RAS 14386

Staff Exhibit B

U.S. NUCLEAR REGULATORY COMMISSION
In the Matter of AmerGen Co., LLC
Docket No. 50-0219-LR Official Exhibit No. B
OFFERED by: Applicant/Licensee Intervenor ______
NRC Staff Other ______
IDENTIFIED on 4/6/08 Witness/Panel N/A
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Reporter/Clerk ______

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OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

STAFF INITIAL TESTIMONY

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SECY-02

July 20, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

NRC STAFF TESTIMONY OF HANSRAJ G. ASHAR,
DR. JAMES A. DAVIS, DR. MARK HARTZMAN AND
TIMOTHY L. O'HARA CONCERNING DRYWELL CONTENTION

Q1. Please state your name, occupation, and by whom you are employed.

A1(a). My name is Hansraj G. Ashar ("Ashar").[1] I am employed as a Senior Structural Engineer in the Division of Engineering, Office of Nuclear Reactor Regulation ("NRR"), U.S. Nuclear Regulatory Commission ("NRC"). A statement of my professional qualifications is attached hereto.

A1(b). My name is Dr. James A. Davis ("Davis"). I am employed by the NRC as a Senior Materials Engineer in the Office of Nuclear Reactor Regulation ("NRR"), Division of License Renewal. A statement of my professional qualifications is attached hereto.

A1(c). My name is Dr. Mark Hartzman ("Hartzman"). I am employed by the NRC as a Senior Mechanical Engineer in the Division of Engineering, Office of Nuclear Reactor Regulation ("NRR"). A statement of my professional qualifications is attached hereto.

A1(d). My name is Timothy L. O'Hara ("O'Hara"). I am employed by the NRC as a Reactor Inspector in the Division of Reactor Safety, Region I Office. A statement of my

[1] In this testimony, the sponsors of each numbered response are identified by their last name; no such designation is provided for paragraphs which are sponsored by all witnesses.

professional qualifications is attached hereto.

Q2. Please describe your current responsibilities.

A2(a). (Ashar) I am responsible for performing safety reviews of nuclear power plant structures including containment structures and various structural supports for operating nuclear power plants, license renewal applications, and new reactor design certifications. For the last 33 years, I have reviewed plant license and license renewal applications, and have been involved in nuclear power plant standards development. In license renewal activities, I was the lead technical coordinator for development of Chapter II of Generic Aging Lessons Learned (GALL) related to the positions on PWR and BWR containments. I have reviewed the containment section of license renewal applications for PWR and BWR plants. For the BWR containments, I have principally reviewed drywell shells, tori and connecting vents to ensure the integrity of these pressure retaining structural components during the period of extended operation. As part of my duties, I represent the NRC on committees for a number of organizations that develop standards related to nuclear power plant structures, namely, the American Society of Mechanical Engineers (ASME), American Concrete Institute, and American Institute of Steel Construction.

A2(b). (Davis) Since November 2005, I have served as an audit team leader and as an audit team member for license renewal audits. Prior to joining the Division of License Renewal, I was the lead researcher on steam generator issues in the Materials Engineering Branch of the Office of Nuclear Regulatory Research and a technical reviewer in the Materials and Chemical Engineering Branch of NRR, Division of Engineering, responsible for conducting reviews of coating issues, corrosion of metals, service water issues, threaded fasteners, and license renewal. I have worked on coatings and corrosion control since 1968 and have worked on coating issues in nuclear facilities for the past sixteen years at the NRC. I was the NRC representative to ASTM D-33, "Coatings for Power Generation Facilities." This committee prepared standards for testing and inspection of coatings for nuclear power plants. Prior to joining the NRC, I was a member of the National Association of Corrosion Engineers ("NACE") Technical Practices Committee on Pipeline Coatings where we wrote standards for the testing and inspection of pipeline coatings including epoxy coatings. These standards included testing to detect pinholes or holidays. I was also a member of the American Water Works Association Technical Advisory Committee on Coatings for Steel Water Pipe and elected Chairman of this committee in 1989. The work of this committee included writing standards for epoxy coated pipe, including requirements for holiday and pinhole testing.

A2(c). (Hartzman) I am responsible for reviewing safety analyses of ASME Section III Class 1, 2 and 3 and non-ASME piping systems and components submitted by licensees in license amendment requests. The reviews evaluate licensee-submitted structural integrity analyses of piping systems and components under various Service Level operating conditions, and verifying that the stresses meet the ASME Code Section III or other acceptance criteria for strength and fatigue for each operating service level. I assist regional offices with the evaluation of technical issues arising during inspection activities and, as part of reviews of license renewal applications, evaluate time limited aging analyses of ASME Section III metal components. I represent the NRC at ASME Section III Code-writing working groups, such as the WG Vessels and the WG on Methods Development, and I review ASME Section III Code Cases for NRC endorsement.

A2(d). (O'Hara) As a reactor inspector, I inspect licensee implementation of inservice inspection (ISI) programs. I also participate in license renewal aging management program reviews of licensee ISI activities. In addition, I perform component replacement inspections (steam generators, pressurizers and reactor vessel heads) and general engineering inspections contained in the Reactor Oversight Program.

Q3. Please explain your duties in connection with the Staff's review of the License Renewal Application ("LRA") submitted by AmerGen Energy Company, LLC, ("AmerGen", "Applicant" or "Licensee") for the renewal of the Oyster Creek Facility Operating License No. DPR-16.

A3(a). (Ashar) As part of my official duties, I was responsible for the review of the following sections of the LRA: 1) Section 2.4, "Scoping and Screening Results – Structures;" 2) portions of Section 3.5, "Aging Management of Containment, Structures, Component Supports, and Piping and Component Insulation;" 3) Section 4.7.2, "Time Limited Aging Analysis [TLAA] of Drywell Corrosion;" and 4) Section 4.7.3, "TLAA, Equipment Pool and Reactor Cavity Walls Rebar Corrosion." I prepared Section 4.7.2 of NUREG-1875, "Safety Evaluation Report Related to the License Renewal of Oyster Creek Nuclear Generating Station" (March 30, 2007) (published April 2007) ("SER") (ML070890637). Excerpts from the SER are attached hereto as Staff Exhibit 1. The primary objective of my review is to ensure that there is reasonable assurance that the structural integrity and the safety functions of power plant structures, including a containment structure such as the drywell shell, are maintained when subjected to various combinations of the postulated loads including design basis earthquake and accident loads.

A3(b). (Davis) As part of my official duties, I was an audit team member for the license renewal safety audit at Oyster Creek. I reviewed the Oyster Creek LRA, including the following aging management programs: B.1.11, "Flow Accelerated Corrosion;" B.1.12, "Bolting Integrity;" B.1.15, "Boraflex Rack Management Program;" B.1.21, "Aboveground Outdoor Tanks;" B.1.21A, "Aboveground Steel Tanks- Forked River Construction Tower;" B.1.25, "Selective Leaching of Materials;" B.1.26, "Buried Pipe Inspection;" B.1.26B, "Buried Pipe Inspection – Met Tower

Repeater Engine Fuel Supply;" B.2.2, "Lube Oil Monitoring Activities;" and B.2.5, "Periodic Inspection Program," including preparation of Section 3.0.3 of the SER. I also reviewed aging management reviews not consistent with GALL and prepared Sections 3.1.2.3, 3.2.2.3, 3.3.2.3, 3.4.2.3, 3.5.2.3, and 3.6.2.3 of the SER.

A3(c). (Hartzman) As part of my official responsibilities, I reviewed the applicability of ASME Section III, Division 1 Code Case N-284-1, "Metal Containment Shell Buckling Design Methods, Class MC," (Code Case N-284-1) to the buckling analyses of the Oyster Creek drywell shell performed by General Electric (GE) and the Sandia National Laboratory (SNL). My expertise is based on my (1) education and experience in the field of Engineering Mechanics, which includes the subject of structural stability theory, (2) experience in reviews of structural and mechanical safety evaluation reports, (3) review of the Code Case for NRC endorsement acceptability, and (4) participation, as the NRC representative, in the ASME Section III Working Group on Vessels, which is responsible for maintaining and updating Code Case N-284-1.

A3(d). (O'Hara) As part of my reactor inspector duties, I participated in the License Renewal Aging Management Inspection conducted in March 2006 at the Oyster Creek Nuclear Generating Station. During this inspection, I reviewed the following Aging Management Programs: B.1.27, ASME, Section XI, Subsection IWE Program; and B.1.33, Protective Coating Monitoring and Maintenance Program. I also participated in the NRC inspection of AmerGen's implementation of some license renewal commitments regarding the drywell shell and torus during the Fall 2006 outage at Oyster Creek, and provided information about my inspection activities at Oyster Creek as part of the Staff's presentation at the January 2007 meeting of the Advisory Committee on Reactor Safety ("ACRS").

Q4. What is the purpose of your testimony?

A4. The purpose of this testimony is to present the Staff's position regarding Citizens' contention. As admitted by the Board, LBP-06-22, 64 NRC at 255-56, Citizens allege that:

> [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 plan to perform UT tests prior to the period of extended operations, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals is insufficient to maintain an adequate safety margin.

We have read relevant portions of: the SER; LBP-06-22, 64 NRC 229 (2006); Citizens' "Petition to Add a New Contention" (June 23, 2006) ("June 23 Petition"); Citizens' "Supplement to Petition to Add a New Contention" (July 25, 2006) ("Supplement") and the attached Memorandum from Dr. Rudolf H. Hausler to Richard Webster (July 25, 2006) ("July 25 Hausler Memo"); "AmerGen's Motion for Summary Disposition of Citizens' Drywell Contention" (Mar. 30, 2007); "Citizens' Answer Opposing AmerGen's Motion for Summary Disposition" (Apr. 26, 2007); "Citizens' Response to NRC" (May 7, 2007); the "Memorandum and Order (Denying AmerGen's Motion for Summary Disposition)" (June 19, 2007) (unpublished); and the "Memorandum and Order (Clarifying Memorandum and Order Denying AmerGen's Motion for Summary Disposition)" (July 11, 2007).

