APPLICANT'S EXH. 3

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U.S. NUCLEAR REGULATORY COMMISSION
In the Matter of AMERGEN ENERGY CO., LLC
Docket No. 50-0219-LR Official Exhibit No. 3
OFFERED by: Applicant/Licensee Intervenor
NRC Staff Other
IDENTIFIED on Witness/Panel
Action Taken: ADMITTED REJECTED WITHDRAWN
Reporter/Clerk

10 CFR 50
10 CFR 51
10 CFR 54

December 8, 2006

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555
Attention: Mr. Michael A. Junge
Mail Stop: T2E26

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating License for Oyster Creek Generating Station (TAC No. MC7624)

Reference: AmerGen Letter to NRC, "Change to Timing for Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating License for Oyster Creek Generating Station (TAC No. MC7624)," dated November 1, 2006

In accordance with the Reference letter, AmerGen hereby submits information to the Advisory Committee on Reactor Safeguards (ACRS) Plant License Renewal Subcommittee related to AmerGen's application for renewal of the Oyster Creek Generating Station (OCGS) operating license. This information is intended to assist the Subcommittee in its preparation for a meeting being scheduled for January 2007 between the Subcommittee, the NRC Staff and AmerGen.

Contained within the Enclosure is a detailed discussion of the primary containment drywell corrosion issue history, which includes information learned during the October 2006 refueling outage. Numerous source documents are referenced in the discussion, and these are provided as part of the Enclosure.

If you have any questions regarding this information, please contact Fred Polaski at 610-765-5935.

Respectfully,

Michael P. Gallagher

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Vice President, License Renewal
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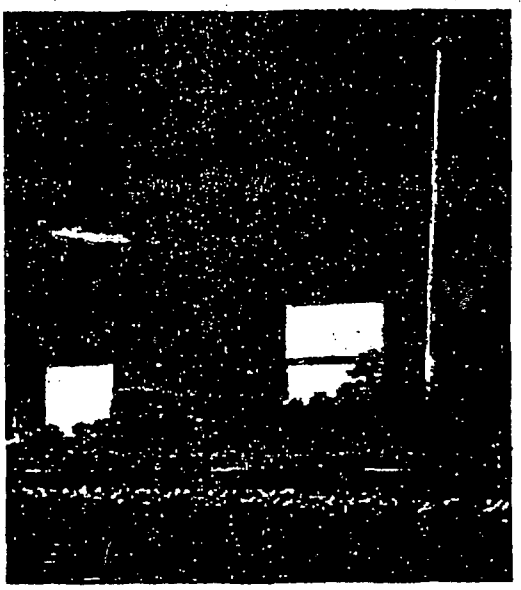
Enclosure: Oyster Creek License Renewal Project, Drywell Monitoring Program – Information for ACRS Subcommittee

cc: NRC Director (Acting), License Renewal, w/o Enclosure
Regional Administrator, USNRC Region I, w/o Enclosure
NRC Project Manager, NRR - License Renewal, Safety, w/Enclosure
ACRS Staff Lead – Cayetano Santos, w/Enclosure (15 copies)
NRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosure
NRC Project Manager, OCGS, Part 50, w/o Enclosure
NRC Senior Resident Inspector, OCGS, w/o Enclosure
New Jersey Bureau of Nuclear Engineering, w/o Enclosure
Oyster Creek File No. 05040

Oyster Creek
License Renewal Project

Drywell Monitoring Program



Information for ACRS Subcommittee

December 8, 2006

Enclosure - Table of Contents

This package of historical information and 2006 outage information is being provided to the ACRS Subcommittee reviewing the License Renewal Application for Oyster Creek. The purpose of the information is to respond to questions that were raised at the ACRS Subcommittee meeting on October 3, 2006 concerning the corrosion of the drywell shell and to update the Subcommittee on the results of recent inspection activities. This package is meant to help the ACRS members understand the information that the NRC staff has already reviewed over the course of weeks of audits and inspections. As such, the information set forth in this package consists of documents and responses to questions that were available to the NRC staff during the NRR AMR and AMP audits in January and February 2006, during the NRC Region 1 inspection in March 2006, in response to NRC RAIs during the review of the Oyster Creek License Renewal Application, in docketed correspondence between GPUN or AmerGen and the NRC, and in documents reviewed by NRC Region 1 during the 2006 refueling outage. The information provided also includes some historical information that serves as the basis or support for documents that were reviewed by the NRC.

Although the information included in this package has been available to the NRC, AmerGen has in many cases formatted the information differently in order to address some of the questions asked by ACRS members. For example, the NRC staff may have reviewed numerical data on drywell shell corrosion provided in a table. In this document, however, AmerGen prepared a graphical representation of the data to show how the drywell shell corrosion rate has changed with time up to and including data obtained during the 2006 refueling outage and including the margin that is available.

The information being provided by AmerGen is organized into the following five primary areas of interest dealing with the corrosion on the surfaces of the Oyster Creek drywell shell:

- Leakage of water onto the drywell shell external surface during refueling outages. (Section 4)
  - Includes a summary of significant events related to water leakage, information on the historic identification and evaluation of reactor cavity liner defects, historic troubleshooting and repairs to the reactor cavity trough area, and actions in place to minimize, detect and assess the impact of any leakage going forward.
- The Upper Regions of the drywell. (Section 5)
  - Includes information on periodic UT measurements taken from the inside of the drywell, the process to determine the locations monitored, and the random sampling confirmation of the monitored locations.
- The Sandbed Region. (Section 6)
  - This includes information on historical and recent UT thickness readings, the early 1990s General Electric buckling analysis, and early 1990s preparing and coating of the external surface of the drywell shell.

- The embedded part of the drywell shell exterior. (Section 7)
  - Includes information on environmental conditions for the embedded part of the shell located below the sandbed region.
- The embedded part of the drywell shell interior. (Section 8)
  - Includes information on construction, required shell thicknesses and environmental conditions for the embedded part of the shell that is inside the drywell

Information in each topic area is presented somewhat differently. Topics 1, 4 and 5 are generally narrative in nature presenting historical and technical information, with references to supporting documents. Topics 2 and 3 provide both a narrative presentation of the topic, and include UT measurement data that support AmerGen's understanding of and position on corrosion of the outer surface of the drywell shell.

The information on each of the five topics references many source documents, all of which are included in this package. Some of the references include the detailed inspection results.

In addition to these 5 topics, the package also includes a timeline that shows the sequence of relevant events, starting with the first discovery of water in the sand bed drains in 1980 up to and including the inspections performed during the refueling outage in October 2006. Also, the package includes a section on the general description of the Oyster Creek drywell, with associated drawings and figures.

1969	Begin Oyster Creek plant operation.
1980	Water identified coming from sand bed drains.
1980, 83, 86, and 89	Investigation into source of water leaking from sandbed drains, and the leakage path.
1986	• 2 trenches excavated in the floor inside the containment to gain access to the inside of the drywell shell at an elevation corresponding to a lower portion of the sandbed region (Bays 5 & 17).
1986 to 89	• Corrosion monitoring of the drywell shell from the inside to establish and characterize the extent of corrosion. • 19 grid locations inside the drywell at Elev. 11' 3" established for monitoring corrosion in the sandbed region with UT measurements. • Approximately 1,000 UT points taken circumferentially around the inside of the drywell shell. • 12 representative grid locations selected from the 1,000 points for continued monitoring of the upper drywell area. • Core samples taken at 9 locations of the drywell shell.
1988	• Cathodic protection system installed on drywell shell. • Sand removal from the sandbed region started. • Repairs made to reactor cavity concrete trough to improve drainage. • Visual and UT inspections in trenches.
1990	UT thickness measurements of the drywell shell taken at 57 randomly selected locations to confirm the 12 grid locations identified previously for monitoring were representative of the leading corrosion locations. One additional location added to the original 12.
1992	• Cathodic protection system removed because it was not effective in preventing corrosion. • Sand removal from the sandbed regions completed. • External surface of the drywell shell in the sand bed region cleaned. • 125 UT readings taken to confirm minimum thickness locations from the external surface. • Epoxy coating applied to the external surface of the drywell shell in the sandbed region. • Surface of the concrete floor in the sandbed regions finished with epoxy and sealed against the drywell shell. • UT of the sandbed region from inside the drywell at 19 grid locations at Elevation 11'-3". • UT readings from the inside of the drywell shell at the 13 grid locations in the upper elevations.
1994	• UT of the sand bed region from inside the drywell at 19 grid locations at Elevation 11'-3". • Visual inspection of epoxy coating on outside of drywell in the sand bed region (Bays 3 & 11). • UT readings from the inside of the drywell shell at the 13 grid locations in the upper elevations.
1996	• UT of the sand bed region from inside the drywell at 19 grid locations at Elevation 11'-3", but some data appeared anomalous. • Visual inspection of epoxy coating on outside of drywell in the sand bed region (Bays 11 & 17).

	• UT readings from the inside of the drywell shell at the 13 grid locations in the upper elevations.
2000	• Visual inspection of epoxy coating on outside of drywell in the sand bed region (Bays 1 & 13). • UT readings from the inside of the drywell shell at the 13 grid locations in the upper elevations.
2004	• Visual inspection of epoxy coating on outside of drywell in the sand bed region (Bays 1 & 13). • UT readings from the inside of the drywell shell at the 13 grid locations in the upper elevations.
2005	Oyster Creek License Renewal Application submitted to the NRC on July 22, 2005.
2006	• Visual inspection of epoxy coating on outside of drywell in the sand bed region in all 10 bays. • Visual inspection of the caulk seal at the junction between the sand bed region floor and the drywell shell in all 10 bays. • UT readings at 19 grid locations in the sand bed region from inside the drywell at Elevation 11'-3". • UT readings at 106 locally thinned areas (previously inspected in 1992) from outside the drywell in the sand bed region. • Visual inspections and UT readings of the drywell shell in the two trenches inside the drywell including additional excavation in the Bay 5 trench. • UT readings at two grid locations each at two transition plate locations from inside the drywell (Elevations 23'-6" and 71'-6"). • UT readings from the inside of the drywell shell at the 13 grid locations in the upper elevations to confirm low corrosion rates or no observable corrosion. • Boroscopic examination of reactor cavity trough drain line and all 5 sand bed drain lines. • Monitored the Sandbed Regions drains for leakage. • Monitored the Reactor cavity trough drain for leakage. • Repaired/modified areas internal to the drywell to minimize the potential for water intrusion into the area between the embedded. drywell shell and the drywell concrete floor.

The Oyster Creek primary containment is a General Electric Mark I design, with a drywell, suppression chamber, and a vent system connecting the drywell and the suppression chamber. It is designed, fabricated, inspected, and tested in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, and Nuclear Code Cases 1270N-5, 1271N, and 1272N-5.

The drywell is a steel pressure vessel, in the shape of an inverted light bulb, with a spherical section and a cylindrical section (See Figures 1 thru 4) located inside the Reactor Building. The Reactor Building Foundation floor is a 10 ft thick reinforced concrete mat. The bottom elevation of the mat is minus 29' 6" and its top elevation is minus 19' 6" (See Figure 4). There is a waterproof membrane at the bottom of the mat that extends up the outside of the exterior walls to an Elevation of 5' 0". The concrete pedestal that supports the drywell is located at the center of the mat. The Torus Room completely surrounds this concrete pedestal with a floor elevation of minus 19' 6" (top of mat). The drywell shell has a bottom elevation of 2' 3".

The spherical section of the drywell was supported on a 39-foot diameter continuous steel skirt during construction (See Figures 4 & 7). The area within the skirt was filled with concrete and the floor inside the bottom of the sphere (drywell floor) was poured up to elevation 10' 3". The reactor support structure (pedestal) sits on top of the drywell floor (See Figure 5). The area within the reactor pedestal provides access for Control Rod Drive exchanges and is typically referred to as the Sub-Pile Room. The room also contains the drywell sump and a drainage trough that collects any leakage within the drywell. The Sub-Pile Room floor is raised at the center and slopes toward the drainage trough. Leakage outside the Sub-Pile Room, in the drywell, is directed to the drainage trough through 4 holes in the reactor pedestal equally spaced around the circumference. A concrete curb is installed around the perimeter of the drywell floor (See Figure 4 & 5) to prevent any water that collects on the floor from coming in contact with the drywell shell. The curb is removed in two locations where two trenches (Figure 3) were excavated in the floor in 1986 to allow UT thickness measurements to be taken below the floor. A moisture barrier was added at the junction of the curb and the drywell shell and inside the trenches during the 2006 refueling outage to prevent water and moisture intrusion into the embedded drywell shell.

Outside the drywell support skirt and the spherical section, concrete was poured in contact with the sphere up to elevation 8' 11". At this point, the concrete was stepped back 15" radially up to elevation 12' 3" and later filled with sand (sandbed region), refer to Figures 5 & 7 for details. The purpose of the sandbed was to provide a cushion to smooth the transition of the shell plate from a condition of fully embedded between two concrete masses to a free standing condition. The sandbed region was provided with five drains designed to allow drainage of any water that may enter the region.

Above the sandbed region, the drywell shell is closer to the reactor building concrete shield wall. The outer surface of the drywell shell and the shield wall are separated by a gap filled with compressible material. After construction completion, this material was

compressed by heating and pressurizing the drywell to provide the gap required for free expansion of the drywell under design basis loads and postulated events.

At the top of the Reactor Building concrete shield wall, a concrete trough is located below the reactor cavity seal to collect any water that might leak from the reactor cavity during refueling outages. This trough is equipped with a drain line designed to direct any leakage to the Reactor Building equipment drain tank and prevent it from entering the gap between the drywell shell and the Reactor Building concrete shield wall (See Figure 6).

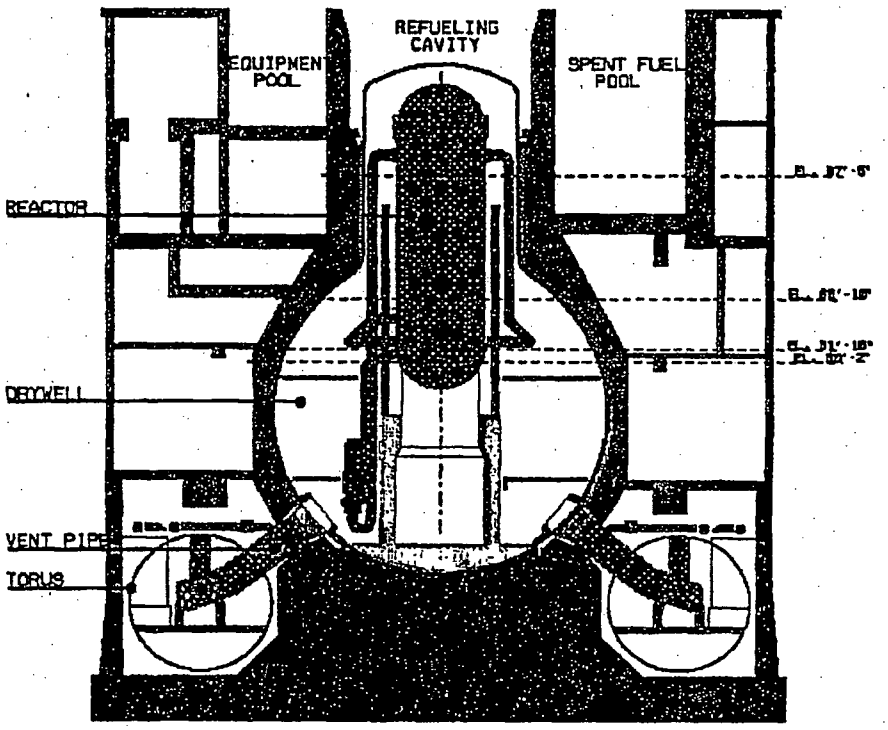
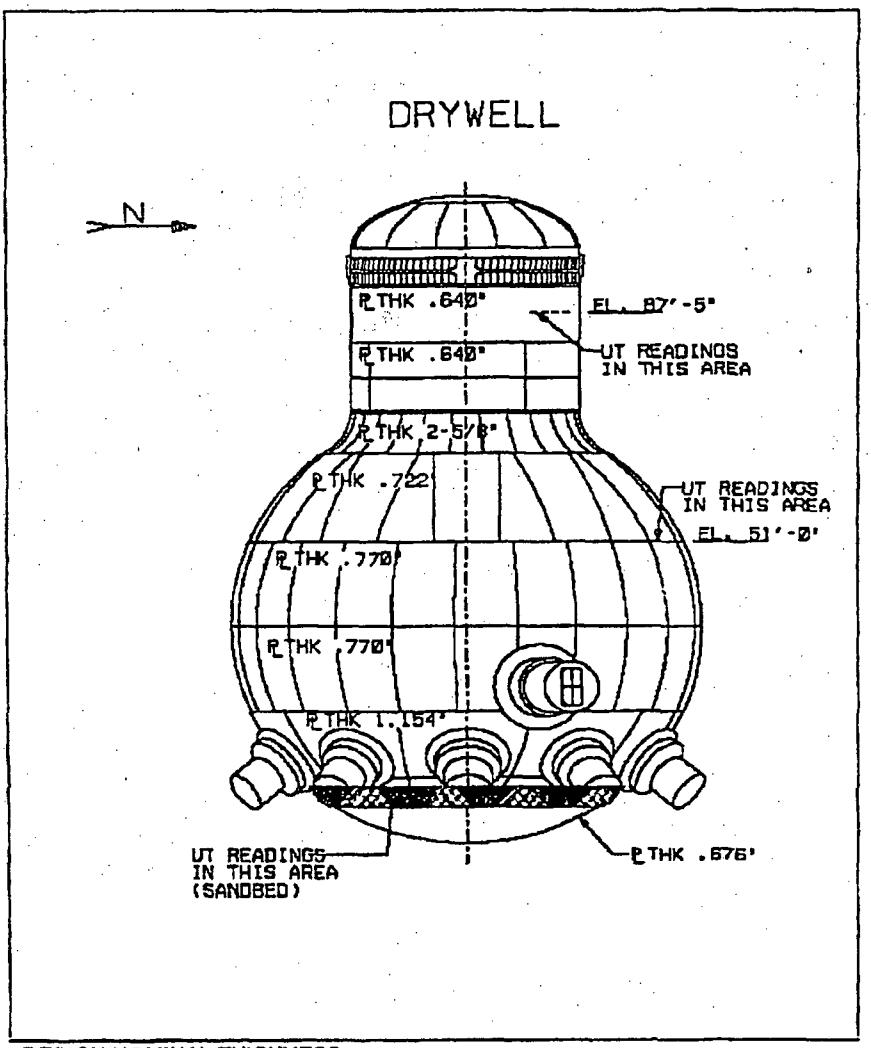


