RAS 12059

DOCKETED
USNRC

July 25, 2006 (3:28pm)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
OFFICE OF THE SECRETARY

ATOMIC SAFETY AND LICENSING BOARD

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

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| In the Matter of | ) | |
| | ) | July 25, 2006 |
| AMERGEN ENERGY COMPANY, LLC | ) | |
| | ) | Docket No. 50-0219-LR |
| (License Renewal for the Oyster Creek | ) | |
| Nuclear Generating Station) | ) | |
| | ) | |

## SUPPLEMENT TO PETITION TO ADD A NEW CONTENTION

## PRELIMINARY STATEMENT

Nuclear Information and Resource Service, Jersey Shore Nuclear Watch, Inc., Grandmothers, Mothers and More for Energy Safety, New Jersey Public Interest Research Group, New Jersey Sierra Club, and New Jersey Environmental Federation (collectively "Citizens" or "Petitioners") submit this Supplement to their Petition of June 23, 2006 at the invitation of the Atomic Safety and Licensing Board ("ASLB" or "Board") in its decision of July 5, 2006 in this proceeding. In accordance with that decision, Citizens now seek to supplement their contention so that it fully addresses the new information provided by AmerGen Energy Co. LLC ("AmerGen") in their commitment letter of June 20, 2006. Citizens therefore set forth modifications to their contention, explain how those modifications satisfy the legal requirements, and provide additional bases for an allegation in the contention about which AmerGen provided

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material new information. The modified contention challenges the adequacy of the latest version of AmerGen's aging management program for the severely corroded steel drywell shell.

In a nutshell, AmerGen is putting the cart before the horse. It is trying to design an adequate monitoring regime before it has established what margins of safety currently exist, what areas it needs to measure, how often it needs to measure them, and what accuracy is required to maintain the safety margins. Thus, the current monitoring scheme is based on an *ad hoc* rather than a systematic approach to the problem. All of these issues could be resolved by taking comprehensive measurements, using sophisticated modeling to determine the existing safety margins, deriving adequate acceptance criteria, and then designing the ongoing monitoring to ensure that those criteria are maintained. Moreover, even if AmerGen's current criteria were deemed adequate, it has failed to systematically ensure that the current scheme matches with the current acceptance criteria. In particular, the current scheme monitors an insufficient area of the drywell shell, fails to take full account of how quickly corrosion could cause the acceptance criteria to be violated, and fails to deal with the inherent uncertainties in the results of the monitoring.

Thus, the aging management regime for the sandbed region of the drywell shell is currently an inadequate mixture of UT measurements in very limited areas, monitoring for corrosive conditions in a non-systematic manner, and responses timed for convenience rather than safety. AmerGen cannot produce an adequate aging management program through *ad hoc* revisions to an outdated scheme that is based on a monitoring regime designed in the 1980s when the sand was still in place and the extent of corrosion was unknown. Instead, AmerGen must now thoroughly redesign the monitoring regime using rigorous acceptance criteria derived from current comprehensive measurements and modeling to determine the existing safety margins. It

should then use those margins to set acceptance criteria for the ongoing monitoring. These criteria would then be used determine how to monitor for corrosive conditions, where and how often to take UT measurements, and how quickly to respond to adverse results. Unless AmerGen undertakes such a redesign, it will be doomed to continue to modify the existing regime without producing an adequate aging management program.

## BACKGROUND

This proceeding concerns the aging of the steel containment vessel of the Oyster Creek Nuclear Generating Station that is termed the drywell shell. The shell provides containment in the event of an accident. The lower portion of the shell is spherical with an inside diameter of 70 feet. Ex. NC 8 at 47. It is free standing from an elevation of 8 feet 11.75 inches from the bottom. Id. at 40. For around 3 feet 4 inches above that level to elevation 12 feet 3 inches, the exterior of the steel shell used to have sand supporting it, but the sand was removed in 1992. Id. at 47-48. This exterior portion of the drywell shell is termed the sand bed region. An interior floor is at elevation 10 feet 3 inches, id. at 47, and concrete curbs around the edge of the floor go up to the 11 foot elevation. Ex. NC 10. In the sand bed region, the design thickness of the vessel was 1.154 inches. Ex. NC 8 at 40.

Citizens initially contended that the testing of the extent of corrosion at all levels of the drywell shell proposed in AmerGen's license renewal application was inadequate to assure the continued integrity of this safety-critical structure for the period of the license extension. Petition at 3. To support this contention, Citizens showed that the drywell shell is a safety-critical structure that acts both as a pressure boundary and as a structural support. Id. at 4. Citizens then showed that water leakage onto the exterior of the drywell shell has caused significant corrosion, particularly in the sand bed region, where the NRC regarded the corrosion

as a "threat to drywell integrity." Id. at 4-6. Citizens showed further that in 1986 NRC regarded ultra-sonic testing of the sand bed region and other accessible areas of the drywell liner as "essential . . . for the life of the plant." Id. at 7.

Citizens asserted that the potential for ongoing corrosion means that ongoing comprehensive testing is required to ensure the remaining razor-thin safety margins are met throughout any extended life of the plant. Indeed, Petitioners' Exhibit 5 at pages 8 and 12 showed that while AmerGen reported the "current thinnest" area to be 0.8 inches in December 1992, the actual thinnest areas are less than 0.736 inches, which was the original acceptance criterion, derived from modeling segments of a spherical shell with uniform thickness. Multiple measurements in bays 1 and 13 and isolated measurements in bays 11, 15, and 17 were below 0.736 inches. Id. at 12.

The ASLB admitted a narrowed version of the initial contention pertaining to the need for ultrasonic ("UT") testing of the drywell in the sand bed region. In the Matter of AmerGen Energy Company (License Renewal for Oyster Creek Nuclear Generating Station), LBP-06-07 (slip op. at 39-40) LBP-06-07, 63 NRC 188 (2006). The ASLB recently found that a new commitment made by AmerGen on April 4, 2006 to use UT testing to verify the thickness of drywell shell in the sand bed region every ten years had rendered the initial contention moot, but also invited Citizens to submit a new contention concerning the adequacy of AmerGen's newly proposed UT testing regime for the sand bed region. LBP-06-16 (June 6, 2006) at 9. On June 20, 2006, AmerGen submitted a new letter enclosing a discussion of the UT testing program for the drywell and new commitments to carry out certain additional testing. Letter from Michael P. Gallagher, AmerGen, to NRC (June 20, 2006).

On June 23, 2006, Citizens submitted a new contention addressing the issues raised by AmerGen's newly proposed testing regime for the sand bed region as presented in the new commitment of April 4, 2006. Citizens also submitted a motion asking leave to supplement the new contention so as to take into account AmerGen's June 20, 2006 commitment letter. The Board granted Citizens' motion, with instructions that the supplement should be limited to discussion of issues raised by the June 20, 2006 commitment, and that the supplement should be a self-contained document. Order (Granting NIRS's Motion for Leave to Submit a Supplement to its Petition), ASLBP No. 06-844-01 at 3 (July 5, 2006) (unpublished).

In their commitment letter of June 20, 2006, AmerGen laid out a monitoring plan that takes into account the importance of monitoring for conditions conducive to corrosion in the drywell. Letter from Michael P. Gallagher, AmerGen, to NRC, Enclosure 2 ("New Commitments") at 3-4. (June 20, 2006). AmerGen's proposed monitoring procedures call for daily monitoring of the drains from the sand bed region during refueling outages and quarterly monitoring of the drains during the plant operating cycle. Id. The proposed procedures include steps to be taken to determine the source of any leakage. Id. However, the proposal does not suggest continuous monitoring or monitoring of moisture in the drywell proper.

AmerGen's most recent commitment also describes proposed procedures for monitoring the epoxy coating. Id. The proposed procedure calls for visual inspection of the epoxy coating if leakage is found during drain monitoring. Id. If the leakage is found during refueling, the coating is to be visually inspected during that outage. Id. If, however, the leakage is detected during the operating cycle, the epoxy is not to be inspected at all until the next refueling cycle. Id. The proposal does not lay out an objective standard for determining whether the coating is degraded, and it does not call for objective testing of the coating.

AmerGen also submitted a considerable amount of new information on engineering and other issues in response to a Request for Additional Information from NRC Staff and in support of the new commitments. Letter from Michael P. Gallagher, AmerGen, to NRC, Enclosure 1 ("New Information") at 3-4. (June 20, 2006). The New Information discussed, among other things, the use of engineering code sections to generate the acceptance criteria, the problems with the UT results taken in 1996, the UT testing frequency for the sand bed region, and details of proposed corrective measures to be taken if water is detected in the sand bed drains. Id. AmerGen explained that their monitoring regime continues to be based on, among other things, an assumption that corrosion is best modeled as a continuing linear decrease in mean thickness of the drywell shell over time. Id. at 3. In interpreting this model, measurements showing a statistically significant slope on the plot of mean thickness versus time trigger a calculation of the uncertainty in the measurements in order to determine the time at which there is a 5% chance that certain acceptance criteria could be exceeded. Id. However, as before, if the measurements do not show a statistically significant slope, AmerGen will not estimate a confidence interval, but will assume instead that no corrosion is occurring or will occur. Id.

AmerGen also expressed its belief that there are no practical methods available to replace the current technique of using ASME Code Section III, Subsection NE-3213.10 to extrapolate from computer modeling done in 1991 by General Electric to real conditions. Id. AmerGen further claimed a minimum measured drywell thickness of 0.800 inches in the sand bed region, id. at 5, which stands in contrast to their reported measurements taken in several bays showing areas with average thickness at 0.703 inches, Ex. NC 2 at 13, and a thinnest individual measurement of 0.603 inches, Ex. NC 1 at 7. While recognizing that this Code Section is not directly applicable to randomly thin areas caused by corrosion, AmerGen asserted that the Code

Section is applicable to the severely corroded areas based on, among other things, their belief that no further significant corrosion will occur in the sand bed. New Information at 5-6.

## ARGUMENT

In response to AmerGen's new commitments, Citizens have modified the previously filed contention. The modifications to the contention are discussed in Section I, which demonstrates that the modifications, like the new contention, meet the requirements for basis, scope, and materiality. In addition, Section II of this Section sets forth additional bases for an unmodified allegation about engineering issues, because AmerGen provided substantial material new information on this issue. Finally, Section III shows that this submission is timely. Otherwise, Citizens rely on the Petition dated June 23, 2006 to plead for the admission of the unchanged allegations in the contention.

### I. The Modified Contention

#### A. Specific Statement of the Amended Contention

In order to bring a contention before the Commissioners, Citizens must "[p]rovide a specific statement of the issue of law or fact to be raised or controverted." 10 C.F.R. § 2.309(f)(1)(i). The amended contention is:

> AmerGen must provide an aging management plan for the sand bed region of the drywell shell that ensures that safety margins are maintained throughout the term of any extended license, but the proposed plan fails to do so because the acceptance criteria are inadequate, the scheduled UT monitoring frequency is too low in the absence of adequate monitoring for moisture and coating integrity and is not sufficiently adaptive to possible future narrowing of the safety margins, the monitoring for moisture and coating integrity is inadequate, the response to wet conditions and coating failure is inadequate, the scope of the UT monitoring is insufficient to systematically identify and sufficiently test all the degraded areas of the shell in the sand bed region, the quality assurance for the measurements is inadequate, and the methods proposed to analyze the UT results are flawed.