A4(a). (Ashar) My testimony will address the Staff's review of AmerGen's aging management program for the aging effect of corrosion on the drywell shell with respect to the Staff's conclusion that there is reasonable assurance that AmerGen's drywell monitoring plan is sufficient to ensure that the drywell can perform its intended function during the proposed license renewal period.

A4(b). (Davis) My testimony will address Citizens' claim that visual inspections of epoxy coating do not reveal that the coating has deteriorated because corrosion may occur under the epoxy coating in the absence of visible deterioration due to nonvisible holidays, or pinholes.

A4(c). (Hartzman) My testimony will address, in the context of license renewal, the Staff's review and evaluation of ASME Code Case N-284-1 as applied to the stability analysis of the drywell shell.

A4(d). (O'Hara) My testimony will provide my observations of the condition of the sand bed region of the drywell shell and the Staff's inspection findings concerning AmerGen's commitments related to license renewal and the drywell.

Q5. Describe the corrosion in the sand bed region of the drywell shell at Oyster Creek.

A5. Corrosion of the sand bed region of the Oyster Creek drywell shell was identified in the late 1980s. SER at 4-42. The accumulation of water from leaks from the reactor cavity into the gap between the drywell shell and the shield concrete during refueling outages caused corrosion of the exterior of the drywell shell in the sand bed region. Significantly corroded areas in the sand bed region are referred to as the "bathtub" ring of corrosion. Because the high corrosion rate in the sand bed region was attributed to galvanic corrosion of the drywell shell caused by water retained in the sand due to a lack of proper drainage, corrective actions taken included removal of the sand in 1992 and the application of a protective coating to protect the drywell shell from additional corrosion. *See* SER at 4-42 to 4-43 (citing AmerGen RAI Response, dated April 7, 2006).

Prior to coating the shell, thickness measurements were taken in each of the 10 bays, from outside the drywell, to establish the minimum general and local thickness of the thinned shell. *Id. at* 4-43. Measurements from outside the drywell showed a minimum average thickness generally greater than 0.800 inch (some local areas were less than 0.800 inch), but the minimum average thickness in these areas was greater than the 0.736 inch to satisfy ASME Section III Code Case N-284 provisions for structural buckling of the drywell shell. *Id.* at 4-43.

Q6. How was the corrosion of the drywell shell considered in the Staff's review of the Oyster Creek LRA?

A6. (Ashar) The Staff reviewed LRA Section 3.5, which contains AmerGen's aging management review results for the drywell, and Section 4.7.2, the TLAA analysis, to determine whether the degraded condition of the drywell shell could withstand the postulated loadings stipulated in the plant's Final Safety Analysis Report (FSAR) without exceeding acceptance criteria. In the description of TLAA 4.7.2, the Applicant states that its ASME Section XI, Subsection IWE aging management program (B.1.27) ensures that drywell shell thickness will not be reduced to less than the minimum required value in any future operation. LRA at 4-55. The Applicant further states that the effects of loss of material on the intended function of the drywell will be adequately managed in accordance with 10 C.F.R. § 54.21(c)(1)(iii) for the period of extended operation. *Id.*

Due to the extent of reported drywell shell degradation in the sand bed area, the Staff sent requests for additional information (RAIs) about differences in 1994 and 1996 UT results, comparison of such results to UT results in 1992, measurement errors, statistical approach in interpreting the UT results, corrosion rates in the upper spherical and cylindrical areas, and the ability to replicate the locations of UT measurements. In March and April 2006, the Staff was at Oyster Creek, discussed some of these RAIs, and discussed earlier Oyster Creek efforts to mitigate future corrosion. The Staff discussed RAIs during a public meeting at NRC Headquarters on June 1, 2006. NRC inspectors observed UT measurements taken during the 2006 outage and provided updates about AmerGen's drywell activities. The Staff also reviewed AmerGen's statistical analysis of previous measurements in Calculation C-1302-187-5300-11, "Statistical Analysis of Drywell Shell Thickness Data Thru 4-24-90" (6/13/90) (see ML06490205) (AmerGen Exhibit 23) and the analysis in Calculation C-1302-187-5320-24, Rev. 0, "OC Drywell Ext. UT Evaluation in Sandbed" (4/16/93) ("Calculation-24") (AmerGen Exhibit 17), and Calculation-24, Rev. 1 (9/21/06) (AmerGen Exhibit 18). *See* SER at 59-60.

Q7. What did the Staff conclude about whether the degraded drywell shell can fulfill its intended function during the period of extended operation?

A7. (Ashar, Hartzman) As stated in SER, the Staff concluded that AmerGen's aging management program is consistent with GALL AMP XI.S1, ASME Section XI, Subsection IWE such that the effects of aging will be adequately managed for the period of extended operation provided AmerGen effectively implements enhancements to its aging management program. *See* SER at 3-143, 4-75. As part of the containment, the drywell shell is required to provide a pressure retaining function under all postulated loadings except refueling. *See* OCNGS FSAR at 3.8-10 to 3.8-19. The current licensing basis for the Oyster Creek is based on analyses performed by General Electric (GE) 1991-92 in GE Reports 9-3, 9-4, "ASME Section VIII Evaluations of the Oyster Creek Drywell for Without Sand Case [Stress and Stability Analyses] – February 1991" (ML0610206140), which are discussed, for example, in the SER at 4-55 to 4-58. The objective of the GE structural analysis of the drywell shell was to provide reasonable assurance that the structural integrity of the as-built shell (i.e., with the degraded wall thickness in the sand bed region) will be maintained under the refueling loading condition, by showing that the stresses do not exceed the ASME Section III Subsection NE stress limits, and satisfy the provisions of ASME Section III, Code Case N-284 for buckling assessment.

The term "buckling" refers to "linear bifurcation buckling," the state where adjacent equilibrium configurations of the shell may exist under the same loading. This loading is called the "theoretical buckling load," and is determined from a type of structural analysis called "bifurcation buckling" analysis. Local imperfections in thin-walled shells, resulting from the fabrication processes, significantly affect the buckling of fabricated thin-walled shells. Thus, actual buckling of such a shell may occur at a load considerably lower than the theoretical buckling load. Buckling has been identified as the postulated governing failure mode of the drywell shell in the degraded sand bed region under the refueling loading condition. In the refueling condition, the drywell shell is loaded in the vertical direction by gravity and inertia type loads. The minimum uniform degraded sand bed wall thickness necessary to prevent buckling under this loading condition is determined from a buckling analysis of the sand bed region. The criteria in ASME Section III Code Case N-284 are appropriate for determining the stability of the degraded drywell shell.

The GE analysis included a bifurcation buckling analysis of the Oyster Creek drywell shell, considering the uniform reduction in the sand bed region wall thickness due to corrosion to 0.736 inches. The analysis, based on the finite element method, determined that, in this portion of the drywell spherical shell, the axial (meridional) stresses were compressive and the hoop (circumferential) stresses were tensile. This analysis provided the theoretical and allowable buckling stresses for the sand region.

In 1992, the Staff's review of that analysis concluded that the Oyster Creek drywell shell analysis was performed in accordance with ASME Code Case N-284 and showed that (1) the load combinations critical to buckling were those involving refueling and post-accident conditions, and (2) application of a factor of safety of 2 and 1.67 for load combinations involving refueling and post-accident conditions, respectively, showed the drywell had adequate margin against buckling with no sand support for an assumed average sand bed region thickness of 0.736 inches. *See* Letter from Alexander Dromerick, NRC, to John Barton, GPU Nuclear Corporation, dated April 24, 1992 (enclosing Evaluation Report on Structural Integrity of the Oyster Creek Drywell) (ML070290668) ("1992 SE"), at 4. The Staff found that the procedure used to calculate allowable buckling load is consistent with ASME Code Case N-284. *See* SER at 4-61 to 4-63.

GE also performed additional buckling analyses where locally thinned areas in the sand bed region were modeled. *See* SER at 3-128. The assumed wall thicknesses in these analyses were 0.536 inch and 0.636 inch, extending over a square foot area and transitioning to a thickness of 0.736 inch over a 9 square-foot area. GE used a refined finite element model which took advantage of the symmetry of the modeled degraded area. The analysis showed that the postulated wall thinning did not have a significant effect on the allowable buckling loads. Oyster Creek adopted these results as criteria for assessing local wall thinning in the sand bed region. *See, e.g.* Calculation-24, Rev.1 (AmerGen Exhibit 18) at 10 of 117. *See also* SER at 4-56 to 4-58.

Based on information received from the 2006 outage inspection, the Staff concluded that overall changes in the extent of drywell shell corrosion since 1992 were relatively small and were bounded by the analysis and calculations done by GE. *See* SER at 3-137 to 3-143, 4-72 to 4-73. Therefore, the Staff concluded that the degraded drywell will be able to perform its intended function and the effects of aging will be adequately managed during the extended period of operation, provided AmerGen implements commitments to its aging management program. *See id.* at 3-422 to 3-424, 4-73 to 4-75.

Q8. Did the Staff rely solely on the results of the 1992 GE analysis?

