and (5) Arthur D. Salomon, Research (Mathematical) Statistician, Office of Nuclear Regulatory Research. See NRC Staff Exh. D, Professional Qualifications of NRC Staff Witnesses; NRC Staff Exh. B; NRC Staff Exh.

C, NRC Staff Rebuttal Testimony and Answer to Board Questions (Aug.17, 2007); NRC Staff Exh. C.1, NRC Staff Sur-Rebuttal Testimony (Sept. 14, 2007).[15]

Finally, Citizens presented, and this Board accepted into evidence as exhibits, the testimony of Dr. Rudolf H. Hausler, President, Corro-Consulta. See Citizens Exh. D, Professional Qualifications of Dr. Rudolf H. Hausler; Citizens Exh. B, Initial Pre-Filed Written Testimony of Dr. Rudolf H. Hausler (July 19, 2007); Citizens Exh. C, Pre-Filed Rebuttal Written Testimony of Dr. Rudolf H. Hausler (Aug. 16, 2007); Citizens Exh. C.1, Pre-Filed Sur-Rebuttal Written Testimony of Dr. Rudolf H. Hausler (Sept. 13, 2007).

Thereafter, on September 24 and 25, 2007, this Board held an evidentiary hearing in Toms River, New Jersey. See Notice of Hearing (Application for 20-Year License Renewal), 72 Fed. Reg. 48,694 (Aug. 24, 2007). In addition to accepting several additional exhibits into evidence and providing counsel with the opportunity to make opening and closing statements (Tr. at 291, 297, 853), we heard testimony by witness panels on the following six topics: (1) drywell physical structure, history, and commitments; (2) acceptance criteria; (3) available margin; (4) sources of water; (5) the epoxy coating system; and (6) future corrosion. All the parties' witnesses were present throughout the hearing to present live testimony. Consistent with the regulations governing our Subpart L hearings (10 C.F.R. § 2.1207(b)(6)), Board members asked the panels questions in those areas that, in the Board's judgment, required

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[15] NRC Staff Exhibit D also included the professional qualifications of two witnesses who neither submitted pre-filed testimony nor testified during the hearing. Citizens argued that, because these individuals had not been identified as witnesses until very late in the proceeding – i.e., on September 18, 2007 (Tr. at 248) – and had not submitted pre-filed testimony, they ought not be permitted to testify at the evidentiary hearing unless Citizens were provided with a reasonable time thereafter to rebut such testimony (Tr. at 241-43, 258-60). Because these two witnesses did not testify at the hearing, Citizens' argument was rendered moot.

additional clarification. The Board was assisted in this endeavor by proposed written questions that the parties provided prior to, and during the course of, the hearing.[16]

At the end of the evidentiary hearing, the Board closed the record except for transcript corrections (Tr. at 878). On October 10, the parties submitted their proposed findings of fact and conclusions of law. By October 22, the parties submitted their motions for transcript corrections, and on October 29, the Board issued an order adopting transcript corrections and closing the record.

III. LEGAL STANDARDS

The scope of license renewal proceedings is limited. Such proceedings 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) (quoting Final Rule, Nuclear Power Plant License Renewal, 56 Fed. Reg. 64,943, 64,946 (Dec. 13, 1991)). Rather, they focus on the "potential detrimental effects of aging that are not routinely addressed by ongoing regulatory oversight programs" (ibid.). Accordingly, 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 & 2; Catawba Nuclear Station, Units 1 & 2), CLI-01-20, 54 NRC 211, 212 (2001)). Renewal applicants must "demonstrate how their [aging management] programs will be effective in managing the effects of aging during the

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[16] Commission regulations establish that the parties' proposed questions "must be kept by the [Board] in confidence until they are either propounded by the [Board], or until issuance of the initial decision on the issue being litigated. The [Board] shall then provide all proposed questions to the Commission's Secretary for inclusion in the official record of the proceeding" (10 C.F.R. § 2.1207(a)(3)(iii)). In accordance with this regulation, this Board will provide the parties' proposed questions to the Commission's Secretary for inclusion in the record following issuance of this decision.

period of extended operation" (Florida Power & Light Co., CLI-01-17, 54 NRC at 8) (citing 10 C.F.R. § 54.21(a)).

Sections 54.21 and 54.29 of 10 C.F.R. Part 54 contain the standards governing the renewal of AmerGen's operating license for Oyster Creek. As relevant here, pursuant to 10 C.F.R. § 54.21, AmerGen must demonstrate that its UT monitoring program is adequate to manage the aging effects of corrosion in the sand bed region of Oyster Creek's drywell shell so the intended functions of the shell (i.e., structural integrity and pressure containment) will be maintained during the renewal period consistent with the current licensing basis ("CLB").[17] Pursuant to 10 C.F.R. § 54.29(a), the NRC Staff – as a condition precedent to granting AmerGen's license renewal request – must find "there is reasonable assurance that the

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[17] Current licensing basis ("CLB") 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 for ensuring compliance with and operation within 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 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 license commitments documented in NRC safety evaluations or licensee event reports.

Citizens may not challenge Oyster Creek's CLB in this proceeding, because the Commission has determined such issues: (1) are not germane to aging management concerns; (2) previously have been the subject of thorough review and analysis; and, accordingly (3) need not be revisited in a license renewal proceeding. See Florida Power & Light Co., CLI-01-17, 54 NRC at 8-9. Whether Oyster Creek currently is in compliance with its CLB is likewise beyond the scope of this proceeding, because the Commission's on-going regulatory process – which includes inspection and enforcement activities – seeks to ensure a licensee's current compliance with the CLB. See 10 C.F.R. § 54.30; 60 Fed. Reg. 22,461, 22,473 (May 8, 1995). Claims that challenge a licensee's compliance with the CLB or with other operational requirements may be raised via a 10 C.F.R. § 2.206 petition.

activities authorized by the renewed license will continue to be conducted in accordance with the CLB." Read together, sections 54.21 and 54.29 require AmerGen to establish an aging management program that provides "reasonable assurance" that the Oyster Creek drywell shell will continue to perform its intended function consistent with the CLB during the period of extended operation (i.e., during the additional twenty years of the renewal period). In this proceeding, AmerGen must demonstrate that it satisfies the "reasonable assurance" standard by a preponderance of the evidence (Commonwealth Edison Co. (Zion Station, Units 1 and 2), ALAB-616, 12 NRC 419, 421 (1980)).

"Reasonable assurance," in this context, is not susceptible to formalistic quantification or mechanistic application. Rather, whether the reasonable assurance standard is satisfied is based on sound technical judgment applied on a case-by-case basis. See Union of Concerned Scientists v. NRC, 880 F.2d 552, 558 (D.C. Cir. 1989); see also North Anna Envtl. Coal. v. NRC, 533 F.2d 655, 667 (D.C. Cir. 1973). And a touchstone for determining whether the reasonable assurance standard is satisfied is compliance with Commission regulations. See Maine Yankee Atomic Power Co. (Maine Yankee Atomic Power Station), ALAB-161, 6 AEC 1003, 1009 (1973).

Moreover, in the context of the instant license renewal proceeding, whether the reasonable assurance standard is satisfied is directly linked to an assessment of the adequacy of the aging management program – that is, whether the aging management program monitors the performance and condition of the sand bed region of the drywell shell in a manner that allows for timely identification and correction of degraded conditions (i.e., corrosion). See Florida Power & Light Co., CLI-01-17, 54 NRC at 8; 60 Fed. Reg. at 22,469; cf. Florida Power & Light Co., CLI-01-17, 54 NRC at 8 ("[a]dverse aging effects generally are gradual and thus can be detected by programs that ensure sufficient inspections and testing").[18]

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[18] Citizens argued that satisfying the reasonable assurance standard in the context

(continued...)

IV. FINDINGS OF FACT

Introduction. We begin this portion of our decision by underscoring the issues presented in this case. The central issue is whether AmerGen's scheduled UT monitoring frequency in the sand bed region during the period of extended operation – which, after a UT inspection during the current licensing period in 2008, will consist of a UT inspection every other scheduled refueling outage (i.e., every four years) – is sufficient to maintain an adequate safety margin. The resolution of this issue implicates several subsidiary questions: namely, (1) what is the acceptance criterion for the drywell shell thickness in the sand bed region (i.e., the minimum thickness needed for the drywell shell to perform its intended function), and what is the available margin before that acceptance criterion is violated; (2) whether there is a reasonable likelihood that corrosion will occur in the sand bed region during the renewal period; and (3) if corrosion occurs in the sand bed region during the renewal period, whether the frequency of AmerGen's UT measurements provides reasonable assurance that the shell thickness will not fall below the acceptance criterion between inspections.

We address these questions in turn. First, in Part IV.A, we explain and identify the acceptance criterion for the drywell shell thickness in the sand bed region, and we find that the available margin before that criterion is violated is not less than 0.064 inch.

Second, in Part IV.B, we find there is no reasonable likelihood that corrosion will occur in the sand bed region during the renewal period because: (1) AmerGen has taken effective steps to eliminate a corrosive environment on the outer wall, and even if water were to leak onto that wall, the robust, triple-layered epoxy coating will protect the wall from corrosion; and (2) there is

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of drywell shell measurements requires using a 95 percent confidence interval where the interval is defined based on a statistical analysis of the thickness data (Tr. at 310-11) (Webster). Because this argument is not supported by Commission regulations or case law, we reject it.

no evidence of measurable past corrosion on the inner wall, nor does its benign environment pose a significant risk of future corrosion.

Third, in Part IV.C, we find that, even assuming arguendo that corrosion were to occur in the sand bed region during the renewal period, AmerGen's plan to take UT measurements every four years is sufficiently frequent to ensure an adequate safety margin will be maintained. To that end, we conclude that Oyster Creek would experience an annual corrosion rate, *at most*, of about 0.0035 inch per year, resulting in corrosion of about 0.014 inch during the four-year interval between UT measurements, which does not even approach the minimum available margin of 0.064 inch.

Moreover, and as also explained in Part IV.C, the available margin of 0.064 inch is based on UT measurements at the *top* of the sand bed region, which is the most heavily corroded area due to the prior presence of sand that retained the moisture and kept it in direct contact with the shell at the air/water interface. Because the sand has been removed from the sand bed region, any future leakage will not be retained at the top of the region; rather, any leakage will drain to the bottom of the region where less corrosion has occurred and where the remaining available margin is at least 0.229 inch (i.e., 300 percent greater than at the top), thus increasing our confidence that the frequency of AmerGen's UT measurements will be adequate.

Accordingly, we conclude that Citizens' contention challenging the frequency of AmerGen's UT monitoring program during the renewal period must be rejected.

A. Acceptance Criteria For Drywell Shell Thickness In The Sand Bed Region, And The Available Margin In That Region Before The Bounding Acceptance Criterion Is Violated

1. The Three Acceptance Criteria: General Buckling Criterion, Local Buckling Criterion, And Pressure Criterion

Four expert witnesses for AmerGen (Mr. Gallagher, Dr. Mehta, Mr. Ouaou, and Mr. Tamburro) and five expert witnesses for the NRC Staff (Mr. Ashar, Dr. Davis, Dr. Hartzman, Mr. O'Hara, and Mr. Salomon) provided information supporting the following conclusions regarding the development and establishment of the acceptance criteria for the thickness of the drywell shell.[19] The drywell shell was designed with a sand bed on the shell exterior between about 8 feet 11 inches and 12 feet 3 inches – i.e., the sand bed region – to structurally support the shell as it transitions from being embedded in concrete on both sides below 8 feet 11 inches (AmerGen Exh. B, Pt. 2, A.8). After the presence of water and its attendant corrosion were identified in the sand bed region in the 1980s, the then-licensee retained General Electric ("GE") to analyze whether the shell would maintain adequate structural integrity if the sand in that region were removed (ibid.; NRC Staff Exh. B, A.7).

The shell in the sand bed region has two modes of potential failure (AmerGen Exh. B, Pt. 2, A.9): (1) buckling failure, which is a structural failure caused by physical loads and stresses; and (2) pressure failure, which is caused by internal pressure. To prevent these types of failures, Oyster Creek has three acceptance criteria that are part of the CLB for its drywell shell in the sand bed region – two for buckling, and one for pressure (AmerGen Exh. B, Pt. 2, A.9, A.14, A.16; NRC Staff Exh. C.1, A.42).

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[19] Acceptance criteria for the drywell shell thickness in the sand bed region are part of the Oyster Creek CLB. See, e.g., Tr. at 413 (Ashar); Tr. at 415 (Gallagher); Tr. at 448 Hartzman). Accordingly, issues relating to the derivation and adequacy of the acceptance criteria are not within the scope of this proceeding (supra notes 14, 17). We nevertheless provide this discussion of the acceptance criteria as a backdrop against which our subsequent finding regarding current available margin may be understood.

The buckling criteria – which were derived from analyses performed by GE in the early 1990s and which have not changed over time (AmerGen Exh. B, Pt. 2, A.6, A.7, A.17; Tr. at 416 (Gallagher)) – are based on ensuring the drywell shell complies with the ASME Boiler and Pressure Vessel Code, which requires Oyster Creek to maintain a safety factor of 2.0 as part of its CLB. See AmerGen Exh. B, Pt. 2, A.8, A.10, A.12 to A.14; AmerGen Exh. C, Pt. 2, A.6; AmerGen Exh. 27, Oyster Creek Drywell Vessel Corrosion Mitigation – TDR No. 1108, at 17-19 (Apr. 29, 1993); NRC Staff Exh. B, A.8; NRC Staff Exh. C.1, A.52; NRC Staff Exh. 1, at 4-71; Tr. at 399 (Mehta); Tr. at 848 (Gallagher). Complying with a minimum safety factor of 2.0 means that the actual stresses the shell would experience during a postulated accident scenario are only half of what would cause it to fail (AmerGen Exh. B, Pt. 2, A.11). In other words, complying with the acceptance criteria derived from the GE analyses provides reasonable assurance that the shell can, without failing, withstand twice the stresses it would experience during the postulated scenario (ibid.).[20]

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[20] The conclusion that the drywell shell currently has a safety factor greater than 2.0 is drawn from the GE analysis, which assumed the entire sand bed region to be uniformly thinned to a thickness of 0.736 inch, when, in fact, the shell measurements have shown that the thickness is on average substantially greater than 0.736 inch (AmerGen Exh. B, Pt. 2, A.10, A.11). Although the precise value of the safety factor can not be determined without performing more extensive measurements and actual calculations (Tr. at 453-54) (Hartzman), compliance with the acceptance criteria – which incorporate several significant conservatisms (AmerGen Exh. C, Pt. 2, A.6; Tr. at 438-40 (Mehta)) – permits the conclusion that the safety factor is at least 2.0, especially given that the thickness of the shell is on average greater than 0.736 inch (Tr. at 399, 441 (Mehta); Tr. at 453-55 (Hartzman)). This conclusion is supported by an analysis of the drywell shell performed by Sandia National Laboratories, which yielded a safety factor of 2.15 using best estimate thicknesses for the drywell shell. See NRC Staff Exh. 6, Excerpts of the Structural Integrity Analysis of the Degraded Drywell Containment at OCNGS (The Sandia Report), at 72 (Jan. 2007).