FIGURE 1 – PRIMARY CONTAINMENT CROSS-SECTION



PL THK = DESIGN NOMINAL THICKNESS

FIGURE 2 – DRYWELL ELEVATION

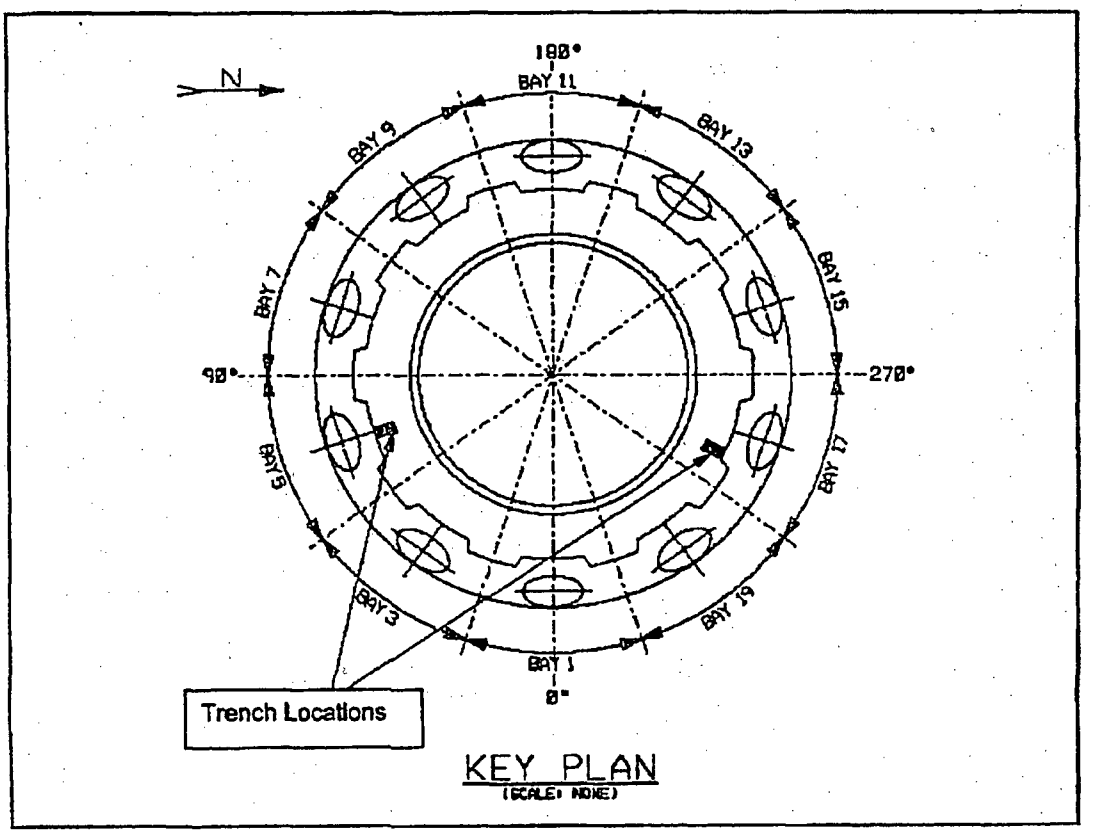
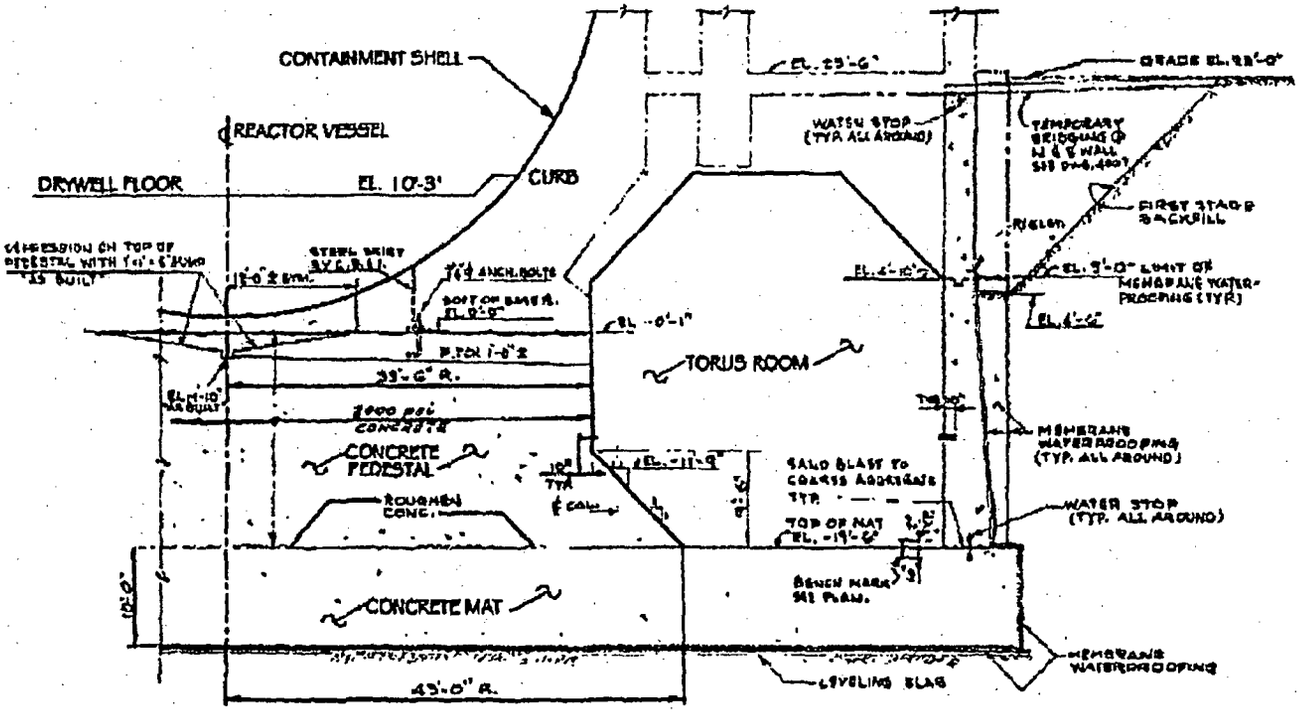


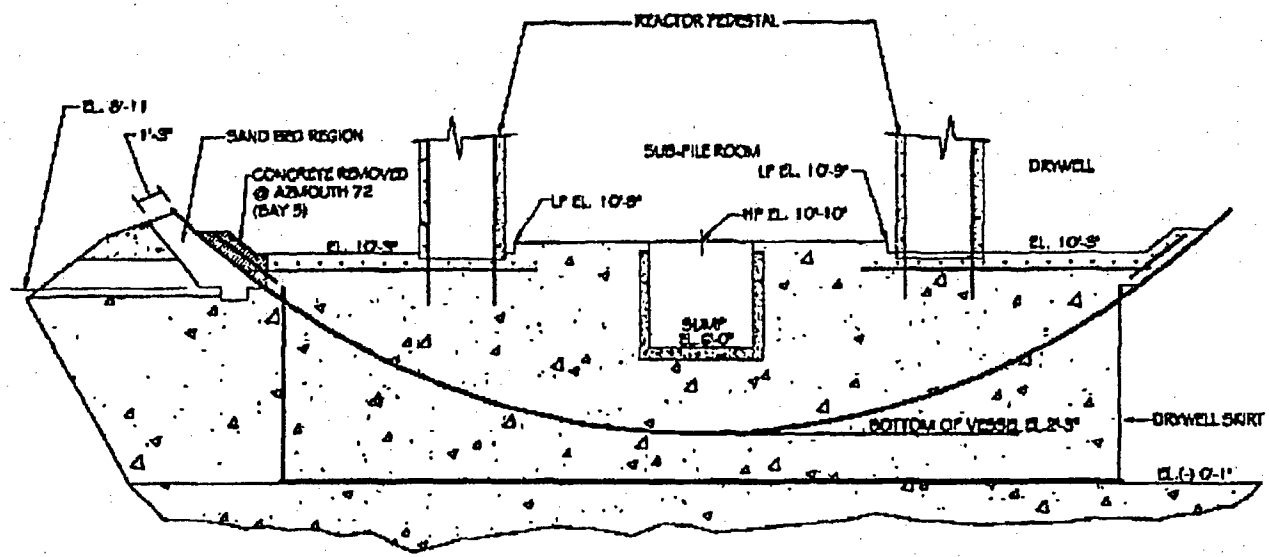
FIGURE 3 – DRYWELL BAYS

REACTOR BUILDING, DRYWELL SUPPORT STRUCTURE



ELEVATION
FIGURE 4

LOWER DRYWELL-
SANDBED, TRENCH & SUMP



ELEVATION LOOKING WEST

FIGURE 5

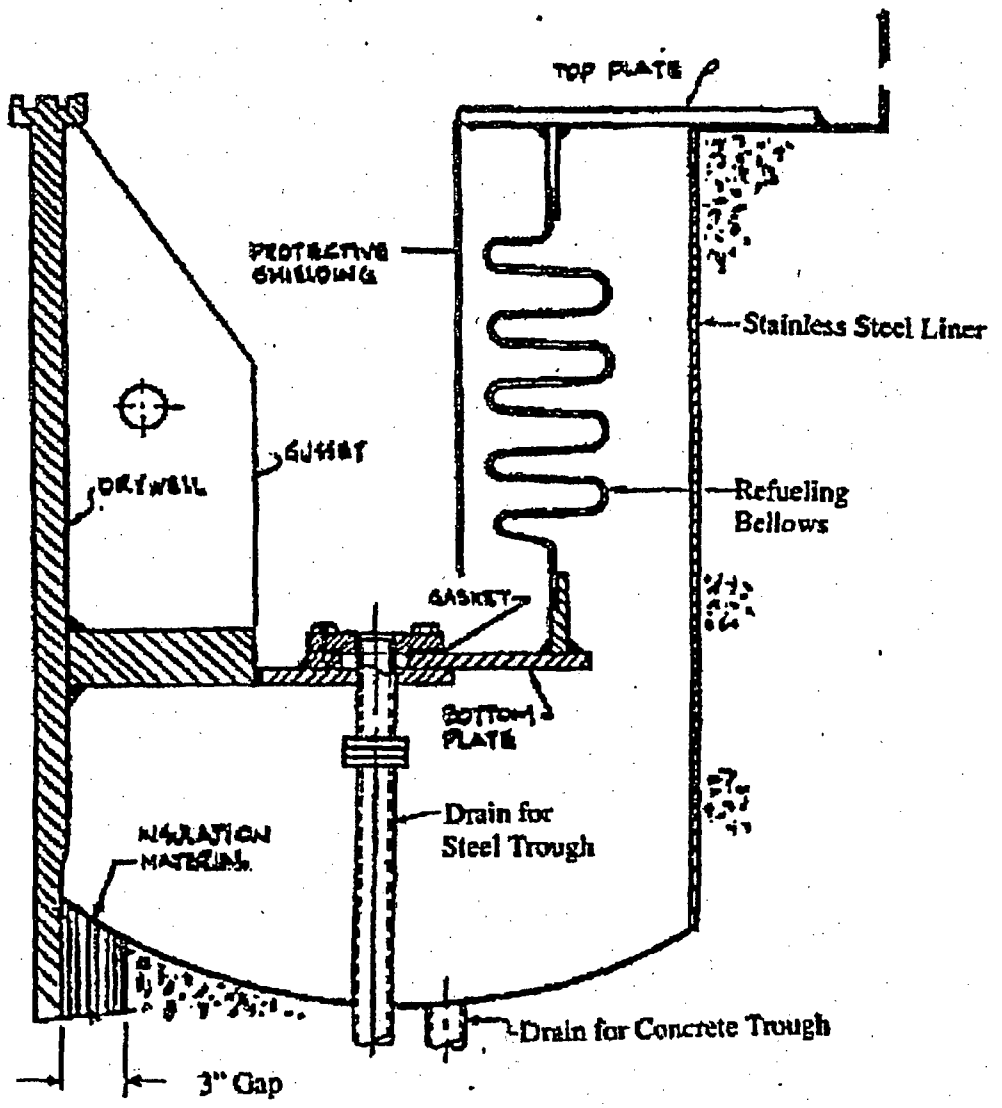


FIGURE 6 – REACTOR CAVITY TROUGH DRAIN

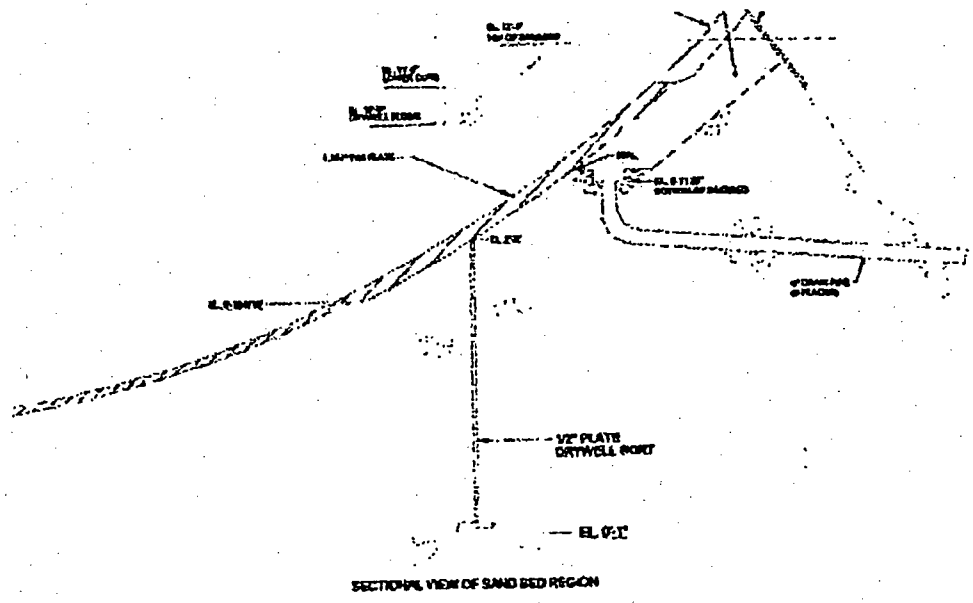


FIGURE 7

The following discussion addresses water leakage onto the exterior surface of the Oyster Creek drywell shell. Part I, below, provides a historic overview of information about water leakage prior to the October 2006 outage. The discussion in Part II summarizes prior commitments made by AmerGen aimed at preventing leakage onto the shell, monitoring for such leakage and performing corrective actions if leakage occurs. Part III sets forth information discovered and analyzed as a result of the October 2006 outage. Overall conclusions about the drywell, AmerGen's performance of associated commitments, and continued drywell operability during the proposed twenty-year renewal term are summarized in Part IV.

I. Historical Background

Water leakage onto the exterior of the Oyster Creek drywell shell over a period of years, in combination with an historically degraded sand bed region drainage system, created a condition that was conducive to corrosion of the exterior surface of the drywell shell. The previous owner/operator of Oyster Creek conducted extensive troubleshooting and repairs to determine and address the leakage and the corrosive effects of that leakage onto the drywell shell. As part of its license renewal activities, AmerGen has reviewed previous actions and instituted new measures (see Section II below) to ensure that leakage will be minimized and monitored, and that corrective actions will be implemented to ensure the drywell continues to perform its intended functions throughout the proposed twenty-year period of extended plant operation.

In addition, drywell commitments for license renewal are embedded in a formal AmerGen tracking system that includes specific work tasks, thereby ensuring timely implementation of the commitments and effective management oversight. Therefore, AmerGen is confident that the measures put into place to prevent and monitor leakage, in conjunction with the implementation of drywell shell visual and ultrasonic testing aging management program activities, will protect the shell such that it continues to perform its intended functions throughout the proposed period of extended operation.

A. Chronology of Significant Events (Also see Timeline, Section 2)

- 1980 – Water was observed coming from the sand bed drains. As part of the original design, these drains had been filled with sand during plant construction. The sand was restrained at the outlet with a 100-mesh stainless steel screen (0.006 inch opening). The intent was to prevent loss of sand from the sand bed region through the drain lines, yet allow drainage of water.
- 1980, 1983 and 1986 refueling outages - Extensive investigations were performed to identify the source of water and the leakage path. Results of the investigations indicated that:
    - Leakage was observed (from the sand bed drains) during refueling outages;

- Leakage was not attributed to the reactor cavity metal trough drain line gasket or the refueling bellows seal (See Figure 6 of Section 3 of this Enclosure).

  The reactor cavity metal trough drain line gasket leak was ruled out as the primary source of water observed in the sand bed drains because there was no clear leakage path to the gap between the drywell shell and reactor building concrete shield wall (i.e., drywell expansion gap). Any gasket leakage would be minor and would be collected in the concrete trough below the gasket. Also, inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested using helium (external) and air (internal) without any indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in the same concrete trough as would collect water from the gasket. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the drywell expansion gap (Ref [13], Attachment III).

- Leakage was attributed to through-wall cracks in the reactor cavity liner attributed to mechanical damage and to fatigue (Ref [13], Attachment III); and

- The leakage path was from the reactor cavity, to the concrete trough (later found to have been degraded – see Section C below) and through the drywell expansion gap down to the sandbed region within the reactor building (See Figure 6 of Section 3 of this Enclosure).

- Between 1988 and 1993, multiple mitigating actions were taken to address the corrosion problem. These actions included (Ref [32], page 9):

  - Cleared the former sand bed region drains of sand and corrosion products to improve drainage.

  - Replaced reactor cavity metal trough drain gasket, which was found to be leaking (See Figure 6 of Section 3 of this Enclosure).

  - Removed water from the sand bed region.

  - Installed a cathodic protection system in bays with greatest wall thinning. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and the system was removed from service in 1992.

  - Removed sand from the sand bed region to break up the galvanic cell (Ref [46]).

  - Removed corrosion products from the external side of the drywell shell in the sand bed region.

- Upon sand removal, the sand bed concrete floor was found to be cratered and unfinished. The concrete floor was repaired, finished and coated to permit proper drainage of the sand bed region (Refer to Section 7 of this Enclosure for details).

- Applied an epoxy caulk seal at the junction of the drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the drywell shell embedded in concrete (Refer to Section 6 of this Enclosure for details).

- Applied a multi-layered epoxy protective coating to the exterior surfaces of the drywell shell in the sand bed region (i.e., one pre-primer coat, and two top coats). (Refer to Section 6 of this Enclosure for details).

- Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal cracks in the stainless steel liner, in order to limit leakage from the reactor cavity. (Note that the steel tape was applied to larger cavity liner cracks and then the strippable coating was applied over the entire liner surface that would be (otherwise) wetted.)

- Confirmed that the reactor cavity concrete trough drain line was not clogged (See Figure 6 of Section 3 of this Enclosure)

B. Discovery and Evaluation of Cavity Liner Defects

In 1987, defects in the reactor cavity liner were documented and evaluated in material nonconformance report MNCR 87-240 (Ref [49]). These defects consisted of through-wall and surface indications detected by non-destructive examination of the liner near weld joints. The purpose of the cavity liner is to facilitate filling the reactor cavity with water for refueling activities.