A8. (Ashar, Hartzman) No. In order to provide additional assurance that the aging management program would ensure that the drywell shell could perform during the renewal period, the Staff asked Sandia National Laboratories ("Sandia") to perform an analysis of the degraded drywell shell based on advanced techniques for modeling and analyzing the complex shell structure and to determine controlling postulated load conditions. *See* SER at 4-71. Sandia developed a full (360°) three-dimensional (3D) finite element model of the Oyster Creek drywell shell that permitted a more sophisticated analysis of structural details that accounted for asymmetries of drywell shell. Sandia used the degraded shell thicknesses in the Applicant's

Calculation-24, Rev. 0 (AmerGen Exhibit 17) and performed analyses for both the undegraded and degraded shell. For the degraded shell, the load condition with a minimum margin against the ASME allowable limits was found to be the refueling condition. For this loading condition, the safety factor against buckling was found to be 3.85 for the undegraded shell and 2.15 for the degraded shell. For the operational load condition, such as the refueling condition, the ASME Code specifies a minimum safety factor of 2.00. Thus, the Sandia analysis confirmed that the Oyster Creek degraded drywell shell could withstand the postulated load conditions without exceeding the design limits in ASME Code, Section III, Subsection NE. *See* SER at 4-72. This confirmation provides assurance that the Oyster Creek drywell shell can fulfill its intended function of providing the pressure retaining barrier against uncontrolled release of radioactivity under all postulated load conditions, provided the drywell shell does not experience significant additional degradation.

Q9. You testified that the Sandia analysis used information from the 1993 version of Calculation-24. Did the Staff consider information in later versions of that calculation during its review of AmerGen's LRA?

A9. (Ashar) Yes. The Staff was aware of Calculation-24, Revision 1 (AmerGen Exhibit 17), which had used the same 1992 bathtub area measurements that are in Rev. 0. In Calculation-24, Rev. 0 (AmerGen Exhibit 17), there are eight raw 1992 UT data points in Bay 1, that are between 0.636 inch and 0.736 inch, and no UT data point is less than 0.636 inches. In Bay 13, there are nine raw data points between the thickness of 0.636 inch and 0.736 inch, and one data point (i.e., 0.618 inch) below 0.636 inch, but above 0.536 inch. AmerGen has adjusted the raw data points less than 0.736 inch to account for surface roughness for their use in its structural evaluation. *Id.* at 67-87 of 117.

Based on a review of the Calculation-24, Revs. 0 and 1 (AmerGen Exhibits 17 and 18) analysis of degraded areas, and AmerGen responses to Staff RAIs (*see* SER section 4.7.2), AmerGen has three criteria related to acceptance of the shell thicknesses: 1) a general minimum average required thickness of 0.736 inch; (2) a minimum locally thin thickness of 0.536 inch, in an area of one square foot, with a surrounding one foot transition area to 0.736 inch; and (3) the minimum thickness of 0.49 inch in an isolated area not exceeding an area of a circle having a diameter of two and one-half inches. *E.g.*, Calculation-24, Rev. 1 (AmerGen Exhibit 18) at 10-11 of 117. In addition, AmerGen has elected to use a thickness of 0.636 inch to characterize the extent of degradation below 0.736 inch. *See id.*

The Staff did not consider Calculation C-1302-187-5320-024, Rev 2 (Mar. 2007) (AmerGen Exhibit 16) during the review of the LRA because that document was not submitted to the NRC for review in connection with the LRA (or available before issuance of the SER). Although the Staff has not conducted a detailed technical review of Calculation-24, Rev. 2, Section 6.0 (at 10-15 of 183) of the calculation indicates that AmerGen analyzed 2006 UT results from the drywell exterior using a local acceptance criterion different from a previous version of the calculation. Section 6.1 of Calculation-24, Rev. 2, indicates a general uniform wall thickness criterion of 0.736 inch and methods for implementing the criterion under various UT measurements, but a local wall thickness criterion for buckling as an average of 0.636 inch in an area no larger than 12 inches by 12 inches square. *See* AmerGen Exhibit 16 at 10-15 of 183. The criterion allows the transition (from 0.636 inch to 0.736 inch) thickness in the area no larger than 36 inches by 36 inches. *Id.* However, Revision 2 refers to the same analysis that was used in Calculation-24, Revisions 0 and 1. The very local wall thickness criterion of 0.49 in an area not exceeding a 2½ inch diameter circle has not changed. Thus, it appears that the Calculation-24, Revision 2 criterion for locally thin areas (i.e., 0.636 inch) is a more stringent criterion, and is encompassed by the Staff's review based on a very local criterion of 0.536 inch discussed at SER pages 4-55 to 4-60.

Q10. How often will UT measurements of the sand bed region of the drywell be taken under AmerGen's aging management program?

A10. (Ashar) In LRA, section B.1.27, "ASME Section XI, Subsection IWE," AmerGen indicates that inspection of the drywell shell and other primary containment components is in accordance with this aging management program. LRA at B-75. Commitment 27, Item 21, indicates that, during the period of extended operation AmerGen will perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope inspection is defined as:

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

The Staff found AmerGen's Commitment 27 items acceptable. *See* SER at 4-75. As noted in the SER (at 1-18), the Staff plans to include a license condition that requires the applicant to perform full scope inspections of the drywell sand bed region every other refueling outage during the proposed renewal period.

Q11. Why did the Staff find the monitoring frequency adequate?

A11. (Ashar, Davis) UT measurements taken during the October 2006 outage confirmed that the epoxy coating in the sand bed area has been effective in reducing the potential for corrosion in this area since the change in thicknesses were small. In its letter of December 3, 2006 (ML063390664) (AmerGen Exhibit 12), AmerGen indicated that wall thinning of 0.038 inch had taken place in trenches 5 and 17, since 1986, when the trenches were constructed. *See* SER at 3-423 to 4-424. These trenches are in the inside of the drywell and do not have an epoxy coating to prevent corrosion. This corrosion identified in the trenches is equivalent to about 2 mils per year of corrosion in the specific areas of the trenches.

The Staff reasoned that, if this corrosion rate is applied to the lowest average thickness of 0.8 inch for four years, the average thickness would be reduced to 0.792 inch, and hence, higher than the average minimum thickness of 0.736 inch. This approach is conservative because it involves the application of a very local thickness reduction to the entire sand bed region and, because the rate of future corrosion normally decreases over time due to the formation of corrosion products. In addition, AmerGen has committed (Commitment 27, Items 16, 20 and 21) to perform inspections during the 2008 outage, which will include UT examinations in the trench areas, as well as in the rest of the sand bed area. *See* SER at 4-74 to 4-75. Any anomaly associated with these measurements will be tracked prior to the start of the extended period of operation. In summary, the Staff's view is that no significant corrosion is occurring in the sand bed area at a rate that would warrant the UT measurement at an interval shorter than in Commitment 27, Item 21 (*i.e.*, every other outage).

Q12. Can a corrosive environment exist in the sand bed region after removal of the sand and application of the epoxy coating?

A12(a). (Ashar) Because the drywell is inerted during operation, the likelihood of corrosive environment existing inside the drywell during operation of the plant is very low. However, certain leakages from components inside the drywell can create a corrosive environment during outages, as found in the trenches during the October 2006 inspections. In Commitment 27, Item 20 (*see* SER at A-31 to A-32), AmerGen committed to monitor the two trenches for the presence of water.

> Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling

outages, at which time the trenches will be restored to their original design (e.g., refilled with concrete) to minimize the risk of future corrosion.

Proper implementation of this commitment will ensure that the embedded portion of the inside of the drywell shell will not be subjected to corrosion. Routine implementation of IWE program (LRA AMP B.1.27) will ensure that the junction between the bottom concrete floor and the drywell shell is monitored during each inspection period.

A12(b). (Davis) As far as eliminating sources of water, Oyster Creek has committed (Commitment 27, Item 3) to monitor the sand bed region drains quarterly during the operating cycle. If water is detected, the following actions will be taken: 1) The leakage rate will be quantified for flow rate and trended; 2) The source of water will be investigated and diverted, if possible, from entering the sand bed region; 3) The water will be analyzed to determine the source of leakage; 4) If a leak is detected, the coating and moisture barrier will be inspected in any bays affected by the leakage during the next refueling outage or outage of opportunity; 5) If the coating is degraded, and visual inspection indicates corrosion has taken place, then UT measurements will be taken in the affected areas of the sand bed region from either the inside or outside of the drywell to ensure that the shell thickness in areas affected by water leakage is measured; 6) UT measurements will be taken in the upper region of the drywell consistent with the existing program; and 7) Any degraded coating or seal will be repaired in accordance with station procedures. *See* SER at 1-17.

Oyster Creek has also committed (Commitment 27, Item 2) to use a strippable coating during the period of extended operation that has been shown to be effective in mitigating water intrusion into the annular space between drywell shell and shield wall. This has been applied to the refueling cavity liner during periods when the refueling cavity is flooded. This commitment applies to refueling outages prior to and during the period of extended operation. *See* SER at 3-115.

Q13. Citizens contend that corrosion (not visible to an inspector) can occur in pinholes or holidays in the epoxy coating on the external surface of the drywell. Do you agree?

A13. (Davis) In my opinion, Citizens' contention lacks technical merit because AmerGen has committed to conduct inspections of the coatings in the sand bed region in accordance with the ASME Code Section XI, Subsection IWE. *See* Commitment 27, Items 4 and 21 and Commitment 33 in SER, Appendix A. During the audit at Oyster Creek, the Applicant stated that visual inspection of the containment drywell shell, conducted in accordance with ASME Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containment are considered inaccessible by ASME Code Section XI, Subsection IWE; thus, visual inspection was not possible for a typical Mark I containment before the sand was removed from the sand bed region in 1992. After removal of the sand, an epoxy coating was applied to the exterior wall in the sand bed region. *See* SER at 3-118 to -119. Excerpts from Subsection IWE are attached as Staff Exhibit 2.

Q14. What is the potential for corrosion under epoxy coating due to defects in and deterioration of the coating?