Dr. Hartzman stated that the ASME Code provision that establishes the safety factor of 2.0 is a requirement for the drywell shell only at the "design" stage. The safety factor may be reduced, he averred, at the "as-built" stage when the "structure" and "loading conditions" are well known and, hence, the uncertainties that existed at the design stage are reduced (Tr. at 430-32). He further represented that if actual corrosion in the sand bed region revealed a true safety factor of 1.9, "the Staff believes that the sand bed shell . . . would not be susceptible to

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The buckling and pressure acceptance criteria – that is to say, the minimum thickness the shell must maintain consistent with the ASME Code – are based on two limiting scenarios involving combinations of extreme conditions. The limiting buckling scenario occurs during a postulated accident when, simultaneously, the reactor is shut down and the refueling cavity is filled with water, an earthquake occurs, and the drywell shell is under a negative pressure of 2 psi, resulting in bounding compressive stresses on the shell (ibid.; AmerGen Exh. 3, Letter from Michael P. Gallagher to NRC, Enclosing AmerGen's Submittal of Information to the Advisory Committee on Reactor Safeguards ("ACRS"), at 6-7 to 6-8 (Dec. 8, 2006); AmerGen Exh. 40; NRC Staff Exh. C, A.28). The limiting pressure scenario is based on a scenario involving a postulated loss-of-coolant accident while the reactor is at full power, resulting in bounding tensile stresses on the shell (AmerGen Exh. B, Pt. 2, A.9).

The first buckling acceptance criterion – the "general buckling criterion" – requires that the shell maintain an *average* thickness across the entire sand bed region of 0.736 inch (AmerGen Exh. B, Pt. 2, A.14). However, an average thickness less than 0.736 inch remains adequate (i.e., it satisfies the CLB) if it meets the second buckling acceptance criterion, which relates to permissible localized thinning (ibid.; NRC Staff Exh. B, A.7, A.9).

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[20](...continued)
buckling" (NRC Staff Exh. C, A.28). Neither this representation, nor Dr. Hartzman's other testimony regarding a reduced safety factor (e.g., NRC Staff Exh. C.1, A.54; Tr. at 760), alters our conclusion that Oyster Creek's CLB *presently* requires it to maintain a safety factor of 2.0 (e.g., AmerGen Exh. B, Pt. 2, A.10; AmerGen Exh. C, Pt. 2, A.6; NRC Staff Exh. B, A.8; NRC Staff Exh. C.1, A.52; NRC Staff Exh. 1, at 4-71; Tr. at 399 (Mehta); Tr. at 848 (Gallagher)). As AmerGen correctly acknowledges (AmerGen Exh. C, Pt. 2, A.8), if it wishes to adopt different acceptance criteria based on a different analysis, or if it otherwise wishes to alter Oyster Creek's CLB by, for example, seeking to reduce the shell safety factor to a value less than 2.0, it would be required to submit its analysis for NRC review and approval. Accord Tr. at 848 (Gallagher); NRC Staff Exh. C, A.12(e). The instant record provides no support for the conclusion that AmerGen requested to reduce the drywell shell safety factor to a value less than 2.0, much less that the NRC Staff reviewed such a request and approved it.

The second buckling acceptance criterion – the "local buckling criterion" – assesses the acceptability of localized areas that have an average thickness less than 0.736 inch, and it assumes the remaining thickness of the drywell shell in the sand bed region is 0.736 inch (AmerGen Exh. B, Pt. 2, A.14). This criterion was developed from a computation employing a geometrical configuration that resembles a three-feet by three-feet "tray," as is illustrated in AmerGen Exhibit 11. The center of the tray covers a one-square-foot area that is 0.536 inch thick, which transitions to a surrounding shell thickness of 0.736 inch over a linear distance of one foot in each direction, resulting in a localized area of nine square feet that has an average thickness of less than 0.736 inch. See AmerGen Exh. 11, Drawings of the 0.536 Inch Local Buckling Acceptance Criterion "Tray" (front and isometric views); AmerGen Exh. B, Pt. 2, A.14; NRC Staff Exh. B, A.7, A.9.[21]

Finally, the third acceptance criterion for the sand bed region – the "pressure criterion" – is a localized thinning to 0.490 inch that is not more than 2.5 inches in diameter (AmerGen Exh. B, Pt. 2, A.14; NRC Staff Exh. B, A.9). A very small hole in the shell would exceed the pressure criterion because it would allow internal pressure to escape, even though it would have no effect on buckling (AmerGen Exh. B, Pt. 2, A.12).

We conclude that the above acceptance criteria are part of Oyster Creek's CLB in that they are "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 C.F.R. 50.71" (10 C.F.R. §

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[21] AmerGen points out that both buckling criteria are volumetric criteria – a concept that may be understood by considering the local buckling criterion. The three feet by three feet "tray" represents a total contiguous area of nine square feet that has a thickness below 0.736 inch, and the total volume of this tray that is missing (with respect to a uniform thickness of 0.736 inch) is 124.8 cubic inches (AmerGen Exh. B, Pt. 2, A.14, A.15). Thus, the local buckling criterion is not violated when localized corrosion removes dozens, or even scores, of cubic inches from the tray (AmerGen Exh. B, Pt. 2, A.15).

54.3) and, accordingly, they properly guide our analysis in this proceeding. See Tr. at 420-23 (Ashar, Gallagher).[22]

2. The Shell In The Sand Bed Region Has An Available Margin Of 0.064 Inch Before The Bounding Acceptance Criterion Is Violated

a. Internal UT Measurements Demonstrate The Acceptance Criteria Are Satisfied And Reveal An Available Margin Of 0.064 Inch. Five expert witnesses for AmerGen (Mr. Abramovici, Dr. Harlow, Mr. Gallagher, Mr. Polaski, Mr. McAllister, and Mr. Tamburro) and four expert witnesses for the NRC Staff (Mr. Ashar, Dr. Davis, Mr. O'Hara, and Mr. Salomon) provided testimony supporting the conclusion that the shell in the sand bed region has an available margin of 0.064 inch before the bounding acceptance criterion is exceeded. Citizens' expert, Dr. Hausler, opined that the shell does not have 0.064 inch of available margin and, moreover, it may already violate the acceptance criteria. As discussed below, we conclude that AmerGen demonstrated by a preponderance of the evidence that the sand bed region

[22] Citizens' expert, Dr. Hausler, argued in passing that the local buckling criterion "tray" represented in AmerGen Exhibit 11 consisted of an area of only 4.5 square feet, not 9 square feet (Citizens Exh. C, A.6). He is incorrect. As AmerGen and the NRC Staff explained, Dr. Hausler's argument is based on a misunderstanding of the exhibit. Because of symmetry, the 6 inch by 12 inch and 1.5 feet by 3 feet areas modeled by GE and represented in the exhibit actually analyze 12 inch by 12 inch and 3 feet by 3 feet areas, respectively. See AmerGen Exh. 39, Letter from Dr. Mehta to Dr. Tuminelli, Sand Bed Local Thinning and Raising the Fixity Height Analyses, at Fig. 1a (Dec. 11, 1992); NRC Staff Exh. C.1, A.48; NRC Staff Exh. 6 at 47-50, 67; Tr. at 403, 411-12 (Mehta); Tr. at 410-11 (Gallagher). Dr. Hausler's failure to understand the exhibit may be attributable to his conceded lack of structural engineering experience. See Tr. at 353-54, 446, 479 (Hausler).

Citizens also asserted that the local buckling criterion discussed above is not part of Oyster Creek's CLB, arguing that AmerGen has used more conservative (i.e., thicker) local buckling criteria in the past (Citizens Exh. B, A.24). This assertion lacks merit. Although AmerGen conceded that on occasion, it assessed locally thin areas using more conservative "administrative limits" (AmerGen Exh. B, Pt. 2, A.18 to A.20), it correctly stated that its discretionary use of "administrative limits" did not transform these limits into part of the CLB (AmerGen Exh. B, Pt. 2, A.19, A.20; Tr. at 425 (Tamburro)). A contrary conclusion would be wholly at odds with the regulatory definition of CLB (supra note 17). See also NRC Staff Exh. B, A.9 (Staff testifies that AmerGen's administrative limits are not part of the licensing basis, nor were they relied on during review of the renewal application).

satisfies the acceptance criteria, and that there will be an available margin of at least 0.064 inch when Oyster Creek enters the renewal period.

The condition of the drywell shell in the sand bed region (i.e., the region between 8 feet 11 inches and 12 feet 3 inches) was determined by taking UT thickness measurements in that region from the interior of the drywell shell during the 1992, 1994, 1996, and 2006 refueling outages (AmerGen Exh. B, Pt. 3, A.9). These internal UT measurements were taken on fixed grids, rather than as single points, which enables calculations of the average thickness of an area (AmerGen Exh. B, Pt. 3, A.10, A.11). Using metal template grids, measurements were taken at nineteen locations, with at least one grid in each of the ten bays (AmerGen Exh. B, Pt. 3, A.12).[23]

The locations for the nineteen grids were selected by taking over 1,000 UT measurements to identify the thinnest areas in each bay (Tr. at 601) (Tamburro). Permanent marks were placed on the shell's interior so the metal template could be placed at the same location each time a measurement is taken (AmerGen Exh. B, Pt. 3, A.13). The grid locations all are in the upper portion of the sand bed region centered on or near a shell elevation of 11 feet 3 inches, where the observed corrosion was concentrated (AmerGen Exh. B, Pt. 3, A.12; Tr. at 324 (Hausler); Tr. at 344-45 (Gallagher)). The internal concrete curb at elevation 11 feet prevents placing the grids at a lower elevation, except in the two trenches that were excavated in the concrete in the 1980s in Bays 5 and 17 (AmerGen Exh. B, Pt. 3, A.12).[24]

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[23] The grid measurements are taken from the shell's interior because UT measurements require a flat surface, and the shell's interior surface is essentially flat, unlike the shell's corroded – and consequently uneven – exterior surface (AmerGen Exh. B, Pt. 3, A.11).

[24] In 2006, AmerGen excavated an additional 6 inches from the trench in Bay 5 (AmerGen Exh. 40, at 51, 111-12, 128), which allowed AmerGen to examine the shell "a little bit below the sand bed floor" (Tr. at 344) (Gallagher).

The metal template grids are in two sizes. Twelve templates are squares that are six inches by six inches, each collecting a total of forty-nine UT measurement points (AmerGen Exh. B, Pt. 3, A.12). The remaining seven grids are rectangular, one inch by seven inches, and each of these collects seven UT measurement points (ibid.).

The table below contains the measurement data that were averaged over each grid to produce average thicknesses (AmerGen Exh. B, Pt. 3, A.38):

Grid Location by Bay	Split Grids	1992	1994	1996	2006
1D			1.101	1.151	1.122
3D			1.184	1.175	1.180
5D			1.168	1.173	1.185
7D			1.136	1.138	1.133
9A			1.157	1.155	1.154
9D		1.004	0.992	1.008	0.993
11A		0.825	0.820	0.830	0.822
11C	Bottom	0.859	0.850	0.883	0.855
	Top	0.970	0.982	1.042	0.958
13A		0.858	0.837	0.853	0.846
13D	Bottom	0.906	0.895	0.933	0.904
	Top	1.055	1.037	1.059	1.047
13C		1.149	1.140	1.154	1.142
15A			1.114	1.127	1.121
15D		1.058	1.053	1.066	1.053
17A	Bottom	0.941	0.934	0.997	0.935
	Top	1.125	1.129	1.144	1.122
17D		0.817	0.810	0.848	0.818
17/19	Top	0.976	0.963	0.967	0.964
	Bottom	0.989	0.975	0.991	0.972
19A		0.800	0.806	0.815	0.807
19B		0.840	0.824	0.837	0.848

19C		0.819	0.820	0.854	0.824

As discussed supra Part IV.A.1, the three acceptance criteria are: (1) the general buckling criterion, which requires a minimum uniform average thickness for the sand bed region of 0.736 inch; (2) the local buckling criterion, which requires a local area with an average thickness less than 0.736 inch to maintain a thickness no less than a tray configuration that has a center thickness of 0.536 inch covering a one foot by one foot area that, in turn, transitions over a linear distance of one foot to a surrounding shell thickness of 0.736 inch; and (3) the pressure criterion, which requires a thickness no less than 0.490 inch over an area of no more than 2.5 inches in diameter.

Regarding the pressure criterion, because all of the individual UT measurements in the grids were substantially greater than 0.490 inch (AmerGen Exh. B, Pt. 3, A.5, A.29; NRC Staff Exh. 1, at 3-120), this criterion plainly is satisfied. See AmerGen Exh. B, Pt. 3, A.5 ("[t]he thinnest single UT measurement obtained at any time between 1992 and the present is 0.602 [inch]"); infra note 31.