The defects do not pose problems except when the reactor cavity is filled with water during refueling outages. If no preventive action is taken, the defects allow water to leak behind the liner and run down into the reactor cavity concrete trough. If the flow rate exceeds the capacity of the two-inch trough drain, then water would back up into the drywell expansion gap and drain onto the outside of the drywell shell.

Safety Evaluation 328257-002 was generated in 1988 with the purpose of addressing the adequacy of the design and the safety impact of installation of a temporary barrier on the OC Reactor Cavity Pool to prevent leakage of water during refueling operation (Ref 6, pages 7 - 13). In it, two major options were considered – weld repair of the liner and a temporary barrier over the entire cavity liner. The weld repair option had the following drawbacks: (a) there were too many defects in the liner, (b) weld repair of these defects would produce large residual stresses and warping of the liner, and (c) if weld repairs were implemented, the repair areas would eventually fail due to the same mechanism, in the future. Therefore, the temporary barrier option of metal tape and strippable coating was chosen for the repair (Ref [6], page 6).

C. Reactor Cavity Concrete Trough Area Testing and Repairs

As a result of observations of water leaking from concrete biological shield penetrations and sand bed drain lines during refueling outages in the early 1980s, numerous troubleshooting and repair activities were implemented over several years. These included:

- Air and helium leak testing of the bellows seal in the bottom of the reactor cavity (no leakage detected) and cavity drain line (no significant leakage found),
- Leak testing and some minor repairs to reactor cavity liner welds,
- Further pressure testing of the bellows (no leakage detected) at a later outage,
- Liquid penetrant testing of the cavity "steps" upon which the cavity shield plugs are placed (no indications detected), and
- Air purge testing of the drain line that channels refueling cavity leakage away from the gap between the drywell shell and concrete drywell shield wall (drain line did not appear to be restricted).

During the 1986 refueling outage, the drain line from the refueling cavity metal trough was inspected and the drain line gasket was found to have leaks, and was replaced. Additional leak tests were performed on the bellows during the 1986 outage and no leaks were detected (Ref [1], Attachment 2, pages 2-1 and 2-2).

During the 1986 refueling outage, camera inspections identified that the lip of the reactor cavity concrete trough was not sufficient to assure that water would not enter the area between the concrete shield wall and drywell shell. (Ref [5], page 3). Prior to reactor cavity flooding for the 1988 refueling outage, repairs were made to the concrete trough to rectify the condition. These repairs were determined to be effective based on visual inspections for leakage during the 1988 outage.

As noted previously, the mitigating features described above were implemented between 1988 and 1993. For the strippable coating, a latex coating was used at first. This latex coating had (a) stringent surface preparation requirements; (b) long curing time; and (c) lack of strength to absorb mechanical abuse during refueling. Accordingly, it was not applied during the 1994 and 1996 refueling outages. Discontinuation was also prompted by the fact that sand had been removed from the sand bed region and drainage in the area was improved during the 1994 outage. However, the observed water leakage during the 1996 outage prompted investigation and use of a more durable barrier. InstaCote ML-2 coating barrier was effectively used on the reactor cavity during the 1998 outage. (Ref [28], page 6). Strippable coating has also been applied to the reactor cavity in all refueling outages since 1998.

II. Summary of IWE Program Elements Related to Water Leakage

The following is a summary of Oyster Creek's commitments related to preventing and monitoring for water leakage onto the exterior surface of the drywell shell. These are captured within the ASME Section XI, Subsection IWE Aging Management Program. These committed actions were performed during the 2006 refueling outage and will be performed during refueling outages in the future, including during the period of extended operation. For further details on these commitments, see Ref [39], Enclosure 2.

- Strippable coating, as discussed above in Section C, is applied to the reactor cavity liner surface prior to filling the reactor cavity with water for refueling activities.
- Periodic verification (once per refueling cycle) that the reactor cavity trough drain is functional (clear).
- Periodic monitoring (when reactor cavity is flooded) of reactor cavity trough drain for leakage.
- Daily visual monitoring of drywell sand bed drains for leakage during refueling outages when the reactor cavity is flooded. If leakage is detected, AmerGen will determine the source of leakage and investigate and address the impact of leakage on the drywell shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.
- Quarterly visual monitoring of the sand bed drains for leakage during plant power operation. If leakage is identified, then the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:
    - Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
    - UTs of the upper drywell region consistent with the existing program
    - UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred
    - UT results will be evaluated per the existing program

Any degraded coating or moisture barrier will be repaired.

- When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program.

Through these commitments, AmerGen will minimize any water leakage through the reactor cavity liner that may occur during refueling outages, and prevent or minimize water from reaching the external surface of the drywell shell. These commitments were made with the expectation that corrosion of the external surface of the drywell shell will be minimized, thus maximizing the margin remaining above the design-required thicknesses of the drywell shell.

III. Findings and Analysis from the 2006 Outage

During the 1R21 (October 2006) refueling outage, AmerGen implemented its commitments related to preventing water from reaching the outer surface of the drywell shell and monitoring for evidence of water leakage. The results of these activities were successful. Based on daily observations of sandbed drain water collection bottles and upon numerous visual reports from the sand bed region, no water leakage onto the exterior surface of the drywell shell during 1R21 was evident and no corrective actions related to water leakage onto the shell were required (Ref [47]).

The reactor cavity was coated with a strippable coating prior to flooding the cavity for refueling activities. A small amount of leakage (approximately 1 gallon per minute (GPM)) was observed coming from the cavity trough drain line during the time period when the refueling cavity was flooded. Daily observations of the cavity trough drainage confirmed a steady stream of approximately 1 GPM during this period. Because this small amount of leakage did not exceed the drainage capacity of the trough, no water would have leaked onto the exterior surface of the drywell shell. The minor leakage was discharged to the plant's radwaste system as designed.

Specifically, AmerGen performed the following actions during the October 2006 refueling outage to prevent or minimize water leakage onto the exterior of the drywell shell. These activities are consistent with commitments made in AmerGen Letter 2130-06-20358 (Ref [39]).

- Applied a strippable coating to the reactor cavity liner prior to flooding the cavity for refueling activities.
- Verified that the reactor cavity trough drain was clear prior to flooding the reactor cavity for refueling activities.
- Monitored the trough drain for leakage daily while the cavity was flooded with water. Documented results identified only a steady "pencil stream" of water coming from the trough drain, indicating, as expected, that the leakage was being handled by the cavity trough drain system, keeping water away from the drywell shell.

- Inspected the five sand bed drain lines to verify they were clear; removed some debris from two of the drain lines.
- Inspected the five poly collection bottles associated with the sand bed drains on a daily basis. Documented results identified no leakage observed coming from the sand bed drains.
- Verified no water on the concrete floor in any of the ten bays of the sand bed region through visual inspection.
- Inspected the seal at the junction between the sand bed region floor and drywell shell in all 10 bays. The inspection revealed the seal at this junction to be in good condition with no repairs required.

IV. Conclusion

Oyster Creek historically experienced water leakage onto the external surface of the drywell shell as described in Section I above. Various investigative and corrective activities have been performed to understand the issue and prevent water from continuing to drain onto the shell during refueling activities.

As part of the License Renewal process, AmerGen has established specific commitments within the formal Exelon Passport commitment tracking system to ensure license renewal commitments, including those addressing water leakage onto the drywell shell external surface (described in Section II above), are implemented. In addition, the recurring tasks, preventive maintenance activities, and surveillance procedures that are used to implement these commitments are annotated such that it is clear from looking at them that the subject actions are associated with commitments made to the NRC. In this way, there are formal controls to ensure awareness and oversight of the activities and to ensure that commitments are implemented.

The inspections performed during the 2006 refueling outage (1R21) confirm that the license renewal-related committed actions for leakage prevention and monitoring prevented water from reaching the external surface of the drywell shell. AmerGen has committed to perform these preventive/monitoring actions in future refueling outages, with the objective of preventing water leakage onto the drywell shell exterior. In addition, commitments are in place to investigate and address any leakage onto the shell exterior, should it occur.

This set of actions, aimed at preventing water from reaching the external surface of the drywell shell, serve as an additional level of assurance beyond that provided by performing and trending drywell shell thickness measurements and conducting visual inspections of the epoxy coating in the sand bed region (also part of the IWE Aging Management Program), that corrosion is not impacting the ability of the drywell to perform its design functions.

The following discussion addresses upper drywell corrosion at the Oyster Creek Generating Station. Part I, below, provides an overview of information pre-dating the October 2006 outage. The discussion in Part II sets forth information discovered and analyzed as a result of the October 2006 outage. Overall conclusions about the upper drywell, and its continued operation during the proposed twenty-year renewal term, are summarized in Part III.

I. Historic Summary and Past Findings

Outer drywell shell corrosion was first identified at Oyster Creek in the late 1980's. As explained in the Section 4 of this Enclosure, water intrusion into the gap between the drywell shell and the drywell shield wall was determined to be the source of the water, which created the corrosive environment. Corrective actions have been taken to mitigate corrosion in the upper region of the outer drywell shell. These actions have effectively reduced the rate of corrosion to a negligible amount in the upper region as demonstrated by UT thickness measurements (Ref [32], Table 1). In 1991, Oyster Creek and its consultants performed stress and buckling analyses considering all design basis loads and load combinations (Ref [15], Ref [16]). The results of these analyses indicate that the minimum measured drywell shell thickness satisfies ASME Section III Requirements.

A. Original Inspection Plan (1986 – 1992)

Inspections using UT thickness measurements were conducted during refueling outages and outages of opportunity between 1986 and 1989 to establish and characterize the extent of corrosion of the outer drywell shell. The initial UT measurements were not based on a sampling process. Instead the measurements were taken in areas that correspond to locations where water leakage was observed from the sand bed region drains. The UT measurements were then expanded around the drywell perimeter and vertically into the upper drywell to establish locations affected by corrosion. Approximately 1000 ultrasonic (UT) thickness measurements were taken at various elevations to access extent/scope of corrosion around the drywell perimeter and vertically to establish locations affected by corrosion and to identify the thinnest areas (Ref [4b], Ref [4c], Ref [4d]). Based on the results of the above-mentioned 1000 UT measurements, Oyster Creek continued to monitor 12 grid locations at elevations 50' 2", and 87' 5", that would be representative of the upper drywell shell condition. In addition, core samples of the drywell shell were taken at upper drywell region locations, believed to be representative of general corrosion, to confirm UT results (Ref [7]).

In addition to the above mentioned core samples of the drywell shell, the impact of Firebar-D on the drywell shell corrosion was discussed in a General Electric report (Ref [3]). Section 2.1.3.2 of the GE report discusses the material and Section 6.2.1 discusses the impact. The report concluded that the lack of γ•Fe_2O_3 in the oxide on the core plug surface/crust, the relative low amount of Mg in the sand samples and the absence of corrosion at the 51' elevation level suggest that the role of Firebar-D in the degradation of the OC drywell corrosion phenomena is not significant.

In 1990, a third elevation, 51' 10", was added to the scope of inspection after it was determined that the supplied plate thickness is slightly less than the adjacent 50' 2" plate. For each of the three elevations, sets of 49 UT measurements, spaced approximately 1" apart within a 6"x6" area, were taken from inside the drywell around the entire perimeter of each elevation. The 6"x6" area with one inch spacing results in a 7x7 grid of points located on one inch centers. These are identified as 49 point UT grid locations.

Engineering evaluation of the UT results concluded that monitoring of 12 upper drywell grid locations within these three elevations would represent the outer drywell shell condition and provide reasonable assurance that significant corrosion would be detected prior to a loss of an intended function. This is because the 12 grid locations were selected considering the degree of drywell shell thinning and the minimum required thickness to satisfy ASME stress requirements. Seven of the locations are at elevation 50' 2", three locations are at elevation 87' 5", and two locations are at elevation 51' 10" (Ref [31]). These locations are inspected from the inside of the drywell shell on a frequency of every other refueling outage.

B. Sampling Plan Justification and Confirmation - Augmented Inspection Plan (1990 - 1995)

In response to an NRC Staff concern regarding whether the inspected locations represent the condition of the entire drywell, in 1990 a new random UT inspection plan (also know as the augmented inspection) was prepared (Ref [11]). The plan was based on a non-parametric statistical approach using attribute sampling that assumes no prior knowledge of the distribution of corrosion above the sand bed region (Ref [12]). The plan consisted of random UT testing of 60 drywell shell plates. 57 plates were included in the inspection plan because three plates were inaccessible for inspection. On each plate, 49 point UT measurements were made on one 6"x6" area. Acceptance criteria were that the mean and local thickness of the shell equal or exceed the required minimum thickness plus a corrosion allowance necessary in order to reach the next inspection.

Inspection results using the new random inspection plan confirmed that previously monitored locations bound the condition of the drywell above the sand bed region; except one location at elevation 60' 10". This elevation was added to elevations 50' 2", 51' 10", and 87' 5" and all four elevations have been monitored on the frequency of every other refueling outage since 1992 (Ref [31], Ref [32]).

The augmented inspection plan, the original inspection plan, and justification for sampling techniques and statistical methodology were submitted to the NRC on November 26, 1990 (Ref [14]). In its Safety Evaluation dated November 1, 1995, the Staff noted that the licensee provided a table of UT measurement results from the Fall 1994, 15th refueling outage inspection. This table shows the locations of the measurements, the nominal as-constructed thickness, the minimum as-measured thickness, the ASME Code required thickness and the corrosion margin available at the time. The Staff found the current program based on the submitted information acceptable.

The current ongoing inspection plan is described in Oyster Creek specification IS-328227-004 (Ref [41]). The current inspection results are provided in Tables 1 and 2.

II. Confirmatory Actions During the October 2006 Outage

During the 2006 refueling outage (1R21), UT thickness measurements were taken at the 4 elevations (50' 2", 51' 10", 60" 10", and 87' 5") discussed above in accordance with the Oyster Creek ASME Section XI, Subsection IWE aging management program. The results of the UT thickness measurements indicated that no statistically observable corrosion is occurring at elevations 51' 10", 60' 10" and 87' 5". A single grid location (Bay 15 –23) of the elevation 50 '2" continues to experience minor corrosion at a rate of 0.66 mils/yr. The corrosion rate for the elevation 87' 5" is now statistically insignificant and this elevation can be considered as no longer undergoing statistically observable corrosion (Ref [47]), however it will continue to be monitored.

In addition, UT measurements were taken on 2 locations (bay #15 and bay #17) at elevation 23' 6" where the circumferential weld joins the bottom spherical plates and the middle spherical plates. This weld joins plates that are 1.154" thick to the plates that are 0.770" thick. These two bays were selected because they are among those that have historically experienced the most corrosion in the sandbed region. At each location, 49 UTs over a 6"x6" area grid were taken above the weld on the 0.770" thick plate and 49 UTs over a 6"x6" area grid were taken below the weld on the 1.154" thick plate. The minimum average thickness measured on the 0.770" thick plate is 0.766" and 1.160" on the 1.154" thick plate. The minimum measured local thickness on the 0.770" thick plate is 0.628" and on the 1.154" thick plate is 0.867". The minimum measured general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin (Ref [47]).

UT measurements were also taken on 2 locations (bay #15 and bay #19) at elevation 71' 6" where the circumferential weld joins the transition plates (referred to as the knuckle plates) between the cylinder and the sphere. This weld joins the knuckle plates (2.625" thick) to the cylinder plates (0.640" thick). These two bays were selected because they also have historically experienced the most corrosion in the sandbed region. At each location 49 UTs over a 6"x6" area grid were taken above the weld on the 0.640" thick plate and 49 UTs over a 6"x6" area grid were taken below the weld on the 2.625" thick plate. The minimum measured average thickness on the 0.640" thick plate is 0.624" and 2.530" on the 2.625" thick plate. The minimum measured local thickness on the 0.640" thick plate is 0.449" and 2.428" on the 2.625" thick plate. The minimum measured general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin (Ref [47]).

The above information identified during the recent outage has confirmed the condition of the upper drywell as described in previous submittals. AmerGen thus concluded that outer drywell shell corrosion at Oyster Creek is being effectively managed both during the current and proposed renewed terms of plant operation. The monitored locations under the current term were subject to extensive UT measurements conducted over several years. NRC Staff found the sampling methodology to identify these locations, and the results of inspections, acceptable for the current term.

III. Conclusion

In conclusion, Oyster Creek has conducted extensive examinations of the OCNGS upper drywell to identify the cause of drywell corrosion, employed a sampling process, quantified the extent of outer drywell shell thinning due to corrosion, and assessed its impact on the drywell structural integrity. Inspection results for the upper region are provided in Table 2. A summary of the upper region outer drywell shell corrosion rates and margins and the associated reference source documents are provided on Table 1. A summary of corrosion rates of UT measurements taken in the upper drywell every 4 years through year 2006 is provided below:

- There is no statistically observable ongoing general corrosion at three elevations (51' 10", 60' 10", and 87' 5")
- Based on statistical analysis, one location at elevation 50' 2" is undergoing a minor general corrosion rate of 0.66 mils per year
- The drywell corrosion inspection program will ensure sufficient margin will be maintained through 2029

Therefore, AmerGen has concluded that upper drywell corrosion at Oyster Creek is effectively managed, both during the current and proposed renewed term of plant operation. The upper drywell region is not experiencing statistically observable corrosion, except a single location that continues to experience minor corrosion at a rate of 0.66 mils/yr. When this monitored corrosion rate is projected through the year 2029, sufficient margin exists to acceptance criteria.

Table 1

Drywell Shell Thickness and Minimum Available Thickness Margins are provided below:

Drywell Region (Elevation monitored)	Nominal Design Thickness, mils (Ref [40])	Minimum Measured Thickness, mils (Ref [21], Ref [25], Ref [31], Ref [47])	Minimum Required Thickness, mils Acceptance Criteria (Ref [43], Ref [15])	Minimum Available Thickness margin, mils
Cylindrical (87' 5")	640	604	452	152
Upper Sphere (51' 10", 60' 10")	722	676	518	158
Middle Sphere (50' 2")	770	678	541	137

Conclusions:

Summary of Corrosion Rates of UT measurements taken every 4 years through year 2006 (Ref [47])

- There is no statistically observable ongoing general corrosion at three elevation (51' 10", 60' 10", and 87' 5")
- Based on statistical analysis, one location at elevation 50' 2" is undergoing a minor general corrosion rate of 0.66 mils per year
- The drywell corrosion inspection program will ensure sufficient margin will be maintained through 2029

For illustrations of the margins of monitored locations in upper drywell see attached Key Plan and Graphs 1-13.