Thus, the changes to the new contention are, as follows:

1) "the monitoring frequency is too low and is not adaptive to possible future narrowing of the safety margins " is changed to "the scheduled UT monitoring frequency is too low in the absence of adequate monitoring for moisture and coating integrity and is not sufficiently adaptive to possible future narrowing of the safety margins" (the "Amended Allegation");

2) "the monitoring for moisture and coating integrity is inadequate" is added (the "First Added Allegation");

3) "the response to wet conditions and coating failure is inadequate" is added (the "Second Added Allegation") and

4) "UT" has been inserted in the last line. ("Minor Modification")

The Minor Modification has been made for clarity, but does not change the meaning of the allegation. It is therefore not addressed further in this Supplement.

**B. Basis for Modifications**

At this preliminary stage, Citizens do not have to submit admissible evidence to support their contention, rather they have to "[p]rovide a brief explanation of the basis for the contention," 10 C.F.R. § 2.309(f)(1)(ii), and "a concise statement of the alleged facts or expert opinions which support the ... petitioner's position." 10 C.F.R. § 2.309(f)(1)(v).

This rule ensures that "full adjudicatory hearings are triggered only by those able to proffer ... minimal factual and legal foundation in support of their contentions." In the Matter of Duke Energy Corp. (Oconee Nuclear Station, Units 1, 2, and 3), CLI-99-11, 49 N.R.C. 328, 334 (1999) (emphasis added). The Commission has clarified that, "an intervener need not . . . prove its case at the contention stage. The factual support necessary to show a genuine dispute exists need not be in affidavit or formal evidentiary form, or be of the quality necessary to withstand a summary disposition motion." In the Matter of Georgia Institute of Technology, CLI-95-12, 42 N.R.C. 111, 118 (1995). Thus, the Commission has indicated that where petitioners make

technically meritorious contentions based upon diligent research and supported by valid information and expert opinion, the requirement for an adequate basis is more than satisfied.

Because part of the new contention filed on June 23, 2006 alleged that the UT monitoring frequency was too low when no monitoring of moisture and coating integrity and no contingent monitoring was proposed, the basis set out for that element of the new contention in the Petition of June 23, 2006 is directly applicable to the Amended Allegation. In summary, the drywell shell is 0.026 inches or less from violating AmerGen's acceptance criteria. Under corrosive conditions, long-term corrosion rates of more than 0.017 inches per year have been observed. Thus, if corrosive conditions are possible, a UT monitoring frequency of once per year or more would be necessary. Furthermore, if the next scheduled UT monitoring that is to occur before the end of the licensing period shows that these safety margins have narrowed, even more frequent monitoring would be needed.

AmerGen's new proposal to add a round of scheduled UT monitoring at the second refueling outage does not respond to these problems because the monitoring is scheduled after corrosion beyond the safety margins could occur. In addition, the proposal to review the frequency of the monitoring after the second round of monitoring is not sufficiently adaptive because, as discussed below, AmerGen has yet to set adequate acceptance criteria, which are essential to establish the required monitoring frequency. Indeed, it appears that the selection of four years as the time interval for the first scheduled monitoring in any license renewal period was based on a suggestion from NRC Staff rather than any reasoned analysis on AmerGen's part. Ex. NC 4 at 59:6-9.

However, the related proposal to monitor the presence of water and the integrity of the coating could provide a solution, if the monitoring were sufficient to ensure that corrosive

conditions cannot go undetected and the action triggered by the detection of corrosive conditions were adequate. Unfortunately, neither the monitoring of corrosive conditions proposed by AmerGen on June 20, 2006 nor the response to the results of that monitoring is adequate. To address these issues, the First Added Allegation concerns the inadequacy of the proposed monitoring for corrosive conditions, while the Second Added Allegation concerns the inadequacy of the response to that monitoring.

With respect to the monitoring for moisture, AmerGen committed to visually monitoring the drains from the sand bed daily during refueling outages and quarterly during normal operations. New Commitments at 3-4. The danger of leakage going undetected is obvious in this scheme. Minor leaks or condensation may never reach the drains and leaks could occur at times when inspections are not occurring. Furthermore, no objective data would be created. As set out in the attached Memorandum of Dr. R. H. Hausler, moisture sensors are readily available that could monitor for the presence of water on the exterior of the drywell shell continuously. Memorandum of Dr. R. H. Hausler, dated July 25, 2006 at 5. In addition, the results from these monitors could be recorded. The superiority of continuous monitoring of moisture on the exterior of the shell is self-evident.

Turning to the proposed monitoring of the epoxy coating, AmerGen now proposes visual inspection of the epoxy coating if water is detected in the sand bed drains. New Commitments at 3-4. In addition, AmerGen asserts that it will perform visual inspections of the coating every other refueling outage. Id. at 13. Citizens note that the April 4, 2006 commitment actually required such visual inspections only once every ten years on a scheduled basis, Letter from Gallagher to NRC, dated April 4, 2006 Enclosure at 1, and the language of the New

Commitments is carefully phrased so that the discussion in the New Information does not make regulatory commitments. New Commitments at 2.

Dr. Hausler opines that "holidays and pinholes in the coating cannot be assessed by 'visual examination'" and therefore recommends use of standard technology that can more accurately establish the integrity of the coating. Memorandum of Dr. R.H. Hausler dated July 25, 2006 at 6. This opinion provides part of the basis for the allegation that AmerGen's proposed monitoring of the coating integrity is inadequate.

With regard to the frequency of the coating inspection, AmerGen has committed to completing a coating inspection before exiting the refueling outage, if moisture is first detected during an outage, or during the next refueling outage, if moisture is first detected during operation. New Commitments at 3-4. In contrast, Dr. Hausler opines that the first coating inspection should occur "at the onset of moisture being detected" and "quarterly, while wet conditions prevail." Memorandum of Dr. R.H. Hausler dated July 25, 2006 at 6. Dr. Hausler states that the corrosion rate in the sand bed was as much as 0.033 inches per year from 1986 through 1992, id. at 3, and that monitoring should occur half way towards the shortest predicted service life. Id. at 2. Because the margins are 0.026 inches or lower, in wet conditions coating failure could lead to the loss of the safety margin within nine and one-half months. Thus, if water is present the inspections of the coating must occur at intervals that are smaller than 4.75 months. Because this is a safety-critical application and corrosion rates are uncertain, Dr. Hausler has selected quarterly monitoring as most appropriate for the ongoing inspection frequency while wet conditions prevail. In addition, if water is detected will be uncertain how long it has been in contact with unmonitored parts of the coated area. Because dangerous corrosion could occur rapidly if wet conditions prevail and the coating has failed Dr. Hausler

recommends a coating integrity check as soon as water is detected. This is in sharp contrast to AmerGen's proposal to wait until the next refueling outage, which could allow the drywell shell to remain wet for up to two years without any check of the integrity of the coating.

Furthermore, the Second Added Allegation deals with the inadequacy of AmerGen's proposed response to the detection of moisture and coating failure. AmerGen has committed to perform UT testing on "any areas in the sand bed region" where water is found, the coating is defective, and "corrosion has occurred." New Commitments at 3-4. The damaged area of coating would then be repaired. Id. This commitment is inadequate for two reasons; first, the spatial extent of the action is too narrow; and second, AmerGen cannot know whether corrosion has occurred without first doing UT testing, because corrosion could occur below the damaged coating without being observed visually.

Looking first at the spatial extent of the action, Dr. Hausler believes that when a coating failure is found, the entire coating should be removed and replaced because failure of the coating in one area would indicate that it could also rapidly fail in other areas. Memorandum of Dr. R.H. Hausler dated July 25, 2006 at 6. This opinion is reinforced by the physical constraints on UT monitoring. Dr. Hausler points out that monitoring of most of the sandbed region is impossible from the inside of the drywell shell because of the concrete floor and a concrete curb that goes to the top of the sandbed in many areas. Id. at 3, Figures 3-4. He also points out that UT monitoring of the sandbed from the outside cannot be done from the outside through the epoxy coat. Id. at 6. Thus, once it is known that corrosion could have occurred in one area, the whole vessel should be comprehensively monitored and its integrity checked, while it is possible to do so. This would reestablish the safety margins and would verify whether the monitoring for corrosive conditions is effective.

Turning to the trigger for UT testing, it is totally illogical to condition the testing on whether corrosion has occurred, which is precisely the question that the testing seeks to answer. Because corrosion could occur and not be visible, LBP-06-07 at 26, 63 NRC 188 (2006), visual inspection alone is not adequate to determine whether corrosion is occurring. Instead, detection of moisture combined with coating failure should automatically lead to UT testing. Memorandum of Dr. R.H. Hausler dated July 25, 2006 at 6.

**C. All New Allegations Relate to the UT Testing Program**

The Board has ordered that this submission must be "limited to AmerGen's UT program for the sand bed region." LBP 06-844 at 3. AmerGen or the NRC Staff may argue that allegations regarding the adequacy of the corrosive conditions monitoring stray beyond the confines of the Board's instructions. If so argued, this would be incorrect, because AmerGen has stressed that the commitments regarding the aging management of the drywell liner form an "integrated package." Ex. NC 4 at 55:23-27. NRC Staff has also stressed the importance of moving beyond a scheduled regime for UT testing into an adaptive regime that would require such testing when water leakage is detected. Id. at 59:18-22. Thus, because the corrosive conditions monitoring is the trigger for additional UT testing, it is part of the UT monitoring program for the sandbed, and so may legitimately be addressed in this submission.

More specifically, Citizens have shown that without any monitoring for corrosive conditions, UT measurements would have to be infeasibly frequent to ensure that safety margins continue to be met. Tacitly acknowledging this fact, AmerGen has now proposed to monitor corrosive conditions and adapt its UT testing program to the results of the corrosive conditions monitoring. However, if the corrosive conditions monitoring is inadequate, too few UT measurements will be taken to maintain safety margins. Thus, because the monitoring for

corrosive conditions is an essential part of the UT testing program, the adequacy of the conditions monitoring is an appropriate topic for this submission.

### D. Allegations Regarding Monitoring for Corrosive Conditions Are Otherwise Admissible

Even if the Board decides that the allegations regarding the monitoring for corrosive conditions are not admissible within the terms of the Board's most recent order, they would be admissible as new contentions because they are within the scope of the proceeding. Citizens have ample basis for the Added Allegations, the Added Allegations raise material issues about whether AmerGen's aging management program is adequate to assure that safety margins will be maintained throughout the licensing period, and the filing of the contentions would be timely in accordance with 10 C.F.R. § 2.309(c) and (f)(2), because they are based on material new information that only became available to Citizens recently. Thus, if the Board decides that some of the new Added Allegations are not admissible within the terms of its most recent Order, Citizens seek leave to file the new allegations as contentions based on the New Information and New Commitments or as late-filed contentions.