Regarding the buckling criteria, because the thinnest average measurement recorded in the past fourteen years from the internal grids was 0.800 inch in 1992 from grid 19A which measured a portion of Bay 19, and because that value is greater than the general buckling criterion of 0.736 inch, the general buckling criterion is satisfied.[25] Because the general buckling

[25] The thinnest average measurement of 0.800 inch existed over an area six inches by six inches square. The AmerGen witness who performed the structural analysis attested – and Citizens' witness did not dispute (Tr. at 479) (Hausler) – that properties varying over a region of characteristic length less than 18 inches would not affect the structural analyses for this shell (Tr. at 476) (Mehta). Thus, for the 0.800 inch measurement to be a valid measure of the remaining margin, it would have to extend over an area not less than approximately 18 inches by 18 inches. No data has been presented to this Board indicating that such a large area in the sand bed region is degraded to 0.800 inches on the average. Accordingly, when AmerGen and the NRC Staff base their estimates of remaining margin on the assumed thickness of 0.800 inch, they are making a very conservative assumption.

criterion is satisfied, there is no need to compare the grid measurements to the local buckling criterion, which is likewise satisfied (AmerGen Exh. B, Pt. 3, A.5, A.15).[26]

Subtracting the general buckling criterion of 0.736 inch from the thinnest average measurement recorded in the sand bed region (0.800 inch in Bay 19) results in a margin of 0.064 inch, which we conclude – based on the record evidence, including the fact that the average thicknesses in the sand bed region remained virtually unchanged between 1992 and 2006 – will be the available margin when Oyster Creek enters the renewal period.[27]

b. External UT Measurements Support The Conclusion That The Acceptance Criteria Are Satisfied. Over 100 UT measurements were taken in the sand bed region from the exterior of the drywell shell during the 1992 and 2006 refueling outages. Unlike the internal UT measurements, the external measurements were taken and evaluated as single points, not as averaged grids. This is so because the single UT measurement points were selected in 1992 based on a determination that they were among the thinnest (i.e., the most corroded) locations in the sand bed region.

Two important requirements for a UT probe to provide an accurate measurement are that (1) the surface area must be smooth over an area at least as large as the circular area of the probe, and (2) the probe needs to sit perpendicular to the surface of the metal. To ensure these two requirements were met, the metal at the individual points located throughout all ten drywell bays was ground to be flat – removing about 0.10 to 0.20 inch of additional metal (Tr. at

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[26] Because the UT measurements show that the buckling criteria are satisfied, the requirement that the drywell shell maintain a safety factor of 2.0 is satisfied (supra text accompanying note 20).

[27] Our conclusion that the sand bed region has an available margin of 0.064 inch is based on the assumption that the entire sand bed region has a uniform thickness of 0.800 inch. Because all the other average grid measurements were greater than 0.800 inch, it may be seen that our conclusion is based on a significantly conservative assumption. See AmerGen Exh. B, Pt. 3, A.31.

604-05) (Polaski, Tamburro) – over an area of about two inches in diameter to allow the UT probe to sit on a smooth surface perpendicular to the shell.[28] To perform UT measurements on a grid on the external wall would have required grinding much larger areas (six inches by six inches or larger), which would have resulted in unnecessarily reducing the thickness of the drywell shell in areas that had already been determined to be among the thinnest. See AmerGen Exh. B, Pt. 3, A.16 to A.18.

In 1992 Oyster Creek took over 120 single point UT measurements, and in 2006 it took single point UT measurements from 106 of the previously measured locations (AmerGen Exh. B, Pt. 3, A.20).[29] These individual points were compared to, and satisfied, the pressure criterion. See AmerGen Exh. B, Pt. 3, A.21, A.29.[30]

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[28] This grinding occurred prior to coating the external wall of the sand bed region with epoxy (AmerGen Exh. B, Pt. 3, A.18).

[29] Fewer measurements were taken in 2006 because some of the 1992 measurement points included two readings from the same location, and some of the locations of the 1992 single point measurements could not be relocated (AmerGen Exh. B, Pt. 3, A.20). To preclude this problem in the future, AmerGen in 2006 enhanced its techniques for identifying the measurement locations (AmerGen Exh. B, Pt. 3, A.19).

[30] These single UT measurements taken on the exterior of the shell were not averaged and compared to the general buckling criterion, because each point was selected based on its thinness. Moreover, these points had to be ground flat to allow proper placement of the UT probe and, consequently, they were made even thinner by about 100 to 200 mils, or 0.10 to 0.20 inch (Tr. at 604-05) (Polaski, Tamburro). These points are thus not representative of the overall shell thickness and do not provide a basis for determining available buckling margin. Rather, they are representative of the most severely corroded areas, which were then thinned even further by the grinding process (Tr. at 603-04) (Polaski). An average of these measurements would reflect this bias, resulting in a skewed and unrealistic assessment of the shell. See AmerGen Exh. B, Pt. 3, A.22, A.23. Accordingly, these points are used to provide individual snapshot indicators of whether the shell complies with the pressure acceptance criterion, not to calculate available margin until the general buckling criterion is violated (AmerGen Exh. B, Pt. 3, A.30).

Citizens endeavored to rely on contour plots of the drywell shell's sand bed region – which were generated by Dr. Hausler based on exterior UT measurements – to support their argument that the available margin is less than 0.064 inch (Citizens Exh. C.1, Attachment 1; Citizens Exh. B, A.14). This they may not do, because relying on these contour plots to

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Specifically, with regard to the pressure criterion, the thinnest external single point measurement is 0.602 inch in Bay 13, which is 0.112 inch thicker than required by the pressure criterion of 0.490 inch.[31] Because the available margin of 0.112 inch for the pressure criterion (which is based on the thinnest external single point measurement) is greater than the available margin of 0.064 inch for the general buckling criterion (which is based on the thinnest interior average grid measurement in Bay 19 (supra Part IV.A.2.a)), the external single point measurements support the conclusions that (1) the acceptance criteria are satisfied, and (2) the bounding margin for purposes of this proceeding is the general buckling criterion margin of 0.064 inch (AmerGen Exh. B, Pt. 3, A.32; accord NRC Staff Exh. 1, at 4-57 to 4-60).

B. AmerGen's UT Program Provides Reasonable Assurance That The Sand Bed Region Will Not Violate The Acceptance Criteria During The Renewal Period, Because The Record Shows That Corrosion Has Effectively Been Arrested

Citizens assert that the exterior and interior walls of the drywell shell in the sand bed region will likely experience significant corrosion during the renewal period due to the existence of a continuing corrosive environment.

We agree with AmerGen and the NRC Staff that Citizens' argument is insubstantial. Based on the exhibits and testimony, we find there is reasonable assurance that the *exterior* wall in the sand bed region will not experience any significant corrosion during the renewal

[30](...continued)
determine Oyster Creek's acceptance criteria is effectively an attack on the derivation of Oyster Creek's CLB and, thus, beyond the scope of this proceeding (supra note 19). In any event, we find that the contour plots are not reliable representations of the condition of the drywell shell, because they are based on the exterior UT measurements, which are significantly biased in the thin direction (see AmerGen Exh. C, Pt. 2, A.7; AmerGen Exh. C, Pt. 3, A.10, A.40; NRC Staff Exh. C, A.26, A.27, A.12(d)).

[31] Because the area in which this 0.602 inch measurement was taken had been ground thinner by about 0.10 to 0.20 inch to allow for accurate UT measurements (supra note 30), it becomes clear that this "thinnest" external single point measurement is conservative in the extreme. Taking the grinding into account, the actual thickness of that point is somewhere in the range of 0.702 to 0.802 inch, which means that the margin to the pressure criterion is in the range of 0.212 to 0.312 inch.

period because: (1) the refueling cavity liner is the only known source of water onto the exterior wall in the sand bed region, and AmerGen's corrective actions have adequately mitigated that leakage; and (2) even if water entered the exterior wall in the sand bed region, the drywell shell will be adequately protected by the shell's robust epoxy coating. We also find that the *interior* wall in the sand bed region will not experience significant corrosion during the renewal period, because there is no evidence of measurable past corrosion there, and the record reveals that the environment is benign and will not pose a serious threat of future corrosion.[32]

1. It Is Highly Unlikely There Will Be Future Corrosion On The Exterior Wall In The Sand Bed Region

Citizens argue that future corrosion will likely occur on the exterior wall of the drywell shell in the sand bed region because (Citizens' Response to AmerGen and NRC Staff Initial Testimony at 18-23 (Aug. 17, 2007)): (1) there are potential sources of water other than the refueling cavity liner, and AmerGen has been unable to stem water leakage from the refueling cavity liner in any event; and (2) the epoxy coating likely contains defects that could allow corrosion to develop, or that could cause the coating to rapidly deteriorate during the period of extended operation. We disagree.

a. AmerGen Has Taken Effective Steps To Eliminate Corrosion-Causing Moisture On The Exterior Wall Of The Sand Bed Region. Citizens dispute whether the refueling cavity liner – which is filled with water during refueling outages and other rare outages in which the reactor vessel must be opened – has been established as the only

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[32] Testimony regarding the potential for future corrosion was presented over the course of two panels: Panel 4 (Sources of Water) and Panel 5 (The Epoxy Coating). Citizens presented one witness, Dr. Rudolf H. Hausler. AmerGen presented eleven witnesses: (1) Mr. Jon R. Cavallo; (2) Mr. Scott R. Erickson; (3) Mr. Michael P. Gallagher; (4) Mr. Barry Gordon; (5) Mr. Jon C. Hawkins; (6) Mr. Edwin Hosterman; (7) Mr. Martin E. McCallister; (8) Mr. John F. O'Rourke; (9) Mr. Ahmed Ouaou; (10) Mr. Francis H. Ray; and (11) Mr. Peter Tamburro. The NRC Staff presented five witnesses: (1) Mr. Hansraj G. Ashar; (2) Dr. James A. Davis; (3) Dr. Mark Hartzman; (4) Mr. Timothy L. O'Hara; and (5) Mr. Arthur D. Salomon.

source of water on the exterior portion of the drywell shell in the sand bed region. According to Citizens, documentation from AmerGen establishes that the Oyster Creek equipment pool has leaked and "fuel pool water that did not originate from the refueling cavity has been found in the sand bed region" (Citizens Exh. 37, Overview of the Relevant Facts Regarding Corrosion of the Drywell Shell at the Oyster Creek Nuclear Generating Station at 17 (initially submitted as Citizens Exh. B, Att. 5 (July 20, 2007)). Citizens' witness, Dr. Hausler, observed that "a number of potential sources of water . . . have been identified by the reactor operator, including the refueling cavity [and] the equipment pool" (Citizens Exh. B, A.17). In addition, Dr. Hausler, in his written testimony, asserted there is a potential for condensation to form on the exterior wall of the sand bed region due to AmerGen's "use of drywell chillers, which are used during refueling and other outages when access to the drywell is needed" (Citizens Exh. C, A.20) (citing AmerGen Exh. B, Pt. 4, A.15). This is "apparently confirmed," he added, "by an analysis of water that had drained from the exterior of the sand bed region before March 2006, which showed no activity" (ibid.) (citing Citizens Exh. 23, AmerGen Drywell Inspection Leakage Plan); see also Citizens Exh. B, A.17; Citizens Exh. 12, Memorandum from Dr. Rudolf H. Hausler to Richard Webster, Esq. at 8 (Apr. 25, 2007). Because of this alleged uncertainty as to "where the water may be coming from," Dr. Hausler stated that "one can safely assume that water could be present at some time in the future and at least during each outage" (Citizens Exh. 12, at 8). Dr. Hausler's arguments are refuted by the record.

During the late 1980s and early 1990s, the then-licensee of Oyster Creek conducted "[e]xtensive investigations of a large number of other plant components . . . [to] provide reasonable assurance that these components are not sources of water in the sand bed region" (AmerGen Exh. B, Pt. 4, A.13). Specifically, the following components were eliminated as potential sources of water in the sand bed region: "the bellows seal at the bottom of the refueling cavity, . . . the refueling cavity drain line, the refueling cavity metal trough and its associated gasket, . . . the concrete trough located below the metal trough, the refueling cavity steps, the equipment pool and refueling cavity skimmer systems, the equipment pool liner, drain, and support pad, the spent fuel pool liner, and piping buried in concrete" (ibid.) (citations omitted); see also Citizens Exh. 21, Letter from J.C. DeVine, Jr., GPU Nuclear, to U.S. NRC (Dec. 5, 1990), Att. III, GPUN Detailed Summary Addressing Water Intrusion and Leakage Effects Related to the Oyster Creek Drywell. When the Board questioned Dr. Hausler during the hearing, he indicated that he had no evidence of a source other than the refueling cavity as causing water to be present on the external shell. See Tr. at 698.[33] Because Citizens failed to present any probative evidence supporting their assertion about an alternate source of water leaking onto the sand bed region, we find that the only source of water leaking onto the sand bed region is the refueling cavity liner. See Tr. at 384-85, 799.[34]

With respect to the potential for condensation to occur on the exterior sand bed region, condensation occurs only when the drywell shell is cooler than the surrounding air. Because

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[33] Notably, at the hearing, Dr. Hausler conceded that the only historical source of water that caused a corrosive environment in the drywell shell was leakage from the refueling cavity (Tr. at 687). Although Dr. Hausler's concession renders nugatory Citizens' arguments about other potential sources of water, we nevertheless address those arguments and reject them as meritless.