Table 2

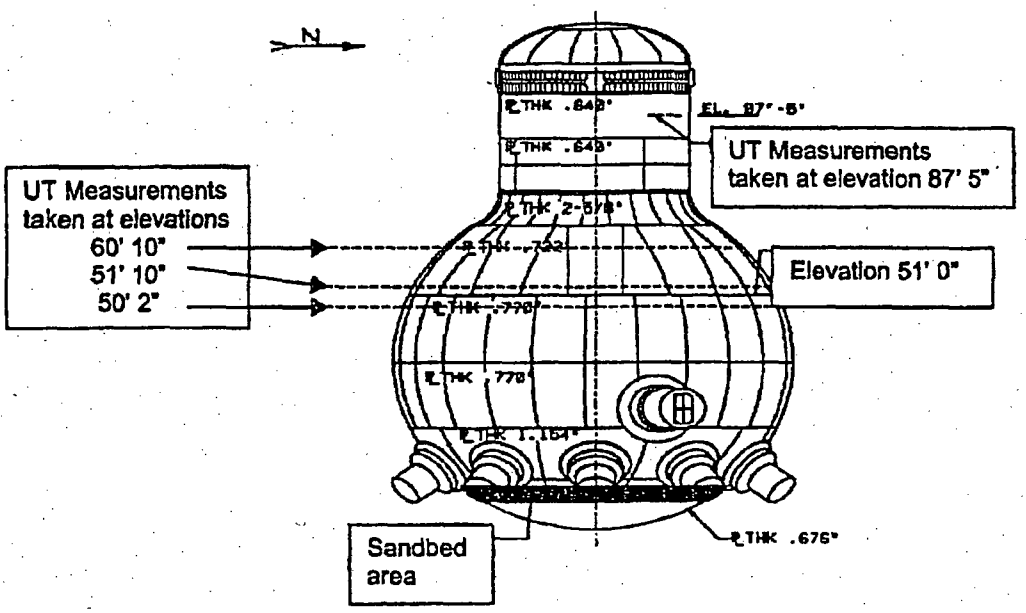
Monitored Elevation	Location	Minimum Required Thickness, Inches [5]	Average Measured Thickness [1,2,4], inches												Projected Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1998	2000	2004	2008	
Elevation 50' 2"		0.541"													
	Bay 5–D12					0.743 0.745 0.748	0.742 0.745 0.748	0.747 0.747		0.741	0.748	0.741	0.743	0.747	No Observable Ongoing Corrosion
	Bay 5–5H					0.761 0.761	0.755 0.758 0.760	0.759 0.759		0.754	0.757	0.754	0.756	0.760	No Observable Ongoing Corrosion
	Bay 5–5L					0.706 0.703	0.703 0.705 0.706	0.703 0.702		0.702	0.705	0.706	0.701	0.705	No Observable Ongoing Corrosion
	Bay 13–31H					0.762 0.779	0.760 0.758 0.765	0.765 0.763		0.759	0.768	0.762	0.758	0.762	No Observable Ongoing Corrosion
	Bay 13–31L					0.687 0.684	0.689 0.678 0.688	0.685 0.688		0.683	0.690	0.682	0.693	0.678	No Observable Ongoing Corrosion
	Bay 15–23H					0.758 0.764	0.762 0.762 0.765	0.767 0.763		0.758	0.760	0.758	0.757	0.749	0.720
	Bay 15–23L					0.726 0.728	0.726 0.729 0.725	0.726 0.724		0.728	0.724	0.729	0.727		

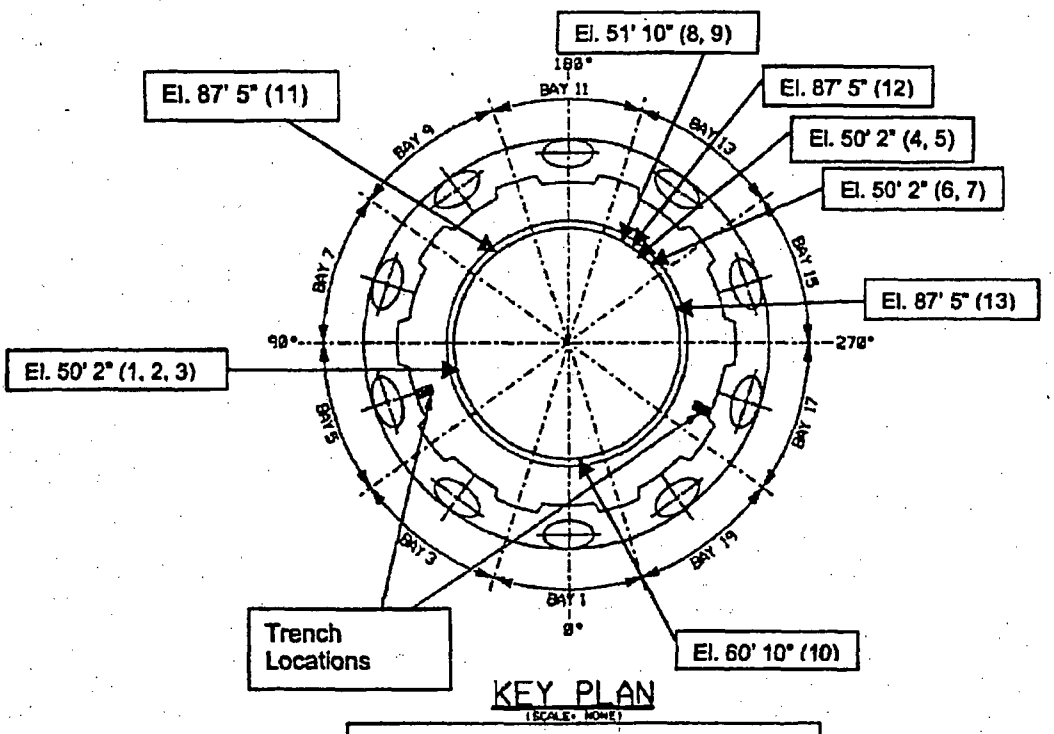
Monitored Elevation	Location	Minimum Required Thickness, Inches [5]	Average Measured Thickness [1,2,4], Inches												Projected Thickness in 2029
			1987	1988	1989	1990	1991	1992	1993 [3]	1994	1996	2000	2004	2008	
Elevation 51' 10"		0.518" (8)													
	Bay 13–32H					0.716	0.715 0.715 0.720	0.717 0.717		0.714	0.715	0.715	0.713	0.715	No Observable Ongoing Corrosion
	Bay 13–32L					0.686	0.683 0.683 0.682	0.683 0.676		0.680	0.684	0.679	0.687	0.685	No Observable Ongoing Corrosion
Elevation 60' 10"		0.518"													
	Bay 1–50-22								0.693	0.711	0.693	0.689	0.693	0.691	No Observable Ongoing Corrosion
Elevation 87' 5"		0.452"													
	Bay 9–20		0.619	0.622 0.620	0.619	0.620	0.614 0.612	0.629 0.614		0.613	0.613	0.604	0.612	0.617	No Observable Ongoing Corrosion
	Bay 13–28		0.643	0.641 0.642	0.645	0.643	0.635 0.629	0.641 0.637		0.640	0.636	0.635	0.640	0.642	No Observable Ongoing Corrosion
	Bay 15–31		0.638	0.636 0.636	0.638	0.642	0.628 0.627	0.631 0.630		0.633	0.632	0.628	0.630	0.633	No Observable Ongoing Corrosion

Notes:

1. The average thickness is based on 49 Ultrasonic Testing (UT) measurements performed at each location
2. Multiple inspections were performed in the years 1988, 1990, 1991, and 1992.
3. The 1993 elevation 60' 10" Bay 5-22 inspection was performed on January 6, 1993. All other locations were inspected in December 1992.
4. Accuracy of Ultrasonic Testing Equipment is plus or minus 0.010 inches.
5. Reference SE-000243-002 (Ref [25]).

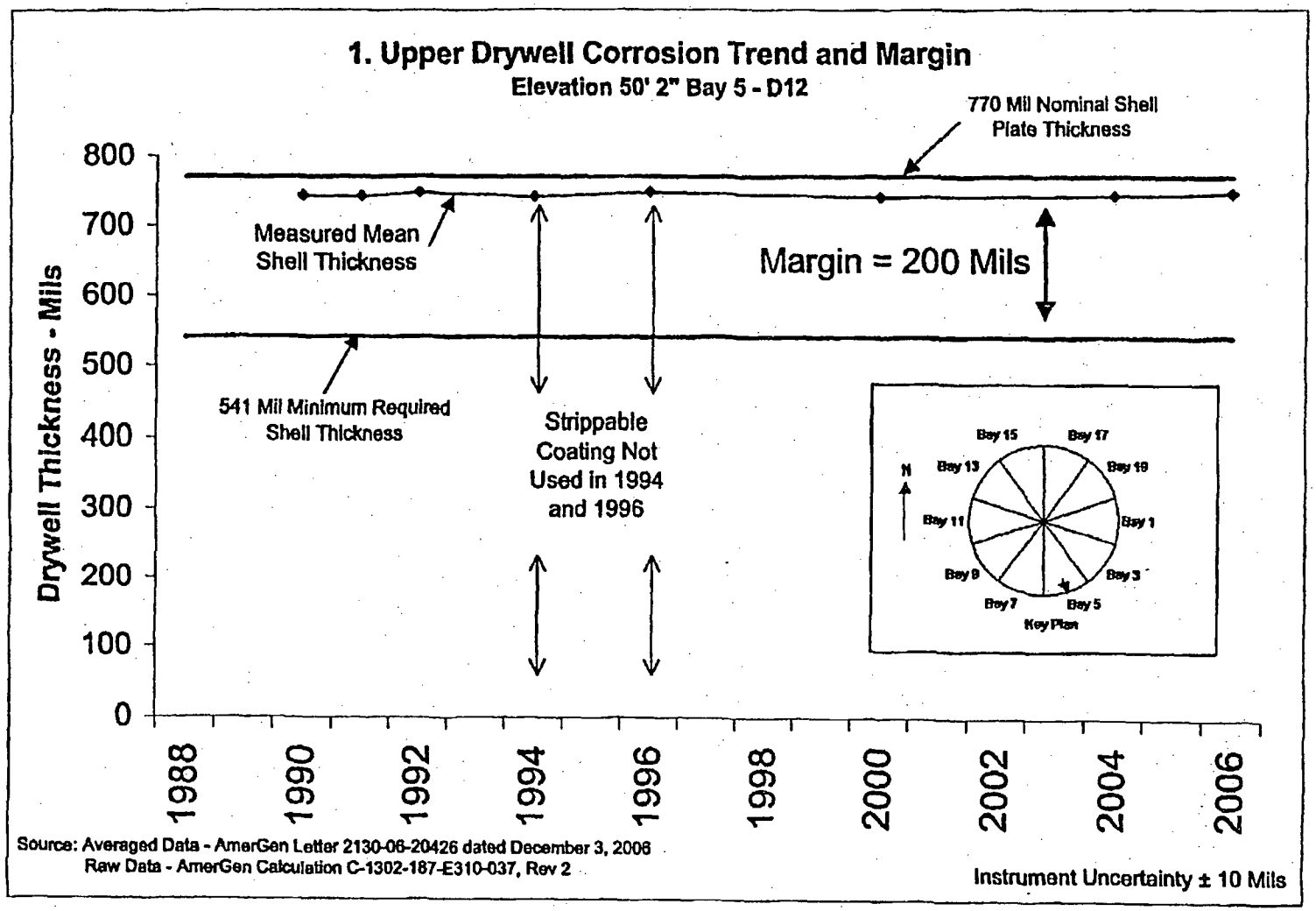
Ongoing Upper Drywell Thickness Monitoring
UT Measurement Locations

