**UNITED STATES OF AMERICA**
**NUCLEAR REGULATORY COMMISSION**

**ATOMIC SAFETY AND LICENSING BOARD**

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

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

**AFFIDAVIT OF PETER TAMBURRO**

Lacey Township )
)
State of New Jersey )

Peter Tamburro, being duly sworn, states as follows:

**INTRODUCTION**

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

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

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

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

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

**EDUCATION AND EXPERIENCE**

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

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

   - Implementing the above- and below-ground piping monitoring program to ensure piping is capable of performing its intended function. This includes maintaining operating history, risk-ranking plant piping systems, establishing inspection scope and criteria, analyzing inspection results, sponsoring modification and replacement based on inspection results, and overseeing the design and installation of new piping systems. My responsibilities also include the temporary and permanent repair of piping leaks at OCNGS.

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

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

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

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

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

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

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

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

## OPINIONS OF PETER TAMBURRO

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

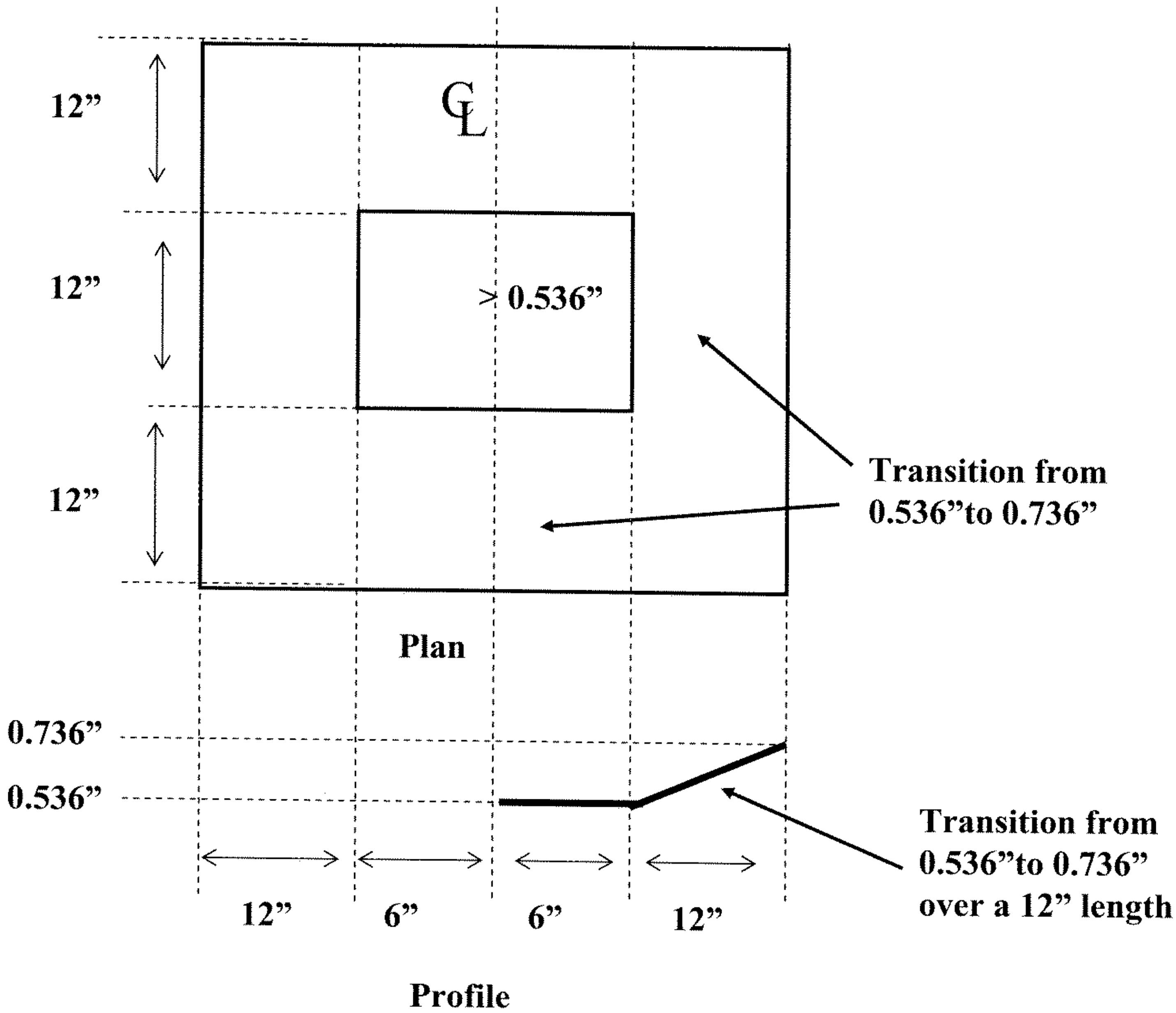
Peter Tamburro
Oyster Creek Nuclear Generating
Station
Route 9
Forked River, NJ 08731