### E. The Modifications Are Within the Scope of the Hearing

Petitioners are required to demonstrate that the issues raised in their contentions are within the scope of the proceeding, 10 C.F.R. § 2.309(f)(1)(iii). After extensive briefing of this issue, the ASLB concluded that corrosion of the drywell shell is within the scope of license renewal proceedings. In the Matter of AmerGen Energy Company (License Renewal for Oyster Creek Nuclear Generating Station), LBP-06-07 (slip op. at 39-40), 63 N.R.C. 188 (February 26, 2006). That finding directly applies to the current contention, because it concerns the very same issue; the aging management of the drywell shell in response to the potential for further corrosion. Thus, the issue of scope is currently *res judicata* in this proceeding and is not subject

to further dispute. However, the decision to admit the initial contention is currently on appeal to the Commission. Therefore, should the Commission amend the ASLB's finding regarding scope in its review of the AmerGen's appeal, Citizens request an opportunity to file a supplemental briefing addressing the Commission's findings.

**F. The Modifications Raise Material Issues**

The regulations require petitioners to "[d]emonstrate that the issue raised in the contention is material to the findings the NRC must make to support the action that is involved in the proceeding." 10 C.F.R. § 2.309(f)(1)(iv). A showing of materiality is not an onerous requirement, because all that is needed is a "minimal showing that material facts are in dispute, indicating that a further inquiry is appropriate." Georgia Institute of Technology, CLI-95-12, 42 N.R.C. 111, 118 (1995); Final Rule, Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process, 54 Fed. Reg. 33,171 ( Aug. 11, 1989). Similarly, in Gulf States Utilities Co. (River Bend Station, Unit 1), CLI-94-10, 40 N.R.C. 43 (1994), the Commission stated that, at the contention filing stage, "the factual support necessary to show that a genuine dispute exists need not be in formal evidentiary form, nor be as strong as that necessary to withstand a summary disposition motion." 40 N.R.C. at 51. Rather, the petitioner need simply make "a minimal showing that the material facts are in dispute, thereby demonstrating that an inquiry in depth is appropriate." Id. (internal quotation marks omitted).

In admitting the initial Petition, the ASLB found that a genuine and material dispute existed about whether the then-proposed aging management program, which did not include periodic UT measurements, would enable AmerGen to maintain safety margins during the term of any extended license. LBP-06-07 at 38-39. This new contention concerning AmerGen's June 20, 2006 commitment continues this material dispute and alleges that AmerGen's most recent commitment is inadequate to maintain safety margins throughout the licensing period.

In addition, the New Information had made it less clear what assurances AmerGen is able to give regarding its ability to maintain safety margins over the 20-year renewal period. Previously, AmerGen stated that the April 4, 2006 commitment would "provide assurance that the drywell shell will remain capable of performing its design functions throughout the license renewal period." Letter from Michael P. Gallagher, AmerGen, to NRC (Apr. 4, 2006). While AmerGen have not formally retracted these claims, it is notable that even though the New Commitments provide for additional monitoring, AmerGen makes somewhat weaker claims as to the level of assurance the new proposed procedures will provide. AmerGen now claims that the procedures will suffice "to ensure that significant drywell corrosion will be detected and addressed prior to impacting the intended function of the containment." Letter from Michael P. Gallagher, AmerGen, to NRC at 13 (Jun. 20, 2006). But in its June 20, 2006 submission, AmerGen no longer makes the explicit claim that it believes the drywell actually will be able to operate for 20 years while remaining within safety margins.

In this Supplement, Citizens have shown by reference to exhibits and expert opinion that due to the absence of adequate monitoring for moisture and coating integrity, the proposed scheduled UT monitoring by AmerGen is too infrequent and is not sufficiently adaptive to possible future narrowing of the safety margins to allow the current razor-thin safety margins to be maintained. Furthermore, Citzens have demonstrated that AmerGen's proposed program of monitoring for moisture and coating integrity is inadequate, and that AmerGen's proposed responses to detected moisture and degradation of the coating are inadequate. Thus, Citizens contend that the proposed program would fail to ensure that safety margins would continue to be met during any license renewal period.

In contrast, AmerGen has stated that the committed monitoring regime will be adequate to ensure the drywell shell remains within safety margins. Id. The material dispute about the adequacy of the testing regime results from material disputes about more detailed issues, such as how best to detect moisture, how and when to check coating integrity, and what response is required when moisture is found and the coating is not intact. Finally, because the safety of the reactor hinges on the outcome of the overall dispute, it must be resolved before the NRC can issue any extended license.

## II. New Basis for Previously Contended Issues Arising from New Submission

A portion of the new contention alleges that "the acceptance criteria are inadequate." In its June 20, 2006 submission, AmerGen discussed in some detail the applicability of the engineering codes used to derive the acceptance criteria in an attempt to justify the current approach. New Information at 3-6, 8-9. AmerGen also made new commitments to take additional UT measurements. New Commitments at 2-4. For any UT monitoring taken in response to visual inspections prompted by wet conditions during refueling outages, AmerGen proposed to evaluate the results "per the existing program." See New Commitments at 3. Thus, AmerGen has decided not to change the acceptance criteria. Presumably, AmerGen based this decision on a belief that it had adequately justified the bases for the acceptance criteria in the New Information.

In its July 5, 2006 Order, the Board allowed Citizens to set forth new bases, based upon the New Information and the New Commitments. Because AmerGen's June 20, 2006 submission set forth new information and assertions regarding the derivation of the acceptance criteria and relied upon those analyses to continue to assess the additional UT measurements in the same manner as previously proposed, Citizens had the new submission and other relevant

documents reviewed by Stress Engineering Services, Inc. ("Stress"), a well-qualified firm of structural engineers, to determine if the commitment to evaluate future UT results in the sand bed region "per the existing program" is adequate. The resumes of the individual engineers from Stress who provided the opinion are provided as Exhibit NC 11.

As set forth in the attached expert opinion dated July 15, 2006, Stress has concluded that AmerGen's current approach to assessing the continued integrity of the drywell shell is outdated and may not properly capture the behavior of the shell in its degraded state. Letter from Stress to Webster dated July 15, 2006 ("Stress Opinion") at 2. Furthermore, Stress points out that the engineering code used relates to pressure integrity and governs construction of pressure vessels, not serviceability. Id. The authors of the code did not intend its rules to be the only arbiter of pressure vessel structural integrity. Id. at 3. Stress opines that much better techniques than those used by AmerGen are now available and are code compliant. Id. at 2. The new techniques are routinely used today and provide the most accurate assessment of vessel integrity possible. Id. Thus, the new techniques are superior to the outdated techniques currently employed by AmerGen.

One critical advance is the use of lasers to map the actual shapes of pressure vessels, along with sophisticated UT techniques that measure the wall thickness. Id. Stress points out that the G.E. analysis modeled small slices of the vessel and used idealized geometries, such as a perfect sphere for the lower part of the drywell. Id. at 1-2. These calculations were then adjusted by making assumptions about surface irregularities, plasticity, and local buckling. Id. at 2. Thus, the calculated values used by AmerGen are vulnerable to incorrect assumptions. In particular, if, as is perfectly possible, the lower portion of the drywell shell is not truly spherical, the strength of the vessel would be considerably reduced. As far as Citizens are aware,

AmerGen has not checked the shape of the vessel, but has nonetheless assumed that it is spherical. It is this type of assumption that the laser measurement technique described by Stress can eliminate.

Furthermore, the G.E. model only modeled one bay, all the other bays were assumed to behave in the same way simultaneously. This technique inherently assumed that symmetrical buckling would occur, when, in fact the buckling may be a combination of symmetrical and anti-symmetrical buckling. Id. This means that the G.E. model may have missed the most critical buckling mode.

In the New Information, AmerGen wrestled with some of the problems that Stress points out. For instance, AmerGen stated that one of the code sections is not directly applicable to the issues involved in setting the acceptance criteria. New Information at 3. However, AmerGen attempted to justify continued use of the modeling carried out by G.E. in 1991 and extrapolation of that modeling using sections of the code by stating that "AmerGen is not aware of any new practical engineering analysis methods that can be used as an alternative to ASME Section III, Subsection NE-3213.10 to more accurately reflect the corroded drywell shell." New Information at 3. Citizens have now established that even if AmerGen is not aware of advances in engineering analysis that could be applied to the problem of assuring the continued integrity of the drywell, such advances have in fact occurred, and should be applied to accurately determine the margins of safety available during any license extension period.

In addition, AmerGen has admitted that code case N-284 requires consideration of surface irregularities, but has relied upon a minimum "margin in the general thickness of the two bays [bays 17 and 19]" of 0.074 inches and 0.064 inches, respectively, to "offset uncertainties related to the surface roughness." New Information at 9. There are many problems with this

approach. Most obviously, it is by no means clear that the postulated margins are the smallest, as is discussed in detail below. In addition, as the sentence quoted above acknowledges, the surface roughness is highly uncertain because AmerGen has not measured this parameter. It has therefore provided only a very rough estimate of the surface roughness induced by corrosion and has provided no estimate at all of the roughness due to fabrication. New Information at 8.

The estimate of surface roughness caused by corrosion is underestimated because it uses 0.736 inches as the corroded thickness, when 0.603 inches is the thinnest observed. Ex. NC 1 at 7. Assuming an error of 5% of wall thickness the 0.603 inch measurement is consistent with an actual thickness of 0.572 inches. Substituting 0.572 into the equation provided by AmerGen yields a roughness of 0.654. This compares to an acceptable roughness of 1.0, New Information at 8, and is dangerously close to the acceptable limit, given the uncertainty about the current corroded thicknesses and the lack of information about the fabrication roughness. The calculation also shows that the equation is very sensitive to the value for the corroded thickness, which has not yet been systematically determined. Indeed, the last UT measurements in the sandbed were taken in 1996 as part of AmerGen's highly circumscribed monitoring program. These ten year old data have now been admitted to contain "data anomalies." New Information at 8.

Furthermore, AmerGen has argued that "the overall net effect of the corrosion-induced eccentricities would be insignificant." New Information at 8. This flies in the face of observations made from the outside of the drywell shell which found parts of its surface to be "rough, . . . [and] full of dimples comparable to the outer surface of [a] golf ball. Ex. NC 3 at 13. In addition, AmerGen has failed to even estimate fabrication irregularities. Thus, AmerGen's attempt to show that the total surface roughness does not exceed the code requirement of 1.0

completely fails. It is precisely these kinds of difficulties that the technique proposed by Stress would eliminate. If the shape and thickness of the drywell were systematically measured and modeled, there would be no need to rely on making educated guesses about the values of various parameters, such as the roughness factor.