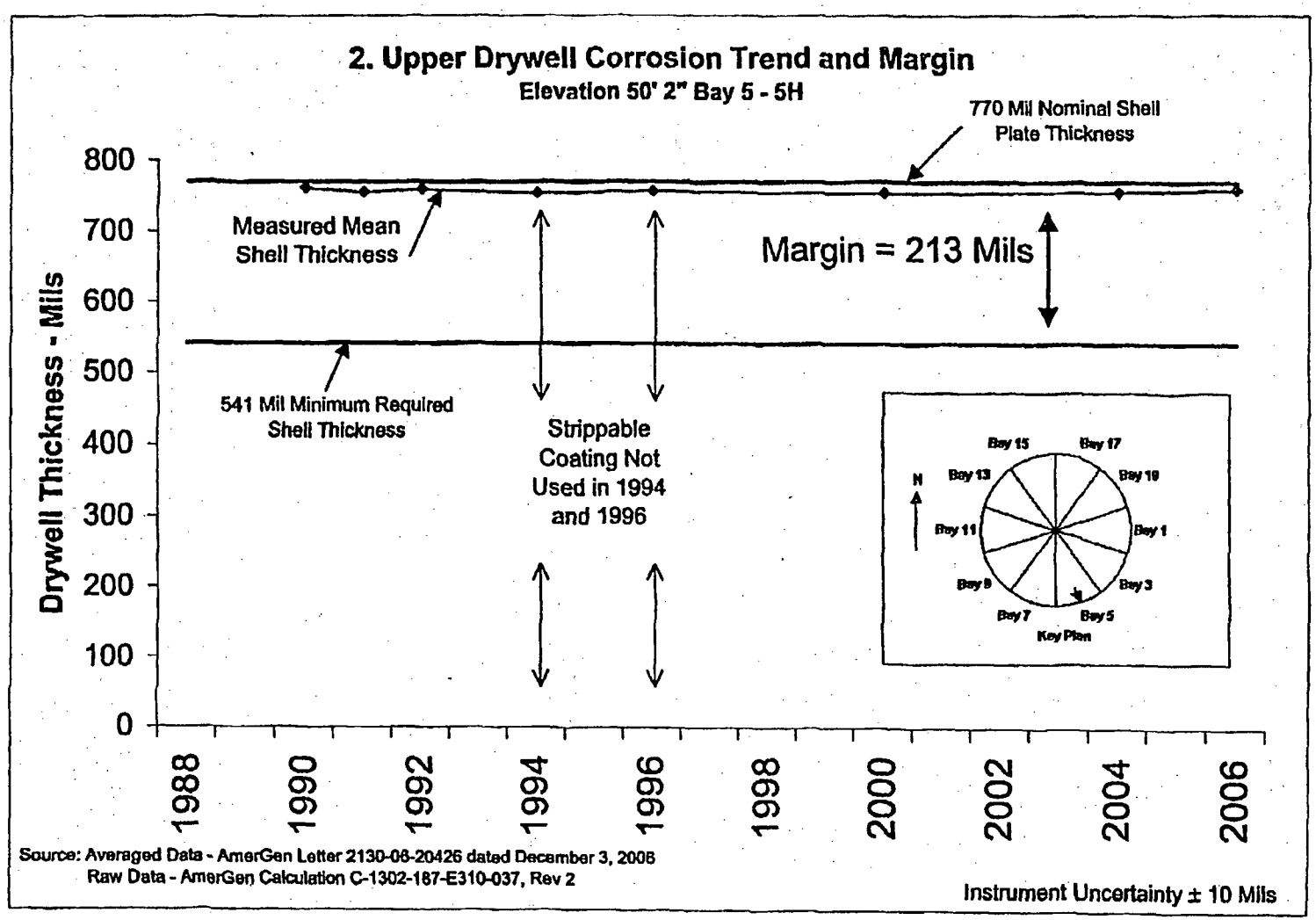


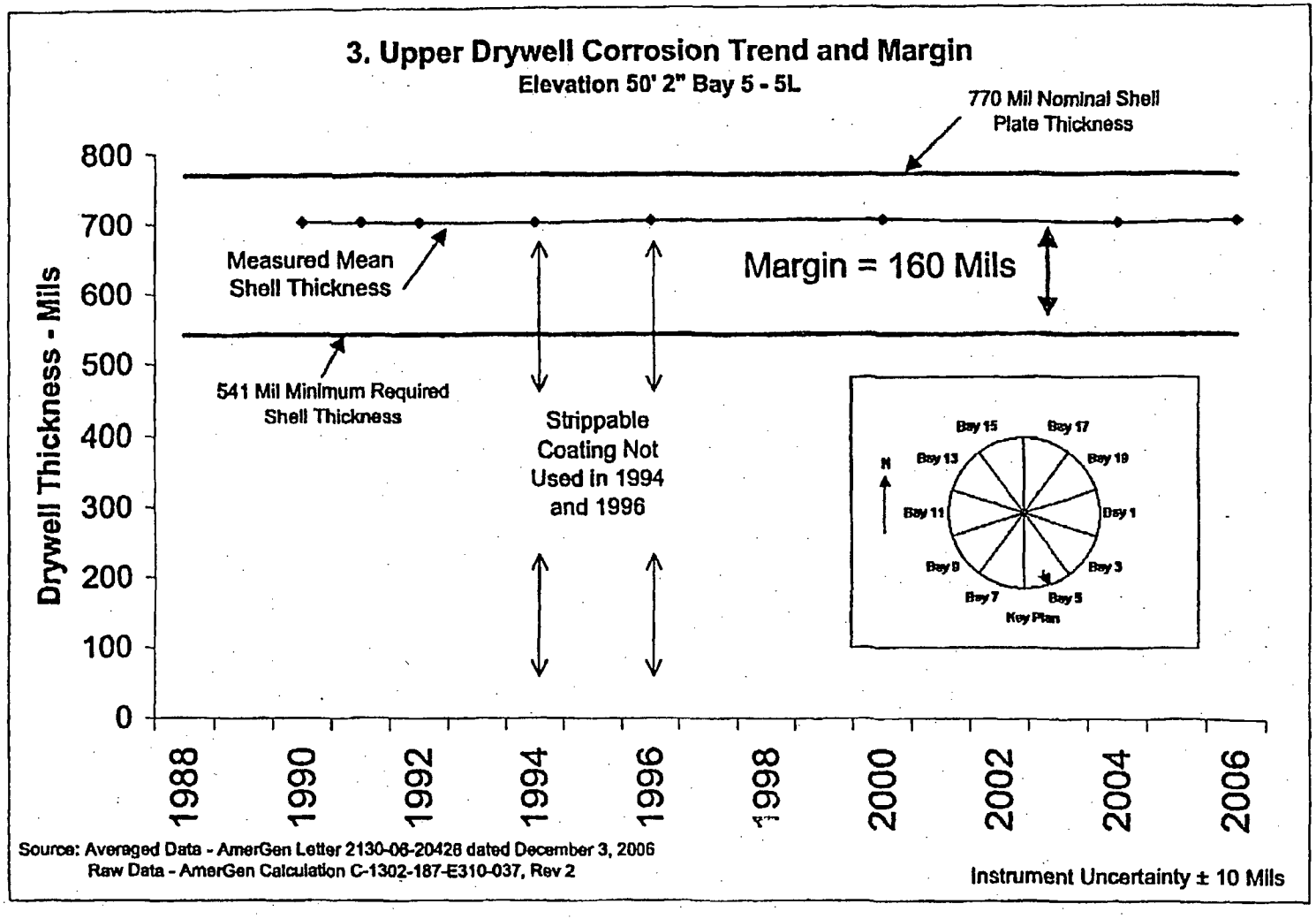


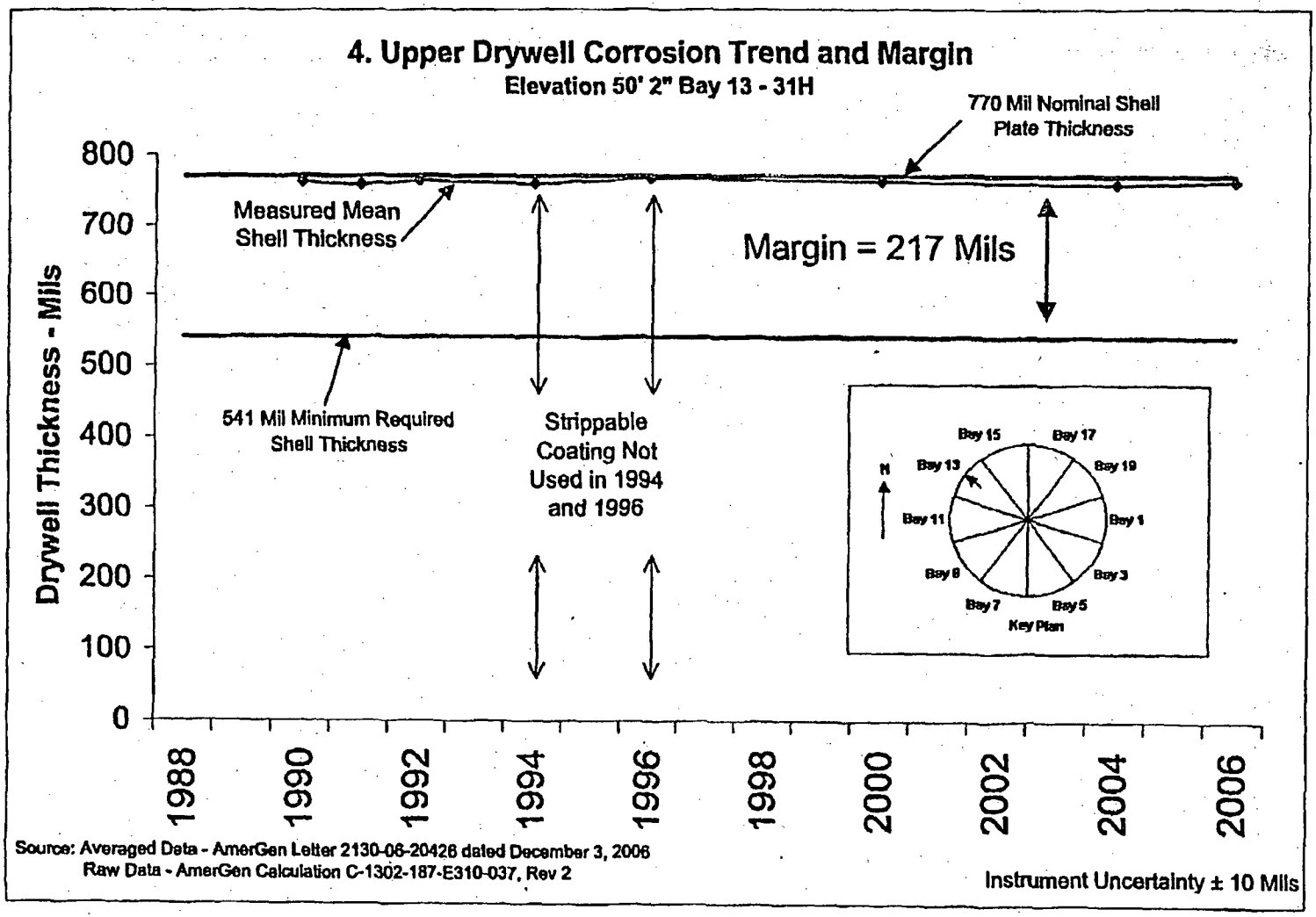
KEY PLAN
(SCALE: NONE)

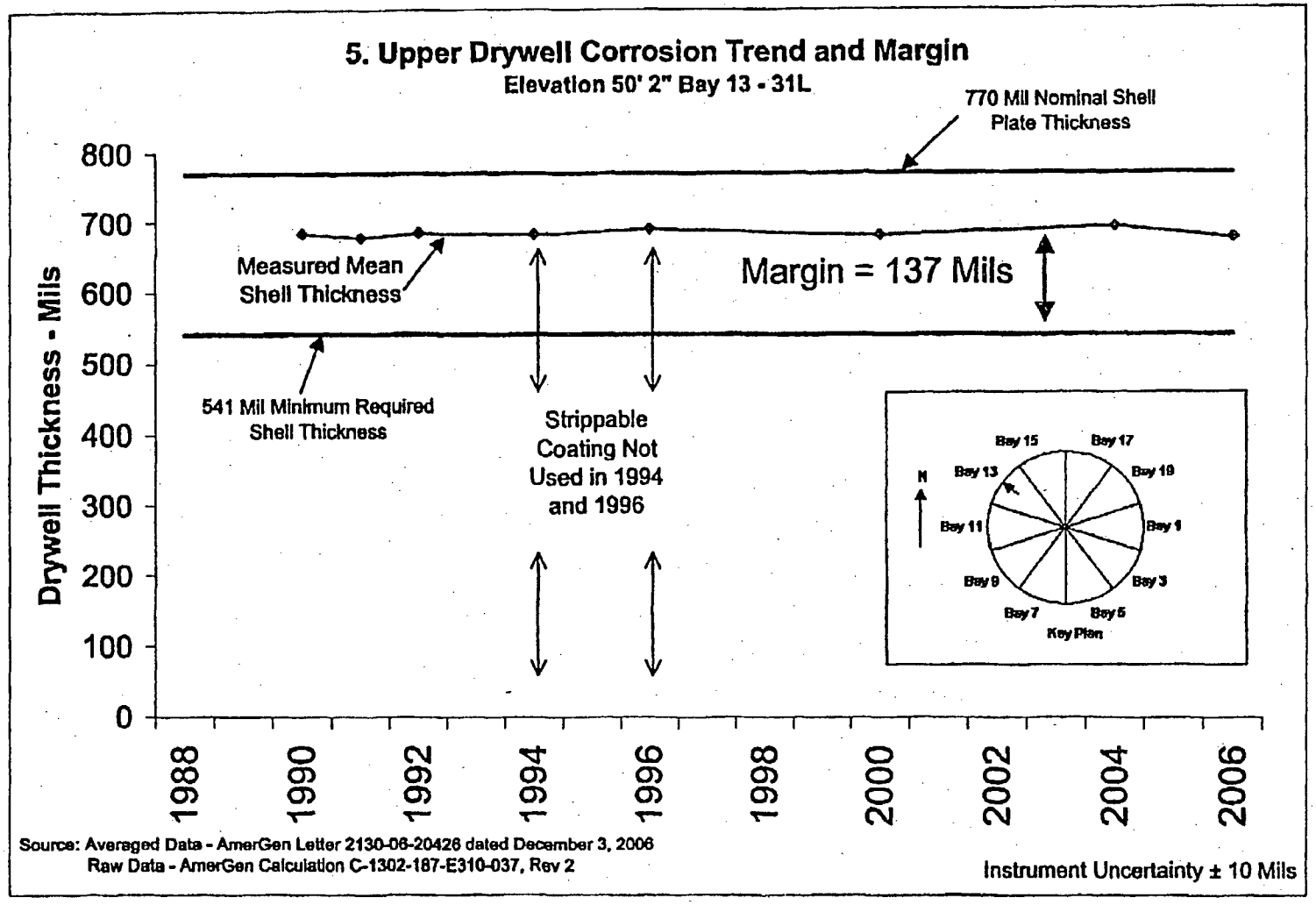
Numbers in parentheses refer to the attached Graph identification numbers.


1. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 5 - D12
770 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 200 Mils
541 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils


2. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 5 - 5H
770 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 213 Mils
541 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils

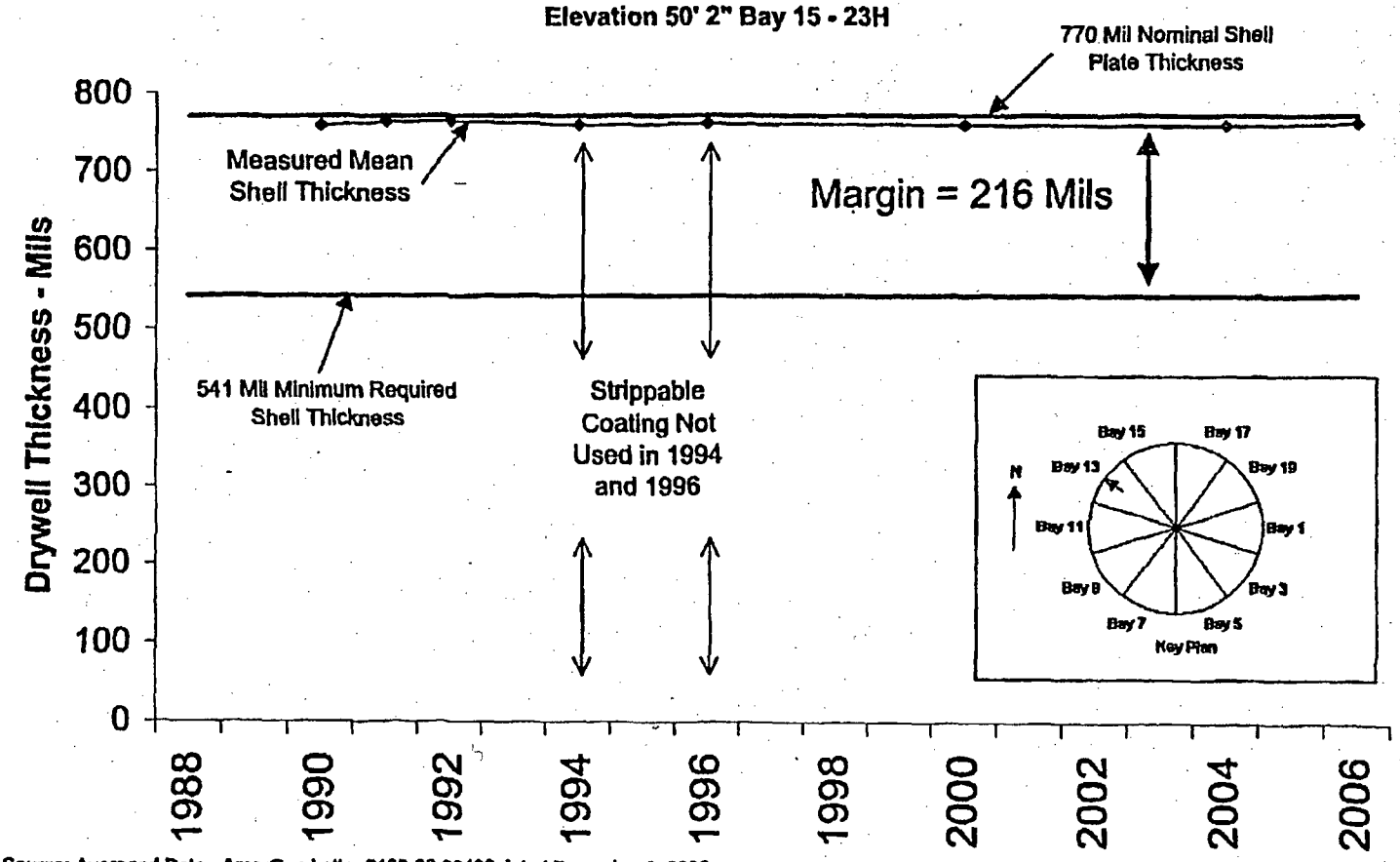

3. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 5 - 5L
770 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 160 Mils
541 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils


4. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 13 - 31H
770 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 217 Mils
541 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils


5. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 13 - 31L
770 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 137 Mils
541 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20428 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils

6. Upper Drywell Corrosion Trend and Margin

Elevation 50' 2" Bay 15 - 23H



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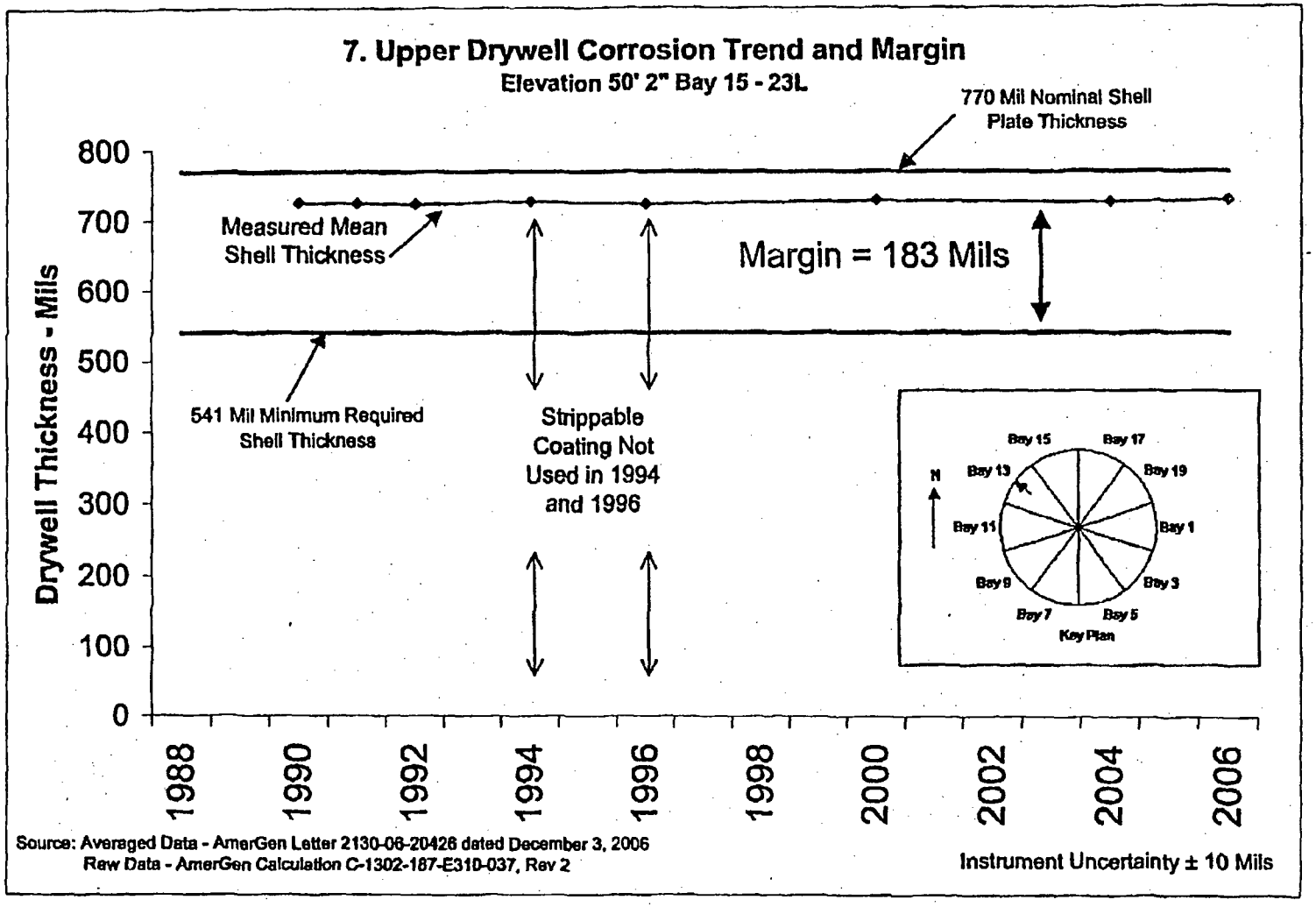
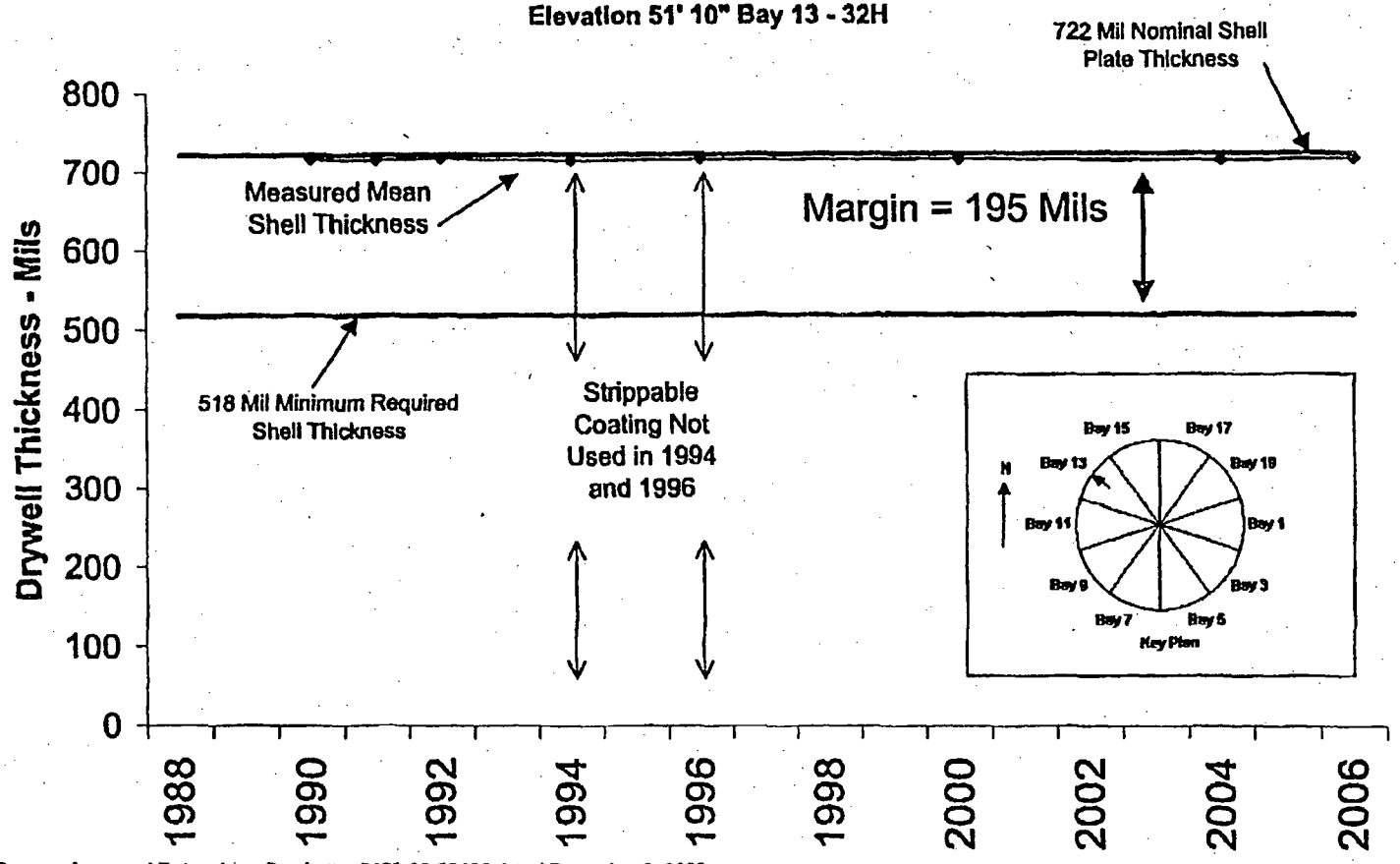
Instrument Uncertainty ± 10 Mils