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

Notary Public

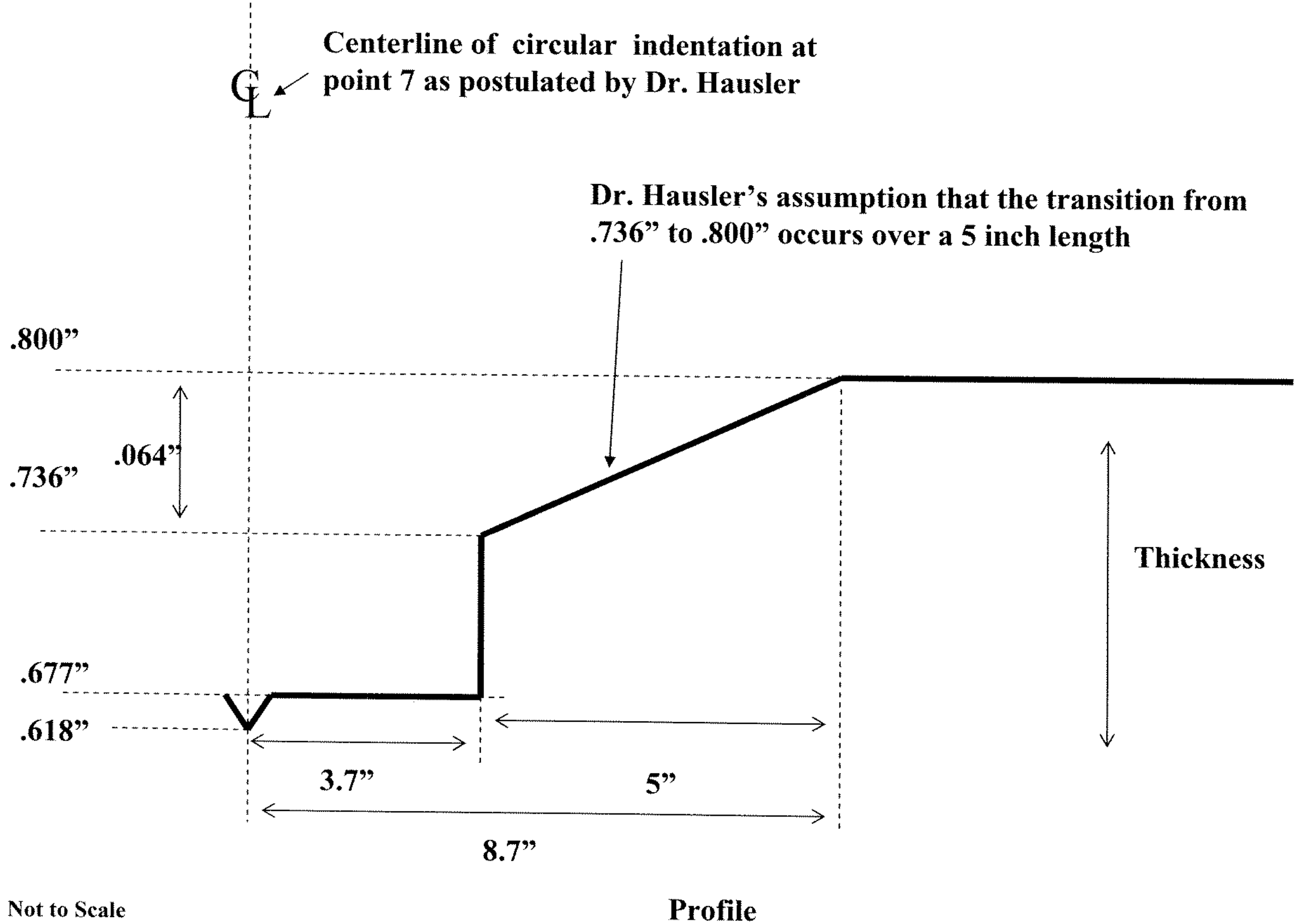
My Commission Expires: VALERIE LAUDEMAN
NOTARY PUBLIC OF NEW JERSEY
Commission Expires 9/28/2010