Looking in more detail at the issue of the minimum margins, the measurements taken from the outside show that bays one and 13 were the most corroded in 1992. Ex. NC3 at 1-2. Thus, it is to be expected that the margins in these bays should be lower than the margins in bays 17 and 19. The fallacy in AmerGen's reasoning is exposed by Table 1, which gives the "minimum measured thickness" in the sandbed region as 0.800 inches. New Information at 5. As previously discussed, actual measured thicknesses have ranged as low as 0.603 inches in the sand bed region. Ex. NC 1 at 7. Further, in bay 13, at least nine areas of less than 0.736 inches are present. Ex. NC 9 at 28. Thus, the margins in bays one and 13 are probably smaller than those in bays 17 and 19. In addition, the justification for the procedure actually assumes insignificant corrosion in the sand bed region even though nothing is known about the corrosion of the drywell shell in the sand bed region over the last ten years. New Information at 6. Therefore, using the calculated margins in bays 17 and 19 to "offset for uncertainties related to surface roughness" is a non-rigorous procedure that just confirms the degree to which the current methods employed by AmerGen to evaluate the effect of the corrosion on the structural integrity of the drywell shell rely on highly uncertain calculations that contain numerous unverified assumptions.

As Stress has opined, the accuracy of AmerGen's current calculations could be improved by adopting the most up to date methods. Furthermore, using such methods would allow the unverified assumptions and educated guesses employed by AmerGen at present to be replaced by

systematic measurements. The results of such an exercise would allow the significance of the existing corrosion to be evaluated and would allow quantitative predictions to be made about the structural impact of possible further corrosion during any extended licensing period. Such information is vital to accurately establish how much safety margin is currently available. Once known, the safety margin would dictate the acceptance criteria for future measurements, how accurate the testing regime for any extended license period would have to be, and how quickly the response to corrosive conditions would have to occur. These parameters would be used to design an appropriate monitoring regime.

AmerGen has committed to review the frequency of scheduled UT monitoring during any license renewal period after the results of the second scheduled UT testing. New Commitments at 2. While the commitment does not specify how this review would be undertaken, Citizens believe that it would necessarily involve comparing the amount of additional corrosion that could occur to the amount of corrosion that would impair the structural integrity of the vessel. This is precisely the information that would result from the analysis recommended by Stress.

Thus, Citizens seek to add the new bases discussed above for the portion of the contention alleging that the "acceptance criteria are inadequate" without amending the wording of the contention or changing the bases already submitted.

**III. Timeliness of Submission**

Petitioners may amend contentions after filing their initial petition, so long as they act in accordance with 10 C.F.R. § 2.309(f)(2). See Entergy Nuclear Vermont Yankee, L.L.C. (Vermont Yankee Nuclear Power Station), LBP-05-32, 62 NRC 813 (2005). The Commission's regulations allow for a new or amended contention to be filed upon a showing that:

(i) The information upon which the amended or new contention is based was not previously available;

(ii) The information upon which the amended or new contention is based is materially different than information previously available; and

(iii) The amended or new contention has been submitted in a timely fashion based on the availability of the subsequent information.

10 C.F.R. § 2.309(f)(2)(i)-(iii).

In Vermont Yankee, the Board first admitted a contention of omission challenging an applicant's failure to perform structural and seismic analyses. The applicant subsequently performed structural and seismic analyses, after which it filed a motion to dismiss the contention as moot, which the Board granted. See Vermont Yankee, LBP-05-32, 62 NRC 813, 820. The Board gave the petitioner 20 days to file a new contention. Id. In response, the petitioner filed a contention challenging the sufficiency of the structural and seismic analyses. Id. In admitting the new contention, the Board held that the analyses were clearly information that was "not previously available" and that they were materially different than information previously available "because something is obviously different than nothing." Vermont Yankee, LBP-05-32, 62 NRC 813, 820; 10 C.F.R. § 2.309(f)(2)(i)-(ii).

The Board's analysis in Vermont Yankee is directly applicable to this case. The New Commitments were previously nonexistent; their content therefore constitutes new information that is necessarily "materially different than information previously available." Vermont Yankee, LBP-05-32, 62 NRC 813, 820. Similarly, much of the New Information concerns engineering analyses used to try to justify the New Commitments. Because knowledge of the safety margins is essential to designing an appropriate aging management regime, and the

analyses showed major inadequacies in the approach used to derive the acceptance criteria, the new engineering analyses are also materially different new information. Thus the New Information and the New Commitments are materially different new information satisfying the requirements of 10 C.F.R. § 2.309(f)(2)(i) and (ii).

Additionally, the Board's Order of July 5, 2006 allowed Citizens to submit this supplement based on AmerGen's June 20, 2006 submission, illustrating that the Board believed that the submission contained materially different new information. Indeed, AmerGen also acknowledged this fact by requesting that Citizens be allowed to submit a completely new petition based on the monitoring regime as modified in the June 20, 2006 submission.

Furthermore, because this contention is being filed within the timeframe specified by the Board's Order of July 5, 2006 and 24 days from the June 20, 2006 submission it satisfies 10 C.F.R. § 2.309(f)(2)(iii). Furthermore, the parties need not address the requirements under 10 C.F.R. § 2.309(c), which apply to "nontimely filings." See Licensing Board Memorandum and Order (Contention of Omission is Moot, and Motions Concerning Mandatory Disclosure are Moot), LBP-06-16 at n.12 (Jun. 6, 2006) (unpublished). Finally, should the Board decide to treat the Added Allegations as late-filed contentions, Citizens believe that they meet the requirements of 10 C.F.R. § 2.309(c). If it would be helpful to the Board, Citizens would be pleased to brief this issue in detail.

## CONCLUSION

For the foregoing reasons, the ASLB should allow the proposed new contention to be modified as specified in this supplement.

Respectfully submitted

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Dated: July 25, 2006

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# MEMORANDUM

**To:** Richard Webster, Esq. July 25, 2006

**From:** Rudolf H. Hausler

**Subject:** **Oyster Creek, Drywell Liner**
**Integrity Assurance and Monitoring Frequencies**

## I. Background

The drywell liner of GE Mark I BWR nuclear power plants, as is well known, is an important safety structure in case of a catastrophic failure of the nuclear reactor it contains. In addition, structural failure of the liner could actually cause an accident. It is therefore important that its integrity is assured prior to any relicensing of the 40-year old Oyster Creek nuclear power plant, and that subsequently its integrity is monitored throughout any extended license. The drywell liner at Oyster Creek has suffered from serious corrosion, which has brought the structure close to the limit of operability. As a consequence, the existing thin margin between acceptable and unacceptable integrity, must be maintained for another twenty years, if the reactor is to continue operating beyond the current licensed period. In an attempt to accomplish this task, AmerGen, the operator of the Oyster Creek nuclear power plant, proposed a new testing regime for the drywell liner on June 20, 2006. This memorandum attempts to discuss some of issues involved with this all-important task and finds that the June 20, 2006 proposal is a step in the right direction, but is still far from adequate.

## II. The Basic Monitoring Program

In order to gauge the remaining service life of a corroding structure one needs to know the inherent corrosion (or pitting) rate. It is generally impossible to assess this rate a priori on the basis of either laboratory measurements or theoretical calculations. Hence, corrosion rates need to be established in the field under service conditions. A commonly accepted procedure is demonstrated in Figure 1. A structure such as a vessel or a pipeline has a given nominal wall thickness and is subject to corrosion. The useful service life is determined by a minimum allowable wall thickness, depending on operating conditions, the allowable "target penetration".

In Case 1 the prevailing corrosion rate (loss of wall thickness with time) appears to be low enough such that at the end of the projected service life the remaining wall

thickness is above the minimum target. In this case in service wall thickness measurements (also called direct assessment), for instance by UT technology or an intelligent pig (in case of a pipeline), would be carried out at half of the remaining service life. If the corrosion (penetration) rate can be reaffirmed, one would likely not verify the integrity of the structure by direct assessment again until the end of the service life. However, one would continue to monitor ongoing corrosion or changes of the environment, which could result in a change of the corrosion rate, by other means, such as corrosion coupons or sensors, or in the case of Oyster Creek by moisture monitors (also referred to a indirect assessment [1]).

In Case II, the known corrosion rate predicts the minimum target wall thickness to be reached at the end of the service life. In this case verification would occur at the half-life of the structure, and again half way between it and the end of the service life. Simultaneously, changes of the environment, or changes in corrosion rate would be monitored continuously. In this case the latter is all the more important.

In Case III, the corrosion rate is such that the structure would have to be abandoned prior to the expected full service life. Nevertheless, the structure would be routinely examined in order to obtain as long a service life as possible. This situation prevailed at Oyster Creek in 1992, prior to preventive measures having been applied (Ref. 2)

This general scheme is based on a number of assumptions. These are:

a) the corrosion rates are known,
b) the corrosion rates are constant, i.e. the loss of wall thickness is linear with time
c) the conditions under which the corrosion rates have been established originally remain constant with time.

In practice, none of these assumptions hold true. Various means must to be brought to bear in order to rectify the situation. First, corrosion rates must be established, usually by simpler means than direct assessment over long intervals, such as for instance corrosion coupons, which are exchanged and examined on a monthly basis. On line monitors are also used to verify the constancy of the corrosion rates with time and to observe possible changes of the corrosion rates with changes of the environment. The programmatic direct assessment schedule of the vessel or structure is then adjusted as dictated by these results.

## III. The Oyster Creek Drywell Liner

[1] The distinction between direct assessment and routine monitoring (indirect assessment) is made because direct assessment methodologies are expensive, time consuming, and often require shut down of the unit. Indirect assessment can be done routinely on line is inexpensive, and does not require shut down. However, a relationship between the two has to be established, and it cannot be assumed a priori that indirect monitoring truly reflects what is going on in the unit.

Applying these principles to Oyster Creek is not a simple task, mainly because the corrosion rates in the critical areas, i.e. the sand bed area are not known, cannot be measured by simple means, cannot be assumed to be constant with time and cannot easily be established by full examination of the vessel. These issues and others will be discussed in some detail below.

## 1. Assessment of the Integrity of the Drywell Liner

Review of the areas investigated

The first issue to be addressed pertains to the overall integrity of the vessel in the sandbed area in particular. The plant was built in 1968; however, water was first detected in 1980 in the area between the drywell and the concrete shield. In 1983 work began to identify the origin of the water. Only in 1986 were UT wall thickness measurement performed in order to determine if the presence of water had caused external corrosion to the drywell liner (Ref.1). The measurements in 1986 purportedly were carried out to determine the areas of most severe corrosion. Out of a total of 143 UT measurements, 60 indicated a wall loss in excess of ¼ inch. These measurements were carried out from the inside of the liner in a very narrow area above the curb (see Fig. 2) at elevation 11 ft 3 in to 12 ft 3 in (Ref. 1). However, Fig. 2 is somewhat misleading in that it creates the impression that the curb at elevation 11ft extends along the entire periphery of the inside of the vessel. This is not the case. In order clarify the physical realities inside the drywell, Figure 3 is a clearer rendering of the curb. The curb actually rises to an elevation of 12'3" and is therefore at the same height as the top of the sandbed. Only around the vent pipes is curb lowered (cut-out) to a top elevation of 11'. Hence, as shown in Fig.4 there exists an area above the curb of 6 to 8 inches below and besides the vent pipe where UT measurements can be made such that corrosion on top of the sandbed can be assessed. Below this area there are 24 inches inaccessible to UT measurements from the inside. Furthermore, the area where UT measurements were actually made is very small with respect to the circumference of the vessel, about 150 feet at this elevation.