7. Upper Drywell Corrosion Trend and Margin
Elevation 50' 2" Bay 15 - 23L
770 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 183 Mils
541 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils

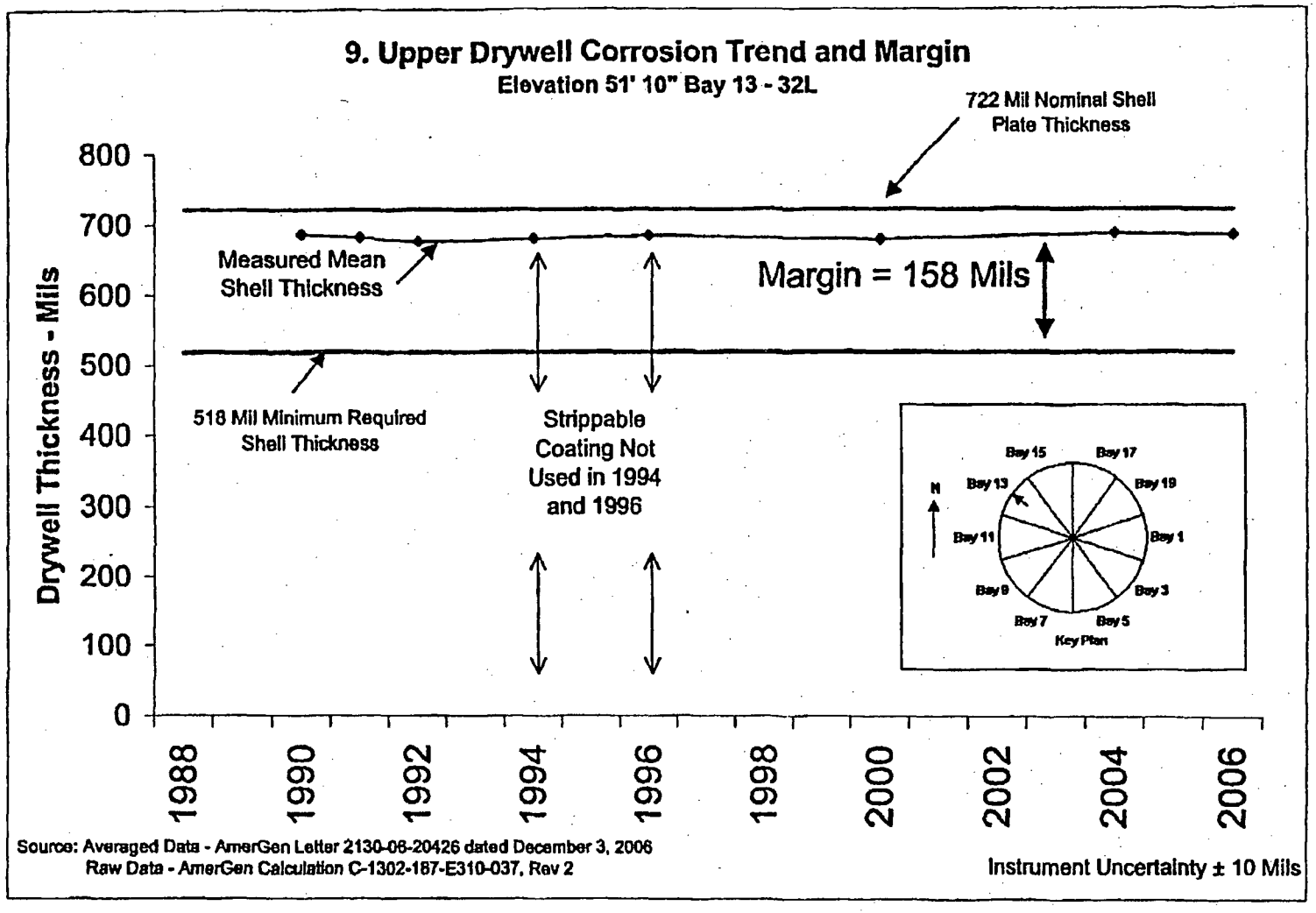
8. Upper Drywell Corrosion Trend and Margin

Elevation 51' 10" Bay 13 - 32H



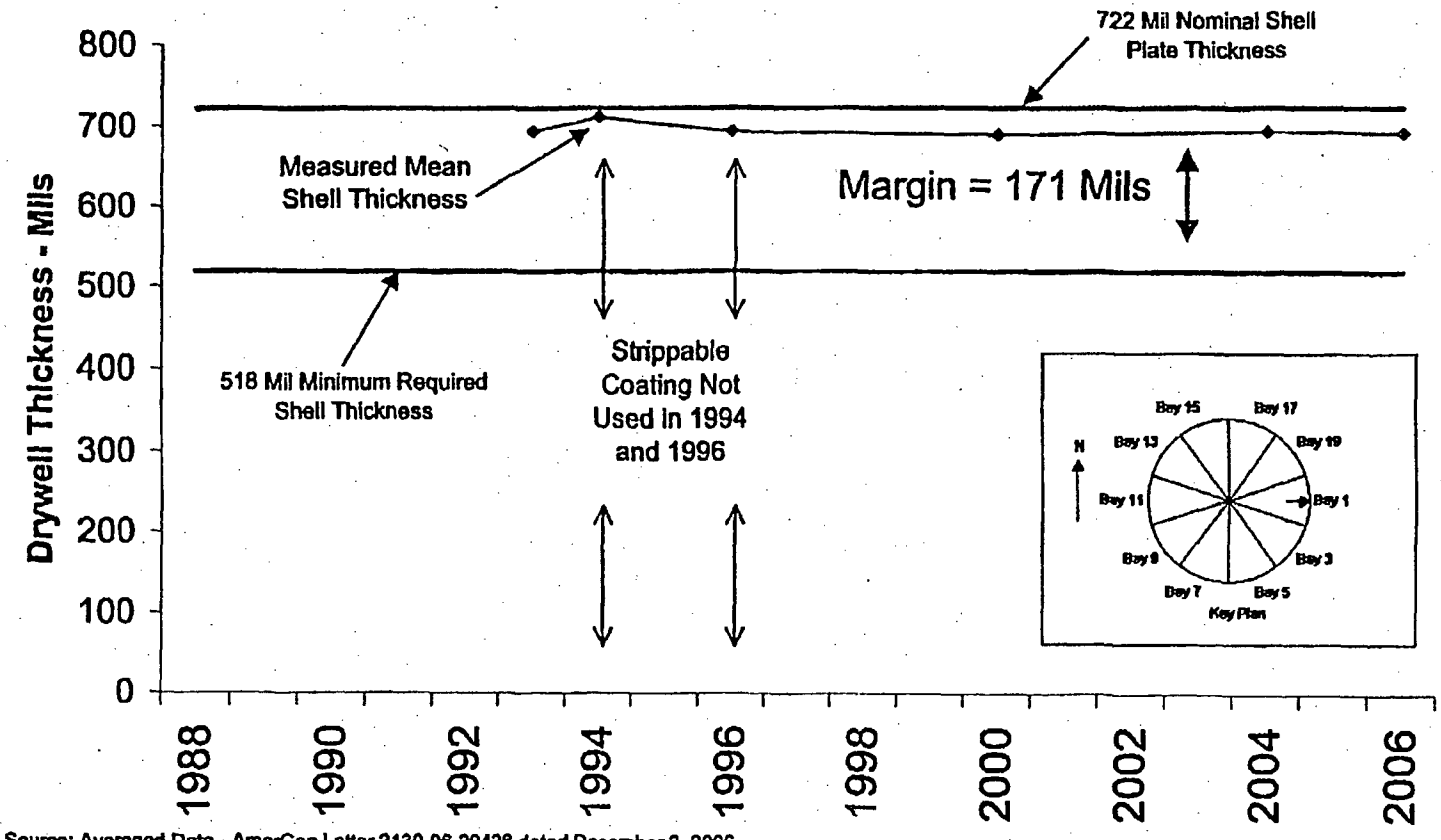
Source: Averaged Data - AmerGen Letter 2130-08-20426 dated December 3, 2008
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

Instrument Uncertainty ± 10 Mils


9. Upper Drywell Corrosion Trend and Margin
Elevation 51' 10" Bay 13 - 32L
722 Mil Nominal Shell Plate Thickness
Measured Mean Shell Thickness
Margin = 158 Mils
518 Mil Minimum Required Shell Thickness
Strippable Coating Not Used in 1994 and 1996
Drywell Thickness - Mils
800
700
600
500
400
300
200
100
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
N
Bay 15
Bay 17
Bay 13
Bay 19
Bay 11
Bay 1
Bay 9
Bay 3
Bay 7
Bay 5
Key Plan
Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2
Instrument Uncertainty ± 10 Mils

10. Upper Drywell Corrosion Trend and Margin

Elevation 60' 10" Bay 1 - 50 - 22

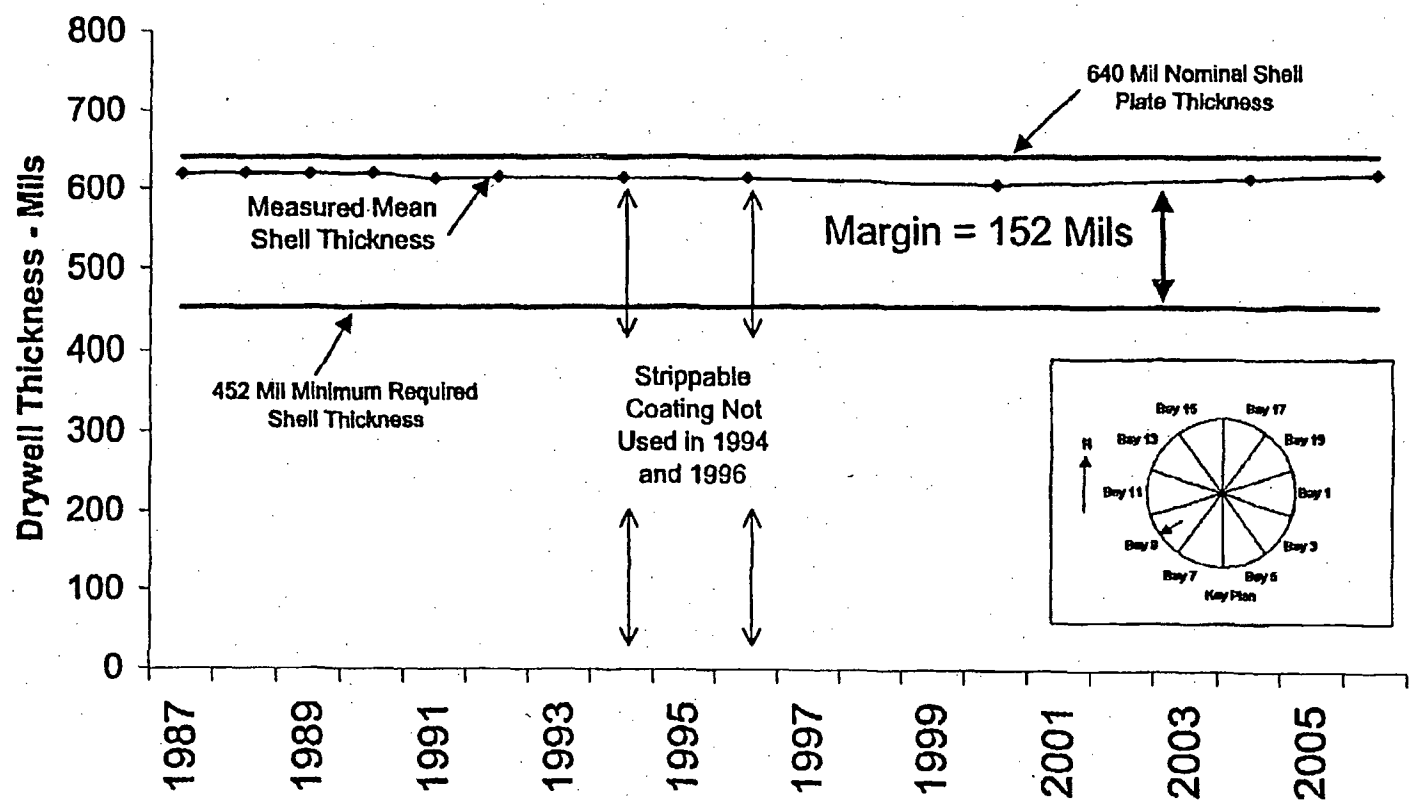


Source: Averaged Data - AmerGen Letter 2130-06-20428 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

Instrument Uncertainty ± 10 Mils

11. Upper Drywell Corrosion Trend and Margin

Elevation 87' 5" Bay 9 - 20

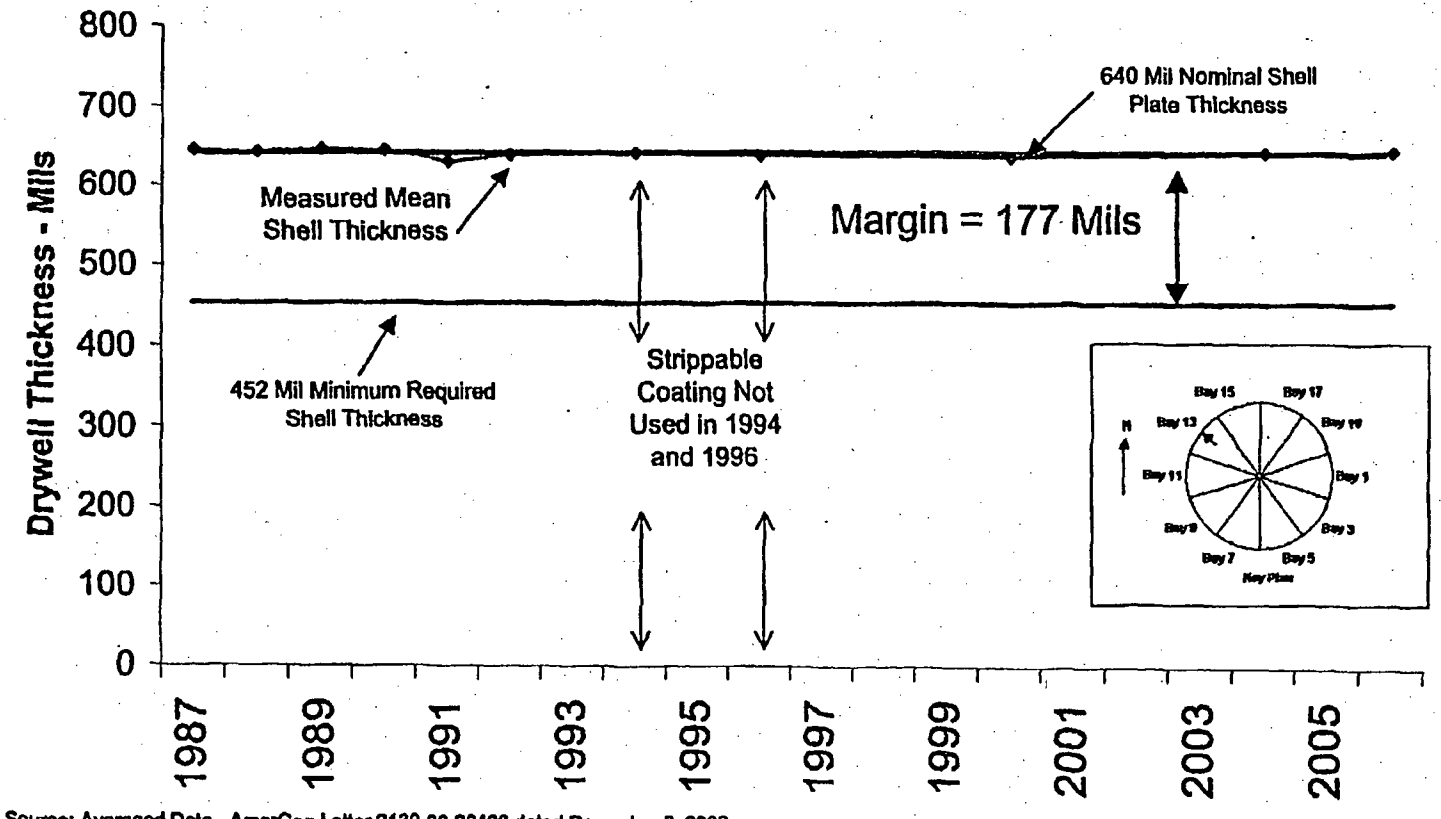


Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

Instrument Uncertainty ± 10 Mils

12. Upper Drywell Corrosion Trend and Margin

Elevation 87' 5" Bay 13 - 28

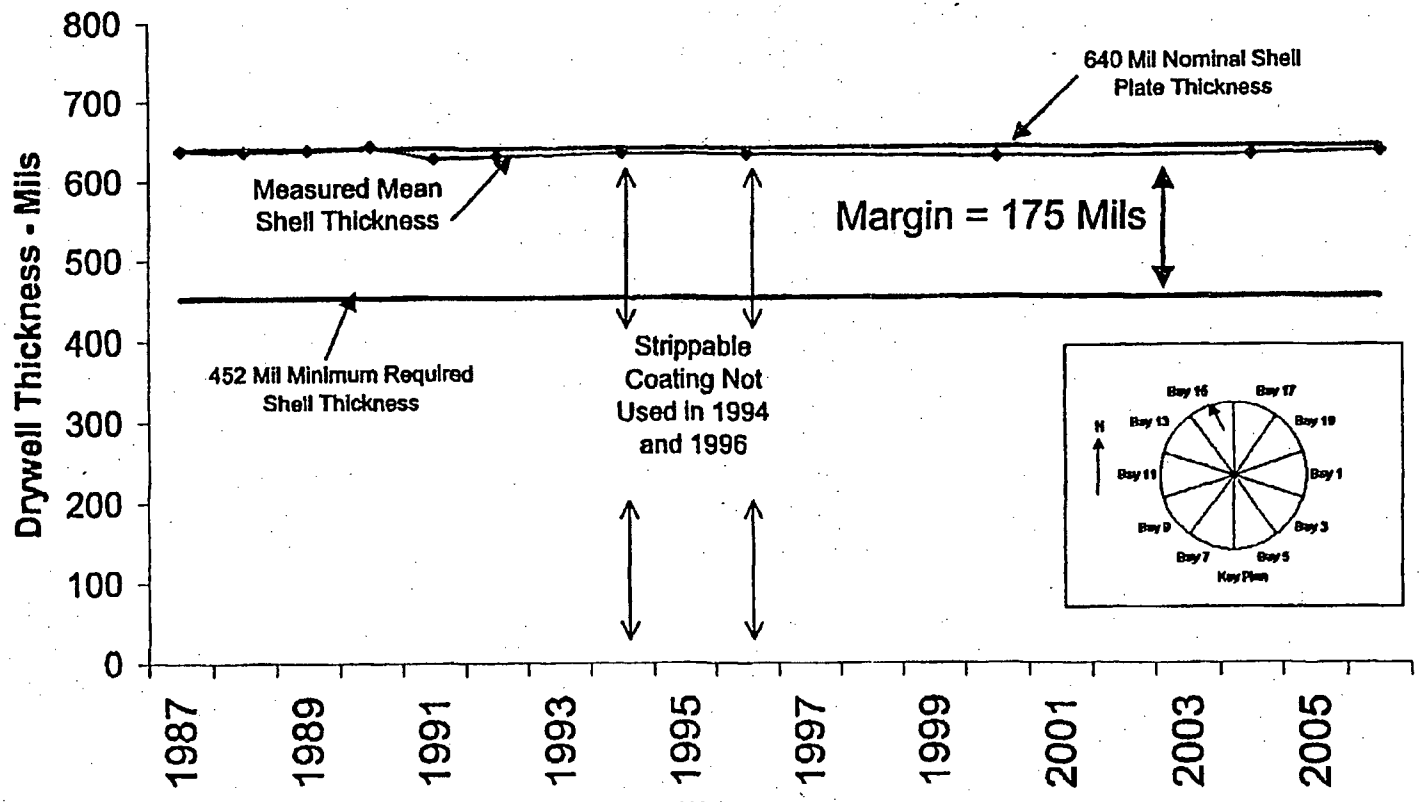


Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

Instrument Uncertainty ± 10 Mils

13. Upper Drywell Corrosion Trend and Margin

Elevation 87' 5" Bay 15 - 31



Source: Averaged Data - AmerGen Letter 2130-06-20426 dated December 3, 2006
Raw Data - AmerGen Calculation C-1302-187-E310-037, Rev 2