Figure 1 Schematic Demonstrating Local Area Average Acceptance Criterion




Not to Scale

Figure 2




Not to Scale

Figure 3

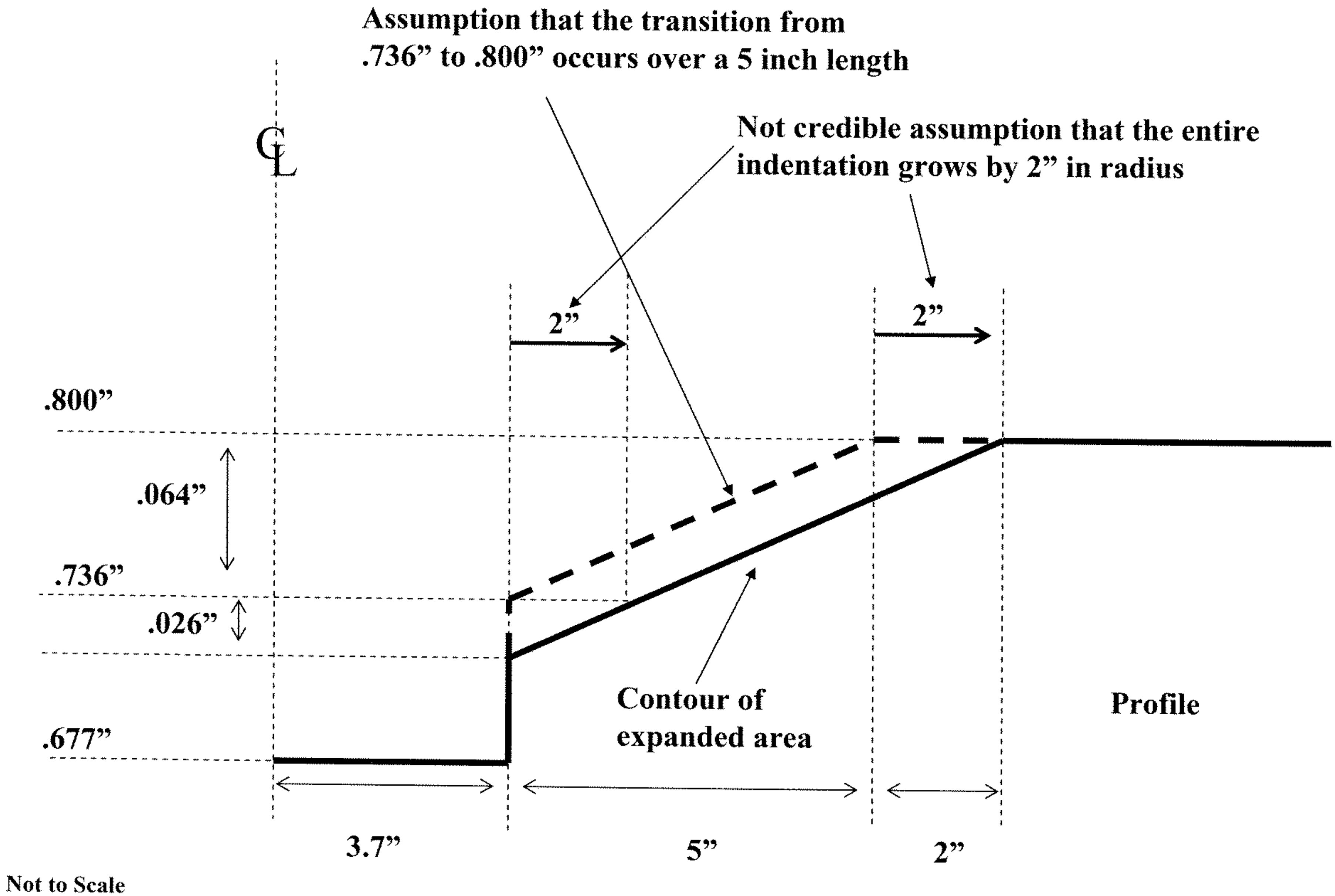
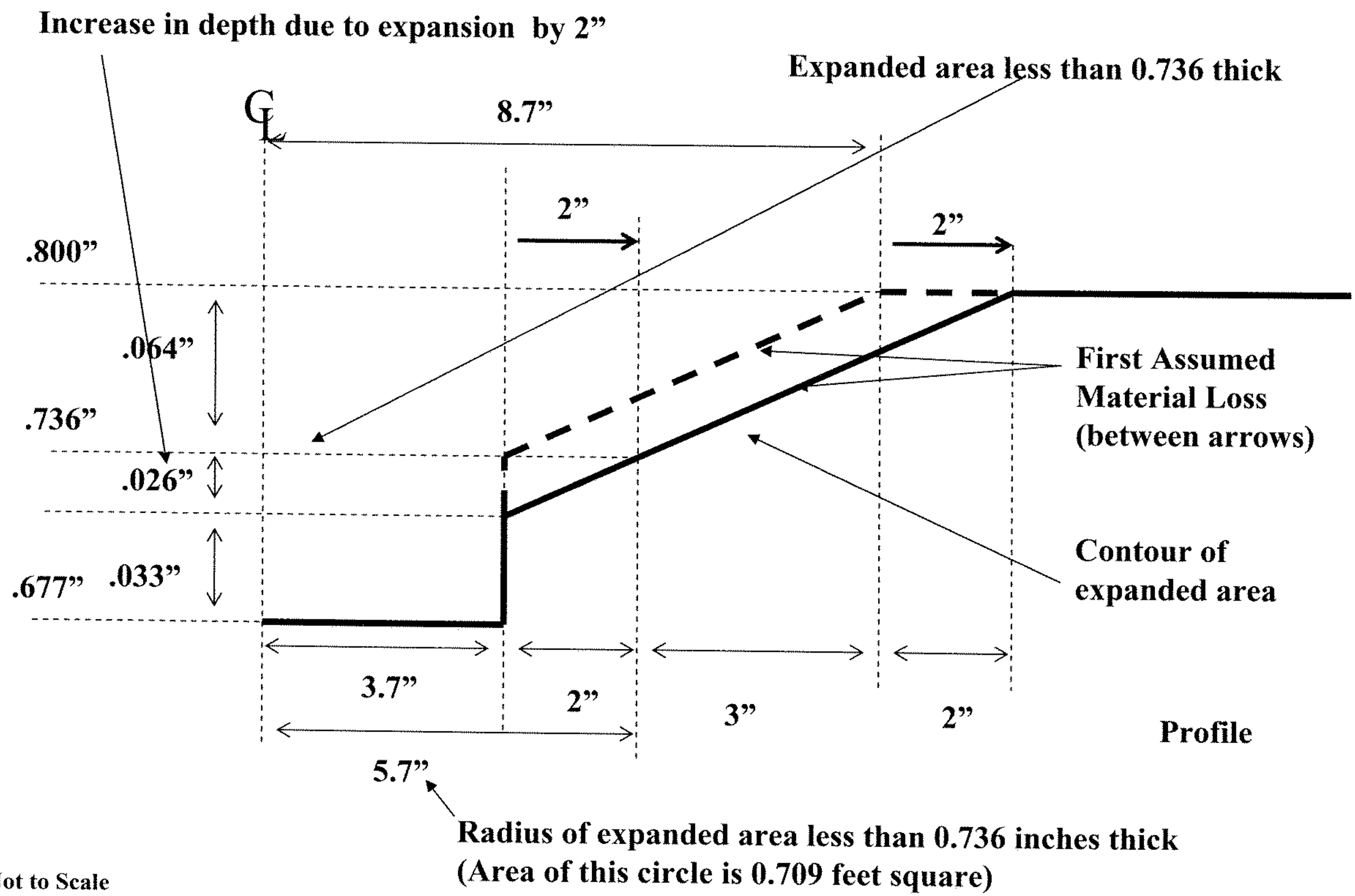
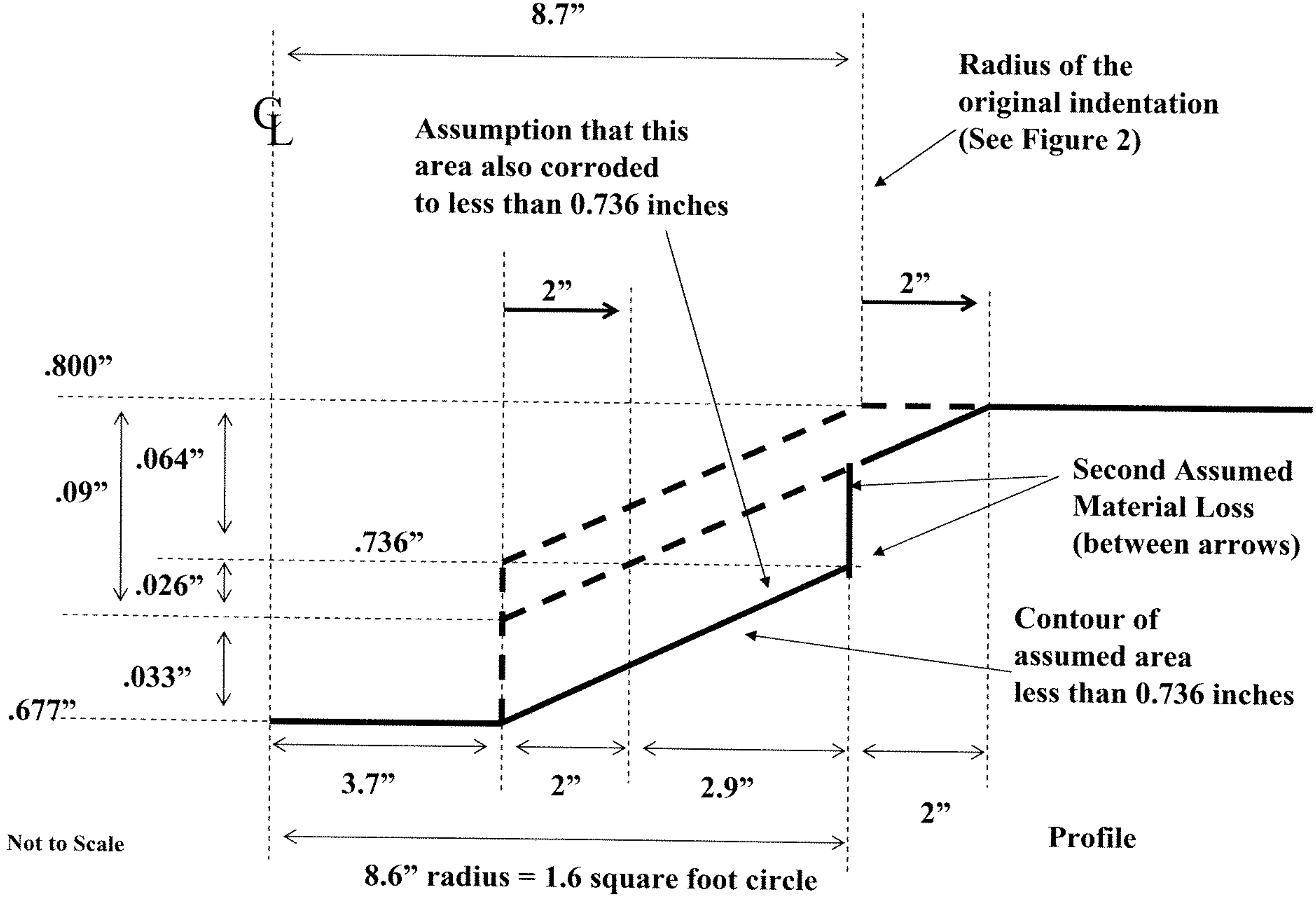