[34] We reject Citizens' allegation (Citizens Exh. 37, at 17) that Citizens Exhibit 21 demonstrates there has been leakage from the equipment pool onto the external wall of the drywell shell in the sand bed region. Rather, we find that the record supports the conclusion that the leakage described in Citizens Exhibit 21 "is isolated from the drywell shell and, based on the physical configuration of [Oyster Creek], there is no credible leakage path from the underside of the equipment pool to the drywell shell" (AmerGen Exh. C, Pt. 4, A.9). We likewise reject Citizens' claim (Citizens Exh. 37, at 17) that fuel pool water that did not originate from the refueling cavity has been found in the sand bed region. The author of Citizens Exh. 22, Technical Data Report ("TDR") 964, Drywell Sand Bed Drain Leakage (Mar. 3, 1989)), upon which Citizens rely, "proposes that the water discovered might have been 'old' fuel pool water, i.e., water left over from a previous refueling outage, when the refueling cavity was filled with water" (AmerGen Exh. C, Pt. 4, A.13). Although analysis of water samples collected from each bay drain proved inconclusive, following the TDR, the then-licensee conducted extensive investigations that "ultimately found no source of leakage other than the refueling cavity liner" (ibid.).

the "reactor pressure vessel and other equipment located inside the drywell generate a significant amount of heat," the drywell shell is heated to temperatures "significantly above the Reactor Building ambient temperature. This temperature differential will prevent condensation from forming on the exterior of the drywell shell in the sand bed region" (AmerGen Exh. B, Pt. 4, A.14). Although it is possible for condensation to occur during an outage due to the use of drywell chillers – which are used during outages when extended access to the drywell is required (AmerGen Exh. B, Pt. 4, A.15) – "such postulated condensation would only last until restart, when the drywell shell temperature would rise and any water would evaporate" (AmerGen Exh. B, Pt. 4, A.15). During the 2006 outage, AmerGen reported no evidence of condensation on the exterior of the drywell shell in the sand bed region (AmerGen Exh. B, Pt. 4, A.16). Significantly, Dr. Hausler testified at the hearing that he did not believe that "condensation on the [exterior of the drywell shell] is really a source of water that we might have to worry about" (Tr. at 687). We agree. The evidence shows that condensation can not occur during normal operations, and during outages, any condensation that could form due to the use of drywell chillers would evaporate before posing a corrosion risk. See AmerGen Exh. B, Pt. 4, A.14 to A.17.[35]

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[35] Although Dr. Hausler's written rebuttal testimony disputed the evaporation rate of condensation in the sand bed region presented by AmerGen's expert, Mr. Gordon, we view Dr. Hausler's subsequent testimony at the hearing (Tr. at 687) as negating, and withdrawing, Citizens' argument that condensation on the exterior of the drywell shell is a potential source of corrosion. Even if we were to consider Dr. Hausler's written rebuttal testimony, however, we would give no weight to his unsupported assertion that Mr. Gordon did not "use[ ] a reasonable approach to estimate the time in which any water on the exterior of the shell would evaporate" (Citizens Exh. C, A.22). Dr. Hausler failed to provide any probative evidence in support of his bare assertion that the sand bed region has a limited air exchange, which would cause any water in the sand bed region to become fully saturated during the outage. See, e.g., Citizens Exh. 39, Memorandum from Dr. Rudolf Hausler, to Richard Wester, Esq., at 19 (Aug. 16, 2007) (speculating that "the former sand bed area . . . is a totally stagnant space"); cf. AmerGen Exh. C.1, Pt. 6, A.8 ("[t]he gaps between the vent headers and the concrete provide substantial area for air flow, as do many piping penetrations from the drywell"); accord Tr. at 771-72 (Gallagher).

Citizens also argue that the corrective actions AmerGen has taken to ensure the refueling cavity will not leak into the sand bed region – i.e., repair and monitoring of the collection trough and application of stainless steel tape and strippable coating during outages – are ineffective (Citizens Exh. C.1, A.25). This argument cannot be reconciled with the record.

After corrosion was discovered on the exterior of the drywell shell in the sand bed region, the then-licensee of Oyster Creek took multiple corrective actions, including (AmerGen Exh. B, Pt. 1, A.23): (1) clearing the sand bed drains; (2) repairing the leakage collection trough "to minimize the possibility of water escaping the trough and entering the area between the concrete shield wall and exterior drywell shell" (AmerGen Exh. B, Pt. 4, A.8); (3) clearing the trough drain; and (4) applying stainless steel tape and a strippable coating to the refueling cavity during refueling outages. AmerGen witnesses testified that during the 2006 refueling outage, "[n]o water was observed on the exterior of the drywell shell in the sand bed region, or in [or from] the sand bed drains" (AmerGen Exh. B, Pt. 4, A.10). Messrs. Hawkins and Erickson confirmed they personally entered the sand bed regions in nine of the bays during the 2006 outage "and did not see water either on the exterior of the drywell shell, or on the concrete floor of the sand bed region" (AmerGen Exh. B, Pt. 4, A.11).

AmerGen has committed to apply the measures utilized during the 2006 outage at every outage during the renewal period when the refueling cavity is flooded. First, AmerGen will apply stainless steel tape and a strippable coating to the refueling cavity liner prior to flooding the refueling cavity. See AmerGen Exh. 10, Commitment 27(2); AmerGen Exh. B, Pt. 1, A.14; Tr. at 696-97.[36] Second, AmerGen will verify that the "refueling cavity concrete trough drain [is] . . .

[36] During the evidentiary hearing, AmerGen attested (Tr. at 696-97) (O'Rourke), and the NRC Staff agreed (Tr. at 697) (Ashar), that AmerGen's commitment consisted of applying stainless steel tape and a strippable coating to the refueling cavity liner during *every* outage – scheduled and unscheduled alike – when the refueling cavity is flooded. Given this unequivocal commitment, we summarily reject Citizens' assertion that AmerGen may flood the (continued...)

clear from blockage once per refueling cycle[, and a]ny identified issues will be addressed via the corrective action process" (AmerGen Exh. 10, Commitment 27(13)). Third, AmerGen will monitor the refueling cavity seal leakage trough drains and the drywell sand bed region drains for leakage. The sand bed region drains will be monitored daily during refueling outages and quarterly during the operating cycle. "If leakage is detected, procedures will be in place to determine the source of leakage and investigate and address the impact of leakage on the drywell shell," and appropriate corrective actions will be taken (AmerGen Exh. 10, Commitment 27(3)); see also NRC Staff Exh. B, A.12(b). Additionally, at the hearing, AmerGen represented it would expand this commitment to include periodic inspections of the sand bed drains for blockage. See Tr. at 843-44; supra note 12.

Citizens raise two challenges to the above mitigation measures. First, Dr. Hausler asserts the leakage collection trough "was damaged. . . . and was seen to be far from ideal in the most recent outage" (Citizens Exh. C, A.20). If the trough degraded further, he states, water could enter the drywell again and create a corrosive environment (ibid.). We reject Dr. Hausler's conjectural concern. He fails to cite any evidence demonstrating defects in the trough as of the 2006 refueling outage; rather, the exhibits on which he relies are from 1986 and 1996. See ibid. (citing Citizens Exhs. 48, 49). Nor does he provide evidentiary support for his speculation that the trough could degrade further or that undetected clogging of any drains could recur. See ibid.; Citizens Exh. B, A.18. AmerGen has committed to verify that the "refueling cavity concrete trough drain [is] . . . clear from blockage once per refueling cycle," and to monitor the refueling cavity seal leakage trough drains for leakage (AmerGen Exh. 10, Commitment 27(3), (13)). And AmerGen also has committed to verify periodically that the sand

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[36](...continued)
refueling cavity without applying leakage mitigation measures during a forced outage (Citizens Exh. C, A.20).

bed drains are unclogged and exhibit no evidence of leakage (id., Commitment 27(3)). "Any identified issues will be addressed via the corrective action process" (id., Commitment 27(13); see also id., Commitment 27(3)), thereby providing reasonable assurance there will be no corrosive environment on the exterior wall in the sand bed region.

Second, Citizens assert that the "metal tape and strippable coating is not always effective in preventing significant leaks" (Citizens Exh. C.1, A.25). Citizens do not allege the tape and coating were ineffective during the 2006 outage; rather, they rely on a February 1, 1993 memorandum that addressed leakage from the refueling cavity liner onto the sand bed region during the 1992 refueling outage. Although Citizens are correct that there was leakage from the refueling cavity liner during the 1992 outage notwithstanding the use of the tape and coating, they ignore that this outage was *prior to* the then-licensee's repair of the leakage collection trough and the concrete trough drain. See Citizens Exh. 50, Internal GPU Nuclear Memorandum, Re: 14R Reactor Cavity Leak Detection Effort, at 2 (Feb. 1, 1993) ("[s]everal areas considered having the highest potential for being a leak were repaired or are scheduled for repair prior to the next cavity flood up"). Since the 1992 outage, the troughs have been repaired, and AmerGen's use of the tape and coating during the 2006 outage not only "reduced the amount of [refueling] cavity liner leakage," it eliminated leakage on the external wall in the sand bed region (AmerGen Exh. B, Pt. 4, A.9). The fact that no water was discovered in the sand bed region during the 2006 outage when the tape and coating were used defeats Citizens' assertion that these leakage-mitigation measures are ineffective.

Further, although Citizens correctly observe that the leakage from the refueling cavity liner during the 2006 outage – approximately one gallon per minute (AmerGen Exh. B, Pt. 4, A.9) – demonstrates that AmerGen "has not yet devised a means of preventing the reactor fueling cavity from leaking" (Citizens Exh. 37, at 17), this fact is not critical to our resolution of the contention presented. Rather, the salient question is whether water will leak from the refueling cavity liner at a sufficient rate to overwhelm the trough and drains and enter onto the exterior wall in the sand bed region, thereby creating a corrosive environment. The record requires that we answer that question in the negative. As AmerGen explained, "[l]eakage from the [refueling] cavity is not relevant unless it exceeds the capacity of the trough drain" (AmerGen Exh. C, Pt. 4, A.14). The one gallon per minute leakage observed during the 2006 outage "is well within the capacity of the refueling cavity trough drain system, which is estimated using standard hydraulic principles to be approximately 50 gallons per minute" (AmerGen Exh. B, Pt. 4, A.9). The trough drain system directed the leakage into the controlled drainage collection system, thus preventing it from reaching the drywell shell, much less the sand bed region.[37]

The Board therefore finds that: (1) AmerGen has demonstrated that the refueling cavity liner is the only source of corrosive-causing water on the external wall of the drywell shell in the sand bed region; (2) AmerGen's commitments effectively eliminate the potential for water leakage from the refueling cavity liner into that area; and (3) in the absence of such water, there will be no further corrosion in that area. Absent further corrosion, the thickness of the shell in the sand bed region will not violate the acceptance criteria during the renewal period, and Citizens' challenge to the frequency of AmerGen's UT program must be rejected.[38]

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[37] Citizens correctly observe that in 2006, AmerGen discovered the following indications that water had been present in the sand bed region: (1) white discoloration was seen on the concrete floor, which appeared to be residue left behind by water; and (2) water was found in three of the five plastic bottles that collect water from the sand bed drains. Based on the totality of the evidence, we accept AmerGen's explanation that these were hoary indicators of long-past leakage, "because the plastic drain lines from the sand bed drains were dry and there was no water on the Torus Room floor" (AmerGen Exh. B, Pt. 4, A.12; Citizens Exh. 37, at 17).

[38] This conclusion takes into account our subsequent finding (infra Part IV.B.2) that there will likewise be no measurable corrosion on the interior wall of the drywell shell in the sand bed region during the renewal period.

b. Even If Water Entered The Exterior Wall Of The Drywell Shell, The Sand Bed Region Is Protected From Further Corrosion By A Robust, Triple-Layered Epoxy Coating. During the 1992 refueling outage, the then-licensee of Oyster Creek applied to the drywell shell in the sand bed region a one hundred percent solid, three-layer epoxy coating system – consisting of one pre-prime and two additional coats – to prevent corrosion from forming on the metal surface of the drywell shell in the event water were to reach the sand bed region. See AmerGen Exh. B, Pt. 5, A.6; NRC Staff Exh. B, A.14. AmerGen has committed to visually inspect the epoxy coating in all ten drywell bays prior to the period of extended operation and every other refueling outage thereafter (AmerGen Exh. 10, Commitment 27(4)), employing a Protective Coating Monitoring and Maintenance Program that "incorporate[s] coated surfaces inspection requirements specified in ASME Code Section XI, Subsection IWE" (NRC Staff Exh. B, A.15).

Specifically, AmerGen's epoxy coating program requires it to: (1) examine the inspected areas "for evidence of flaking, blistering, peeling, discoloration, and other signs of distress";[39] (2) resolve by engineering evaluation, or correct by repair or replacement, any suspect areas in accordance with IWE-3122; and (3) perform, when specified as a result of engineering evaluation, supplemental examinations in accordance with IWE-3200 (NRC Staff Exh. 1, at 3-120; see also NRC Staff Exh. B, A.15). If the epoxy coating is damaged and corrosion is observed, AmerGen must conduct UT measurements of the affected area and evaluate the results per its existing program. See NRC Staff Exh. B, A.15 (citing AmerGen Exh. 10, Commitment 27(1)). The NRC Staff concluded that AmerGen's commitments will "provide[ ] assurance that effects of

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[39] ASME Section XI, Subsection IWE criteria require direct visual inspection of the entire exterior surface, from the base of the sand bed floor (approximately elevation 8'11") to the top where the drywell shell rises into the 3" gap with the concrete (approximately elevation 12'3") (see AmerGen Exh. B, Pt. 5, A.22).

aging will be adequately managed so that intended functions will be maintained throughout the renewal period" (ibid.) (citing NRC Staff Exh. 1, at 3-114 to 3-143, 3-163 to 3-167).

Citizens nevertheless assert that if any water is present on the exterior sand bed region during the period of extended operation, the epoxy coating system will not adequately protect against corrosion, because: (1) inaccessible areas of the drywell shell in the sand bed region were not coated (Citizens Exh. C, A.21; Tr. at 707); (2) water could penetrate through defects in the epoxy that likely formed when the coating was applied (Citizens Exh. B, A.21; Tr. at 721); (3) visual observation may not be sufficient to detect the early stages of coating failure (Citizens Exh. B, A.21; Tr. at 739); and (4) the epoxy coating might rapidly deteriorate between scheduled inspections (Citizens Exh. B, A.21; Tr. at 730, 733-35). None of these arguments has merit.