A14. (Davis) There is a multi-layer epoxy coating on the exterior of the Oyster Creek drywell shell in the sand bed region to prevent corrosion in that region. This coating was discussed in detail under SER Open Item 4.7.2-3, which has been closed. This coating was applied as part of corrective actions taken in the late 1980s and early 1990s to prevent additional corrosion of the drywell shell in the sand bed region. This coating was discussed in detail under Open Item 4.7.2-3 in the SER. In addition to removing the sand from the sand bed region, a coating was applied to the exterior of the drywell shell in the sand bed region with a multi-layered epoxy system (i.e., one pre-primer coat, and two top coats) to prevent any water or moisture that might reach the sand bed region from contacting the exterior shell. *See* SER at 1-15 to 1-18, 3-163 to 3-167, 4-67 to 4-70.

Thus, the use of multiple layers of epoxy coatings at Oyster Creek results in an extremely low probability that pinholes and holidays will line up in the three layer coating system. In addition, pinholes usually develop during the initial cure of the coating and new pinholes would not likely develop over time in the absence of conditions such as mechanical impacts or exposure to ultraviolet light.

Q15. What is the basis for your conclusion that corrosion would be visible?

A15. (Davis) When a steel surface corrodes, the oxide film that is generated has a higher volume than the original volume of the steel because iron in the steel is converted to iron oxide that is then hydrated, which leads to blistering and other observable anomalies in the coating. The film will be rust colored and will be obvious against the gray colored epoxy coating.

AmerGen's protective coating monitoring and maintenance program specifies VT-1 visual inspections of epoxy coating using qualified inspectors. The rust colored corrosion product will be easily detected during VT-1 inspections of the coating on the external surface of the drywell shell in accordance with the ASME Code, Section XI, Subsection IWE. Additional guidance for inspection of the epoxy coatings on the drywell shell are in GALL section XI.S1, "ASME Section XI, Subsection IWE," and XI.S8, "Protective Coating Monitoring and Maintenance Program." These sections indicate that inspectors are to be trained to inspect the surfaces within the scope of IWE for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation. AmerGen has committed to follow this guidance (Commitment 27, Items 4 and 21 and Commitment 33 in the SER Appendix A).

The Applicant further stated that the existing Protective Coating Monitoring and Maintenance Program does not invoke all of the requirements of ASME Code Section XI, Subsection IWE. AmerGen has committed (Commitment 27, Item 4) to enhance the program to incorporate coated surfaces inspection requirements specified in ASME Code Section XI, Subsection IWE and has provided specific enhancements that will be made to the program as follows:

> Sand bed region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1.
>
> a. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.
>
> b. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.
>
> c. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

SER at 3-120. If the coating is damaged and corrosion is observed, AmerGen will conduct UT measurements of that area and will evaluate the results following the existing program. SER at A-18 to A-20 (Commitment 27, Item 1). The Applicant committed to conduct additional visual inspections of the epoxy coatings applied to the external surface of the drywell shell in the sand bed region prior to entering the period of extended operation. SER at A-22 to A-23 (Commitment 27, Item 4). AmerGen has committed (Commitment 27, Items 4 and 21, and Commitment 33) to enhance the Inservice Inspection Program to require 100% inspection of the epoxy coatings every other refueling outage during the period of extended operation.

The Staff, as noted in SER Sections 3.0.3.2.23 and 3.0.3.2.27, concluded that the performance of ASME Section XI, Subsection IWE, visual inspections of the drywell in all ten bays of the sand bed region every other refuelling outage, and AmerGen taking appropriate actions when significant corrosion is detected, provides assurance that effects of aging will be adequately managed so that intended functions will be maintained throughout the renewal period.

It should also be noted that, Regulatory Guide 1.54, Rev. 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," which refers to ASTM D 5163, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant," and ASME Code Section XI, Subsection IWE, "Requirements for Class MC and Metallic Liners of Class CC Components of Light Water Cooled Plants," recommend visual inspection of coatings for evidence of degradation before conducting additional tests.

Q16. What did the NRC learn during license renewal inspections at Oyster Creek?

A16. (O' Hara) As an inspector, I reviewed the implementation of AmerGen's B.1.27, ASME Section XI, Subsection IWE Program, during the March 2006 inspection and found that AmerGen's program was consistent with guidance for managing aging effects of the drywell. This decision was reached after interviews with cognizant engineering and management personnel from AmerGen, review of historical data on the drywell corrosion issue, review of the licensee's evaluation and analysis of the historical drywell testing data, and the licensee's commitment to significantly improve the rigor with which they had been addressing the condition of the drywell and their program to monitor the aging effects of the drywell. See NRC Inspection Report 05000219/2006007 (Sept. 21, 2006) (ML062650059), at 16. The Staff also concluded, regarding B.1.33, Protective Coating Monitoring and Maintenance Program, that the licensee's program provided adequate guidance to ensure that aging effects of the drywell shell will be adequately managed. *Id.* at 16-17. This program is used to monitor the coating on the exterior of the drywell.

Q17. Did NRC inspectors observe UT measurements of the drywell shell during the Fall 2006 outage?

A17. (O'Hara) Yes. During the fall 2006 inspection, I observed the use of a qualified UT procedure, performed by qualified technicians. Exelon Procedure TQ-AA-122, Revision 3; "Qualification and Certification of Nondestructive (NDE) Personnel" provides the standard used by AmerGen to qualify and certify NDE technicians. In general, UT personnel are qualified in accordance with ASNT SNT-TC-1A, through 1984 edition; ANSI/ASNT CP-189, 1991 and 1995 editions; and ASME Section XI, 1986 Edition through 2001 Edition, 2003 Addenda, as applicable. For UT, personnel certification, Attachment 5 of TQ-AA-122 provides the detailed qualification which must be demonstrated to perform examinations for the requirements of ASME Section XI. All the aforementioned standards have been previously reviewed and accepted by the NRC for the specified qualification processes. The calibrations and data collection activities were performed per the procedure, recorded on appropriate data sheets, and the results were reviewed and approved by a qualified, Level III Nondestructive Evaluation Examiner. Then all data was evaluated and analyzed by qualified, experienced engineers to determine whether acceptance criteria were met. Upon confirming that all recorded data met the wall thickness criteria, the Licensee determined that the GE Analysis report of record was validated for the wall thickness data recorded. Based upon the calculated corrosion rate (2006) and the remaining wall thickness, the Licensee demonstrated that the drywell wall thickness will be maintained above minimum requirements until the next refueling outage in 2008.

The UT and visual (VT) records from this inspection in the fall of 2006, were well documented, the data was correctly collected, personnel were knowledgeable and qualified to perform the required inspections. The NDE level III supervising the data collection was knowledgeable and provided accurate direction to the data collection personnel. All data collected was reviewed for acceptability before it was given to engineering. Upon receiving the validated data, engineering personnel conducted appropriate and accurate analyses and evaluations based upon written procedures and criteria. Upon completion of the evaluations, appropriate engineering and station management reviews were conducted.

The external UT wall thickness measurements taken during 2006 showed no significant corrosion compared to1992 measurements. It should be noted that the Licensee had intended to re-measure approximately 115 external points which had been prepared and measured in 1992, prior to application of the epoxy coating. Due to the difficulty in finding and matching up all of these points, the licensee was able to obtain 2006 comparison readings for approximately 106 of the planned 115 points. For the external points measurements I observed during the inspection, AmerGen found it difficult to locate and identify some of the points. For example, some measurements had not been ground as deeply as others and some had not been referenced correctly. This indicates that it may not always be appropriate to compare 2006 point readings with external readings from previous years.

During my observations of the internal drywell UT measurements, there was a very light surface coating of oxidation present on small uncoated portions of the drywell shell in the trenches in Bay 5 and 17, however, no wall thickness loss (i.e., flaking) was apparent. The licensee had coated the internal drywell test locations with grease after prior UT measurements in 1994 to prevent this oxidation, but had apparently not coated these areas or the grease was disturbed during preparation for the 2006 inspection. The presence of the water in the trenches in Bay 5 and Bay 17 was the only evidence of a corrosive environment inside the drywell. The Licensee monitors the inside of the drywell under their ASME Section XI, Subsection IWE program, and I verified that the interior of the drywell is inspected and actions taken when coating deterioration is detected. And, in addition, the internal sections of the drywell are measured with UT for wall thickness in the area of the sand bed. The water in the trenches was determined to not be a corrosive environment because the water had reacted with the concrete and had become a non-corrosive (i.e., basic) environment.

Q18. How were the UT measurements taken during the 2006 outage?

A18. (O'Hara) During the 2006 outage measurements, the licensee employed a UT measurement technique (automatic nullification of the epoxy coating thickness) that eliminated an additional measurement step which had been used in previous measurements prior to 2006. Prior to 2006 the licensee had measured the epoxy coating thickness and then manually subtracted the thickness from the recorded thickness of the coating and shell measured together. The new technique, known as wave skip or half-wave technique, involved calibration of the UT instrument to record the first signal reflection of the coating-to-metal interface and deduction of that distance from the overall coating and metal thickness measurement, thus effectively cancelling out the coating thickness and reporting only the remaining metal thickness. This technique had not been used during previous inspections of the drywell thickness after the epoxy coating had been applied in 1992. In my opinion, this technique provided more consistent and accurate measurements than pre-2006 measurements.

During the Regional Aging Management inspection, in March 2006, I was assigned to review the ASME, Section XI, Subsection IWE Program and the Protective Coating Monitoring and Maintenance Program. In reviewing the historical evolution of the drywell corrosion issue, I inquired about the licensee's past data and data collection procedures. Discussions with AmerGen regarding how past data could be directly compared to the 2006 data, in part, led to AmerGen commitments that were verified and results reported in NRC Inspection Report

05000219/2006013 (Jan. 17, 2007) (ML070170396). Basically, the Licensee has completed a well-documented baseline inspection on the internal and external drywell condition which will be reinspected, at appropriate intervals based upon recently-measured corrosion rates, to ensure that the drywell wall thickness remains adequate to perform its safety function.

Q19. What is your opinion regarding AmerGen's UT measurement uncertainties during the 2006 outage?