Assumption that the transition from
.736” to .800” occurs over a 5 inch length
Not credible assumption that the entire
indentation grows by 2” in radius
℄
2”
2”
.800”
.064”
.736”
.026”
.677”
Contour of
expanded area
Profile
3.7”
5”
2”
Not to Scale

Figure 4



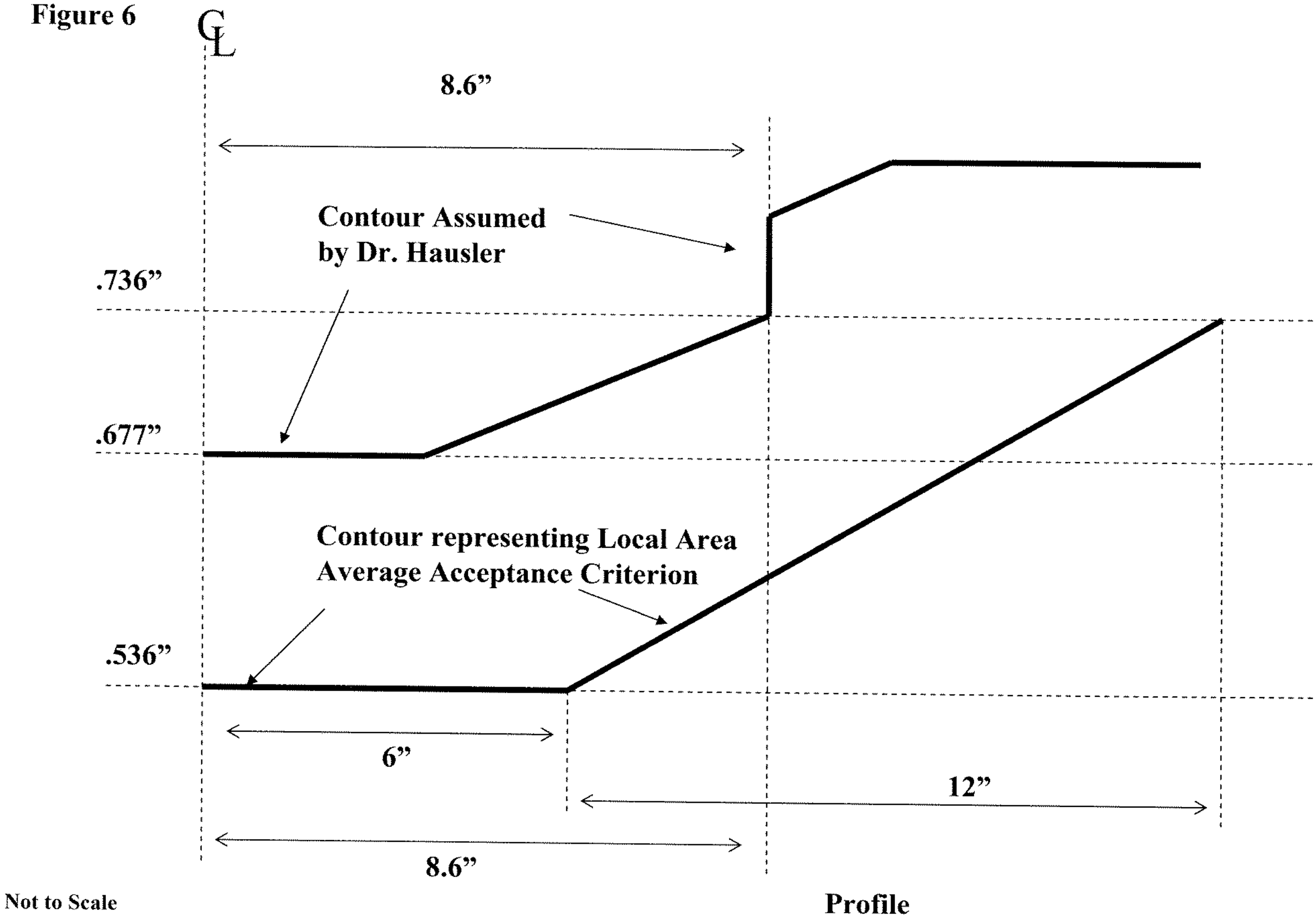

Not to Scale

Figure 5




Not to Scale

Figure 6


CL
8.6”
Contour Assumed
by Dr. Hausler
.736”
.677”
Contour representing Local Area
Average Acceptance Criterion
.536”
6”
12”
8.6”
Not to Scale
Profile

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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

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

## AFFIDAVIT OF BARRY GORDON

City of San Jose )
)
State of California )

Barry Gordon, being duly sworn, states as follows:

## INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station ("OCNGS") operating license, and admitted by the Licensing Board on October 10, 2006. That contention challenges the frequency of AmerGen's UT measurements of the drywell shell in the sand bed region. In part of their contention, Citizens speculate that significant corrosion of the exterior of the OCNGS drywell shell in the sand bed region could occur through tiny defects (called "pinholes" or holidays") in

the three-layer epoxy coating system: "corrosion may occur under the epoxy coating in the absence of visible deterioration due to non-visable holidays, or pinholes."

2. As I discuss below, it is my expert opinion that these allegations have no technical merit because: (a) significant corrosion is not possible with an epoxy-coated drywell shell; and (b) even if such a corrosion rate was possible, AmerGen's committed frequency of UT measurements is more than adequate to detect such corrosion (even under unrealistic assumptions), before the ASME Code-specified margins are exceeded. Accordingly, Citizens' argument is not only factually irrelevant but simply immaterial to the integrity of the drywell shell during the proposed period of extended operation.

## EDUCATION AND EXPERIENCE

3. For the past 38 years, I have been an engineer focusing on corrosion and material issues in light-water reactors, with special emphasis on stress corrosion cracking (SCC). I have addressed numerous materials and corrosion issues in the nuclear industry in a wide range of contexts including reactor internals, piping, fuel hardware, water chemistry transient and core flow issues, weld overlays and repairs, crack growth rate modeling, alloy selection, failure analysis, license renewal, NRC inspection relief, dry fuel storage, and decontamination.

4. I received my B.S. and M.S. degrees in Metallurgy and Material Science from Carnegie Mellon University in 1969 and 1971, respectively. Since then, I have completed additional courses from M.I.T., the University of Pittsburgh and the National Association of Corrosion Engineers (NACE) in Corrosion Science.

5. I am a Registered Professional Engineer in Corrosion Engineering in the State of California (#208), a Registered Corrosion Specialist with NACE International (#1986) and a Member of the International Cooperative Group on Environmentally Assisted Cracking (ICG-EAC).

6. I was certified as an Instructor for the International Atomic Energy Agency (IAEA) on February 2001 and am an Adjunct Professor at the Colorado School of Mines, in Golden, Colorado where I currently supervise one Ph.D candidate. I teach the following course: "Corrosion and Corrosion Control in LWRs" for Structural Integrity Associates, Inc. and have taught "Corrosion and Corrosion Control in BWRs" for GE Nuclear Energy (GENE). I have held instructor credentials for Engineering in California Community Colleges since 1986.

7. From 1969 to 1975, I was employed as a materials engineer by Westinghouse Electric at the Bettis Atomic Power Laboratory, located in West Mifflin, Pennsylvania.

8. From 1975 to 1998, I was employed by GE Nuclear Energy, located in San José, California. While at GE Nuclear Energy, I was a technical expert in corrosion engineering, a project manager in corrosion technology, and a program manager in stress corrosion cracking.

9. Since 1998, I have been employed by Structural Integrity Associates, Inc., also located in San José, California, as an Associate.

10. I am familiar with the historical corrosion of the OCNGS drywell shell because I started working on that issue in 1986 as the OCNGS drywell project manager when I was employed by GENE.

11. More recently, I prepared an evaluation report on the corrosion of steel embedded in concrete on the exterior of the drywell (June 5, 2006) and on effects of water on corrosion propensities of concrete embedded steel identified in the interior of the drywell (November 3, 2006). I also testified before the Advisory Committee on Reactor Safeguards (ACRS) on both subjects on January 18, 2007.