First, contrary to Citizens' argument, we conclude that ample record evidence shows that the entire sand bed region is coated with the protective three-layer epoxy coating. AmerGen witness Mr. Cavallo attested that "workers who inspected the external coating in all ten bays during the 2006 refueling outage confirmed that all of the areas were coated" (AmerGen Exh. C.1, Pt. 5, A.6). See also Tr. at 706 (Hawkins) (AmerGen witness testifies that the entire sand bed region, "from 8 foot 11 [inches] to 12 foot 3 inches . . . is completely coated" with the epoxy). Likewise, NRC Staff witness Mr. O'Hara testified that, based on his first-hand knowledge from inspecting two bays during the 2006 outage, "[a]ll the regions on the outside of the drywell were coated" (Tr. at 718). We find that this evidence, which includes convincing eye-witness testimony, negates Citizens' bare assertion that a portion of the sand bed region is not protected by epoxy.[40]

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[40] In his pre-filed rebuttal testimony, Dr. Hausler stated that "documents [he has] received from AmerGen indicate that areas of the shell in the sand bed region were not coated with epoxy because they are inaccessible" (Citizens Exh. C, A.21). But the documents relied upon by Dr. Hausler – Citizens Exhibits 40 and 41 – fail to support his allegations. See Citizens Exh. 40, E-mail from John G. Hufnagel, Jr., to Ahmed Ouaou and Donald B. Warfel, Sr., Re:

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Second, we reject Citizens' assertion that the epoxy likely contains defects – i.e., pinholes or holidays – that formed when the coating was applied and through which water could penetrate. A pinhole or holiday is a microscopic, localized defect in the epoxy coating that is created "by the chemistry of the coating (e.g., solvent entrapment)" or due to a problem in the original application of the coating, "such as failure to properly cure the coating"; they are not defects caused by degradation of the coating over time (AmerGen Exh. B, Pt. 5, A.13). Dr. Hausler opines that pinholes may have been present in the coating when it was applied. See Citizens Exh. B, A.21. As a consequence of these defects, he asserts, "any water in the sand bed can penetrate the coating . . . [which] would then reach [the] steel interface beneath the coating and cause further corrosion" (Citizens Exh. B, A.21).

Citizens' argument fails to recognize that the nature of the epoxy coating at Oyster Creek minimizes the likelihood of pinholes and the infiltration of water for two reasons. First, the formation of pinholes "has to do with solvent migration leaving very small holes in the coating," but the epoxy coating at Oyster Creek has "no solvents in any one of the three coats" (Tr. at 724) (Cavallo). See also AmerGen Exh. 35, Application Guide for DEVOE Coatings Pre-Prime 167 and Devran-184 (indicating both the pre-prime and top coats are 100 percent solids).[41]

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[40](...continued)
Challenge Board #1 additional comment (Nov. 30, 2006, 10:41); Citizens Exh. 41, Technical Functions Safety/Environmental Determination and 50.59 Review (EP-016), Clean and Coat Drywell Ext. In Sand Bed (Jan. 5, 1993). Neither Exhibit 40 nor 41 indicates that actual areas of the sand bed region were left uncovered (AmerGen Exh. C.1, Pt. 5, A.6). Citizens Exhibit 40 "is based entirely on a historical document that pre-dated the cleaning and coating of the exterior shell" (ibid.), and Citizens Exhibit 41, which was written in December 1992, merely conjectures that "'patches of the drywell exterior may be left uncleaned and/or uncoated'" (ibid.) (quoting Citizens Exh. 41, at OCLR00022257). We find these speculative documents to be unconvincing, and we credit, instead, the testimony of AmerGen and NRC Staff witnesses who averred, based on first-hand knowledge, that the drywell shell in the sand bed region is completely coated with the three-layer epoxy coating.

[41] Citizens' witness, Dr. Hausler, conceded that he was unaware that the epoxy coatings contained no solvents (Tr. at 748). Although Dr. Hausler speculated that the viscous
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Second, because the epoxy coating is a three-layer system, "[i]f a pinhole or holiday exists in the primer coat, it would likely be covered up by the second coat. The likelihood that a pinhole or holiday would extend through both coats is quite small [and t]he likelihood that a pinhole or holiday would extend through all three coats . . . is even smaller" (AmerGen Exh. B, Pt. 5, A.14); see also NRC Staff Exh. B, A.14.[42]

Beyond preventing the formation of pinholes and the infiltration of water in the first instance, the epoxy coating system applied to the Oyster Creek drywell shell also allows for easy detection of signs of deterioration through the use of contrasting pigments in the top two layers. See AmerGen Exh. B, Pt. 5, A.6. Because the early indications of epoxy coating failure include pinpoint rusting and rust staining (AmerGen Exh. C, Pt. 5, A.7), the "grayish white" top coat of the epoxy will provide "a very good visual contrast to . . . [the] iron oxide or red rust, . . . [which] would be very visible to, particularly, trained [Visual Testing ("VT")]-1 inspectors" (Tr. at 725) (Cavallo).[43] See also id. at 722-23 (Cavallo); AmerGen Exh. B, Pt. 5, A.16; NRC Staff Exh. C, A.36 ("early stages of coating failure would be apparent during a VT-1 inspection," because the resulting "film will be rust colored and will be obvious against the grey colored epoxy

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[41](...continued)
composition of solvent-free epoxy makes it more difficult for air bubbles to escape (ibid.), he provided no information that would lead the Board to question the persuasive testimony of the AmerGen and NRC Staff witnesses regarding the robust nature of the coating. Mr. Cavallo also testified that – contrary to Dr. Hausler's assertion (Tr. at 721) – dust in the atmosphere at the application stage is not a material causative factor of pinholes in this type of epoxy coating (Tr. at 724).

[42] Notably, in Dr. Hausler's pre-filed written submission, he conceded that "pinholes are rare when two coats of . . . [epoxy coating] have been applied" (Citizens Exh. 39, at 17). Moreover, when questioned by the Board, Dr. Hausler acknowledged he knows of no evidence in the record that would suggest the existence of any pinholes in the Oyster Creek epoxy coating (Tr. at 722).

[43] VT-1 inspectors are trained and qualified in accordance with ASME Section XI, Subsection IWE to "inspect surfaces such as the drywell shell for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation that would be early signs of potential coating failure" (AmerGen Exh. B, Pt. 5, A.12).

coating"); NRC Staff Exh. B, A.15. Had there been any pinholes in the coating, the corrosion that would have resulted from water that was present in the sand bed region during the 1994 and 1996 refueling outages – when the strippable coating was not used in the refueling cavity liner – "would be visible today due to the volume of corrosion products (iron oxides) and surface rust staining caused by the corrosion process" (AmerGen Exh. B, Pt. 5, A.14).

In addition to surface discoloration, because iron oxide corrosion products occupy a volume "between approximately seven and ten times greater than the metal being corroded," if corrosion were occurring under the epoxy coating, the metal surface would become very uneven (AmerGen Exh. B, Pt. 6, A.8; see also Tr. at 726 (Cavallo); NRC Staff Exh. B, A.15). Specifically, the corrosion would generate "an irregularly shaped fairly circular rough surfaced deformation of the coating . . . centered on the area of the pinhole," known as a "carbuncle" (Tr. at 726-27 (Cavallo); see also AmerGen Exh. B, Pt. 5, A.15). However, in a benign environment, such as the Oyster Creek drywell, if there were pinholes in each of the three layers of epoxy coating, and if all three pinholes were aligned, AmerGen testified that it would "[not] expect to see carbuncles[, rather it] . . . would expect to see [only staining] over a period of three or four years, which is the frequency of inspection" (Tr. at 727) (Cavallo).

Significantly, AmerGen's visual inspection of the epoxy coating on the drywell shell in the sand bed region during the 2006 refueling outage confirmed that neither of the key indicators of corrosion was present. Messrs. Erickson and Hawkins – both of whom are certified VT-1 inspectors (AmerGen Exh. B, Pt. 4, A.3; supra note 43) – testified that during the 2006 outage they collectively inspected nine of the ten bays (AmerGen Exh. B, Pt. 4, A.18, A.19), and they found no evidence of "any flaking, chipping, blistering, peeling, pinpoint rusting, cracking, chalking or discoloration, or any evidence of corrosion or corrosion products from the exterior drywell shell in the sand bed region. . . . There was a visible shine indicative of a coating in pristine condition" (AmerGen Exh. B, Pt. 4, A.23; see also Tr. at 723 (Hawkins, Erickson);

AmerGen Exh. 24, ASME IWE (Class MC) Containment Visual Examination Record (Oct. 22, 2006)). Likewise, NRC Staff witness Mr. O'Hara testified that during the 2006 refueling outage he physically inspected the external epoxy coating on the outside of the drywell shell in two of the bays, and the coating "appeared to be in excellent condition with no visible evidence of cracking, peeling, or blistering" (NRC Staff Exh. B, A.20). After reviewing video tapes of all the other bays along with the data sheets for each bay, Mr. O'Hara testified the tapes "showed the same general condition in all bays and showed that the epoxy coating had not been visibly disturbed since the original application" (ibid.; see also Tr. at 723 (Cavallo) (testifying that there are no "visual indications of pinholes, . . . [which] allows me to state unequivocally we do not have pin holes in the coatings applied to the drywell in 1992")).

In short, we find that overwhelming record evidence supports the conclusion that – contrary to Citizens' assertion – there are no pinholes in the protective epoxy coatings, much less pinholes in each of the three layers that are aligned and through which water has penetrated, or will likely penetrate.

Nor do we accept Citizens' argument that visual inspections may not reliably detect the early stages of coating failure. Dr. Hausler contends that "[o]nce a defect . . . provides access for water to the steel surface underneath, corrosion begins slowly," and although "hardly noticeable from the surface . . . as corrosion progresses the coating will start to crack, opening up a larger defect" (Citizens Exh. 12, at 9; see also Citizens Exh. 39, at 19-20). Dr. Hausler thus criticizes AmerGen's proposed four-year inspection cycle as inadequate, because "damage might occur between inspections" (Citizens Exh. 12, at 8). Dr. Hausler's unsupported allegations are not credible.[44]

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[44] Because Dr. Hausler is not familiar with the specific composition of epoxy in use at Oyster Creek (Tr. at 734-35) (Hausler)), and because his expertise in oil field applications (Tr. at 667 (Hausler)) – which "generally involve continuous immersion service with highly corrosive (continued...)

The "use of visual inspections to detect coating failures . . . is based . . . on established industry practice" (AmerGen Exh. C, Pt. 5, A.6), and has been endorsed by the NRC in the Generic Aging Lessons Learned ("GALL") Report, NUREG-1801, Vol. 2, Section XI.S1 (NRC Staff Exh. B, A.15). In addition, NRC Regulatory Guide 1.54, Rev. 1, Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants "recommend[s] visual inspection of coatings for evidence of degradation before conducting additional tests" (ibid.; see also LBP-06-22, 64 NRC at 245).[45] AmerGen's Protective Coating Monitoring and Maintenance Program follows the NRC Staff guidance set forth in the GALL Report, and satisfies the requirements of ASME Code Section XI, Subsection IWE, which is mandated by 10 C.F.R. § 50.55a. See AmerGen Exh. C, Pt. 5, A.6; NRC Staff Exh. B, A.13, A.15; LBP-06-22, 64 NRC at 247; see generally NRC Staff Exh. 2, Subsection IWE Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Plants (1992).[46]

We therefore reject Citizens' assertion that visual inspections may not be sufficient to detect the early stages of coating failure. The record shows that "early indications of epoxy coating failure . . . include pinpoint rusting and rust staining, long before widespread coating failure in the form of cracking and delamination" (AmerGen Exh. C, Pt. 5, A.7). Because these early indications of coating failure would develop at a "very slow rate" in the "benign non-

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[44](...continued)
pressurized fluids, corrosive gases and continuous fluid flow" (AmerGen Exh. C, Pt. 5, A.5) – is inapplicable to the benign operating environment at Oyster Creek, we accord diminished weight to his assertions attacking the reliability of AmerGen's coating inspection program.

[45] According to Mr. Cavallo, a recent Electric Power Research Institute study on which he served as a principal investigator "confirms that visual inspections would detect the early signs of coating system failure" (AmerGen Exh. C, Pt. 5, A.6).

[46] To the extent Dr. Hausler suggests that AmerGen should use alternative means for monitoring the epoxy coating – e.g., "electric and sponge type surface examinations" (Tr. at 739) (Hausler) – he is introducing concerns beyond the scope of this proceeding. See Tr. at 739-40 (Chairman Hawkens); LBP-06-22, 64 NRC at 244-48 (rejecting Citizens' challenge to AmerGen's monitoring of the coating in the sand bed region).

immersion environment" of the sand bed region (ibid.), we find that AmerGen's commitment to conduct visual inspections of the epoxy coating every four years provides reasonable assurance that early stages of coating failure will be detected. See NRC Staff Exh. B, A.15; see also AmerGen Exh. C, Pt. 5, A.7 ("Dr. Hausler's speculation about the inability of visual inspections to 'detect the early stages of coating failure' is simply not technically credible").

Finally, Citizens argue that the epoxy coating may suffer rapid deterioration between scheduled inspections, thereby allowing significant corrosion. This argument is based principally on Citizens' understanding that the lifetime of the coating is unknown – "estimated at anything from ten to twenty years" (Citizens Exh. B, A.21). Because the coating already is fifteen years old, Citizens assert that it will likely experience a precipitous failure during the renewal period (Citizens Exh. C.1, A.31). Assuming such a failure, Citizens argue that AmerGen's proposal to inspect the coating every four years is inadequate (Citizens Exh. 39, at 17). This argument is insubstantial.