A19. (O'Hara) From my observation of the UT equipment calibration, observation of the data collection and the Level III review of the reported data, the measurement uncertainty on these measurements was very low. The use of UT technology as a thickness gauging tool is a very elementary application of the technology and has been shown to be very accurate in many industrial applications. In addition, it is my opinion that the elimination of an additional measurement step to account for the epoxy coating thickness simplified the measurement of the actual remaining metal thickness and enabled measurement with greater accuracy. Also, my experience has been that there would be significant variability in thickness for a manually applied coating applied in the confined space of the external drywell bays. The licensee's use of a technique that accounts for the thickness of the epoxy at each reading location removed a significant potential measurement error. Thus, in my opinion, the 2006 data should be considered to be more accurate than the licensee's previous UT metal thickness measurements.

It is also my opinion, based upon discussions with several licensee personnel about the methods used to remove the sand and scale from the exterior of the drywell and the methods used to prepare the metal surface prior to applying the epoxy coating in 1992, that the licensee has included some additional conservatism in the external UT thickness measurements by not taking credit for metal that was intentionally removed in 1992 prior to applying the epoxy coating. In order to provide a smooth surface for UT readings in 1992, the licensee prepared the dimpled surface of the external locations to be measured by grinding smooth, flat surfaces on the outside of the drywell. During this preparation process, the licensee did not control the amount of material removed. Thus, readings taken since the application of the epoxy coating can be expected to be thinner than the original, 1992 actual thickness by some amount not attributable to corrosion, but attributable to the surface prep process. This added conservatism would affect measurements taken since the application of the epoxy coating, however, because the licensee cannot quantify the amount of this conservatism, no credit has been taken by the licensee in its analysis of the drywell condition. The licensee also has some limited video and pictorial records on the processes followed during the 1992 effort to remove the sand and to clean the drywell and apply the epoxy coating, which I viewed.

Q20. What did you observe regarding the condition of the epoxy coating on the exterior of the drywell shell in the sand bed region?

A20. (O'Hara). During the fall 2006 outage, I inspected (by physically entering the Bays 11 and 13) the external epoxy coating on the outside of the drywell. The coating in both bays was grayish-white in color and appeared to be in excellent condition with no visible evidence of cracking, peeling or blistering. The general condition of each bay was good with no moisture visible. I could not see any sign that corrosion had disturbed the epoxy coating and saw no evidence that corrosion was occurring under the epoxy coating.

In addition to entering Bays 11 and 13, I also viewed video tapes of all Bays and reviewed the VT data sheets from all Bays. The video tapes showed the same general condition in all bays and showed that the epoxy coating had not been visibly disturbed since the original application. The epoxy coating, in all Bays, appeared to be in good condition and undisturbed since the application of the epoxy in 1992.

Regarding the potential for a corrosive environment to exist on the outside of the drywell, my visual observations of (and a review of records concerning) the exterior of the drywell and the epoxy coating condition did not reveal any evidence of moisture on the drywell exterior or the coating in the sand bed region. Additionally, my reviews did not identify any evidence that a corrosive environment had been recently active on the drywell exterior or the epoxy coating in the sand bed region.

Q21. What do the 2006 UT results show about whether remaining thicknesses of the shell exceeds AmerGen's UT acceptance criteria?

A21. (Ashar) A review of the 106 UT thickness measurements in the locally thinned areas made during the October 2006 outage, in general, indicated that the metal thicknesses in these areas were lower than those in 1992. *See* AmerGen Letter to NRC (Dec. 3, 2006) (AmerGen Exhibit 12). AmerGen attributed the lower metal thickness as largely due to using a more accurate UT instrument and the procedure used to take the measurements, which involved moving the instrument within the locally thinned areas to locate the minimum thickness in the area (SER at 3-138). However, a review of the data attached to AmerGen's December 3 letter (*see* SER at 3-424) indicated that the measurements did not exceed the acceptance criteria for the locally thinned areas. Thus, the results of the 2006 UT measurements do not indicate any significant corrosion that would challenge the integrity of the drywell shell. *See* SER at 3-142 to 3-143.

Q22. What is the corrosion rate in the sand bed region, including uncertainties related to its determination?

A22. (Ashar) AmerGen has asserted, based on the comparison of the UT measurements in October 2006, and earlier UT measurement data, that the drywell corrosion in the sand bed area has been arrested. *See, e.g.,* SER at 3-126. AmerGen, however, has described ten sources of uncertainties associated with UT measurements of the drywell shell (e.g. UT instrumentation, drywell surface roughness, probe location repeatability, UT probe rotation, temperature effects, NDE technician, UT unit setting, etc.) and plans to address each source of uncertainty through implementation of proper procedures and training. *See* SER at 4-53 to 4-55. Between 1986 and 1992, the wall thickness loss at the thinnest located was reported to be 70 mils, resulting in linear corrosion rate of 12 mils/year. SER at 4-43.

As indicated on SER pages 4-59 and 4-60, the Staff evaluated the process used by AmerGen related to the UT measurements taken after the epoxy coating was applied. Initial locations identified in 1986 and 1987 where corrosion loss was most severe were selected for repeat inspection over time to measure corrosion rates. For locations where the initial investigations found significant wall thinning, new wall thickness were measured by UT at 49 points in 6" x 6" area, and verified for compliance with the minimum required wall thickness criteria. A statistical analysis was then performed of this dataset, and the mean value was compared to the previously calculated mean values at this location. A linear regression analysis of the old and new values was then performed to determine the slope and 95% upper and lower confidence intervals. For a non-zero slope, the slope of the line represents the corrosion rate at this location. The lower 95% confidence interval was then projected into the future and compared with the required minimum wall thickness criteria.

The use of the lower 95% confidence interval in projecting the future thicknesses, and the requirement that the thickness acceptance criteria are met, is consistent with the ASME Subsection IWE requirements for evaluating the UT results. The Staff concluded that the use of this process is acceptable for assessing the future corrosion rate. *See* SER at 4-60.

As previously noted, October 2006 outage results confirmed that the epoxy coating in the sand bed area has been effective in reducing corrosion in this area and indicated a corrosion rate of about 2 mils per year based on the wall thinning in the trenches. *See* SER at 3-424. When this corrosion rate is applied to the lowest average thickness of 0.8 inch for four years, the average thickness would reduce to 0.792 inch, which would be higher than the average minimum required thickness of 0.736 inch.

Q23. What is the Staff's position regarding the necessity for UT monitoring of the Oyster Creek drywell shell when visual inspection results for the epoxy coating do not identify any evidence of deterioration of the epoxy coating?

A23. The Staff position is that UT monitoring in the sand bed region is necessary even when visual inspection results for the epoxy coating satisfy the acceptance criteria of ASME Section XI, Subsection IWE-3512 due to (1) the inability to make a definitive assessment regarding the uncertainties related to corroded areas, (2) only three reliable points of metal thickness data, and (3) the unknown duration of the effectiveness of the epoxy coating in protecting the sand bed region metal surfaces. Thus, both the VT-1 examination of the epoxy coating and UT monitoring should continue throughout the extended period of operation as committed by AmerGen in Commitment 27, Item 21.

Q24. What is the Staff's conclusion regarding whether the aging management program for the drywell shell is adequate for the license renewal period?

A24. The results of the 2006 outage inspection indicate that AmerGen corrective actions (removal of the sand and application of epoxy coating) have been effective in managing corrosion of the drywell shell. AmerGen's Aging Management Program includes commitments listed in Appendix A of the SER to periodically monitor corrosion in the sand bed region of the drywell shell, identify the extent of additional degradation, perform additional UT measurements and compare thickness differentials, report statistically significant corrosion to the NRC, and perform an operability determination and justification for operation until the next inspection.

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

Hansraj G. Ashar
Statement of Professional Qualifications

CURRENT POSITION:

Senior Structural Engineer Division of Engineering, Office of Nuclear Reactor Regulation

U.S. Nuclear Regulatory Commission
Rockville, MD

EDUCATION

Bachelor of Civil Engineering, Gujarat University, India
Masters Degree in Civil-Structural Engineering, 1958, University of Michigan, Ann Arbor, MI

Registered Professional Engineer in the States of Ohio and Maryland.

EXPERIENCE

For the last 33 years, I have been working as a Structural engineer/Sr. Structural Engineer with the U.S. Nuclear Regulatory Commission in review of the plant licenses, standards development, containment related research activities and license renewal activities. For the first eleven years of my career, I have worked as a Bridge Engineer in the States of Ohio, New Jersey; and in Wiesbaden Germany on designing steel, reinforced and prestressed concrete bridges. The next five years, I worked as a Lead Civil Engineer on developing design documents and procurement specifications for nuclear power plants, namely, Three Mile Island, Unit 2, Forked River, and Oyster Creek.

I represent NRC in a number of Standards Developing Organizations, namely, American Society of Mechanical Engineers (ASME), American Concrete Institute, and American Institute of Steel Construction on several committees developing standards related to the nuclear power plant structures. I am a fellow member of the American Concrete Institute, and the American Society of Civil Engineers.

REGULATORY DOCUMENTS (Principal Author):

Information Notices

IN 93-53	Effects of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned, April 1994
IN 95-49	Seismic Adequacy of Thermo-Lag Panels, October 1995 Supplement 1: Seismic Adequacy of Thermo-Lag Panels, December 1997
IN 97-10	Liner Plate Corrosion in Concrete Containments, March 1997
IN 97-11	Cement Erosion from Containment Subfoundation at Nuclear Power Plants, March 1997

IN 97-22 Failure of Welded Steel Moment-Resisting Frames During the Northridge Earthquake, April 1997

IN 97-29 Containment Inspection Rule, May 1997

IN 98-26 Settlement Monitoring and Inspection of Plant Structures Affected by Degradation of Porous Concrete Subfoundation, July 1998

IN 99-10 Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments, April 1999

IN 06-01 Torus Cracking in a BWR Mark-I Containment, January 2006

ISG 06-01 Aging Management Program for Inaccessible Areas of BWR Mark-I Containment Drywell shell, September 2006

Inspection Procedures

IP 62002 Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants, Dec. 1996

IP 62003 Inspection of Steel and Concrete Containments at Nuclear Power Plants, June 1997

Regulatory Guides

RG 1.35 Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments. Rev. 1 (1974), 2 (1976), 3 (1990)

RG 1.35.1 Determining Prestressing Forces for Inservice Inspection of Prestressed Concrete Containments: Draft (1979), final (1990)

RG 1.90 Inservice Inspection of Prestressed Concrete Containments with Grouted Tendons: (1977).