Instrument Uncertainty ± 10 Mils

The following discussion addresses corrosion of the Oyster Creek outer drywell shell in the sanded region. Part I, below, provides an overview of historic information pre-dating the October 2006 outage. The discussion in Part II sets forth information discovered and analyzed as a result of the October 2006 outage. Overall conclusions about the drywell, and its continued operation during the proposed twenty-year renewal term, are summarized in Part III.

I. Historical Summary and Past Findings

In the 1980's, the Oyster Creek containment drywell experienced wall thinning in the sandbed region caused by water in contact with the outer drywell shell. Beginning in 1986, corrective actions were implemented to monitor, mitigate or reduce the rate of corrosion, which was initially estimated to vary from negligible in certain bays to 39 mils/year at the thinnest location in bay 13 (Ref [10]). The corrective actions were effective in reducing accelerated corrosion as evidenced by the decline in the rate of corrosion starting in 1990 (see Attachment 1).

Beginning in 1986, UT thickness measurements were taken at elevation 11'3" from the interior of the drywell shell in each bay using a 6"x6" template every refueling outage and outage of opportunity. The template is centered on points determined by UT thickness measurements taken between 1983 and 1986 to be thinnest location in each bay. The points were marked on the shell to ensure that the same location is examined each time (See Attachment 2).

Analysis and trending of UT thickness data collected between 1986 and 1992 showed that thinning of the shell was not uniform and varied within a bay and from one bay to another. The measured average thickness in some bays (1,3,5,7,15) is nearly equal to the plate original nominal thickness of 1154 mils. In other bays, the nominal thickness is reduced significantly, with bay 19 having the thinnest area of 800 mils. In all cases, the average thickness is greater than 736 mils, which is required to satisfy ASME Code buckling stress requirements.

As shown in Table-1 below, the thinnest average measured area in each bay has adequate thickness margin in addition to the ASME Code safety factor of 2 for refueling load combination and 1.67 for post accident load combination (Ref [32]). As explained in Part II, below, AmerGen took UT thickness measurements during the October 2006 refueling outage to confirm the margin remains within the calculated uncertainty listed in Table-6.

Table-1. Minimum Available Thickness Margin

Bay No.	1	3	5	7	9	11	13	15	17	19
Minimum Available Margin, mils	365	439	432	397	256	84	101	306	74	64

Corrosion mitigating actions in the sand bed region were completed in 1992, when the sand was completely removed from the region, followed by removal of corrosion products, and preparation of the shell surface for the epoxy coating. Prior to applying the coating, the entire surface of the sandbed area was visually inspected to validate UT thickness measurements, previously made from inside the drywell, and to identify local areas thinner than the minimum required average general thickness of 736 mils. 125 local areas were identified by visual inspection as areas that could be potentially thinner than 736 mils (See Table-2). UT thickness measurements of the 125 locations identified 20 locally thinned areas less than the minimum required general thickness of 736 mils, but greater than analyzed local criteria of 536 mils (the minimum required to withstand buckling), and 490 mils local criteria developed in accordance with ASME Code requirements (the minimum required to withstand design pressure).

Following the UT inspections discussed above, the outer drywell shell surface in the sandbed region was coated with a multi-layered epoxy coating system designed for moisture environment. The sandbed region floor also was repaired to improve drainage of the region and the junction of the embedded outer drywell shell with the sandbed region concrete floor was sealed to prevent moisture intrusion into the embedded outer drywell shell.

Analysis of UT thickness measurements conducted in 1992 and 1994 showed that corrosion of the outer drywell shell in the sandbed region had been arrested. UT thickness measurements taken in 1996 also indicated that corrosion in the outer drywell shell had been arrested. Some of the1996 data contained anomalies that are not readily justifiable but the anomalies did not significantly change the results (Ref [37]). Between 1996 and the October 2006 outage, UT thickness measurements had not been taken; instead the epoxy coating in selected bays was inspected every other refueling outage.

Coating inspections conducted in 1994 (Bays 11, 3), 1996 (Bays 11, 17), 2000 (Bays 1, 13), and 2004 (Bays 1,13) showed that the coating was in good condition and there were no indications that the outer drywell shell was undergoing further corrosion (Ref [34]). Furthermore, the periodic UT thickness measurements of the shell in the upper regions of the drywell that are not coated with epoxy can be used conservatively as an indicator of the condition of the outer drywell shell in the sandbed region. The 2004 and 2006 upper region UT results showed that the highest general corrosion rate is less than 1 mil/year.

A detailed discussion of the various historic activities follows:

A. Initial Corrective Actions

Upon discovery of water in the sandbed region in 1980, corrective actions were initiated to a) determine the source of water leakage, b) establish if corrosion is occurring by taking UT thickness measurements, and c) assess the impact of corrosion on the drywell structural integrity.

1. Source of Water Leakage into the Sand Bed Region

Extensive examination and testing of potential water sources concluded that water found in the sandbed region was from the refueling cavity during refueling outages. Cracks were identified in the reactor cavity stainless steel liner that permitted water to leak from the cavity, collect in an improperly functioning concrete trough below the cavity seals, and enter the gap between the outer drywell shell and the reactor building concrete. Once water entered the gap, it flowed down to the sandbed region. The water collected and was retained in the sandbed region in part as a result of unfinished concrete floor in some bays and clogged sandbed drains. Refer to the section 4 of this Enclosure for additional details.

2. Initial Ultrasonic Testing (UT) Thickness Measurements

Initial UT thickness measurements were made in 1983 from inside the drywell, through paint, above the concrete floor level (elev. 10' 3") in the bays that corresponded to where water was observed coming from sandbed drains. The measurements indicated that the drywell shell was thinner than expected. The accuracy of these measurements was questioned because the readings were taken through paint. As a result, calibration tests were conducted to evaluate the impact of the paint on the UTs. The test results indicated that UT measurements through paint overestimated the actual thickness by 0.3% for a 5-mil coating and 1.5% for a 10-mil coating. For this reason, the paint was removed at the inspection locations and a new set of UT measurements was taken from inside the drywell in 1986. The new UT readings continued to indicate that the drywell shell was thinner in those sand bed bays. (Ref [7])

The scope of the UTs was expanded to include several areas near the drywell floor adjacent to the sandbed region (elevation 11' 3"). The new readings also indicated that the drywell shell was thinner than expected. (Ref [7])

As a result of the 1986 UT readings, a program was initiated to obtain detailed measurements in order to determine the extent and characterization of the thinning. Where thinning was detected, additional measurements were made in a cross pattern to determine the extent of the thinning. After the cross pattern was completed, the lowest reading at each location was used to expand the UT readings to a 6"x6" grid on 1" center with the lowest reading at the center of the grid. Approximately

560 total UT measurements were made in the ten bays at locations shown in drawing 3E-SK-S-85 (Ref [4a]). In 1986, as part of an ongoing effort at the Oyster Creek Generating Station to investigate the impact of water on the outer drywell shell, concrete was excavated at two locations inside the drywell (referred to as trenches) to expose the drywell shell below the Elevation 10' 3" concrete floor level to allow ultrasonic (UT) measurements to be taken to characterize the vertical profile of corrosion in the sand bed region outside the shell. The trenches (approximately 18" wide) were located in Bays 5 and 17 with the bottom of the trenches at approximate elevations 8' 9" and 9' 3" respectively (The elevation of the sand bed region floor outside the drywell is approximately 8' 11"). A total of 579 UT thickness measurements were taken inside the 2 trenches. The measurements inside the 2 trenches showed that the reduction in shell thickness below the drywell concrete floor level (Elev. 10' 3") is no greater than indicated above the floor level (Ref [7], Ref [4a], Ref [8], Ref [47])

Additional UT thickness measurements were taken at the plate-to-plate welds under the vent lines and the vent opening reinforcement plates. These areas were given extra consideration on the basis that material sensitized by welding may have been attacked by a corrosion mechanism with greater potential for damage or cracking. The readings did not detect wall thinning or cracks at these locations (Ref [7]).

3. UT Thickness Data Statistical Analysis Prior to 2006

The following steps have been performed to test and analyze the UT measurement data for those locations where 6"x6" grid data has been taken at least three times. The results of the analysis yield the measured average general thickness (± standard error), F-Ratio, which was used to determine if corrosion was occurring, and the upper 95% confidence interval was used after corrosion was identified. See Table-5, Table-6, and Attachment 1 for the results of the analysis. The steps are:

- Edit each 49-point data set by setting all invalid points to "missing". Invalid points are those that are declared invalid by the UT operator or are at a plug (i.e., core sample) location.
- Perform a Univariate Analysis of each 49 point data set to ensure that the data is normally distributed.
- Calculate the mean thickness and variance of each 49-point data set.
- Perform an Analysis of Variance F-test to determine if there is a significant difference between the means of the data sets.
- Using the mean thickness values for each 6"x6" grid, perform linear regression analysis over time at each location

- Perform F-test for significance of regression at the 5% level of significance.
- Calculate the ratio of the observed F value to the critical F value at 5% level of significance. The result of this test indicates whether or not the regression model is more appropriate than the mean level.
- Calculate the coefficient of determination (R^2) to assess how well the regression model explains the percentage of total error and thus how useful the regression line will be as a predictor
- Determine if the residual values for the regression equations are normally distributed.
- Calculate the y-intercept, the slope and their respective standard errors. The y-intercept represents the fitted mean thickness at time zero, the slope represents the corrosion rate, and the standard errors represent the uncertainty or random error of the two parameters. Calculate the upper 95% one-sided confidence interval about the computed slope to provide an estimate of the maximum probable corrosion rate at 95% confidence after corrosion was identified.
- When the corrosion rate is not statistically significant compared to random variations in the mean thickness, the slope and confidence interval slope computed in the regression analysis still provides an estimate of the corrosion rate, which could be masked by the random variations.

- Use the chi-square goodness-of-fit test results to determine if low thickness measurements are significant pits. If the measurement deviates from the mean thickness by three standard deviations, it is to be considered a pit. (Ref [27])

4. Verification of UT Thickness Measurements

The UT thickness measurements described above were verified in 1986 by removing seven 2-inch diameter core samples from the sandbed region shell. Core sample locations shown in Table-3 below (bays 11, 15, 17, &19) were selected to represent areas where UT measurements showed the most significant wall thinning, as well as areas where UT measurements indicated little or no wall thinning. Thicknesses obtained by physical measurement of the core samples were consistent with the UT readings, and in general were greater by about 2% (Ref [7]).

Table 3 – Core Sample Thickness Evaluation

Sample No.	Location (Bay No.)	Pre-removal UT Average thickness, mils	Post-removal Measured Average Thickness, mils
1	19C	815	825
2	15A	1170	1170
3	17D	840	860
4	19A	830	847
5	11A	860	885
6	11A	1170	1190
7	19A	1140	1181

Source: Ref [1]

In summary, extensive UT readings of drywell shell thickness were taken inside the drywell to establish areas of largest wall thinning between 1986 and 1992. UT measurements were also taken in 2 trenches excavated in the drywell concrete floor to establish the vertical profile of corrosion in the sandbed region in 1986 and in 1988. The measurements showed that corrosion in the sandbed region below the drywell floor level, elevation 10' 3", was no greater than the corrosion measured at the floor level. UT measurements taken from outside the drywell after removing the sand in 1992 (discussed in section C.1below) confirmed this observation. Thus locations selected inside the drywell for repetitive UT measurements represented the condition of the entire sandbed region.

5. Initial Analysis to Assess Impact of Corrosion on the Drywell Structural Integrity and Operability.

A detailed engineering analysis was conducted in 1987, assuming a corroded thickness of 700 mils. The analysis concluded that, with sand in place and conservatively assuming the thickness was reduced to 700 mils, the drywell was capable of performing its intended function and that the containment is operable (Ref [2])

B. Other Corrective Actions Taken in Response to UT Measurements

As a result of significant wall thinning and accelerated rate of corrosion in the sandbed region (bays 11, 13, 17, and 19), Oyster Creek initiated additional corrective actions in 1987 to assess the impact on corrosion on the drywell intended function, and minimize the rate of corrosion. These included but were not limited to: a) an initial analysis to determine if the containment was operable, b) actions to minimize the potential for water intrusion into the affected area, c) actions to effect removal of any water that might intrude into the affected area, d) installation of a cathodic protection system in 2 bays, e) taking UT measurements every refueling outage and outage of opportunity, and f) trending the UT results. Refer to (Ref [32]) for additional details.

1. Corrective Actions to Minimize the Rate of Corrosion

Beginning in 1988, the strippable coating was applied to reactor cavity walls to minimize water leakage during the refueling outages. Leakage monitoring, implemented later, confirmed that this coating is effective in minimizing the water intrusion into the sandbed region. See section 4 of this Enclosure for additional details.

UT thickness measurements taken through 1988 showed that the corrosion rate of the outer drywell shell in the sandbed region continued to increase (see Attachment 1). Also the rate of corrosion in the bays where the cathodic protection system was installed showed no improvement. It was then concluded that the most effective way to mitigate corrosion was to remove the sand and corrosion products, and apply a protective coating to the outer drywell surface in sandbed region. Refer to section C.1 below for details of the coating. (Ref [9], Ref [32]).

2. Engineering Analysis Performed to Establish the Minimum Required Thickness With Sand Removed

An engineering analysis, based on ASME Code requirements, was conducted in the early 1990's to establish the minimum required general thickness without sand for both pressure and buckling stress (Ref [15], Ref [16], Ref [32]). The analysis was based on a partial finite element model (36-degree slice – Fig. 1) of the drywell. Loads and load combinations were in accordance with the original design basis requirements as follow: (Ref [16])

CASE I - INITIAL TEST CONDITION
Deadweight + Design Pressure (62 psi) + Seismic (2 x DBE)

CASE II - FINAL TEST CONDITION
Deadweight + Design Pressure (35 psi)+ Seismic (2 x DBE)

CASE III - NORMAL OPERATING CONDITION
Deadweight + Pressure (2 psi external) + Seismic (2 x DBE)

CASE IV - REFUELING CONDITION
Deadweight + Pressure (2 psi external) + Water Load + Seismic (2 x DBE)

CASE V - ACCIDENT CONDITION
Deadweight + Pressure (62 psi @ 175'F or 35 psi @ 281'F) + Seismic (2 x DBE)

CASE VI - POST ACCIDENT CONDITION
Deadweight + Water Load @ 74'6" + Seismic (2 x DBE)

Note: Subsequent to this analysis GE developed Oyster Creek plant specific accident pressure, approved in accordance with Technical Specification Amendment 165 (Ref [46])

The results of the analysis showed that the minimum required thickness was controlled by buckling and that a general thickness of 736 mils will satisfy ASME Code requirements with a safety factor of 2 against buckling for the controlling operating load combination (Case IV - refueling condition), and 1.67 safety factor for accident flooding load combination (Case V – Accident condition). See Table 4 below for additional details). (Ref [32]).

Local areas where the thickness was less than the general 736 mils were evaluated based on 490 mils local acceptance criteria (Ref [42]). The local acceptance criteria of 490 mils was confined to an area less than 2½"[1] in diameter experiencing primary membrane + bending stresses based on ASME B&PV Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE-3213.2 and NE-3213.10. In particular, NE-3213.10 limits the meridional distance between openings without reinforcement to 2.5 x (square root of Rt). Also Paragraph NE-3335.1 only applies to openings in shells that are closer than two times their average diameter.

A review of all the 1992 UT data presented in Appendix D of calculation C-1302-187-5320-024 (Ref [42]) indicated that all thicknesses in the drywell sand bed region exceeded the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph were not required for the very local wall thickness evaluation presented in Calculation C-1302-187-5320-024 (Ref [42]).