AmerGen's expert witness, Mr. Cavallo, testified that, in his experience, a properly applied coating, such as Oyster Creek's, will not deteriorate rapidly due to age (Tr. at 732; see also AmerGen Exh. B, Pt. 5, A.8). Mr. Cavallo's opinion was shared by AmerGen witness, Mr. Ouaou (Tr. at 732), and NRC Staff witness, Dr. Davis (Tr. at 732-33). Underlying their opinions is the fact that the epoxy coating is designed to withstand conditions far more severe than those it will experience here. For example, it is designed for constant immersion, but here it is not used in a submerged environment; it is rated for up to 250 degrees Fahrenheit, but here the normal operating temperature in the drywell is only 139 degrees Fahrenheit; and it can withstand radiation up to 1×10^9 rads, but here the expected radiation will only be 1.8×10^6 rads. See AmerGen Exh. B, Pt. 1, A.18; AmerGen Exh. B, Pt. 5, A.7. The coating is thus exposed to a comparatively benign environment relative to its design capability, which provides "an extra order of confidence to the [coating's] performance" (Tr. at 741) (Cavallo).[47]

Additionally, Dr. Davis testified that improperly applied coatings usually fail within the first few years, and once the coating gets beyond the first few years, rapid failure is not likely (Tr. at 732-33; accord AmerGen Exh. B, Pt. 5, A.9). Here, because visual inspections indicate the epoxy coating is in good condition after 15 years, it is evident that the coating was properly applied and that rapid failure is unlikely. See NRC Staff Exh. C, A.35; NRC Staff Exh. C.1, A.56, A.57; see also AmerGen Exh. B, Pt. 5, A.11 (Mr. Cavallo testifies that, based on his review of the records from the 2006 visual inspections of the epoxy coating, he has "very high confidence that the epoxy coating system is still in excellent condition"); AmerGen Exh. B, Pt. 5, A.23 (Mr. Cavallo, Mr. McAllister, Mr. Erickson, and Mr. Hawkins testify that, based on their inspections or review of inspection records from the 2006 visual inspections, the "coating system is in excellent condition").

Finally, it bears noting that the record shows that this type of coating has been successfully used for decades in U.S. nuclear power plants with no signs of end-of-life deterioration (AmerGen Exh. B, Pt. 5, A.7). As Mr. Cavallo testified (AmerGen Exh. B, Pt. 5, A.9):

> The purpose of AmerGen's inspection program is to identify the early signs of deterioration, long before widespread coating failure could take place. In the U.S. nuclear industry there have been similar coating systems that have been in service for approximately 30 years that still do not exhibit such end of life deterioration.

See also AmerGen Exh. B, Pt. 5, A.7 (Mr. Cavallo testifies that "to the best of [his] knowledge, not a single epoxy coating in an atmospheric environment applied at a nuclear power plant has

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[47] Two principal causes of deterioration for this type of coating are ultraviolet light and mechanical damage, such as abrasion or gouging (AmerGen Exh. B, Pt. 5, A.7). Here, the coating is not susceptible to either type of damage, because it is not exposed to ultraviolet light, and it is isolated from moving parts (ibid.). During plant operation, the coated area is completely inaccessible (ibid.).

reached its end-of-life"); AmerGen Exh. B, Pt. 5, A.9 (citing as examples two nuclear facilities where coatings have been "used for decades with no significant degradation," Mr. Cavallo states that "industry experience with epoxy coating systems of this type indicates that short life-span estimates . . . are overly conservative").

Based on the persuasive testimony provided by the exceedingly knowledgeable and experienced witnesses on behalf of AmerGen and the NRC Staff, we reject Citizens' assertion that the epoxy coating may suffer rapid deterioration between scheduled inspections, thereby allowing significant corrosion that would not be detected in time by the periodic UT measurements.[48]

In sum, we conclude that even if water were to leak onto the exterior wall of the drywell shell in the sand bed region during the period of extended operation, the epoxy coating system will adequately protect that region against corrosion. Absent further corrosion (see supra note 38), the thickness of the shell in the sand bed region will not violate the acceptance criteria

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[48] In support of Citizens' argument that the epoxy coating may experience rapid failure, Dr. Hausler observed that the 2006 inspection revealed that "the coating on the [sand bed] floor was cracked in some bays along with the concrete of the former sand bed floor" (Citizens Exh. 12, at 8; see also Citizens Exh. 39, at 17). What Dr. Hausler failed to recognize, however, is that the coating system on the concrete sand bed floor is materially different than the coating system on the steel drywell shell. The floor coating – unlike the shell coating – was not designed to prevent moisture penetration; rather, it was designed to correct irregularities in the concrete floor and alter the contours to guide any leakage toward the sand bed drains (Tr. at 744-45) (Cavallo, Ouaou). Because the floor coating is not intended to serve as a moisture barrier, it was not pre-primed with a penetrating epoxy sealer and is therefore more susceptible to delaminating (Tr. at 744) (Cavallo). Moreover, because the floor coating was not designed to serve as a moisture barrier, there was no need to adhere to application procedures recommended by the manufacturer (see Tr. at 744-45) (Cavallo, Ouaou). For example, although the manufacturer recommends limiting the coating thickness to a quarter of an inch (Tr. at 744) (Cavallo), in some cases, it was applied on the floor to a thickness of eight inches (Tr. at 745) (Ouaou). For these reasons, Dr. Hausler's ill-conceived attempt to compare the shell coating to the floor coating is unavailing. Significantly, the floor defects discovered in 2006 – which have been repaired (AmerGen Exh. 3, at 7-3) – would not have prevented the flow of any leakage toward the sand bed drains (ibid; AmerGen Exh. C, Pt. 4, A.18).

during the renewal period, and Citizens' challenge to the frequency of AmerGen's UT program must be rejected.

2. There Is No Likelihood Of Future Corrosion On The Interior Wall Of The Sand Bed Region

Although Citizens' arguments focus principally on the potential for further corrosion on the *exterior* wall in the sand bed region, they also assert that, based on UT measurements in Bays 5 and 17, a corrosive environment exists on the *interior* wall in the sand bed region that caused the wall to lose a thickness of about 0.038 inch between 1986 and 2006 (Citizens Exh. C, A.19; NRC Staff Exh. B, A.11), which – at that rate – would result in a further loss of about 0.038 inch during the renewal period. We find that Citizens' premise regarding *internal* corrosion lacks evidentiary support. Rather, the record supports the conclusion that the interior wall of the sand bed region has not experienced measurable corrosion in the past, and will not experience measurable corrosion during the renewal period.[49]

Notably, AmerGen does not dispute that UT measurements in Bays 5 and 17 between 1986 and 2006 indicate a loss in thickness of about 0.038 inch. But AmerGen vigorously disputes Citizens' assertion that this loss occurred on the *interior* of the shell (AmerGen Exh. C, Pt. 6, A.9 to A.12). AmerGen witnesses Mr. Gordon, Mr. Gallagher, and Mr. Tamburro testified that in 2006 AmerGen removed concrete from a portion of the internal side of the drywell shell in the sand bed region (AmerGen Exh. C, Pt. 6, A.10). The surface of the newly exposed portion of the shell – which had been embedded in concrete since construction of the Oyster Creek facility – revealed "no measurable corrosion" (ibid.). They attested that the absence of corrosion "demonstrates that the conditions inside the drywell will not lead to significant

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[49] As explained supra Part II.A, the sand bed region begins at a shell height of 8 feet 11 inches (the level of the exterior concrete floor) and extends to 12 feet 3 inches. The interior wall of the shell remains embedded in concrete up to a height of about 11 feet (beneath the torus vent headers) and 12 feet 3 inches (between the torus vent headers).

corrosion during the period of extended operation because interior drywell conditions over the next 22 years are expected to be the same as over the past 38 years" (ibid.). We agree.[50]

By way of background, AmerGen assumes that water has impregnated the internal concrete floor and will normally be in contact with the internal wall of the drywell shell (AmerGen Exh. 3, at 8-2 to 8-4). Nevertheless, for the following reasons, the conditions inside the drywell shell are such that "[a]ny corrosion [during the renewal period] would be vanishingly small and of no engineering concern" (AmerGen Exh. C, Pt. 6, A.9). First, because the water in contact with the interior wall of the shell has migrated through the alkaline-rich concrete floor, it has a high pH level that inhibits corrosion (AmerGen Exh. 3, at 8-3; AmerGen Exh. C, Pt. 6, A.10; NRC Staff Exh. B, A.17).[51] Second, any new water that enters the drywell interior (e.g., reactor coolant) and enters the concrete-to-shell interface will also have an increased pH due to its migration through the concrete, resulting in a non-aggressive, alkaline environment (AmerGen Exh. 3, at 8-3; AmerGen Exh. C, Pt. 6, A.10). Third, during operations, the non-aggressive, alkaline environment is rendered even more benign because the drywell is inerted with nitrogen, thus reducing any corrosive-promoting oxygen (AmerGen Exh. 3, at 8-3; AmerGen Exh. C, A.10 to A.12; NRC Staff Exh. B, A.12(a)).[52]

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[50] The NRC Staff agrees with AmerGen that, contrary to Citizens' assertion, the thickness reduction of about 0.038 inch was caused by corrosion on the *exterior* wall of the drywell shell (NRC Staff Exh. C.1, A.45). Further, the NRC Staff convincingly explains (ibid.), and AmerGen agrees (AmerGen Exh. 3, at 8-2), that "[i]t is reasonable to assume that most of the exterior corrosion took place between 1986 and 1992, when the exterior surface of the drywell shell in the sand bed region had wet sand present and was not protected by the three-layer epoxy coating" (ibid.).

[51] As AmerGen expert Mr. Gordon explained, the high-pH water in contact with the shell "produces a protective film on the steel, and the corrosion rate is essentially negligible" (Tr. at 772). The record also shows that the levels of impurities in the high-pH water are significantly below the EPRI embedded steel guidelines action level recommendations (AmerGen Exh. 3, at 8-3; AmerGen Exh. C, A.10).

[52] The NRC Staff acknowledged that leakage from components inside the drywell

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Finally, the record shows that during the 2006 outage, a structural engineer performed a comprehensive evaluation of the integrity of the inner drywell shell embedded in the concrete, and this evaluation was reviewed by an industry corrosion expert and an independent third-party expert on the continued integrity of the shell (AmerGen Exh. 3, at 8-3). The evaluation concluded that the "protective passive film established during concrete installation at the embedded steel/concrete interface is still intact and significant corrosion of the interior embedded drywell shell would not be expected as long as this benign environment [inside the shell] is maintained" (ibid.). Indeed, the industry corrosion expert concluded that, given the innocuous environment, "water could remain in contact with the interior drywell shell indefinitely without adverse impacts" (ibid.).

In our judgment, the evidence mandates the conclusion that the interior wall of the drywell shell in the sand bed region will not experience measurable corrosion during the renewal period. Absent further corrosion, the thickness of the shell in the sand bed region will not violate the acceptance criteria during the renewal period, and Citizens' contention challenging the frequency of AmerGen's UT program must be rejected.

C. Even If Corrosion Were To Occur In The Sand Bed Region, AmerGen's Plan To Take UT Measurements Every Four Years Provides Reasonable Assurance That The Shell Will Not Violate The Acceptance Criteria

Even if we were to accept Citizens' assertion that the sand bed region will experience significantly measurable corrosion during the renewal period (which we do not), we would nevertheless reject their attack on AmerGen's plan to take UT measurements every four years, because – as we explain below – we find that Oyster Creek would experience an annual

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[52](...continued)
may cause a corrosive environment during outages (when ambient air replaces the nitrogen) if the trenches in Bays 5 and 17 fill with water (NRC Staff Exh. B, A.12(a)). AmerGen has committed to monitoring the trenches for the presence of water, however, to preclude the creation of such an environment (ibid.) (citing NRC Staff Exh.1, at A-31 to A-32).

corrosion rate, *at most*, of about 0.0035 inch per year. At that rate, during the four-year interval between UT measurements, the sand bed region would experience corrosion of about 0.014 inch, which is far less than the minimum available margin of 0.064 inch. This negates Citizens' assertion that, if further corrosion occurs, AmerGen's UT measurements are not sufficiently frequent to prevent the shell from exceeding the acceptance criteria.

To determine the maximum expected annual rate of corrosion on the exterior wall, we start by accepting Citizens' invitation (Citizens Exh. B, A.16) to use the highest historical corrosion rate ever measured in the Oyster Creek sand bed region, which was about 0.039 inch per year (AmerGen Exh. C, Pt. 6, A.14; Tr. at 765, 768 (Gordon)).[53] We divide the corrosion rate of 0.039 inch per year by 365 days, to get a daily corrosion rate of 0.0001069 inch (AmerGen Exh. C, Pt. 6, A.15). We then multiply the corrosion rate of 0.0001069 inch per day by 30 days to compute the corrosion expected during a month-long refueling outage, which gives a corrosion value of 0.003 inch.[54] Finally, because Oyster Creek refueling outages are

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[53] We agree with AmerGen and the NRC Staff, who believe that an assumed annual corrosion rate of 0.039 inch during the renewal period is not realistic because the pre-1992 environment in which it occurred consisted of water-saturated sand in direct contact with an uncoated drywell, which contrasts sharply with the current environment, where the water-retaining and ion-containing sand has been removed, the ingress of water has been mitigated, and the drywell shell has been covered with a protective epoxy (AmerGen Exh. C.1, Pt. 6, A.6). The NRC Staff states that a more realistic, but appropriately conservative, corrosion rate would be about 0.002 inch per year (NRC Staff Exh. C.1, A.45), and AmerGen states that a more realistic, but appropriately conservative, corrosion rate would be about 0.0014 inch every refueling outage, which equates to 0.0007 inch per year (AmerGen Exh. B, Pt. 6, A.15). Although we acknowledge that an assumed annual corrosion rate of 0.039 inch is enormously conservative, we choose to use it in the present circumstance to show that – even accepting the corrosion rate advocated by Citizens (Citizens Exh. B, A.16) – Citizens' challenge to AmerGen's UT program lacks merit.