RG 1.107 Qualification of Cement Grouting for Prestressing Tendons in Prestressed Concrete Containments: (1977)

RG 1.136 Materials, Construction and Testing of Concrete Containments (Endorsement of ASME Section III/Div. 2 (or ACI 359): (1981)

RG 1.142 Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments): (1981)

Technical Support to the principal coordinators of 10 CFR 50.55a, (Codes and Standards) Revisions on endorsing Subsections IWE/IWL (ISI of Containments) of the ASME Code: 1994 to Present

PROFESSIONAL AND COMMUNITY ACTIVITIES

Participation in National and International Standards Organizations

Member of the following NSO and INSO Committees:

- American Institute of Steel Construction (AISC)
  Chairman: Nuclear Specification Committee (AISC/ANSI N690)
  Member: Building Specification Committee
  Advisory: Seismic Provisions Committee
- American Concrete Institute (ACI) 349 Committees
  Member: Main committee
  Member: Subcommittee 1 on General Requirements, Materials and QA
  Member: Subcommittee 2 on Design
- American Society of Mechanical Engineers (ASME):
  Member: Working Group on Inservice Inspection of Concrete and Steel Containments (Subsections IWE and IWL of ASME Section XI Code)
  Member: ASME/ACI Joint Committee on Design, Construction, Testing and Inspection of Concrete Containments and Pressure Vessels
- Member: RILEM Task Committee 160-MLN: Methodology for Life Prediction of Concrete Structures in Nuclear Power Plants
- Member: Federation Internationale du Beton (FIB) Task Group 1.3: Containment Structures
- Consultant to IAEA on Concrete Containment Database (2001 to 2005)

PROFESSIONAL MEMBERSHIPS

Professional Engineer: State of Ohio, State of Maryland
Fellow - American Concrete Institute
Fellow - American Society of Civil Engineers
Professional Member - Post-tensioning Institute

COMMUNITY ORGANIZATIONS - SERVICES

Member- Montgomery County Energy and Air-Quality Advisory Committee (1995 to 2001)
Science Fair Judge (Montgomery County) - 1994-2001
Member-Architectural Committee – Hickory Crest, Columbia, Association

Peer reviewer of number of papers to be published in ASCE Material Journal, NED Periodicals, and ACI International.

PUBLICATIONS/PRESENTATIONS

1. Ashar, H., Terao, D., Imbro, E.: "Reliability of Containment and Risk-Informed Decision Making - A Perspective," Presented at SMiRT17 International Conference in Prague, Czech Republic, August 2003.

2. Ashar, H., Imbro, E, Terao, D.: Integrated Leak Rate Testing of Containments - A Regulatory Perspective, Presented by Eugene Imbro at ICONE11 in Tokyo, Japan, April 2003.

3. Ashar, H.: Inspection of Containment Structures in the U.S.A. Presented at the 16th International Conference on Structural Mechanics in Reactor Technology, Washington DC. August 12-17, 2001.

4. Kotzalas, M., Ashar, H.: Regulatory Issues Involved in the Use of the ASME XI, IWE/IWL, Presented at the ASME Pressure Vessel and Piping Conference, Atlanta, GA. July 2001.

5. Ashar H., Kotzalas, M.: Implementation of Containment Inspection Rule, 10 CFR Part 50.55a, Presented at the ASME Pressure Vessel and Piping Conference, Atlanta, GA. July 2001.

6. Ashar, H.: Implications of Concrete Structure Degradations in Nuclear Power Plants, Proceedings of the International RILEM Conference on Life Prediction and Aging Management of Concrete Structures, Cannes, France, October 16-18, 2000.

7. Ashar, H., Bagchi, G.: "Monitoring Degradation of Concrete Structures in U.S. Nuclear Power Plants," Proceedings of the 8th International Conference (Sponsored by RILEM) on "Life Management and Aging Management of Concrete Structures," Bratislava, Slovakia, July 1999.

8. Ashar, H., Bagchi, G.: "Implementation of Maintenance Rule for Structures," Proceedings of the 7" symposium on Current Issues Related to Structures, Systems, and Piping, North Carolina State University, Raleigh, NC, December 1998 (Published in Nuclear Engineering and Design in Nov. 1999).

9. Ashar, H., Costello, J., Graves, H.: "Prestress Force Losses in Containments of U.S. Nuclear Power Plants," Proceedings of the Joint WANO-PCIOECD-NEA Workshop on Prestress Loss in Nuclear Containments, Poitier, France, August 1997.

10. Ashar, H., Bagchi G.: "Safety Related Nuclear Power Plant Structures - Assessment of Inservice Conditions," NUREG 1522, U.S. Nuclear Regulatory Commission, Washington D.C., 20555, May 1995.

11. Ashar, H., Jeng, D.: "Degradation of Passive Components in U.S. Nuclear Power Plants," Proceedings of the 6th Symposium on Current Issues Related to Structures, Systems, and Piping, North Carolina State University, Raleigh, NC, December 1996.

12. Ashar, H., Jeng, D.: "Performance of Structures in Nuclear Power Plants," Paper X/2, Proceedings of the 5th Symposium on Current Issues Related to Structures, Systems, and Piping, Orlando, Fl., December 1994.

13. Ashar, H., Naus, D., Tan, C. P.: "Prestressed Concrete in U.S. Nuclear Power Plants," Concrete International, American Concrete Institute, Detroit, Michigan, Part I in May 1994, Part 2 in June 1994.

14. Jeng, D., Bagchi, G., Ashar, H.: "Structural Issues Related to Containment Performance in Advanced Reactors," Proceedings of the Second ASME/JSME Conference on Nuclear Engineering, San Francisco, CA, March 1993.

15. Ashar, H., Tan, C. P.: "Inservice Performance of Containment Structures - U.S. Experience," Proceedings of the 11th Conference of Structural Mechanics in Reactor Technology (SMIRT), Tokyo, Japan, August 1991.

16. Tan, C. P., Ashar, H.: "Modifications of Concrete Containments for Steam Generator Replacement-Regulatory Considerations," Proceedings of SMIRT 11th, Tokyo, Japan, August 1991.

17. Ashar, H., Jeng, D.: "Effectiveness of Inservice Requirements for Prestressed Concrete Containments," Proceedings of the 2nd International Conference on Containment Design and Operation, Toronto, Ontario, Canada, October 1990.

18. Ashar, H., Degrassi, G.: "Design and Analysis of Free standing Spent Fuel Racks in Nuclear Power Plants," Proceedings of the 10th SMIRT Conference, Anaheim, CA., August 1989.

19. Bagchi, G., Jeng. D., Ashar, H.: "Proposed Modifications of NRC's Standard Review Plan for Seismic Analysis," Proceedings of the 2nd Symposium on Current Issues Related to NPP Structures, Systems, and Piping, Orlando, Fl., Dec. 1988.

20. Ashar, H., Jeng, D.: "Spent Fuel Storage - A Regulatory Perspective," Presented at 1988 ASME Joint Power Generation Conference, Philadelphia, Pa. September 1988.

21. Richardson, J., Ashar, H.: "Regulatory Perspective on Containment Performance," Presented at MITI/NRC Conference on Nuclear Technology, Tokyo, Japan, Dec. 1987.

22. Ashar, H., Naus, D.: "Overview of the Use of Prestressed Concrete in U.S. Nuclear Power Plants," Nuclear Engineering and Design, Val. 75, North Holland Publishing Company, August 1983.

23. Dougan, J., Ashar, H.: "Evaluation of Grease Performance in Prestressed Concrete Containments," Proceedings of 6th SMIRT Conference, Chicago, 11. August 1983.

James A. Davis, Ph. D
Statement of Professional Qualifications

CURRENT POSITION:

Senior Materials Engineer — Division of License Renewal, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Rockville, MD

EDUCATION:

B. Met. E., The Ohio State University, 1965, Metallurgical Engineering
M.S., The Ohio State University, 1965, Metallurgical Engineering
Ph.D., The Ohio State University, 1968, Metallurgical Engineering

SUMMARY:

Over 39 years of experience in material engineering with over 20 years of experience in the nuclear power industry. Significant experience in the following areas:

- Materials Engineering
- Corrosion and Control
- Protective Coatings and Linings
- Welding and Special Repair Processes
- License Renewal
- Nuclear Facilities Audits
- Allegations
- Reviews of Navy Submarine Power Plant Designs
- Quality Assurance
- ASME Code Committees
- ASTM D-33 Committee on Coatings for Power Generation Facilities

EXPERIENCE:

U.S. Nuclear Regulatory Commission, 11/11/1990 - Present

11/13/2005 to Present - Senior Materials Engineer, Division of License Renewal, Office of Nuclear Regulatory Research

- Audit Team Leader for the license renewal safety audit at the Pilgrim Nuclear Power Station

- Audit Team Member for the license renewal safety audit at the Oyster Creek Generating Station

12/15/2001 - 11/13/ 2005 – Senior Materials Engineer in the Division of Engineering Technology, Office of Nuclear Regulatory Research

- Program Manager on the Steam Generator Tube Integrity Program overseeing work conducted at Argonne National Laboratory

- Acting Program Manager for Non-Destructive Examination research at Pacific Northwest National Laboratory

11/11/1990 - 12/15/2001 - Technical Reviewer in the Materials and Chemical Engineering Branch, Chemical Engineering and Metallurgy Section, Division of Engineering, Office of Nuclear Reactor Regulation.