Subsequently areas were defined in each bay were systematic UT measurements would be made using a 6 in by 6 in matrix with holes drilled at 1 in spacings to accommodate the UT probe. This was done in order to be able to repeat the 49 UT measurements at time intervals in exactly the same location in each bay. Repeat measurements over the period of 1986 through 1992 indicated that the average penetration over the 6 in by 6 in grid grew with a corrosion rate of as much as 33 mpy (Ref. 2), such that in several bays the minimum wall thickness would have been reached in 4 to 5 years (mid 1990's) if no preventive measures would have been instituted. This indicated that the drywell liner had already critically corroded in the sand bed area. These results were based on about 3% of the circumference and less than 30% of the sandbed depth. It should be noted that that the "most corroded" areas had been identified in 1986 and the locations thereof essentially fixed in order to achieve subsequent representative measurements. However, the sandbed remained in place from 1986 to 1992, the water leakage had not been arrested (continued corrosion also at the higher locations) and corrosion in the sandbed area continued. **The physical constraints meant that the most corroded areas were not rigorously**

**identified in 1986. Furthermore, after the sand bed was removed, the areas identified in 1986 probably would not have remained the most corroded areas if there was continued corrosion. Thus, in view of the narrowness of the margins of safety remaining for this vessel, a much larger area should be investigated prior to extending the license in order to verify where the most corroded areas are and define the remaining safety margins. This must include all areas previously considered inaccessible because of the presence of the sandbed [2].**

Review of the statistical procedures used in the interpretation of UT measurements

The UT measurements, made over several years in several bays in the sandbed area with the 6 in by 6 in grid, needed to be analyzed in some manner. GPU chose to determine the average of the 49 individual measurements in order to characterize the average state of the wall thickness at that time and that location, in order to compare such averages over time and determine a corrosion rate. A further objective of this calculation was the comparison of the average UT measured wall thickness with a critical value derived from structural fitness for service calculations. This critical value was determined as 736 mils and most of the average wall thicknesses over the 6 in by 6 in grids were around 800 mils, or critically close to the critical value. It is therefore well justified to examine some of the assumptions GPUNuclear made in arriving at certain conclusions.

The first assumption inherent in this procedure pertains to the notion that corrosion in the sandbed area was uniform or nearly so. This, however, is not the case. The surface was not merely "dimpled" but in some cases severely pitted, or even grooved. GPUNuclear got around this problem by assuming that the UT measurements, i.e. local corrosion penetrations should be normally distributed, and that hence Gaussian statistics were applicable. As a consequence the 49 individual measurements (in some cases fewer where plugs had been removed in the 6 in by 6 in areas) were analyzed for "normal" distribution and data points falling outside the 3 s lower limit (wall thickness) were eliminated as atypical from determination of the average wall thickness. This approach, which tended to increase the average wall thicknesses and made the safety margins look larger than they were in reality, is unacceptable for a number of reasons.

Gaussian statistics were developed in order to deal with random variations, occurring for instance in manufacturing processes, which would allow the producer to discard manufactured items outside specified limits. The corrosion process is of an entirely different nature, and deep flaws in a corroding wall cannot simply be disregarded because their depth is outside some assumed normal distribution of all pits. There are many examples in industry, which demonstrate that the combination of

[2] We are well aware that in some bays (Ref. 3) measurements were made from the outside, and trenches were dug into the reactor concrete floor at two locations only to verify that the "bathtub ring" type corrosion did not extend to lower depths in the sandbed. However, the interpretation of the measurements made from the outside was questionable (see my Memo of 6/22/06 (Ref. 4) and the mere fact of these measurements indicates that corrosion did extend below the "bathtub ring".

heterogeneities in metals and variations of the environment, with which they are in contact with, can lead to atypical failures, which would be considered outside the distribution of adjacent corrosion features. It is equally well established that neither pit depths nor the rate of growth of pits (pitting rate) are normally distributed because in many systems some deeper pits grow at the expense of shallower ones.

**For these reasons it is important, for a critical vessel as the reactor drywell liner, to establish the depth, width and length of all the corrosion anomalies. Because it cannot be assumed that the environment in which these anomalies grew over time was uniform throughout the sandbed area, nor that it remained uniform over time, it is necessary to perform a complete UT analysis over the largest area possible in order to establish the true state of integrity of the vessel.**

## 2. Programmatic Monitoring

The Presence of Water

Clearly water is required for corrosion to occur. Apparently water leaks continue to occur, or at least could occur, both during refueling outages as well as during normal operations. Daily monitoring of the drains during RO's and quarterly monitoring during the plant operating cycle as proposed in the June 20, 2006 letter are considered below minimum requirements for a number of reasons.

- Water leakage can occur at any time because failure of seals, welds, valves, etc. cannot be predicted.
- Water is also a necessary ingredient for degradation of polymeric resins (epoxy) and elastomers (sealing compounds).
- Even though the sandbed floor had been repaired 1992, there has never been any assurance that water accumulation has been totally prevented.

**For these reasons it is considered prudent to monitor the presence of water on the outside of the drywell liner continuously. This can easily be done by installation of moisture sensors. Such devices have reportedly been installed in other Mark I power plants and are commonplace in other industries.**

The problem of the Epoxy Coating and the Elastomer Seals

After the sandbed had been removed in 1992 the corroded areas in that region had been coated with a primer and an epoxy resin. Furthermore, the crevice between the floor and the drywell wall had been sealed off with an "elastomer"[3]. It is now being assumed that as long as the coating is not damaged in any way, corrosion is arrested (eradicated). While this is certainly a reasonable assumption if the coating is in good condition, and seems to have been true in the short-term according to UT measurements in 1992, 1994, and 1996, it is not appropriate to assume the coating will not deteriorate in the long term. Both the epoxy coating and the elastomer putty

[3] I believe that in view of the confined space in the sandbed area questions regarding the quality of these measures, as well as the quality control thereof, are well justified.

are subject to degradation in the presence of water, oxygen and elevated temperature. The rate and nature of such degradation are unknown. For this reason, AmerGen proposes to periodically assess the integrity of these components by visual examination every four years (Ref. 5).

**We think that such "visual examination" needs to be augmented by more quantitative assessment. Holidays and pinholes in the coating cannot be assessed by "visual examination". The coatings industry has developed methodologies, which can more accurately establish the integrity of coatings (Ref. 6, 7, 8, 9) . Of particular importance is the integrity of the putty. Water leakage into the crevice will further stimulate corrosion below the sandbed area floor. We think that the coating ought to be inspected quarterly, while wet conditions prevail, and at the onset of moisture being detected.**

UT Measurements

UT measurements (direct assessment) are considered the last defense in the sandbed area. (At the higher elevations above the sandbed region UT measurements should be made in accordance with a schedule dictated by the established corrosion rates as discussed above). If water is present, and if the coating and/or the putty have been established to be leaking water (either due to holidays or because blistering has occurred), UT measurements should be carried out. AmerGen appears to recognize that this monitoring cannot be limited to the locations that have been regularly monitored to date and that monitoring from the outside may be necessary. However, AmerGen fails to note that UT measurements cannot be taken from the outside through the epoxy coating.

**Primary emphasis must be put on prevention of water ingress and the integrity of the coating. If and when both fail, the coating must be removed and the entire sandbed area must be inspected, the remaining wall thickness must be quantitatively assessed, the integrity of the vessel must be reestablished, and the coating must be reapplied and tested. AmerGen has proposed only inspecting areas affected by moisture and coating failure, but this is inadequate because once the coating starts to fail in one area, it could rapidly fail in other areas. Therefore, a complete reapplication is mandated once failure in one area is detected.**

## IV. Conclusions

In conclusion we find AmerGen's proposed drywell liner aging management program flawed in several respects.

- First, we contend that the integrity of the drywell liner needs to be established on a much broader basis than has been done to date. This should include detailed investigations relating to cracking in the corroded areas of the sandbed area. To date less than 3% of the entire drywell wall in the sandbed

area have been examined for corrosion. Integrity predictions based on averages of such small a sample area would seem to be highly questionable.

- Second, the first priority of monitoring needs to be focused on the presence of water.
  - It needs to be established that the water does not come from below, but is in fact linked to water leakage from penetration at higher elevations
  - It needs to be established that no water puddles exist anywhere on the sandbed floor and that the drains work properly. (It does not make any sense to monitor the drains quarterly when in fact standing water prevails on the sandbed floor). Hence, quarterly monitoring of the drains from the sandbed area is not frequent enough. Rather we contend that moisture sensors ought to be installed all over the outside of the drywell shell as well as on the sandbed floor in order to definitely establish that the water originates only from the higher elevations.
- Third, the integrity of the coating and seals needs to be established with methods with can identify holidays and pinholes. Visual inspection will not be sufficient. Since the rate of deterioration of the coating and seals is not known, and since the specified useful life of such is already exceeded, these determinations must be made at least on a quarterly basis during normal cycle operation, when water is present.
- Fourth, if the continued presence of water has been observed, and if the coating has been shown to deteriorate, then UT measurements must be made throughout the sandbed region. Unless new monitoring technology is found effective, the UT measurements must be made from the outside of the drywell shell after the coating has been removed.