[54] As discussed <u>supra</u> Part II.A, the refueling cavity is filled with water only during refueling outages that are scheduled to occur every two years, or in the rare event of a non-refueling outage when the reactor vessel must be opened, which has not occurred at Oyster Creek since 1990 (AmerGen Exh. B, Pt. 1, A.17). Because the record establishes that the refueling cavity, when filled, is the only source of water that could cause corrosion in the sand bed region (<u>supra</u> Part IV.B.1.a), the potential for a corrosive environment in the sand bed

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scheduled to occur every two years, we divide 0.003 inch by 2 years, resulting in an annual corrosion rate of about 0.0015 inch (ibid.). Assuming a corrosion rate of 0.0015 inch per year on the external wall of the drywell shell in the sand bed region, the total amount of corrosion that would occur on the external wall during the four-year interval between UT measurements is 0.006 inch.

To this value of external corrosion that allegedly could occur in a four-year period, we add the corrosion that allegedly could occur on the internal wall of the shell in the sand bed region. For purposes of estimating the internal corrosion, we will again accept the corrosion rate suggested by Citizens and assume that "corrosion from the interior could add 0.002 inch per year" onto the corrosion rate for the exterior (Citizens Exh. B, A.16), which means that 0.008 inch of corrosion allegedly could occur on the internal wall in the sand bed region during the four-year interval between UT measurements.

Adding the external corrosion (0.006 inch) and the internal corrosion (0.008 inch) that allegedly could occur between UT measurements yields a total corrosion value of 0.014 inch every four years, which means that – contrary to Citizens' assertion – AmerGen's plan to take UT measurements at four-year intervals will ensure that corrosion of the drywell shell in the sand bed region will not exceed the minimum available margin of 0.064 inch between measurements.[55]

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[54](...continued)
region may fairly be limited to refueling outages when the refueling cavity is filled (AmerGen Exh. B, Pt. 6, A.18; AmerGen Exh. C, Pt. 6, A.15). Notably, the assumption that the cavity is filled with water for a full month during a refueling outage is conservative. See supra note 4 (refueling cavity filled with water for 17 days during 2006 refueling outage).

[55] Of course, if AmerGen's UT measurements revealed this level of corrosion on the drywell shell, or if it discovered *any* significant corrosion there, it would be required – in addition to notifying the NRC Staff – to take immediate corrective action, consistent with its CLB, to ensure Oyster Creek presents no undue risk of harm to public health and safety (see, e.g., 10 C.F.R. §§ 50.9(b), 50.72(b)(3)(ii)(A) & (B); AmerGen Exh. 10, Commitment 27(1)).

(continued...)

Our conclusion that AmerGen's plan to take UT measurements at four-year intervals is sufficient to ensure an adequate safety margin is fortified by Citizens' statement that any future corrosion of the drywell shell will occur predominantly toward the bottom of the sand bed region, not the top (Tr. at 325) (Hausler). Citizens' expert observed that because the sand has been removed from the sand bed region, it will no longer act as a medium to retain leaking water and to keep it in contact with the drywell shell at the top of the sand bed region; rather, any water will now drain toward the bottom of the region, causing the most severe corrosion to occur there (Tr. at 324-25) (Hausler). This observation – which we find reasonable – means that future corrosion will not be significant in the thinnest, most corroded area at the top of the sand bed region (Tr. at 323-24) (Hausler). Instead, any significant future corrosion will occur toward the bottom

[55](...continued)

We note that AmerGen's commitments include completing the following 3-D structural analysis of its drywell shell prior to the period of extended operation (NRC Staff Exh. 1, at A-30 to A-31):

> AmerGen will perform a 3-D finite element structural analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 C.F.R. 50 requirements.

As explained by the NRC Staff and AmerGen (Tr. at 848-49, 851), compliance with this commitment is not a condition to granting the license renewal; rather, compliance is a license condition that must be completed prior to the period of extended operation. AmerGen represented, however, that if the results of this structural analysis were to reveal a "safety factor less than 2, . . . we would take corrective actions, one of which would be enhancing our inspection program [and] the locations of inspection . . . . [S]ince we [would notify] the [NRC Staff,] they would be involved in any outcomes we come up with" (Tr. at 848) (Gallagher); accord Tr. at 810-11 (Gallagher). See also AmerGen Exh. C, Pt. 2, A.8 (AmerGen would be required to obtain NRC approval if it wished to alter Oyster Creek's CLB by seeking to reduce the shell safety factor to a value of less than 2.0); NRC Staff Exh C, A.12(e) ("if AmerGen wants to revise its acceptance criteria for values that are not encompassed by the GE analyses (e.g., less stringent drywell shell thickness criteria) based on the results of the [3-D analysis], AmerGen would have to submit that analysis for NRC review and approval").

of the sand bed region, which experienced less historical corrosion and, accordingly, has "more metal" (Tr. at 344-45) (Gallagher). The record shows that the remaining available margin toward the bottom of the sand bed region is 0.229 inch (Tr. at 680-82) (Polaski), which is more than 300 percent greater than the 0.064 inch of available margin based on measurements taken at the top. In short, because there is more metal toward the bottom of the sand bed region where future corrosion is most likely to occur, there can be even greater confidence that the frequency of AmerGen's UT measurements during the renewal period will be adequate to ensure that the drywell shell in the sand bed region will not violate the acceptance criteria.

V. PENDING MOTIONS

Pending before us are four motions that were submitted after the close of the evidentiary hearing. We address these motions in turn.

First, by motion dated October 22, 2007, AmerGen asked that we strike portions of Citizens' proposed findings of fact and conclusions of law on the ground that they allegedly contained facts that were outside the record and arguments that were outside the scope of this proceeding (Motion to Strike Portions of Citizens' Findings of Fact (Oct. 22, 2007)). Citizens opposed the motion as lacking in merit (Citizens' Answer to AmerGen Motion to Strike (Nov. 1, 2007)), and the NRC Staff, although it agreed with AmerGen's objections, viewed the motion as unnecessary (NRC Staff Answer to AmerGen's Motion to Strike Portions of Citizens' Proposed Findings of Fact and Conclusions of Law (Oct. 31, 2007)). We agree with the NRC Staff that AmerGen's motion to strike was unnecessary, because the instant decision is based solely on factual material that is a matter of record, and the rationale for our conclusions do not rely on arguments that are outside the scope of this proceeding. We therefore dismiss AmerGen's motion to strike, and the responses thereto, as moot.

Second, by pleading dated October 22, 2007, AmerGen submitted what it characterized as an answer opposing Citizen's alleged demand to hold the proceeding open (AmerGen's

Answer Opposing Citizens' Demand to Hold the Proceeding Open (Oct. 22, 2007)). In its pleading (pp. 1-2), AmerGen asserted that Citizens' proposed findings of fact and conclusions of law included a request to hold this proceeding open to allow Citizens to litigate further the drywell contention if the Board's decision conditions issuance of a renewed license on the outcome of the future drywell shell thickness computer modeling (see supra note 55) (discussing 3-D analysis that AmerGen must complete prior to period of extended operation). AmerGen stated that it interpreted Citizens' request as a motion to hold this proceeding open, which allegedly justified AmerGen's submission of an opposing answer. Citizens moved to strike AmerGen's answer as unauthorized (Citizens' Motion to Strike AmerGen's Unauthorized Answer (Nov. 1, 2007)),[56] and the NRC Staff declined to take a position (Letter from Mary C. Baty, Counsel for the NRC Staff, to Oyster Creek Licensing Board (Nov. 7, 2007)).[57] Although we do not view Citizens' suggestion to hold this proceeding open to be in the nature of a motion, we nevertheless need not rule on the merits of these competing pleadings, because our decision does not contemplate holding this proceeding open. We therefore dismiss these pleadings as moot.

Third, by motion dated October 26, 2007, Citizens asked this Board to strike allegedly erroneous testimony from the record (Motion to Strike Erroneous Testimony (Oct. 26, 2007)). According to Citizens' motion (pp.1-3), new information based on recent experience at the Oconee Nuclear Power Plant showed that critical testimony in this case regarding the potential

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[56] AmerGen opposed Citizens' motion to strike (AmerGen's Answer Opposing Citizens' November 1, 2007 Motion to Strike (Nov. 9, 2007)).

[57] Counsel for the NRC Staff explained that she would not take a position on this or future procedural motions submitted by the applicant or the intervenors "unless the motion challenges the integrity of the Staff or the integrity of the process" (Letter from Mary C. Baty, Counsel for the NRC Staff, to Oyster Creek Licensing Board (Nov. 7, 2007)). We commend counsel for her restraint, believing that the NRC Staff – in the interest of adjudicative efficiency and economy – might profitably consider applying this, or a similar, standard to procedural motions in future proceedings.

for end-of-life epoxy coating failure was incorrect and incomplete. AmerGen and the NRC Staff argued that Citizens' motion lacked merit (AmerGen's Answer Opposing Citizens' October 26, 2007 Motion to Strike (Nov. 5, 2007); NRC Staff Answer to Citizens' Motion to Strike Erroneous Testimony (Nov. 5, 2007)). We agree with AmerGen and the NRC Staff that Citizens' motion is substantively baseless. As explained in the answers submitted by AmerGen (pp. 4-5) (citing the attached Affidavit of Jon R. Cavallo (Nov. 2, 2007), and the NRC Staff (pp. 2-5) (citing the attached Affidavit of James A. Davis, Ph.D (Nov. 5, 2007)), the experience at Oconee is not relevant to this proceeding, because the epoxy used there is produced by a different manufacturer, and it has different specifications for surface preparation, application, and curing. Critically, unlike Oyster Creek, Oconee neglected to comply with the manufacturer's specifications for surface preparation, application, and curing. The coating failure at Oconee thus was not an end-of-life failure but, rather, occurred due to an improper application and curing of the primer, the presence of air in the top coat, and exposure of the system to high humidity during replacement of steam generators and the reactor vessel head. Accordingly, Citizens' reliance on Oconee is misplaced, and their assertion that the experience at Oconee undercuts critical testimony in this case regarding the potential for end-of-life epoxy coating failure is incorrect. We therefore deny their motion to strike.

Finally, by motion dated December 10, 2007, Citizens moved for an extension of time to file an appeal with the Commission.[58] In their motion (pp. 1-2), Citizens explained that if a decision were issued on or around December 20, and if the decision were adverse to Citizens, their petition for review would be due on or around January 4, 2008 pursuant to 10 C.F.R. § 2.341(b).

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[58] AmerGen and the NRC Staff opposed Citizens' extension request, asserting that the request (1) should be directed to the Commission, (2) is premature, and (3) fails to satisfy the "good cause" standard. See AmerGen's Answer Opposing Citizens' Motion For Extension Of Time To File Any Appeal at 1-2 (Dec. 17, 2007); NRC Staff Answer To Citizens' Motion For An Extension Of Time To File Any Appeal at 1-3 (Dec. 17, 2007).

Because their lead counsel will be out of the country from December 22 through December 30, 2007, they argued that – given the complexity of this case and the voluminous record – they satisfy the "good cause" standard for being granted a modest extension of time (10 C.F.R. § 2.307(a)). We agree that Citizens satisfy the "good cause" standard. However, governing case law bars us from granting the relief they request, because "requests for extension of time to file exceptions are to be determined by the [relevant appellate body]" (Consol. Edison Co. of N.Y., Inc. (Indian Point Station, Unit No. 3), ALAB-281, 2 NRC 6, 7 n.2 (1975)). Accordingly, Citizens' request for an extension of time to file a petition of review must be directed to the Commission.[59]

VI. CONCLUSIONS OF LAW

For the foregoing reasons, we conclude that AmerGen has demonstrated by a preponderance of the evidence that the acceptance criteria, which currently are satisfied, will also be satisfied at the beginning of the renewal period (supra Part IV.A.2).

We further conclude that AmerGen has demonstrated by a preponderance of the evidence that the acceptance criteria will be satisfied throughout the renewal period, because there is no likelihood that the sand bed region of the drywell shell will experience significant corrosion during that period (supra Part IV.B). More precisely, we conclude that the *external* wall of the drywell shell in the sand bed region will not experience significant corrosion, because AmerGen's corrective and mitigating actions, coupled with the commitments in its aging management program, provide reasonable assurance that (1) water will not leak into that region (supra Part IV.B.1.a), and (2) even if water were to leak into that region, it will not penetrate the

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[59] It could reasonably be argued that the broad grant of authority in 10 C.F.R. § 2.307(a) was intended to empower Licensing Boards to grant the type of relief requested by Citizens. Cf. Fed. R. App. P. 4(a)(5) (authorizing district court to extend time to file a notice of appeal). However, because the regulations applied by the Appeal Board in Consol. Edison contained a provision (10 C.F.R. § 2.711(a) (1975)) that was substantially identical to section 2.307(a), we are constrained to conclude – absent intervening precedent directing otherwise – that section 2.307(a) does not authorize us to extend the time for filing a petition for review.

robust, three-layer epoxy coating (supra Part IV.B.1.b). Nor will the *internal* wall of the drywell shell in the sand bed region experience significant corrosion given its non-corrosive environment and the absence of any measurable corrosion in the past (supra Part IV.B.2).

Finally, even if we assumed – contrary to our express findings – that the sand bed region would experience measurable corrosion during the renewal period, we conclude that AmerGen has demonstrated by a preponderance of the evidence that its plan to take UT measurements every four years, coupled with the other commitments in its aging management program, is sufficient to ensure the bounding available margin of 0.064 inch is not violated (supra Part IV.C). This is so because the evidence shows that Oyster Creek will experience an annual corrosion rate, *at most*, of about 0.0035 inch per year, resulting in corrosion of about 0.014 inch during the four-year interval between UT measurements, which does not begin to approach the available margin of 0.064 inch. Moreover, the available margin of 0.064 inch is based on UT measurements at the *top* of the sand bed region, which is the most heavily corroded area due to the prior presence of sand that retained the moisture in that area and kept it in direct contact with the shell. Because the sand has been removed from the sand bed region, any future leakage will drain to the bottom of the region, which has corroded less than the top and which has a remaining available margin of 0.229 inch (i.e., 300 percent greater than at the top), thus increasing our confidence that the frequency of AmerGen's UT measurements will be adequate.[60]

VII. ORDER

For the foregoing reasons, Citizens' contention is resolved in favor of AmerGen. Pursuant to 10 C.F.R. § 2.1210(a), forty days after issuance of this decision, it will constitute final agency action on Citizens' contention unless: (1) a party files a petition for Commission review

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[60] All issues or arguments presented by the parties and not addressed herein have been found to be lacking in merit or unnecessary to this decision.

within fifteen days after service of this decision (10 C.F.R. §§ 2.341(b)(1), 2.1212), or a party files a petition for Commission review within any extended period of time granted by the Commission for "good cause" shown (id. § 2.307(a); supra note 59 and accompanying text); or (2) the Commission, in its discretion, determines that review is warranted (id. § 2.1210(a)(3)). Unless otherwise authorized by law, a party who wishes to seek judicial review of this decision must first seek Commission review (id. § 2.1212).