- Coatings for nuclear power plants,

- License renewal for Calvert Cliffs, Oconee, Arkansas Nuclear One, Hatch, and Turkey Point.

- Threaded fastener issues (such as stress corrosion cracking, boric acid corrosion, and fatigue),

- chemical decontamination,

- Boiling Water Reactor internals cracking,

- pump and valve internals cracking,

- pipe integrity issues,

- corrosion behavior for dry cask storage, and interaction of coatings with spent fuel water,

- Coordinated the responses to a generic letter on containment coatings for nuclear power plants.

- NRC representative to ASTM D-33 on coatings for power generation facilities.

- Member of the Board of Directors for the National Board of Registration for Nuclear Safety Related Coating Engineers & Specialists.

- Member of ASME on Welding and Special Repair Processes.

- Member of an Augmented Inspection Team at Palisades on fuel handling problems, Point Beach on the hydrogen burn as a result of interactions between borated water and the inorganic Zinc coating during dry cask loading operations and Davis-Besse on the Boric acid corrosion of he vessel head.

- Contract Technical Monitor and Project Officer for numerous contracts at Brookhaven National Labs.
- Technical reviewer for the design of the Navy Seawolf Submarine and the Virginia Class Submarine
- Reviewer on the DOE project to produce tritium in a commercial reactor (Watts Bar)
- Numerous presentations to senior NRC management including the Chairman, the Executive Director for Operations, the Committee to Resolve Generic Issues, and the Advisory Committee on Reactor Safety and Safeguards.
- Testified before Representative Dingle's staff on the safety of fasteners in nuclear power plants as a result of concerns raised by a private citizen.

Polyken Division of the Kendall Company. Senior Research Associate, 1981 – 1990:

Responsible for Technical Marketing for the pipeline coating division providing technical data and reports to domestic and international customers. Company representative to the National Association of Corrosion Engineers, the American Water Works Association coatings committees, and ASTM coating committees.

Arthur D. Little, Senior Consultant, 1979 - 1981:

Consultant to DOE on Defense Nuclear Waste issues and Waste Tank corrosion issues. Consultant on numerous commercial contracts on corrosion, coating, metallurgical, and plating issues.

Allied Tube and Conduit Corp., Director of Research, 1978-1979:

Responsible for research and development for metallurgical tube forming, welding, chemical cleaning of steel, galvanizing, surface treatment and coating of electrical conduit, fence posts, and specialty tubing. Responsible for Quality Assurance and Process Control.

Allegheny Ludlum Steel Corp., Research Specialist, 1976-1978:

Responsible for customer service for use of stainless steels in corrosive service. Responsible for conducting failure analysis. Conducted research on corrosion mechanisms for stainless steels.

Bell Aerospace Company, Senior Research Scientist, 1970-1976:

Program Manager on numerous Navy sponsored programs involving corrosion of aluminum alloys, stainless steels, and titanium alloys in high velocity sea water for the Navy's high performance ships program. Conducted research on corrosion fatigue, stress corrosion, and fouling in sea water. Conducted research on the compatibility of rocket fuels and oxidizers with fuel handling equipment.

U.S. Steel Corporation, Senior Research Engineer, 1968-1970:

Conducted research on the mechanism of pitting/crevice corrosion, stress corrosion cracking, hydrogen embrittlement, and intergranular corrosion using electrochemical techniques, transmission electron microscopy, optical microscopy, and scanning electron microscopy.

Mark Hartzman, Ph. D.
Statement of Professional Qualifications

CURRENT POSITION:

Senior Mechanical Engineer
Mechanical and Civil Engineering Branch (EMCB)
Division of Engineering
Office of Nuclear Reactor Regulation

EDUCATION:

- B.S. Mechanical Engineering, The City College of New York, New York, N. Y., 1959.
- MS Mechanical Engineering, University of Washington, Seattle, WA, 1963. Major: Engineering Mechanics.
- Ph. D., Mechanical Engineering, University of California, Davis, CA, 1970. Major: Engineering Mechanics.

SUMMARY:

Over 48 years of experience in Engineering Mechanics and Structural Analysis. Over 32 years experience in Nuclear Regulatory review and evaluation. Significant review experience in the following areas:

- Finite element analysis - solid mechanics, statics and dynamics
- Structural seismic analysis methodology
- Structural computer programs
- Piping analysis methodology and criteria
- ASME Section III Code design criteria
- License renewal

EXPERIENCE:

U.S. Nuclear Regulatory Commission, 06/75 - present

Wide variety of assignments over this time period. Representative assignments have consisted or consist of the following:

- Review of a wide variety of license amendment requests, requiring in-depth technical evaluation of licensee calculational methodology and procedures.
- Evaluation of licensee responses to I&E Bulletin 79-07, "Seismic Stress Analysis of Safety Related Piping." Co-author of reports NUREG/CR 1677, "Piping Benchmark Problems", Volumes 1 and 2.
- Development of acceptance criteria for I&E Bulletin 79-02, "Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts."

- Evaluation of industry acceptance criteria and plant responses to I&E Bulletin 88-08 "Thermal Stresses in Piping Connected to Reactor Coolant Systems."

- Evaluation of license renewal requests in the area of time limited aging analysis of ASME Section III metal components (metal fatigue) for the following plants:

  Palisades, St. Lucie
  Browns Ferry, V. C. Summer
  Brunswick, ANO-2

- Evaluation of allegations:

  Example: Deficiencies in piping and base plate design at the Diablo Canyon NPP, 1982-1984.

- Revision and updating of the Standard Review Plan within the scope of the EMCB.

- Evaluation of ASME Section III code cases for acceptance and listing in Regulatory Guide 1.84.

- Assistance to NRC Regions with technical resolution of inspection reports and differing professional opinions (DPOs):

  Example: Fermi HVAC duct safety under tornado loading. Resulted in NRC Regulatory Issue Summary (RIS) 2006-23, "Post-tornado Operability of ventilating and Air Conditioning Systems Housed in Emergency Diesel generating Rooms."

  Example: In 2006, as a member of a Region II Differing Professional Opinion DPO panel, performed the technical evaluation of a DPO regarding Oconee pipe whip structural integrity.

- Participation in ASME Section III Code working groups and committees since 1974. As the NRC representative, participated or currently participate in the following groups:

  Task Group on Faulted Conditions
  Working Group on Dynamic and Extreme Loading Conditions
  Working Group on Vessels (current)
  Working Group on Methods Development (current)

<u>The Lawrence Livermore National Laboratory, Livermore, CA, 1973-1975</u>

(On loan to the USAEC, Mechanical Engineering Branch (MEB))
- Review of new plants construction license applications.
- Assistance with development of the Standard Review Plan within the scope of

the MEB.

- Review of ASME Code Section III faulted condition acceptance criteria.

The Lawrence Livermore National Laboratory, Livermore, CA, 1963-1973.

Computer-based design and analysis of equipment used in testing of nuclear weapons. Ph. D. dissertation based on this work.

The Boeing Company, Seattle, WA, 1959 - 1963

- Design and stress analysis of pilotless aircraft and helicopter engines.

- Research in the fabrication of aircraft components using explosives. MS thesis based on this work.

Timothy L. O'Hara
Statement of Professional Qualifications

CURRENT POSITION:

Reactor Inspector U.S. Nuclear Regulatory Commission, Region 1 Office, Division of Reactor Safety, Plant Support Branch 2

EDUCATION:

Bachelor of Science in Physics, 1970, Saint Francis University, Loretto, PA
U.S. Naval Officer Candidate School, 1971, Newport, RI
U.S. Naval Nuclear Power Program, 1972, Bainbridge, MD and Windsor, CT
Master of Science in Engineering Management, 1980, University of Pittsburgh, Pittsburgh, PA
Master of Business Administration, 1988, Temple University, Philadelphia, PA

EXPERIENCE:

U.S. Nuclear Regulatory Commission, June 2002 - Present

Reactor Inspector, Region I, Plant Support Branch 2, King of Prussia, PA, October 2005 to Present
Conduct engineering inspections and assess licensee performance at commercial nuclear power plants throughout the northeast US. Inspections include Inservice Inspections, Plant Component Replacement Inspections (Steam Generators, Pressurizers, and Reactor Vessel Closure Heads), License Renewal Aging Management Inspections, Plant Modifications, Problem Identification and Resolution, Resident Inspector coverage, and Safety System Design Inspections. Training in ASME Code, Eddy Current Testing, Fracture Mechanics, welding techniques and Construction Procedures.

Reactor Inspector, Region I, Engineering Branch I, King of Prussia, PA, October 2004 - September 2005
Conduct engineering inspections and assess licensee performance at commercial nuclear power plants throughout the northeast US. Inspections include Plant Modifications, Problem Identification and Resolution, Fire Protection, In Service Inspection, Resident Inspector coverage, and Safety System Design Inspections. Training in Digital Circuits, Electrical System Coordination and Short Circuit Calculations.

Reactor Inspector, Region I, Electrical Branch, King of Prussia, PA, June 2002 - September 2004
Conduct engineering inspections and assess licensee performance at commercial nuclear power plants throughout the northeast US. Inspections include Plant Modifications, Problem Identification and Resolution, Fire Protection, In Service Inspection, Resident Inspector coverage, and Safety System Design Inspections. Training in BWR and PWR plant design and operation.