Rudolf H. Hausler

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3. GPU Nuclear Calculation Sheet No. C-1302-187-5320-024 (4/16/93)
4. Corro-Consulta Memorandum to Richard Webster, Esq., June 22, 2006; *Discussion of Monitoring Methodologies At Oyster Creek Nuclear Plant Dry Well.*
5. AmerGen Letter to US NRC April 4 2006 (2130-06-20284)
6. National Association of Corrosion Engineers, International, Standard Test Method **TM-00384**: *"Holiday Detection of Internal Tubular Coatings of 250 μm (10 mils) dry Film Thickness"*
7. National Association of Corrosion Engineers, International, Standard Recommended Practice, **RP-0188-90**, *"Discontinuity Testing of Protective Coatings"*
8. National Association of Corrosion Engineers, International, Standard Test Method **TM-0186-94**: *Holiday Detection of Internal Tubular Coatings of 250 to 760 μm (10 to 30 mils) Dry Film Thickness*
9. National Association of Corrosion Engineers, International, Test Method **TM-0183**, *"Evaluation of Internal Plastic Coating for Corrosion Control of Tubular Goods in Aqueous flowing Environment"*
10. AmerGen Letter to US NRC June 20, 2006
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12. H. H. Uhlig, Corrosion and Corrosion Control, John Wiley and Sons, 1963, page 85.
13. M. Pourbaix, Atlas of Electrochemical Equilibria in Aqueous Solutions, NACE, 1974, pg. 307 – 321.
14. GPU Nuclear Calculation Sheet No. C-1302-187-5300-020 (49/15/92)

Figure 1

**Schematic Monitoring Frequencies depending on corrosion Rate and Limiting Target Wall Thickness**

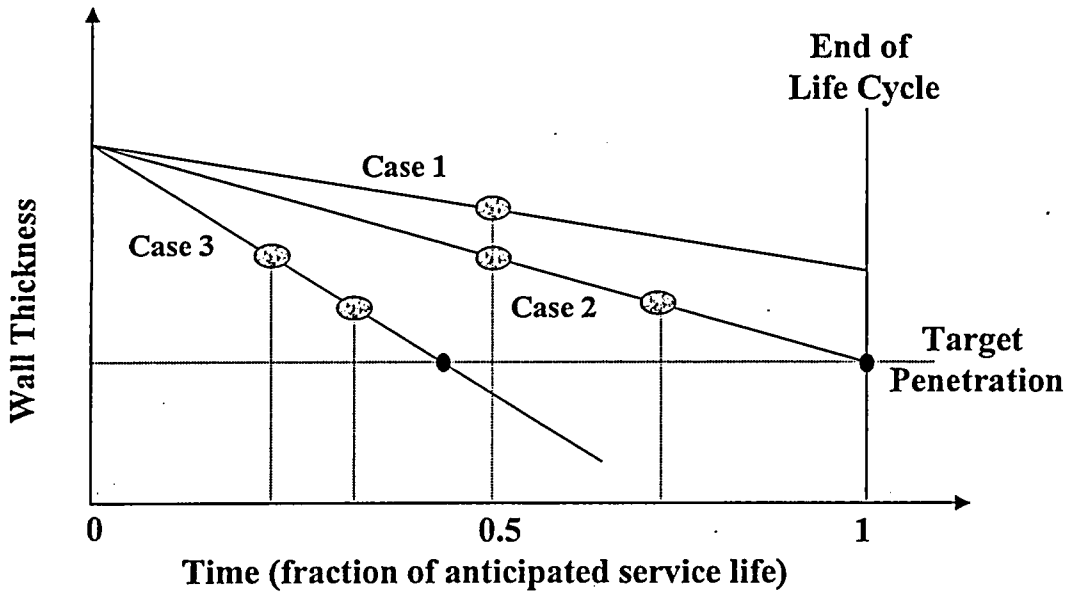


**Figure 2**

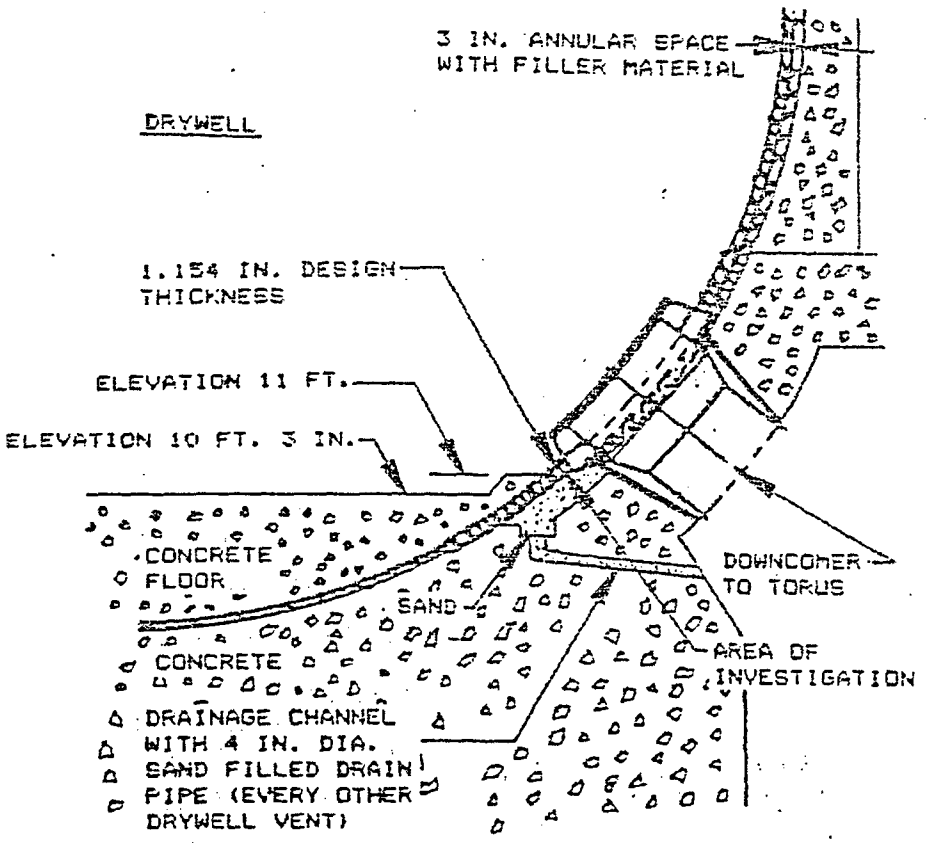
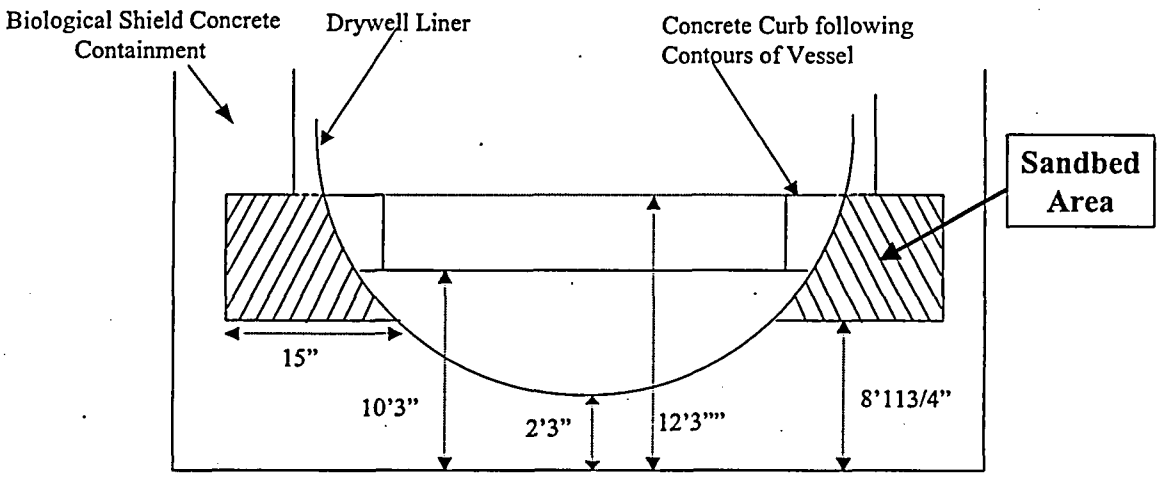

3 IN. ANNULAR SPACE WITH FILLER MATERIAL
DRYWELL
1.154 IN. DESIGN THICKNESS
ELEVATION 11 FT.
ELEVATION 10 FT. 3 IN.
CONCRETE FLOOR
SAND
CONCRETE
DRAINAGE CHANNEL WITH 4 IN. DIA. SAND FILLED DRAIN PIPE (EVERY OTHER DRYWELL VENT)
DOWNCOMER TO TORUS
AREA OF INVESTIGATION

**Figure 3**

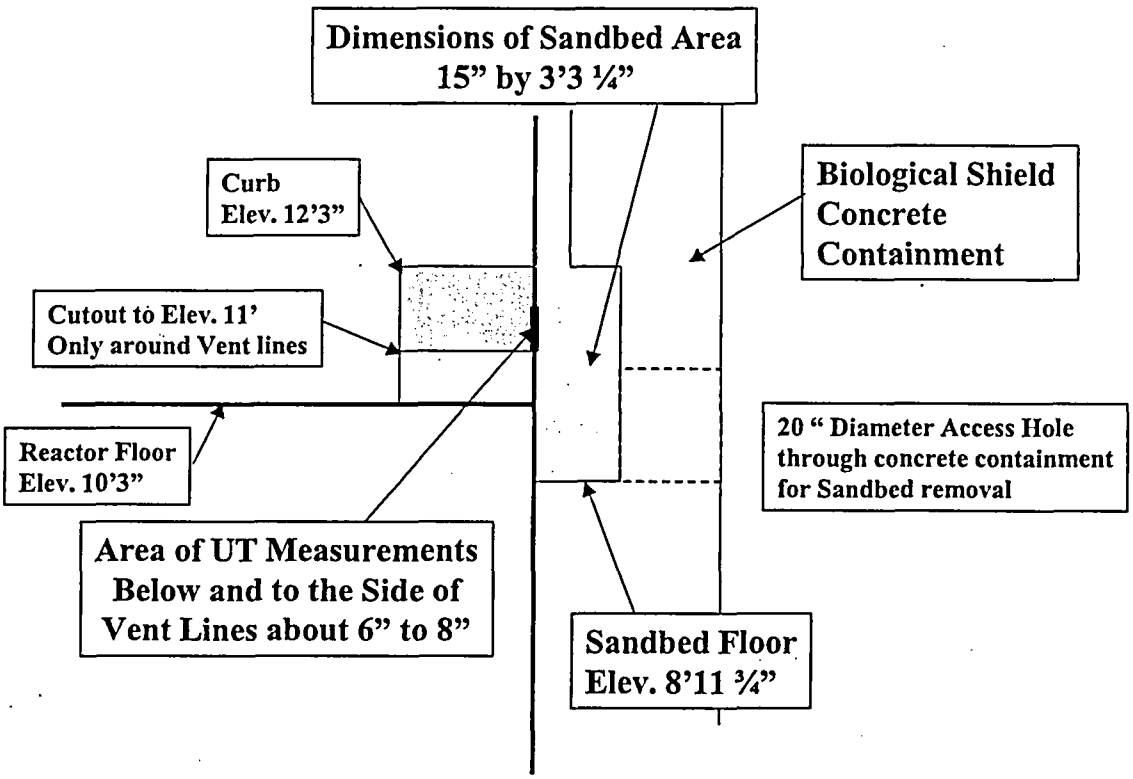
**Schematic Drawing of Lower Spherical Section of Drywell Liner**
(not to size)



## Schematic Cross Section through Sandbed Area

(not to size)

**Figure 4**



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July 15, 2006

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SES Project No.: 131377

**Subject:** Cursory Check of Structural Analyses, Oyster Creek Drywell Vessel

Dear Mr. Webster:

Recently, you requested that Stress Engineering Services, Inc. consider several documents that you provided and others that were made available to us through internet link references from the U. S. Nuclear Regulatory Commission. These documents concern the license renewal of the Oyster Creek Nuclear Generating Station.