## OPINIONS OF BARRY GORDON

12. In his June 23, 2006, memorandum, Dr. Rudolf Hausler suggests that a future corrosion rate of 0.017" per year is possible for the external surface of the drywell shell in the sand bed region at OCNGS. He correctly asserts that this corrosion rate was observed by the former owner of the OCNGS in certain areas of the sand bed region prior to 1992 (after which the external surface of the drywell shell was protected from further corrosion by a sand bed removal and the installation of a multi-layer epoxy coating system). As I demonstrate below, however, this corrosion rate is not possible with an epoxy-coated drywell shell. Moreover, even if this or a significantly higher corrosion rate was possible, AmerGen's committed frequency of UT measurements is more than adequate to detect such corrosion before the ASME Code-specified margins are exceeded.

13. Part of the reason why the corrosion rate was historically as high as 0.017" per year in certain bays of the drywell shell sand bed region is because there was a medium (*i.e.*, sand) to physically hold water against the drywell shell. Specifically, the sand bed region got its name from the sand that was placed there as part of the original design. Once water entered this area, the sand physically held the water against the shell, ensuring a constant source of water to facilitate corrosion of the metal drywell shell.

This sand, however, was removed as part of the corrective actions completed in 1992 to prevent additional corrosion in the sand bed region. So there is no water-retaining media to facilitate future corrosion.

14. Of course, such a corrosion rate of 0.017" per year is unrealistic because the drywell shell is protected from further corrosion by a multi-layer epoxy coating system. AmerGen has demonstrated that corrosion of the external surface of the drywell shell has been arrested, and no additional corrosion is possible unless there is a defect in the coating and water is able to come into contact with the metal drywell shell through that defect. Accordingly, it is my opinion that no corrosion is possible beneath an intact epoxy coating system, such as the one applied on the exterior of the OCNGS. This is because corrosion of a kind significant enough to affect the integrity of the drywell shell requires the presence of water and oxygen, and there is no water or oxygen adjacent to the metal surface of the drywell shell to initiate, let alone sustain, the corrosion process.

15. Dr. Hausler, however, has speculated that there could be tiny defects in the coating, referred to as "pinholes" or "holidays." He essentially argues that water could get to the metal surface of the underlying drywell shell through these hypothetical, tiny defects. It is my opinion that even if there were such defects, they would not allow sufficient oxygenated water to reach the underlying drywell shell for corrosion to exceed ASME Code-specified margins before AmerGen would detect it through its committed inspections (*i.e.*, every four years). Accordingly, this argument is simply not relevant to the long-term integrity of the drywell shell. The support for my opinion is presented in the next paragraphs.

16. We know that the maximum measured historical corrosion rate was not 0.017" per year, but was more than twice that at 0.039" per year (in location Bay 13A).[1] So we know that with the presence of water, wetted sand holding that water adjacent to the uncoated shell, blocked drains preventing that water from being drained out of the sand bed region, and the temperature specific to the exterior of the drywell shell in the sand bed region during operations, that loss of metal at a rate of 0.039" per year is possible.

17. To show how absurd Citizens' argument is—that corrosion significant enough to affect the integrity of the drywell shell could occur through a pinhole or holiday in the epoxy coating—I have made the following assumptions in my calculation, some of which are unrealistic and overly conservative:

- AmerGen performs the visual and UT inspections of the sand bed region in 2008 that it has already committed to;
- AmerGen does not perform inspections of the sand bed region in 2010, also consistent with its commitments (inspections are to be performed every four years after 2008);
- The drywell shell is exposed to water during the 2010 scheduled refueling outage. The source of the water is minor leakage from the refueling cavity, which only contains water during refueling outages, so the shell could not get wet prior to a refueling outage;

---

[1] Citizens' Petition states that a "reasonable estimate of the worst case potential corrosion rate that may occur could be obtained by analyzing the pre-1992 data [*i.e.*, before the sand was removed from the sand bed region].... Observed corrosion rates to 1990 ranged up to 0.035 inches per year and were very uncertain." While it is my understanding that AmerGen is not required to perform "worst case" analyses, the corrosion rates that occurred prior to removal of the sand from the sand bed region simply are not representative of the potential corrosion rates after removal of the sand. As I demonstrate in this Affidavit, even this order of magnitude corrosion does not challenge the integrity of the drywell shell.

- This water is not detected. This is conservative because AmerGen's commitments include monitoring the refueling cavity liner drain during outages, as well as the five sand bed region drains both quarterly and daily during outages;
- The water enters Dr. Hausler's hypothetical pinhole or holiday on the first day of the 2010 refueling outage. This is conservative because the refueling cavity is not even flooded on the first day of the outage;
- The pinhole or holiday is located within the region that has the least remaining margin (*i.e.*, Bay 13). This is conservative because it is statistically unlikely that the thinnest area of the shell also has the defect in the coating;
- Corrosion at the maximum historical rate of 0.039" per year instantly begins as water enters the pinhole or holiday;
- Oxygen's contact with the metal surface is not mitigated by the presence of corrosion products. This is conservative because corrosion tends to be self-limiting when corrosion films are produced on the metal surface and corrosion byproducts (*i.e.*, rust) create a diffusion barrier that reduces the amount of subsequent corrosion of the shell;
- The refueling outage takes four weeks to complete, and the cavity is filled with water during the entire refueling outage;
- The water stays in the pinhole during the entire four-week outage; and
- The water in the pinhole or holiday does not evaporate until a year after the refueling outage is over, and the 0.039" per year corrosion rate continues for the entire year after the outage, for a total of 56 weeks of new corrosion. This

is extremely conservative because the temperature in the sand bed region of the drywell is about 130°F during operations, which would result in the evaporation of the small amount of water in the pinhole or holiday in significantly less time. For example, at 130°F, a drying out rate of about 0.3 pounds per hour, per square foot, is reasonable for a sand bed region with no sand.[2] This would result in evaporation of water in the pinhole or holiday in less than one day. There are many factors involved in the calculation of water evaporation rates. One of the most important factors is the air or wind velocity across the water surface. I derived the 0.3 pounds per hour, per square foot value from the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) equation for evaporation from ponds or pools: $W = [A + (B)(V)](Pw - Pa)/Hv$ (where: W = water evaporation rate, (lb/hr) per sq.ft. of the water's surface area; A = a constant = 95; B = a constant = 37.4; V = air velocity over the pond surface, miles/hr (which I assumed was zero); Pw = vapor pressure of water at the water temperature, inches of Hg; Pa = vapor pressure of water at the air dewpoint temperature, inches of Hg; and Hv = heat of vaporization of water at the pond water temperature, Btu/lb).