<u>Completed the following inspections during the past five years:</u>

Salem U1, Inservice Inspection, September 2004, Team Lead
Indian Point U2, Inservice Inspection, November 2004, Team Lead
Ginna, Inservice Inspection, March 2005, Team Lead
Salem U2, Inservice Inspection, April 2005, Team Lead
Beaver Valley U1, Stream Generator Replacement, January - June 2006, Team Lead
Beaver Valley, SSDI, August 2002
Calvert Cliffs, Modifications & 50.59 Inspection, December 2002
Vermont Yankee, Modifications & 50.59 Inspection, April 2003
Millstone U2 & U3, Modifications & 50.59 Inspection, June 2003
Nine Mile Point U1 & U2, Modifications & 50.59 Inspection, August 2003
Salem, EDG Turbocharger Special Inspection, September 2003
Fitzpatrick, SSDI, October 2003
Salem U1, Inservice Inspection, September 2003
Ginna, Triennial Fire Protection Inspection, November 2003
Oyster Creek, Triennial Fire Protection Inspection, January 2003
Indian Point U2, Triennial Fire Protection Inspection, January 2004
Vermont Yankee, Triennial Fire Protection Inspection, December 2004
Indian Point U3, Triennial Fire Protection Inspection, February 2005
Ginna, License Renewal Inspection, Scoping & Screening, August 2003
Millstone, License Renewal Aging Management Inspection, September 2004
Indian Point U2, Modifications & 50.59 Inspection, January 2005
Nine Mile Point U1 & U2, License Renewal Aging Management Inspection, February 2005
Oyster Creek, License Renewal Aging Management Inspection, March 2006
Oyster Creek PI&R Team Inspection, May 2004
Hope Creek, PI&R Team Inspection, December 2005
Pilgrim, License Renewal Aging Management Inspection, September 2006
Oyster Creek License Renewal Commitment Inspection, October 2006
Vermont Yankee, License Renewal Aging Management Inspection, February 2007
Calvert Cliffs, PI&R Sample (460v breakers), June 2004
Salem PI&R Sample (CC-17 valve), June 2004
Ginna PI&R Sample (Human Performance), July 2006
Salem PI&R Sample (Auxiliary Building Ventillation - Charcoal Filters), June 2005
Peach Bottom PI&R Sample (Corrective Actions), July 2006
Salem PI&R Sample (Corrective Actions), September 2006
Oyster Creek, Resident Backfill, July 2003
Salem Resident Inspector Backfill, June 2004
Hope Creek, Inservice Inspection, April 2006
Peach Bottom U2 & U3, PI&R Sample (Torus Corrosion), July 2006
Salem U2 Inservice Inspection, October 2006
Susquehanna U1, Inservice Inspection, March 2007
Salem U1, Inservice Inspection, April 2007

NRC TRAINING COURSES COMPLETED:

Power Plant Engineering
Effective Communication For NRC Inspectors
Media Training Workshop
Expectations For Inspectors
PRA Basics For Regulatory Applications
Westinghouse 100 Technology
Gathering Information For Inspectors
PRA Techniques and Regulatory Perspectives
Root Cause/Incident Investigation Workshop
Allegations Training - Classroom
Ethics Orientation
Conducting Inspections
GE BWR/4 Technology
GE BWR/4 Advanced Technology
GE BWR/4 Simulator
Field Techniques And Regulatory Processes
Ethics Laws & Rules For Employees
Fire Protection For Power Plants
Response Technical Manual Training
SNE 594, Westinghouse Station Nuclear Engineers Training
Improving Employment Applications
Industrial & Commercial Power Distribution Systems
Digital I & C Training
Low Voltage Protection Course
Eddy Current Testing
Eddy Current & UT Testing of RV Head Penetrations, Wesdyne
GE BWR/4 Simulator Refresher Training
American Concrete Institute Seminar, Inspecting Concrete Structures
Fracture Mechanics Training
Construction Inspector Training
ASME B&PV Code, Section VIII

Denton Vacuum, LLC, June 1997 to February 2002

Operations Manager, Vacuum Equipment Division, Moorestown, NJ
Responsible for material management, manufacturing, assemble and testing of complex vacuum deposition (thin film) equipment and systems for this privately held company.

Scott Specialty Gases, September 1993 to January 1997

General Manager, High Pressure Technology - Plumsteadville, PA

Total business responsibility for the turnaround of high pressure cylinder manufacturing and startup of a custom equipment product line. Establishment of specialty innovative, custom gas handling and distribution equipment. Sales, manufacturing, new product development, and customer service responsibility.

<u>Westinghouse Electric Corporation, December 1975 to August 1993</u>

<u>District Manager</u>, Philadelphia Operations Center - 1989-1993
Total business responsibility for the Engineering Services Division's Philadelphia Region. Performed commercial electrical services and electrical equipment installation. Responsible for sales, customer service, and engineering services for all industrial sectors.

<u>Manager</u>, Nuclear Services Operations, Moorestown, NJ - 1985-1989
Total P&L responsibility for custom manufacturing decontamination and mobile cleaning services. Directed a staff of 5 managers and 150 technicians. Integrated an acquired subsidiary company into an existing corporate division.

<u>Manager</u>, Mechanical Projects, Monroeville, PA - 1981-1985
Field Service responsibility for reactor internals repairs for commercial power plants. Split pin replacement, reactor upflow conversion, spent fuel rack replacement, foreign object search and retrieval, and miscellaneous mechanical repairs. Extensive work with utility representatives, Westinghouse Engineering and research groups. Managed 22 field engineers and 75 field service technicians

<u>Site Manager</u>, Steam Generator Replacement, Surry, VA - 1979-1981
Westinghouse site representative for SG replacement. Responsible for daily contact between utility and Westinghouse engineering, manufacturing and field service resources. Extensive involvement in mechanical problems, welding issues, and plant startup.

<u>Nuclear Fuel Licensing Engineer</u>, Monroeville, PA - 1977 -1979
Lead the Westinghouse effort on reload core licensing. Extensive involvement with utilities and internal Westinghouse Fuel and Engineering Divisions.

<u>Senior Field Service Engineer</u>, Churchill, PA - 1975-1977
Conducted SG eddy current inspections, SG sludge lancing, and SG weld repairs at Westinghouse commercial nuclear power plant. Extensive work with utility representatives and Westinghouse Engineering and Research groups.

<u>U. S. Navy, September 1970 to November 1975</u>

Completed Navy Basic Training and Electronic Technician Class A Training. Attended Officer Candidate School and Naval Nuclear Power Training. Served as a junior engineering office on board USS Seahorse and USS Sam Houston. Served as Electrical Officer, Damage Control Assistant, Ship's Diving Officer, Subsafe Officer, Engineering Plant Watch Officer. Completed extensive ship overhaul and refueling.

<u>PROFESSIONAL MEMBERSHIPS:</u>

American Society of Mechanical Engineers
American Nuclear Society

Beta Gamma Sigma
Society of Manufacturing Engineers

HONORS AND AWARDS:

Frank Castelli Academic Scholarship
Saint Francis University Physics Award
Officer Candidate School, Distinguished Naval Graduate
Temple University Executive MBA Selection, Westinghouse Electric Corporation
Beta Gamma Sigma Distinguished Scholar, Temple University
NRC Team Award, December 2002, Salem Special Inspection
NRC Performance Award, Spring 2003
NRC Performance Award, December 2004
NRC Performance Award, December 2005
NRC Performance Award, December 2006

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF HANSRAJ G. ASHAR

I, Hansraj G. Ashar, do declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

Hansraj G. Ashar

Hansraj G. Ashar

Executed at Rockville, MD
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF JAMES A. DAVIS, PH.D

I, James A. Davis, do hereby declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

James A. Davis

James A. Davis, Ph. D

Executed at Rockville, MD
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF MARK HARTZMAN, PH. D

I, Mark Hartzman, do hereby declare under penalty of perjury that my statements in the foregoing testimony and my statement of professional qualifications are true and correct to the best of my knowledge and belief.

Mark Hartzman PhD

Mark Hartzman, Ph. D

Executed at Rockville, MD
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF TIMOTHY O'HARA

I, Timothy O'Hara, do hereby declare under penalty of perjury that my statements in the foregoing testimony and my statement of professional qualifications are true and correct to the best of my knowledge and belief.

Timothy O'Hara
Timothy O'Hara

Executed at Medford, NJ
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF HANSRAJ G. ASHAR

I, Hansraj G. Ashar, do hereby declare under penalty of perjury that NRC Staff Exhibits B (Staff Initial Testimony), C (Staff Rebuttal Testimony) and C.1 (Staff Sur-Rebuttal Testimony), as corrected, are true and correct to the best of my knowledge and belief.

Hansraj G. Ashar

Executed at Rockville, MD
this 20th day of September, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF JAMES A. DAVIS, PH. D

I, James A. Davis, Ph. D, do hereby declare under penalty of perjury that NRC Staff Exhibits B (Staff Initial Testimony), C (Staff Rebuttal Testimony) and C.1 (Staff Sur-Rebuttal Testimony), as corrected, are true and correct to the best of my knowledge and belief.

James A Davis

James A. Davis, Ph. D

Executed at Rockville, MD
this 20th day of September, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF MARK HARTZMAN, PH. D

I, Mark Hartzman, Ph. D, do hereby declare under penalty of perjury that NRC Staff Exhibits B (Staff Initial Testimony), C (Staff Rebuttal Testimony) and C.1 (Staff Sur-Rebuttal Testimony), as corrected, are true and correct to the best of my knowledge and belief.

Mark Hartzman

Mark Hartzman, Ph. D

Executed at Rockville, MD
this 20th day of September, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

AFFIDAVIT OF TIMOTHY L. O'HARA

I, Timothy L. O'Hara, do hereby declare under penalty of perjury that NRC Staff Exhibits B (Staff Initial Testimony), C (Staff Rebuttal Testimony) and C.1 (Staff Sur-Rebuttal Testimony), as corrected, are true and correct to the best of my knowledge and belief.

Timothy L. O'Hara

Timothy L. O'Hara

Executed at Rockville, MD
this 20th day of September, 2007