One issue of contention in the license renewal at hand is whether the corroded drywell shell retains adequate strength for continued service. Your specific instructions were to review the structural analyses and comment on the approach used to assess their adequacy. Thus, we did not address any issues related to either the preexisting corrosion damage or potential ongoing corrosion of the vessel, unless it was salient to our review of the structural analysis work.

This report contains two sections. The first section addresses the general structural analysis methods and results. The second section addresses the ASME Code provisions. In both sections, it is important to note that our comments and opinions are based on a severely limited review that only touches the highlights of the respective subjects. A more detailed review is needed to address these subjects with the depth of study necessary to uncover the fundamental differences between the work that was done in support of the license and the state-of-the-art in structural analysis.

## Structural Analyses

At issue is the structural adequacy of the drywell shell, which has the shape of an inverted light bulb. The primary structural concern is the drywell shell's ability to resist buckling with an adequate margin for continued safe operation.

The structural analysis results offered by AmerGen were obtained using typical techniques for the period of time in which the analyses were performed. Due to the limited computational power that was readily available at the time, the computer-aided analysis performed by General Electric (GE) utilized relatively small slices of

the vessel, idealized geometries (perfect spheres, cylinders, etc.), and required computationally efficient calculation techniques. Calculated buckling load behaviors for the idealized geometries were subsequently adjusted using assumptions or "capacity reduction factors" for surface irregularities, plasticity, and local buckling; and the resulting adjusted values were taken as representative of the actual buckling load. GE compared the calculated buckling loads with the imposed loads, and safety margins were determined for comparison to ASME Code minimum requirements. Primarily because of these computational limitations, the finite element analysis performed by GE on the drywall vessel may not be adequate to capture its global behavior, which may be some combination of symmetrical and anti-symmetrical buckling.

The state-of-the-art has progressed far beyond the methods available to structural analysts in the early 1990s. Today, when reconstructing or reverse engineering existing structures, it is routine to use laser devices to generate "point clouds" that fully define the surfaces of pressure vessels, including any irregularities. The point clouds are digitalized, and the digitized information is converted into a mathematical representation of the actual surface shape, which is subsequently utilized for full three-dimensional modeling. Since the resulting models account for actual surface waviness, unevenness, bulges, facets, and other potentially deleterious geometric surface conditions, there is no longer any need to resort to the use of "capacity reduction factors" to determine buckling loads, as the GE analysts were forced to do.

The digitized surface is converted into a form suitable for meshing and further processing using finite element analysis (FEA). The mesh areas are then assigned the corroded thicknesses at the specific areas where they actually occur, and any future corrosion allowance is subtracted from the thickness at this time. The FEA mesh density would then be generated as fine as needed to capture the stiffness that resists buckling. The simulated loads are then applied and the buckling load and shape are directly calculated without needing imposed perturbations or anything except the measured geometry and thicknesses.

Utilization of point cloud surface mapping techniques along with measurements that represent the actual wall thickness is thought to give the most accurate structural analysis results possible, with the fewest assumptions, using current technology. Three-dimensional thin shell analyses can be done today with few assumptions concerning stiffness and in a way that complies with Case N-284-1-1320.

**ASME Code[1] Provisions**

At issue is whether the Code is the best tool available for determining the drywell's fitness for continued service.

In general, the Code establishes rules of safety relating only to pressure integrity and governing the construction[2] of boilers, pressure vessels, transport tanks, and nuclear components. Its

[1] ASME Boiler and Pressure Vessel Code, Section III, *Nuclear Components*, and Section VIII, *Rules for Construction of Pressure Vessels*, American Society of Mechanical Engineers, Three Park Avenue, New York, NY 10016

[2] *Construction*, as used in the Code, is an all-inclusive term comprising materials, design, fabrication, examination, inspection, testing, certification, and pressure relief.

wording allows for some latitude in design and analysis methods, anticipates that deterioration of pressure vessels will occur, requires the use of engineering judgment, and recognizes the inevitability of technological progress in design and analysis methods. The following statements, which we excerpted from the FOREWORD of the current edition of the ASME Boiler and Pressure Vessel Code, support this contention.

*"The Committee's function is to establish rules of safety, relating only to pressure integrity, governing the construction of boilers, pressure vessels, transport tanks and nuclear components, and inservice inspection for pressure integrity of nuclear components and transport tanks, and to interpret these rules when questions arise regarding their intent... With few exceptions, these rules do not, of practical necessity, reflect the likelihood and consequences of deterioration in service relating to specific service fluids or external operating environments. Recognizing this, the Committee has approved a wide variety of construction rules in this Section to allow the user or his designee to select those which will provide a pressure vessel having a margin for deterioration in service so as to give a reasonably long, safe period of usefulness. Accordingly, it is not intended that this Section be used as a design handbook; rather, engineering judgment must be employed in the selection of those sets of Code rules suitable to any specific service or need... The Committee recognizes that tools and techniques used for design and analysis change as technology progresses and expects engineers to use good judgment in the application of these tools."*

Clearly, the authors of the Code never intended that its rules be used as the only arbiter of pressure vessel structural integrity. Neither did the authors intend the rules be used to extend, possibly unreasonably, the useful life a significantly corroded nuclear pressure vessel such as the drywell. Nonetheless, some continue to rely on Code construction rules for these purposes. They continue to do so despite the existence of tools such as three-dimensional thin shell analysis that have proven to be more than adequate for nuclear applications when applied in the presence of seasoned engineering judgment.

Respectfully Submitted,

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Stress Engineering Services, Inc.

J. Kirk Brownlee, P. E.
Staff Consultant
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Citizens' Exhibit NC 11

Resumes of
J. Kirk Brownlee, P.E. and
Richard C. Biel, P.E.
of Stress Engineering Services, Inc.

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# J. KIRK BROWNLEE, P. E.

## Specialized Professional Competence

Mr. Brownlee is a registered professional engineer in the State of Texas (#94383). He holds a Bachelor of Science degree in mechanical engineering from Texas A&M University and a Master of Science degree in metallurgical engineering from the Colorado School of Mines. For over 20 years he has developed and demonstrated specialized competencies in the areas of materials selection and evaluation, corrosion control, welding engineering, nondestructive testing, and failure analysis principally as related to facilities for oil and gas production, transportation, and refining.

## Research Activities

As a graduate student at Texas A&M, Mr. Brownlee conducted research on superplastic forming of aluminum alloys. His research at the Colorado School of Mines dealt with the effects of aluminum and titanium on the microstructure and properties of microalloyed steel weld metals. As a summer intern at the Los Alamos National Laboratory, Mr. Brownlee carried out research on the electron beam weldability of 5000-series aluminum alloys.

Since joining industry in 1985, Mr. Brownlee has conducted or participated in several research projects dealing with the sulfide stress cracking behavior of low alloy steels in sour environments.

## Employment History

Staff Consultant, SES, August 2003 - Present
Staff Research Engineer, Shell Global Solutions, April 2001-August 2003
Sr. Staff Engineer, ExxonMobil Production Co., January 2000-April 2001
Sr. Staff Engineer, Mobil E&P US, August 1995-January 2000
Consultant, Metallurgical Consultants, Inc., January 1986-August 1995
Staff Engineer, Brown & Root Marine, May 1985-January 1986
Graduate Research Assistant, Colorado School of Mines, August 1982-May 1985
Pipe Stress Engineer, Fish Engineering & Construction, May 1981-August 1982

## Academic Background

M. S., Metallurgical Engineering, Colorado School of Mines, 5/85
B. S., Mechanical Engineering, Texas A&M University, 5/80

## Professional Honors

Tau Beta Pi
Pi Tau Sigma

**Professional Societies**

Society of Petroleum Engineers (SPE)
National Association of Corrosion Engineers (NACE) #101943-00

**Publications and Presentations**

Brownlee, J. K., The Effects of Aluminum and Titanium on the Microstructure and Properties of Micro alloyed Steel Weld Metal, Master of Science Thesis T-3064, Colorado School of Mines, Golden CO, April 1985.

Brownlee, J. K., Matlock, D. K., Edwards, G. R., The Effects of Aluminum and Titanium on the Microstructure and Properties of Micro alloyed Steel Weld Metal, Proc. Int'l. Conf. On Trends in Welding Research, Gatlinburg, TN, May 18-22, 1986.

Brownlee, J. K., Matlock, D. K., Edwards, G. R., The Effects of Aluminum and Titanium on the Microstructure and Properties of Microalloyed Steel Weld Metal, Advances in Welding Science and Technology, ASM, 1987, pp. 245-250.

Bruno, T. V., Craig, B. D., Brownlee, J. K., The Role of Ni in the SCC of Low-Alloy Steels, Corrosion, Vol. 46, No. 2, February, 1990, pp. 142-146.

Andersen, O., Brownlee, J. K., Craig, B. D., et. al., Material Requirements for Offshore Pipelines/Flowlines, Paper #7, Proc. Int'l. Workshop on Advanced Materials for Marine Construction, February 4-7, 1997, New Orleans, LA, AB S, 1999, pp 461-489.

Dougherty, J., Hausler, R., Brownlee, J. K., Solving Iron Sulfide Problems in a Recirculating Inhibitor Oil System, Paper Presented at NACE International Corrosion 2000, March 26-31, 2000, Orlando, FL.

Brownlee, J.K., Flesner, K.O., Riggs, K.R., Miglin, B.P., Selection and Qualification of Materials for HPHT Wells, SPE Paper No. 97590, 2005 SPE Applied Tech. Workshop on High Pressure/High Temperature Sour Well Design, Houston, TX, 17-19 May, 2005.

Brownlee, J.K., Speed, C.F., Decision Making in Coating Selection, Coatings for Corrosion Protection: Offshore Oil & Gas Operation Facilities, Marine Pipeline & Ship Structures, April 14-16, 2004, Imperial Palace and Casino, Biloxi, MS.

**Engineering Design and Analysis**

- Performed calculations to determine wet $CO_2$ and wet $CO_2/H_2S$ corrosion rates for three deepwater Gulf of Mexico pipelines.
- Specified materials of construction for three CRA clad sour gas submarine pipelines.
- Specified materials of construction for a compressor booster station in Uzbekistan.
- Conducted fitness for purpose tests on CRA materials for sour gas compressor impellers.
- Designed automated corrosion monitoring systems for a large sour gas processing plant and two submarine sour gas pipelines.