18. In summary, therefore, I have assumed that the drywell shell behind the pinhole or holiday will experience the maximum historical corrosion rate of 0.039" per year, for 56 weeks. This results in a total loss of metal of about 0.042", which is well within: (a) the margin of 0.064" remaining in Bay 19 (thickness of 0.800"), when measured

2 This is around 2.4 ounces per hour, per square foot.

against the general average thickness criterion of 0.736"; and (b) the margin of 0.128" remaining in Bay 13A, when measured against the very local area average thickness of 0.490".

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

Barry Gordon
Structural Integrity Associates, Inc.
3315 Almaden Expressway, Suite 24
San Jose, CA 95118-1557

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

PAULA RODGERS
Commission # 1540492
Notary Public - California
Santa Clara County
My Comm. Expires Jan 1, 2009

Notary Public

My Commission Expires: Jan. 1, 2009

**UNITED STATES OF AMERICA**
**NUCLEAR REGULATORY COMMISSION**

**ATOMIC SAFETY AND LICENSING BOARD**

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

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

**AFFIDAVIT OF JON R. CAVALLO**

City of Portsmouth )
)
State of New Hampshire )

Jon R. Cavallo, being duly sworn, states as follows:

**INTRODUCTION**

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station operating license, and admitted by the Licensing Board on October 10, 2006. Citizens' contention as admitted by the Licensing Board is: "AmerGen's scheduled [ultrasonic testing ("UT")] monitoring frequency in the sand bed region is insufficient to maintain an adequate safety margin." The purpose of my Affidavit is provide

information regarding the multi-layer epoxy coating used on the exterior of the Oyster Creek drywell shell in the sand bed region, in order to address Citizens' contention.

2. It is my expert opinion that Citizens' allegations have no technical merit because they are based on a misunderstanding of the nature of the epoxy coating, and of the inspections performed on that coating.

## EDUCATION AND EXPERIENCE

3. I am Vice President of Corrosion Control Consultants & Labs, Inc., and in this capacity I provide corrosion mitigation professional engineering services in surface preparation, protective coatings and linings. I have held this position since 1998. I am also Vice-Chairman of Sponge-Jet, Inc., located in Portsmouth, New Hampshire, a company I helped found which designs and manufactures state-of-the-art surface preparation and decontamination systems.

4. I served as Editor of Electric Power Research Institute (EPRI) Report 1003120 (formerly TR-109937), Revision 1, "Guideline on Nuclear Safety-Related Coatings." I also teach and assisted developing the EPRI protective coatings course. I am also the Principal Investigator of EPRI Report 1009750, "Analysis of Pressurized Water Reactor Unqualified Original Equipment Manufacturer Coatings," (Final Report, March 2005).

5. I have worked on coatings and corrosion control at nuclear power facilities for over 35 years. Specifically:

   - From 1971 to 1983, I was employed by Stone & Webster Engineering Corporation in both the Boston and Denver offices. During this period, I specified coating systems for a number of new nuclear generating facilities as well as performed coating system failure analysis and attendant repair plans for operating nuclear generating facilities.

- After leaving Stone & Webster, I worked with Metalweld, Inc. until 1986 as its Northeastern United States regional manager. I was the project manager for all of the protective coatings work for the Seabrook Nuclear Plant.
- From 1986 to 1991, I was a Senior Associate in the consulting engineering firm of S.G. Pinney & Associates, Inc. During my employment with the firm, I performed protective coating and lining work at a number of nuclear generating facilities. I was the Professional Engineer assigned to all underwater protective lining work conducted by the firm.
- From 1991 to 1998, I was an independent professional engineer performing corrosion engineering consulting services.
- From 1998 to the present, I have worked in my current capacity as Vice President of Corrosion Control Consultants & Labs, Inc.

6. I received my B.S. degree in Engineering Technology, *cum laude*, from Northeastern University in Boston, Massachusetts, in 1979. I have completed a variety of engineering and engineering management study programs, including U.S. Naval Nuclear Power Training, the University of Colorado (engineering project management), and NACE International (corrosion prevention in oil and gas production). I am a Registered Professional Engineer in six states, President of the Maine Society of Professional Engineers, and an SSPC-Society for Protective Coatings certified Protective Coating Specialist.

7. I am active on a number of national technical societies including SSPC, NACE and ASTM. I have served as Chairman of the Northern New England Chapter of SSPC from 1991 to 1998, Chairman of the New England Chapter of SSPC from 2000 to the present, and was a member of the SSPC National Strategic Planning Committee. I was elected Chairman of ASTM Committee D-33 (Protective Coating and Lining Work for Power Generation Facilities) for the period 2004 through 2008. I have also served as Chairman of the Industry Coating Phenomena Identification and Ranking Table (PIRT) Panel reviewing the work of Savannah River Technical Center on the USNRC Containment Coatings Research Project (Generic Safety Issue -191).

8. Based on my review of the relevant historical documentation, I am familiar with the historical corrosion of the OCNGS drywell shell, and the actions taken to control corrosion.

9. I have also reviewed the relevant portions of the OCNGS License Renewal Application ("LRA") submitted to the NRC on July 22, 2005, and the LRA supplement submitted to the NRC on December 3, 2006.

10. Finally, I testified before the Advisory Committee on Reactor Safeguards (ACRS) license renewal subcommittee on January 18, 2007, on the topic of the Oyster Creek drywell shell epoxy coating.