It is so ORDERED.

THE ATOMIC SAFETY
AND LICENSING BOARD[61]

/RA/

E. Roy Hawkens, Chairman
ADMINISTRATIVE JUDGE

/RA/

Dr. Paul B. Abramson
ADMINISTRATIVE JUDGE

/RA/

Dr. Anthony J. Baratta *
ADMINISTRATIVE JUDGE

* Judge Baratta has filed an Additional Statement that immediately follows this Initial Decision.

Rockville, Maryland
December 18, 2007

[61] Copies of this Memorandum and Order were sent this date by Internet e-mail to counsel for: (1) AmerGen; (2) Citizens; (3) the NRC Staff; and (4) New Jersey.

Additional Statement of Administrative Judge Anthony J Baratta, Ph.D.

Although I join with my colleagues in the previous decision in the main, I differ on one point, regarding whether the licensee has fully shown that there is reasonable assurance that the factor of safety required by the regulations will be met throughout the period of extended operation assuming a four-year (every other refueling) inspection cycle.

The design and function of the drywell is governed by 10 C.F.R. Part 50 Appendix A, General Design Criteria (GDC), Design Bases for Protection Against Natural Phenomena and Environmental and Dynamic Effects Design Bases; specifically GDC Number 16, Containment Design, and GDC Number 50, Containment Design Basis. AmerGen complies with these GDC by meeting the applicable ASME[1] Boiler and Pressure Vessel Code standards and specifications (AmerGen Exh. B, Pt. 2, A.8). The relevant ASME Code requirements include a safety factor of two for the ASME Code allowable stresses for the refueling case, which is the limiting load combination. The safety factor of two requires that the actual stresses on the drywell shell be one-half of the stress which would cause the shell to physically buckle under the postulated refueling accident conditions.

In the 1980s, the Oyster Creek Nuclear Generating Station (OCNGS) identified that water from the reactor cavity had penetrated into the sand used to provide additional support for the drywell. This sand, located in the sand bed region, acted to keep the water in direct contact with the uncoated drywell shell. The presence of water, coupled with improper sand bed drainage, resulted in the corrosion of the exterior of the drywell shell. General Electric (GE) was then retained to analyze the structural integrity of the drywell shell in this region if the sand were removed from the sand bed (AmerGen Exh. B, Pt. 2, A.8, A.10, A.11).

The analyses made by GE considered two cases, one in which the sand remained in the sand bed region and the other in which the sand was removed from the sand bed region. Each

[1] American Society of Mechanical Engineers.

analysis is comprised of a stress analysis and stability analysis. Two finite element models, one axisymmetric,[2] and another, a 36 degree pie slice model, were used for a stress analysis. The ANSYS[3] computer program was used to perform the analyses (AmerGen Exh. 37, NRC Safety Evaluation: Drywell Structural Integrity, OCNGS, at 3 (Apr. 24, 1992)).

The axisymmetric model was used to determine the stresses for the seismic and the thermal gradient loads. The pie slice model was used for deadweight and pressure loads. The pie slice model includes the vent pipe and the reinforcing ring and was also used for buckling analysis. The same models were used for the cases with and without sand, except that in the former, the stiffness of the sand in contact with the steel shell was considered. The shell thickness in the sand region was assumed to be 0.700 inch for the with-sand case and to be 0.736 inch for the without-sand case. The 0.700 inch was, as claimed by the licensee, used for conservatism and the 0.736 inch is the projected thickness at the start of fuel cycle 14R. The same thickness of the shell above the sand region was used for both cases (ibid.). The thickness of 0.736 inch was an input the plant owner provided for GE (Tr. at 395) (Mehta).

For buckling, the GE analyses determined that the relevant ASME Code requirements (that include an ASME Code safety factor of two for the allowable stresses) would continue to be met even if the shell in the sand bed region had a uniform thickness of 0.736 inch. In other words, the entire shell in the sand bed region could have been manufactured and erected with a uniform thickness of 0.736 inch and it would have met ASME Code allowable stresses (AmerGen Exh. B, Pt. 2, A.10).

In the early 1990s, GE also performed sensitivity analyses on their original buckling analysis. These analyses sequentially evaluated locally-thinned areas using one-square-foot

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[2] The thickness is assumed uniform throughout the 360 degrees of the sand bed region in such a model. See Tr. at 399 (Mehta).

[3] ANSYS – Structural analysis tool developed by ANSYS, Inc.

areas of 0.636 inch (0.100 inch less than 0.736 inch) and 0.536 inch (0.200 inch less than 0.736 inch), each with a one-foot transition to the surrounding shell to a uniform thickness of 0.736 inch. This configuration is shown in AmerGen Exhibit 11. In addition to using a uniform thickness for the rest of the drywell shell of 0.736 inch, GE's analyses placed the locally-thinned areas in the location of the bay with the largest stresses, which is midway between the torus downcomer penetrations that divide each bay (AmerGen Exh. B, Pt. 2, A.13).

AmerGen stated that there are several sources of conservatism built into the original properties used for the elements in the analysis. One is the use of the conservative value of 0.736 inch because it was known from UT thickness measurements that the shell was on average significantly thicker than 0.736 inch (AmerGen Exh. C, Pt. 2, A.6).

Other sources of conservatisms for the modeling on the whole include the following:

First, the Torus vent pipes that are present in each Bay and the reinforcing plates for their penetrations stiffen the shell. This results in a stress reduction of the shell in their influence zone which would allow uniform and local shell thickness to be below the values modeled by GE and still satisfy ASME requirements. The areas of most significant corrosion are beneath or near the torus vent pipes (<u>ibid.</u>).

A second conservatism is that the local buckling criterion assumes that the rest of the drywell shell in the sand bed region has a uniform thickness of 0.736 inch. This is because the local buckling criterion was derived through sensitivity analyses using the 0.736 inch uniform thickness modeling. Thus, an area could thin to 0.536, as shown in AmerGen Exhibit 11, and still meet the ASME code so long as the <u>remainder of the shell was uniformly thicker than 0.736 inch</u> (<u>ibid.</u>).

It is this latter point that my colleagues fail to appreciate, namely that the analysis did not show the shell was acceptable with both a thinning to 0.736 inch and localized regions that satisfy the local buckling criteria. Rather, the GE analysis said that if the shell is thicker than

0.736 inch, then such regions are acceptable. To date, however, no analysis of the actual condition of the drywell has been done. While I concur with my colleagues that further corrosion of the drywell is unlikely, it can not be ruled out. Thus I consider it essential to have a conservative best estimate analysis of the drywell shell before entering the period of extended operation.

The current analysis by AmerGen uses a thickness of 0.736 inch. AmerGen stated that this value came from the UT data from the internal grids, and that "[p]rior to the sand removal from the sand bed region, the internal grids were inspected at every outage of opportunity" (Tr. at 396) (Tamburro). Curve fits were performed by the owner using a regression analysis on the average data and then statistical testing of the curve fits were performed to ensure that they best represented the corrosion. Based on this regression analysis of the lower 95 percent confidence interval of the average points, the projected thickness in the sand bed was determined at the time of the outage where repairs to the drywell were to be performed. That thickness so determined was 0.736 inch for the most limiting of the internal grids (Tr. at 396-98) (Tamburro).

Thus, the 0.736 inch does not represent the actual condition of the drywell. We do not know what the actual safety factor is. It is thought that the current state of the drywell suggests that the factor of safety is about two or greater. This conclusion is drawn from the GE analysis that assumed the entire sand bed region of the drywell to be uniformly thinned to a thickness of 0.736 inch. The shell measurements have shown that the thickness is on average greater than 0.736 inch. Thus, when all things are taken into account, including the actual thickness, the safety factor is likely to be greater than two, which I concur with. See Tr. at 441 (Mehta). Without doing a calculation, however, one can not determine the actual value (Tr. at 453-54) (Hartzman). This conclusion is supported by the results of an analysis of the OCNGS drywell performed by Sandia National Laboratories and reported in NRC Staff Exhibit 6. The results of the Sandia analysis for the limiting refueling condition yield a safety factor of 2.15 using what

Sandia considered to be the best estimate of thicknesses for the drywell shell. See NRC Staff Exh. 6, at 72.

While the Sandia results are encouraging, they are based on a very limited knowledge of the actual thicknesses of the shell. The measurements used in developing the Sandia model come from the limited set of ultrasonic test measurements taken over time by AmerGen (NRC Staff Exh. 6, at 15, 49). Citizens note that these measurements encompass only a small area of the drywell as depicted in the exhibit. See Citizens Exh. C, A.2, A.11. Thus, there are large areas of the drywell in the sand bed region that do not have recent measurements or any measurements at all.

Because of the lack of complete UT of the drywell, Citizens have suggested that a much thinner point than 0.49 inches might have been observed had additional measurements been made. Their statement is based on the use of an extreme value statistics analysis of the data that predicts such values. See Citizens Exh. C, A.16, A.17. Citizens conclude that there is a small but finite probability that such areas do exist. See Tr. at 822 (Hausler). While I do not agree with the approach used by Citizens in deriving this value I do concur that there is a lack of knowledge about the actual thickness of the drywell shell and that this lack of knowledge must be taken into account in any analysis.

The Staff recognized the need for additional analysis and required it as a license condition. Specifically, the seventh license condition requires the applicant to perform a 3-dimensional (3-D) finite element analysis of the drywell shell prior to entering the period of extended operation (NRC Staff Exh. 1, at 1-18). AmerGen has stated that for the 3-D analysis, the inputs are the already measured thicknesses, which will be retaken in 2008 and will be used to create the 3-D model. The model will use the actual geometries and is a full 360 degree model. Thus, no axisymmetric assumptions are needed allowing the drywell to be modeled exactly. The model will also employ a finer mesh than the previous GE model (Tr. at 659-60) (Gallagher).

To account for the very limited data set of thickness measurements, I would impose an additional requirement on the 3-D analysis to be performed by the applicant. Specifically, the applicant should be required to perform a series of sensitivity analyses, at least one of which includes the use of an extrapolation scheme to determine the thicknesses between the measured locations. The technique might be similar to the one suggested by Citizens' expert, Dr. Hausler, that uses contour plots generated from known thicknesses both interior and exterior.

Thus, while I concur with the majority with their findings of fact, I do not concur that we at this point have a complete understanding of the drywell shell state until a conservative best estimate analysis of the actual drywell shell is performed. This analysis should as a minimum include an approach such as the one outlined above.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

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 foregoing LB INITIAL DECISION (LBP-07-17) (REJECTING CITIZENS' CHALLENGE TO AMERGEN'S APPLICATION TO RENEW ITS OPERATING LICENSE FOR THE OYSTER CREEK NUCLEAR GENERATING STATION) have been served upon the following persons by U.S. mail, first class, or through NRC internal distribution.

Office of Commission Appellate
Adjudication
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Administrative Judge
E. Roy Hawkens, Chair
Atomic Safety and Licensing Board Panel
Mail Stop - T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Administrative Judge
Paul B. Abramson
Atomic Safety and Licensing Board Panel
Mail Stop - T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Administrative Judge
Anthony J. Baratta
Atomic Safety and Licensing Board Panel
Mail Stop - T-3 F23
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Mary C. Baty, Esq.
Kimberly A. Sexton, Esq.
James E. Adler, Esq.
Office of the General Counsel
Mail Stop - O-15 D21
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Richard Webster, Esq.
Julia LeMense, Esq.
Rutgers Environmental Law Clinic
123 Washington Street
Newark, NJ 07102-5695

Paul Gunter, Reactor Oversight
Kevin Kamps
Beyond Nuclear
Nuclear Policy Research Institute
6930 Carroll Avenue, Suite 400
Takoma Park, MD 20912

Donald J. Silverman, Esq.
Kathryn M. Sutton, Esq.
Alex S. Polonsky, Esq.
Raphael P. Kuyler, Esq.
Morgan, Lewis & Bockius LLP
1111 Pennsyvlania Ave., NW
Washington, DC 20004

Docket No. 50-219-LR
LB INITIAL DECISION (LBP-07-17) (REJECTING
CITIZENS' CHALLENGE TO AMERGEN'S
APPLICATION TO RENEW ITS OPERATING
LICENSE FOR THE OYSTER CREEK
NUCLEAR GENERATING STATION)

Bradley M. Campbell, Commissioner
New Jersey Department of
Environmental Protection
P.O. Box 402
Trenton, NJ 08625-0402

Jill Lipoti, Director
New Jersey Department of
Environmental Protection
Division of Environmental Safety and Health
P.O. Box 424
Trenton, NJ 08625-0424

Ron Zak
New Jersey Department of
Environmental Protection
Nuclear Engineering
P.O. Box 415
Trenton, NJ 08625-0415

J. Bradley Fewell, Esq.
Exelon Corporation
4300 Warrenville Road
Warrenville, IL 60555

Suzanne Leta
NJPIRG
11 N. Willow St.
Trenton, NJ 08608

John A. Covino, Esq.
Ellen Barney Balint, Esq.
Valerie Anne Gray, Esq.
Caroline Stahl, Esq.
Deputy Attorneys General
New Jersey Office of the Attorney General
Environmental Permitting &
Counseling Section
Division of Law
Hughes Justice Complex
P.O. Box 093
Trenton, NJ 08625

[Original signed by Adria T. Byrdsong]
Office of the Secretary of the Commission

Dated at Rockville, Maryland
this 18th day of December 2007