- Designed risk-based inspection programs for fixed equipment in sour service.
- Performed failure analyses on numerous oilfield components including pressure vessels, pipelines, well head equipment, drill pipe, casing, tubing, piping & valves, etc.
- Prepared welding and line pipe specifications for a major offshore project in the deepwater GoM
- Determined and alleviated the causes for cracking during high temperature forming of 3Al-2V Ti-alloy pressure vessel heads

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HOUSTON • CINCINNATI • NEW ORLEANS • CHICAGO

**RICHARD C. BIEL, P.E.**

## Specialized Professional Competence

Mr. Biel's current work is focused on fitness for service evaluations of pressure vessels and piping components and systems. This international practice has served a variety of clients including fabricators, petroleum refineries, power and chemical plants and paper mills. Before joining SES in 1994, he was the manager of R&D for a fabricator of pressure vessels and specialty high temperature refinery equipment and associated valves. His design work has included ASME Code pressure vessels for Division 1, 2, and 3 compliance as well as general machine designs. In addition, Mr. Biel has over 14 years of industrial experience in the design of land well heads and gate valves, including designs for Arctic service and critical sour, corrosive service. As a consultant from 1980 to 1985, he had assignments with numerous clients involving well heads, gate valves, pressure vessels, oil tools, general machine design, and forensic engineering.

Mr. Biel currently serves as a member of the Special Working Group on High Pressure Vessels (SWG-HPV SC VIII). This ASME Code committee authors the Boiler and Pressure Vessel Code, Section VIII, Division 3, ***Alternate Rules for Construction of High Pressure Vessels.*** He also serves on various other ASME Code committees.

## Research Activities

Mr. Biel has tested prototype valves and well heads under extreme environmental conditions, including low temperature and high temperature and high pressure gas. He has qualified many well head components to meet API Specifications by classical calculations and physical tests.

He designed modifications to a flowing test facility where he physically life-cycle tested gate valves to 10,000 psi for hundreds of cycles to evaluate wear and performance.

## Employment History

Senior Associate/Staff Consultant, Stress Engineering Services, Inc. 1998 - Present
Staff Consultant, Stress Engineering Services, Inc., 1994 - 1998
Manager, Research and Development, Enpro Systems, Inc., 1990 - 1994
Manager, Material Test Section, NASA White Sands Test Facility, Lockheed Engineering and Sciences Company, 1988 - 1990
Manager, Product Engineering (Wellheads), WKM, 1985 - 1987
President, Cornerstone Engineering, Inc., 1980 - 1985
Senior Design Engineer, National Supply Company, 1978 - 1980
Applications/Design Engineer, Gray Tool Company, 1975 - 1978
U.S. Air Force, 1968 - 1975
Aerospace Engineer, NASA, 1968

**Academic Background**

M.E., Mechanical Engineering, University of Houston, 1979
B.S., Mechanical Engineering, New Mexico State University, 1968
Completed NASA cooperative work-study program and U.S. Air Force ROTC

**Registration**

Licensed (Registered) Professional Engineer: Texas, No. 45901, 1979
Voluntary Continuing Professional Competency Program, Texas, 1998 – 2000 (Voluntary program discontinued)

**Professional Honors**

Alan J. Chapman Award, South Texas Section, ASME, 2005
Meritorious Service Award, South Texas Section, ASME, 2003
Meritorious Service Award, South Texas Section, ASME, 2002
Meritorious Service Award, South Texas Section, ASME, 2001
Meritorious Service Award, South Texas Section, ASME, 1999
Meritorious Service Award, South Texas Section, ASME, 1998
Commendation, South Texas Section, ASME, 1979
Military honors and awards associated with 111 combat missions as a fighter pilot in Vietnam and Cambodia and an instructor pilot in Texas
Outstanding Graduate, U.S. Air Force Undergraduate Pilot Training, 1970

**Professional Society Memberships**

American Society of Mechanical Engineers (ASME)
Member, 1975 - Present
Secretary/Treasurer, Northwest Houston Subsection, 1995 - 1997
Industry Relations Chair, South Texas Section, 1993 - 1995
Public Relations Chair, South Texas Section, 1991 - 1993
Member, National Society of Professional Engineers (NSPE) and Texas Society of Professional Engineers (TSPE), 1996 - Present
Pi Tau Sigma, National Mechanical Engineering Honorary Fraternity, 1966
Chapter President 1967 - 1968
Sigma Tau, National Engineering Honorary Fraternity, 1966

**Professional Activities**

Member, ASME Boiler and Pressure Vessel Code, Special Working Group on High Pressure Vessels (SCVIII, Section VIII, Division 3), and Task Group on Design "TGD", 1994, Appointment "Commission" expires September 2008
Member, ASME Boiler and Pressure Vessel Code, Task Group on Impulsively Loaded Vessels (SCVIII), 2003, Appointment "Commission" expires September 2008
Corresponding Member, ASME Boiler and Pressure Vessel Code, Project Team on Hydrogen Tanks, 2004, Appointment "Commission" expires June 2009

Member, ASME Board on Pressure Technology Codes and Standards (BPTCS) Task Force on Hydrogen Storage and Transport Tanks, 2003 – 2004

Course Coordinator and Instructor, South Texas Section ASME, Pressure Vessel Engineering Seminar; Design by Analysis, Fatigue Analysis, High Temperature Vessels, and Division 3. 1995 - 2005

Instructor, New Orleans Section ASME, The ASME Pressure Vessel Code in Fitness for Service Applications, 1998 - 2001

**Publications and Presentations**

Biel, Richard C., and Alexander, Christopher R.; "Applications of Limit Load Analyses to Assess the Structural Integrity of Pressure Vessels" PVP2005-71724, ASME, Denver CO, July 2005

Young, Kenneth; Alexander, Christopher R.; Biel, Richard C.; and Shanks, Earl, "Updated Design Methods for HPHT Equipment," SPE 97595, 2005 SPE Applied Technology Workshop on High Pressure/High Temperature Sour Well Design, Houston, TX, Society of Petroleum Engineers, 17 – 19 May 2005

Biel, Richard C. "Mechanics of Pressure Vessels," presentation to the Acoustic Emission Working Group, AEWG-48, Houston TX, May 2005

Biel, Richard C. "Applications of Limit Analyses," presentation at the ASME Plant Engineering & Maintenance Trade Show, Pasadena TX, April 2005

Alexander, Christopher R. and Biel, Richard C., "Certification Program for Assessing the Mechanical Integrity of Pressure Vessel Systems" PVP-Vol. 487, *Aging Management and License Renewal*, ASME, La Jolla CA, July, 2004

Alexander, Christopher R.; Jagodzinski J.; and Biel, Richard C., "Stress Analysis of the 46-Inch Reactor Feed / Effluent Heat Exchanger" PVP-Vol. 478, *Analysis of Bolted Joints*, ASME, 2004

Biel, Richard C. "Elements of a Pressure Vessel Certification Program" presentation at the ASME Plant Engineering & Maintenance Trade Show, Pasadena TX, April 2004.

Biel, Richard C. "API 510 Repair Avoids Lengthy Shutdown," Second Pan-American Conference for Nondestructive Testing, ASNT, Houston TX, June 2001

Alexander, Christopher R.; Biel, Richard C., et al., "Fitness for Service Evaluation of a Platformer Reactor Vessel," PVP-Vol. 359, *Fitness for Adverse Environments in Petroleum and Power Equipment*, ASME, Honolulu HI, July 1997

Biel, Richard C. "API-510, An Engineer's Perspective" presentation to the Greater Houston Section, ASNT, March 1995

Biel, Richard C. "Algor FEA Helps Shave 15,000 Lbs. From Huge Butterfly Valve," *Algor Design World*, January 1993.

Biel, Richard C. "FEA Shaves 15,000 Lbs. From Huge Butterfly Valve," *Design News*, November 1992.

**Forensic Work**

Mr. Biel has researched and investigated several matters concerning pressure vessels, piping, and general mechanical design. He has been deposed and has testified as an expert witness in several matters. He has testified internationally on intellectual property matters. He has prepared exhibits for use at trial that explain technical issues clearly. A complete listing of litigation work is available on request.

**Engineering Designs and Analyses**

Mr. Biel has designed, re-rated, and analyzed numerous pressure vessels and prepared Certified User's Design Specifications and Certified Manufacturer's Design Reports for ASME Code Section VIII, Divisions 1, 2, and 3 compliance. These calculations include thermal, cyclic fatigue, wind, transient loading, seismic analyses, and stresses due to external piping loads on nozzles and skirt/saddles. Many of these designs required detailed finite element analysis to adequately describe the stress conditions, including non-linear collapse and limit state calculations.

He has done several studies in high temperature structural material behavior during post weld heat treatment. He designed and analyzed specialty valves for refinery Fluidized Catalytic Cracking Unit (FCCU) catalyst and flue gas service up to 1,800°F as well as catalyst lines for service to 1400°F. His finite element analyses of thermal and elastic/plastic behavior of these valves and piping were used to prevent structural failure and assure function without excessive distortion or binding.

He has designed full product lines of conventional API land well head equipment including conventional and automatic slip-type casing hangers, mandrel casing and tubing hangers, packoff and stripper seals, valve removal plugs and tubing plugs with the associated running tools, and ancillary equipment. Mr. Biel designed, prototyped, and environmentally tested well head assemblies for Arctic gas service. As a consultant to a major oil company, he wrote specifications for Arctic service well heads. He has designed a family of well head gate valves from 2" through 6" - 2,000 psi; 1-13/16" through 4-1/16" - 10,000 psi; and 1-13/16" through 3-1/16" - 15,000 psi.

Mr. Biel has tested prototype valves and well heads under extreme environmental conditions including low and high temperatures and high pressure gas. He designed modifications to a test facility where he physically life cycle tested gate valves to 10,000 psi to evaluate wear and performance.

He was instrumental in the proposal, design and development of a facility to test hypervelocity impacts of pressurized propellant and oxidizer cylinders. This testing simulated collisions of space debris with spacecraft in near earth orbit.

Mr. Biel currently serves as a member of the ASME Special Working Group on High Pressure Vessels. This Code committee authors the ASME BPV Code, Section VIII, Division 3. He also serves on the associated Task Group on Design. His contributions to this Task Group have aided the preparation of the Code rules for these vessels. He formerly chaired a Task Group, within the Special Working Group, that reviewed new construction techniques for inclusion into the Code and was instrumental in the passage of Section VIII, Division 3, Code Case 2390 *Composite Reinforced Pressure Vessels.*

**Miscellaneous**

Mr. Biel has a current passport, and speaks some Spanish.

UNITED STATES OF AMERICA
BEFORE THE NUCLEAR REGULATORY COMMISSION
OFFICE OF THE SECRETARY

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | Docket No. 50-0219-LR |
| AMERGEN ENERGY COMPANY, LLC | ) | |
| | ) | ASLB No. 06-844-01-LR |
| (License Renewal for the Oyster Creek | ) | |
| Nuclear Generating Station) | ) | July 25, 2006 |
| | ) | |

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Supplemental Petition with attachments and Exhibit NC 11 was sent this 25th day of July, 2006 via email and U.S. Postal Service, as designated below, to each of the following:

Secretary of the Commission (Email and original and 2 copies via U.S Postal Service)
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Signed: _____
Richard Webster

Dated: July 25, 2006