## OPINIONS OF JON R. CAVALLO

11. Citizens have asserted that under corrosive conditions, long-term corrosion rates of more than 0.017 inches per year have been observed in the sand bed region of the Oyster Creek drywell shell. This assertion is based on public documents estimating

long term corrosion rates in the period before the application of the epoxy coating to the drywell shell.

12. The historic corrosion occurred because, among other things, the drywell shell in the sand bed region was not coated. The exterior shell is now protected by a three-layer (pre-prime and two coats) epoxy coating system. This coating system was designed for submerged applications, such as tank bottoms, so even if water was always present in the sand bed region, it would have no effect on the coated steel shell. This coating was applied in the following manner:

   - Prior to application, Oyster Creek personnel created a mock-up of the sand bed region. Using the same mechanics, and with the same restricted access, personnel prepared the surface and applied to the coating to this mock-up. Through this process, Oyster Creek personnel qualified the surface preparation, coating application, and inspection techniques for use on the drywell shell.
   - Following surface preparation of the drywell shell by SSPC-SP 2 hand tool cleaning that removed loose rust, loose mill scale, and loose coating, the pre-prime was applied.
   - The pre-prime is a red epoxy coating that soaks and penetrates into the semi-irregular shape of the substrate metal.
   - Then two coats of the whitish-gray Devran-184 epoxy were applied with a brush and roller.
   - Finally, a Devmat 124S caulking was used to seal the interface between the concrete floor and the steel substrate.

13. Citizens speculate that there might be tiny holes in the epoxy coating - "pinholes" or "holidays" - which would allow water to get behind the coating, causing corrosion of the underlying drywell shell. Dr. Hausler has suggested that such holidays would be so small that they could not be detected with the naked eye during a visual inspection. By definition, a pinhole or holiday is a very localized defect in the coating that occurs during the application and cure of the coating. Thus, these localized defects could only be caused by a defect in the original application of the coating, and cannot be caused by degradation over time.

14. As would be expected, the possibility of a pinhole or holiday decreases with each layer of coating that is applied. As I noted, the epoxy protecting the exterior of the drywell shell is comprised of a three layer (a pre-prime and two coats) coating system.

15. AmerGen's protective coating monitoring program includes VT-1 visual inspections of the epoxy coating by qualified inspectors in accordance with NUREG-1801 and ASME Section 11, Subsection IWE. Under the VT-1 method, trained and qualified individuals inspect surfaces such as the drywell shell for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation. The VT-1 technique is a proven method, used throughout the industry, on both boiling water reactors and pressurized water reactors. If a corrosion rate of 0.017" per year had occurred between 1992 and 2006, then it would have been readily detected by the VT-1 inspections performed during the 2006 refueling outage. Future corrosion would also be detectable in a VT-1 inspection.

16. This is because as carbon steel corrodes, the reaction between oxygen and the iron in the steel results in an iron oxide byproduct. The epoxy coating would not allow the corrosion byproducts to migrate from the site of the corrosion, so these byproducts would either accumulate as a blister at the corrosion site, or they would seep out through the postulated pinhole or holiday in the coating onto the otherwise whitish-gray epoxy coating. In either case, the corrosion byproducts would be clearly visible in a VT-1 inspection.

17. It is well accepted corrosion science that corrosion byproduct occupies a volume seven to ten times greater than the underlying corroding steel. For example, if 0.017" of steel corrodes in a year under an epoxy coating, then between 0.119" and 0.170" of byproduct would result. Four years of corrosion at that rate—the interval that AmerGen will perform UT in the sand bed region—would result in between 0.476" and 0.680" of corrosion byproduct. Thus, the amount of corrosion that Citizens postulate would, in a four-year period, generate a blister under the epoxy coating of around ½-inch thickness. Such a blister would be clearly visible to an inspector qualified to perform VT-1 inspections.

18. Therefore, a corrosion rate of 0.017" occurring in a pinhole since 1996 (the last time that strippable coating was not used during a refueling outage), would result in a 1.2" to 1.7" blister in the epoxy coating. Even if significant corrosion could occur behind a pinhole or holiday in the epoxy coating, corrosion at a rate of 0.017" per year would be visible through the VT-1 inspections performed every four years.

19. In fact, Citizens' argument that such local defects have existed since 1992 is inconsistent with their argument that the air in the sand bed region is moist and

capable of corrosion. If a moist environment and pinholes coexisted for the past 14 years (1992 to 2006), then the resulting corrosion would be easily visible during the VT-1 inspections.

20. The VT-1 inspections would also detect the corrosion products caused by much lower corrosion rates. Even a corrosion rate of 0.002 inches per year would yield corrosion products that would cause a blister of between 0.056" and 0.080" in the four year interval between inspections. Such a blister would also be visible in a VT-1 inspection performed by a qualified inspector.

21. The VT-1 Inspection is designed to be used on any type of steel or concrete surface, including textured concrete and irregular surfaces such as welds. Therefore, the techniques used in this inspection would be adequate to use on surfaces such as the Oyster Creek drywell shell.

22. Also, the eight to ten year rated lifetime discussed in Citizens' Exhibit 6 to their original contention (this exhibit is a letter submitted to the NRC in 1995 by the previous owner of Oyster Creek Nuclear Generating Station) is simply incorrect. The multilayer epoxy coating is designed to withstand a submerged environment and to last for the life of the plant, including the extended period of operation, provided that proper VT-1 inspections are conducted and necessary corrective maintenance is performed to address any discrepancies found. This type of coating is commonly used throughout the nuclear industry, and there is no such limitation in life span.

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

Jon R. Cavallo
Jon R. Cavallo
235 Heritage Avenue, Suite 2
Portsmouth, NH 03801

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

Joyce L. Goodwin
Notary Public

My Commission Expires: JOYCE L. GOODWIN, Notary Public
My Commission Expires January 15, 2008