Reviewing the stability analyses provided in both the GE Report 9-4 (Ref [16]) and the GE Letter Report Sand Bed Local Thinning and Raising the Fixity Height Analysis (Ref [22]) and recognizing that the plate elements in the sand bed region of the model are 3" x 3" it was clear that the circumferential buckling lobes for the drywell were substantially larger than the 2 ½"[1] diameter for very local wall areas. This, combined with the local reinforcement surrounding these local areas, indicated that these areas would have no impact on the buckling margins in the shell. It was also clear from the GE Letter Report (Ref [22]) that a uniform reduction in thickness of 27% to 0.536" over a one square foot area would only create a 9.5% reduction in the load factor and theoretical buckling stress for the whole drywell resulting in the largest reduction possible. In addition, to the reported result for the 27% reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5% over a

[1] In some evaluations 2" diameter is conservatively used to define very local areas instead of 2 ½"

one square foot area which only reduced the load factor and theoretical buckling stress by 3.5% for the whole drywell resulting in the largest reduction possible. To bring these results into perspective, a review of the NDE reports indicated there were 20 UT measured areas in the whole sand bed region that had thicknesses less than the 0.736 inch thickness used in GE Report 9-4 (ref [16]) which cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Therefore, to effectively change the buckling margins on the drywell shell in the sand bed region, a reduced thickness would have to cover approximately one square foot of shell area at a location in the shell that is most susceptible to buckling with a reduction in thickness greater than 25%. GE analysis concluded that the buckling of the shell was unaffected by the distance between the very local wall thicknesses; in fact, these local areas could be contiguous provided their total area did not exceed one square foot and their average thickness was greater than the thickness analyzed in the GE Letter Report (Ref [22]) and provided the methodology of Code Case N284 was employed to determine the allowable buckling load for the drywell. Furthermore, all of these very local wall areas were centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the sand bed region, which is located at the midpoint between two vents. (Ref [35], [32], [16])

Table 4 – Buckling Analysis Summary

	Load Combination	
	CASE IV – REFUELING CONDITION	CASE V – ACCIDENT CONDITION
Service Condition	Design	Level C
Thickness used in Analysis, mils	736	736
Factor of Safety Applied	2.00	1.67
Applied Compressive Meridional Stress (ksi)	7.59	12.0
Allowable Compressive Meridional Stress (ksi)	7.59	12.93
Actual Buckling Safety Factor[1]	2.00	1.80

Source: Ref [16]

[1] The actual buckling safety factor is greater than 2.00 and 1.80 since the minimum measured general thickness is greater than 0.736 inches.

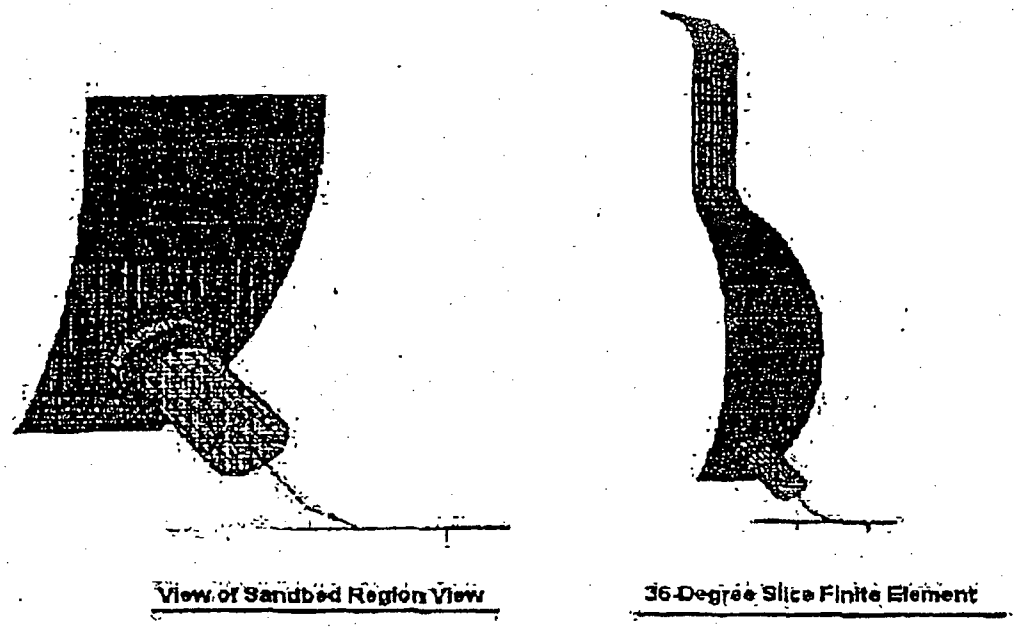


Fig. 1 – Drywell Analysis ANSYS Finite Element Model

C. Final Corrective Actions (early 1990's)

The corrective actions, implemented in early 1993, included removal of sand from the sandbed region, performance of additional UT inspections on the outside of the drywell shell to confirm the results of measurements previously taken from the inside, and application of epoxy coating to the exterior surface of the drywell to protect it from further corrosion.

1. Removal of the sand was initiated in 1988 and completed in 1992. The surface of the outer drywell shell was cleaned in preparation for coating (Ref [19]). Before the coating was applied, inspection of the outer drywell shell in all 10 sandbed bays was conducted. 125 UT measurements were taken in local areas suspected by visual inspection to be less than the minimum required general thickness of 736 mils. Of the 125 UT thickness measurements, 20 were determined to be less than 736 mils, but greater than the analyzed local thickness of 536 mils. The locally thinned areas were evaluated using criteria provided in ASME Section III, Subsection NE3213.10 and found acceptable (Ref [32], [35]). See Table 2.

Table 2 – UT Thickness Measurement of Locally Thinned Areas Taken from Outside The Drywell in the Sandbed Region.

Location	1992 UT Measurements			2006 UT Measurements		
	No. of UT	Number of UT < 736 mils	Thickness in mils	No. of UT	Number of UT < 736 mils	Thickness in mils
Bay 1	23	9	700, 710, 705, 700, 680, 690, 714, 724, 726	23	10	710, 690, 665,680,731, 669,711,722, 719,712
Bay 3	8	0		8	0	
Bay 5	8	0		7	0	
Bay 7	7	0		5	0	
Bay 9	10	0		10	0	
Bay 11	8	1	705	8	1	700
Bay 13	29	9	672, 722, 718, 655, 618, 718, 728, 685, 683	15	6	708, 658, 602,704, 669,666
Bay 15	11	1	722	11	0	
Bay 17	11	1	720	10	1	681
Bay 19	10	0		9	0	
Total	125	21		106[1]	18	

Source: Ref [42], Ref [47]

[1] The locally thinned areas prepared for UT measurements in 1992 were measured in 2006. However the inspection team was able to locate only 106 points instead of 125.

2. Coating of the Outer Drywell Shell in the Sandbed Region:

In 1992 the outer drywell shell was coated with a DEVOE Epoxy system, comprised of one coat of DEVOE 167 Rust Penetrating Sealer followed by two coats of Devran 184 epoxy coating (see attachment 3, Ref [19])

The DEVOE coating system was selected based on anticipation of less than ideal surface preparation of the outer drywell shell due to the confined space of the sandbed region. It was designed for application on surfaces prepared by hand cleaning tools to remove loose rust, mill scale, and other detrimental foreign matter in accordance with Steel Structures

Paint Council surface Preparation Specification No. 2 (SSPC-SP2). (Ref [17])

The Pre-Prime DEVOE 167 Sealer penetrates through rusty surfaces and provides a means of reinforcing rusty steel substrates and thus insures adhesion of the Devran 184. The sealer was recommended by its manufacturer for use in areas where, due to restrictions or economics, blasting or a thorough hand cleaning was not feasible. (Ref[17])

The Devran 184 epoxy coating was designed for coating of tank bottoms, including water tanks, fuel tanks, and selected chemical tanks. (Ref [17])

Before the coating was used, a set of tests was performed outside the sandbed using a mock-up of the sandbed space and lighting. The purpose of these tests was to establish and qualify the painting process considering the limited space and visibility in the sandbed region. Each set of tests was performed on rusted carbon steel test panels that were prepared using tools to resemble as closely as possible the expected condition of the drywell exterior surface. To further simulate the condition of the drywell exterior, the test panels were cleaned with DEVOE DevPrep 88 cleaner and then washed with high-pressure water (Ref [20])

DEVOE Pre-Prime 167 and Devran 184 coatings were applied to the test panel surfaces using brushes and rollers. The wet and dry film thickness of each coat was measured and used to determine the expected ranges of the coating thickness for the drywell exterior surface. Tests were performed to determine if holidays or pinholes were present in the coatings. (Ref [20])

3. Repair of Sandbed Floor to Improve Drainage

The unfinished floor in the sandbed regions was built up using the same epoxy that was used to coat the shell, and reshaped to allow drainage through the sandbed floor drain of any water that may leak into the region. At that time, the joint between the sandbed floor and the external drywell shell was sealed with a caulk compatible with the epoxy coating to prevent any water from coming in contact with any portion of the drywell shell embedded below the level of the sandbed floor. See Section 7 of this Enclosure for additional information.

4. Validation of Corrective Actions Effectiveness

UT inspections of the sandbed region were conducted in 1992, 1994, and 1996 from inside the drywell. The results of these inspections showed that the corrective actions had been effective in arresting corrosion of the outer drywell shell in the sand bed region. (See Table-6). After 1996, additional UT measurements were not taken in the sandbed region; instead, the epoxy coating in critical bays was inspected for cracking, flaking, blistering, peeling, discoloration, and other signs of distress. Inspections conducted in 1994 (Bays 3, 11), 1996 (Bays 11, 17), 2000 (Bays 1, 13), and 2004 (Bays 1,13) show that the coating was in good

condition and there were no indications that the outer drywell shell was undergoing further corrosion (Ref [34]). Furthermore the periodic UT thickness measurements of the shell in the upper regions of the drywell could be used conservatively as an indicator of the condition of the outer drywell shell in the sandbed region. This was because the operating environment was similar in the sandbed region and the upper region of the drywell and the shell in the upper region does not have an epoxy coating. The 2004 upper region UT results showed that the highest corrosion rate is less than 1 mil/year.

Table 5 – Sandbed Region Drywell Shell 95% Confidence Level Average Thickness[1]

Bay	Loc	Dec-86	Feb-87	Apr-87	May-87	Aug-87	Sep-87	Jul-88	Oct-88	Jun-89	Sep-89	Feb-90	Apr-90	Mar-91	May-91	Nov-91	May-92	Sep-92	Sep-94	Sep-96	Oct-2006
1D									1115										1101	1151	1122
3D									1178										1184	1175	1180
5D									1174										1168	1173	1185
7D									1135										1136	1138	1133
9A									1155										1157	1155	1154
9D		1072							1021	1054	1020	1026	1022	993	1008	992	1000	1004	992	1008	993
11A				919	905	922	905	913	888	881	892	881	870	845	844	833	842	825	820	830	822
11C	Btm				917	954	916	906	891	877	891	870	865	858	863	856	882	859	850	883	855
	Top				1046	1109	1079	1045	1009	1016	1005	952	977	982	1002	964	1010	970	982	1042	958
13A		919							905	883	883	862	853	855	853	849	865	858	837	853	846
13D	Btm								962				932	909	901	900	931	906	895	933	904
	Top													1072	1049	1048	1088	1055	1037	1059	1047
13C																		1149	1140	1154	1142
15A									1120										1114	1127	1121
15D		1089							1056	1060	1061	1059	1057	1060	1050	1042	1065	1058	1053	1066	1053
17A	Btm	999							957	965	955	954	951	935	942	933	948	941	934	997	935
	Top	999							1133	1130	1131	1128	1128	1131	1129	1123	1125	1125	1129	1144	1122
17D			922		895	891	895	878	862	857	847	836	829	825	829	822	823	817	810	848	818
17/19	Btm								982	1019	1131	990	986	975	969	954	972	976	963	967	964
	Top								1004	999	955	1010	1006	987	982	971	990	989	975	991	972
19A			884		873	859	858	849	837	829	825	812	808	817	803	803	809	800	806	815	807
19B					898	892	888	864	857	826	845	840	837	853	844	846	847	840	824	837	848
19C					901	888	888	873	856	845	845	831	825	843	823	822	832	819	820	854	824

[1] Source: Ref 47

Table 6 – Minimum Available Thickness Margin Based on Minimum 95% Confidence Level Average Thickness. (Thickness in mils)

Location		Pre-1992	May 1992[1]	Sept 1992		1994[2]		1996[3]		2006[4]		Min. Required	Nominal Thick.	Margin
				Thick	Std Error	Thick	Std Error	Thick	Std Error	Thick	Std Error			
1D		1115				1101	± 10.0	1151	± 13.6	1122	± 8.4			365
3D		1178				1184	± 4.9	1175	± 7.5	1180	± 5.7			439
5D		1174				1168	± 2.6	1173	± 2.2	1185	± 2			432
7D		1135				1136	± 4.3	1138	± 5.9	1133	± 6.5			397
9A		1155				1157	± 4.5	1155	± 4.8	1154	± 4.2			418
9D		992	1000	1004	±10.0	992	± 10.4	1008	± 10.6	993	± 11.2			256
11A		833	842	825	±8.2	820	± 7.7	830	± 8.7	822	± 8.0			84
11C	Bot	856	882	859	±6.4	850	± 4.5	883	± 7.4	855	± 4.5			114
	Top	952	1010	970	±23.8	982	± 23.4	1042	± 21.4	958	± 24.7			216
13A		849	865	858	±9.6	837	± 7.8	853	± 8.8	846	± 8.2			101
13D	Bot	900	931	906	±9.0	895	± 8.2	933	± 9.6	904	± 8.9			159
	Top	1048	1088	1055	±14.1	1037	± 13.6	1059	±11.2	1047	± 13.7	736	1154	196
13C		932		1149	±1.9	1140	± 3.8	1154	±3.2	1142	± 3.1			196
15A		1120				1114	± 16.3	1127	± 10.8	1121	± 16.6			378
15D		1042	1065	1058	±8.7	1053	± 9.0	1066	± 8.5	1053	± 8.9			306
17A	Bot	933	948	941	±11.8	934	± 10.7	997	± 10.7	935	± 10.5			197
	Top	999	1125	1125	±7.2	1129	± 6.8	1144	± 11.1	1122	± 7.2			263
17D		822	823	817	±9.2	810	± 9.5	848	± 8.9	818	± 9.5			74
17/19 Frame	Top	954	972	976	±4.8	963	± 4.9	967	± 6.0	964	± 4.8			218
	Bot	955	990	989	±6.3	975	± 7.8	991	± 6.2	972	± 5.9			219
19A		803	809	800	±8.4	806	± 9.9	815	± 9.6	807	± 8.9			64
19B		826	847	840	±8.7	824	± 7.8	837	± 9.5	848	± 8.6			88
19C		822	832	819	±11.0	820	± 10.5	854	± 11.8	824	± 11.3			83

1. Source – Reference 21
2. Source – Reference 25
3. Source – Reference 27
4. Source – Reference 31, 47

Note: Shaded cells indicate thickness value used to conservatively calculate the margin

II. 2006 Confirmatory Actions

During the 2006 refueling outage (1R21), AmerGen performed UT of the drywell shell in the sandbed region from inside the drywell, at the same 19 grid locations where UT was performed in 1992, 1994, and 1996. Location of the UT grid is centered at elevation 11' 3" in an area of the drywell shell that corresponds to the sandbed region. The 2006 UT measurements were made in accordance with the enhanced Oyster Creek ASME Section XI, Subsection IWE (B1.27) Aging Management Program. The data was statistically analyzed using the methodology described in section 3 to determine the 95% confidence level mean thickness. The results of the statistical analysis of the 2006 UT data were compared to the 1992, 1994 and 1996 data statistical analysis results. Some of the 1996 data contained anomalies that are not readily explained, but the anomalies did not significantly change the results. The comparison confirmed that corrosion on the exterior surfaces of the drywell shell in the sandbed region has been arrested.

Analysis of the 2006 UT data, at the 19 grid locations indicates that the minimum measured 95% confidence level mean thickness in any bay is 807 mils (bay #19A). This is compared to the 95% confidence level minimum measured mean thickness in bay #19 of 806 mils and 800 mils measured in 1994 and 1992 respectively. Considering the instrument accuracy of ±10mils these values are considered equivalent. Thus no statistically observable corrosion has occurred since 1992 and the minimum drywell shell mean thickness at the grid locations remains greater than 736 mils as required to satisfy the worst case buckling analysis, and the minimum available margin of 64 mils for any bay reported prior to taking 2006 UT thickness measurements remains bounded. (Ref [47])

In its statistical analysis of drywell corrosion data, AmerGen has used the F-ratio test as part of its method to determine whether there is ongoing corrosion. In analysis of the data from this outage, AmerGen determined that different statistical treatment of the data would be appropriate to estimate bounding corrosion rates in the sandbed region. Using this updated statistical test of the data, AmerGen cannot statistically confirm that the sandbed region has a corrosion rate of zero. This is because of the high variance in UT data within each 49-point grid (standard within a range of deviation 60 to 100 mils), the relatively limited number of data sets that have been taken and the time frame over which data has been collected since the sand was removed in 1992. The high variance in UT data within the grids is a result of the drywell exterior surface roughness caused by corrosion that occurred prior to 1992. However, AmerGen continues to believe that corrosion of the exterior surface of the drywell shell in the sandbed region has been arrested as evidenced by little change in the mean thickness of the 19 monitored (grid) locations and the observed good condition of the epoxy coating during the 2006 inspection.

In addition to the UT measurements at the 19 grid locations, a total of 294 UT thickness measurements were taken in the bay #5 trench and 290 measurements were taken in the bay #17 trench during the 2006 refueling outage. The computed mean thickness value of the drywell shell taken within the two trenches is 1074 mils for bay #5 and 986 mils for bay #17. These values,

when compared to the 1986 mean thickness values of 1112 mils for the bay #5 trench and 1024 mils for the bay #17 trench, indicated that wall thinning of approximately 38 mils has taken place in each trench since 1986. Engineering evaluation of the results concluded that considering that the exterior surface of bay #5 had experienced a corrosion rate of up to 11.3 mils/yr between 1986 and 1992 and the exterior surface of bay #17 had experienced a corrosion rate of up to 21.1 mils/yr in the same period, the 38 mils wall thinning measured in 2006 is due to corrosion on the exterior surface of the drywell between 1986 and 1992. (Ref [47])

Additionally the 95% confidence level minimum computed drywell shell mean thickness based on 2006 UT measurements within the two trenches is greater by a margin of 250 mils than the minimum required thickness of 736 mils for buckling. Also this margin is significantly greater than the minimum computed margin at other monitored locations outside the trenches (64 mils). Individual points within the two trenches met the local thickness acceptance criterion of 490 mils for pressure computed based on ASME Section III, Subsection NE, Class MC Components, Paragraph NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE 3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The individual points also met a local buckling criterion of 536 mils previously established by engineering analysis. (Ref [47])

The above UT thickness measurements were supplemented by additional UT measurements taken at 106 points from outside the drywell in the sandbed region, distributed among the ten bays. The locations of these measurements were established in 1992 as being the thinnest local areas based on visual inspection of the exterior surface of the drywell shell before it was coated. The thinnest location measured in 2006 is 602 mils versus 618 mils measured in 1992. The difference between the two measurements does not necessarily mean a wall thinning of 16 mils has taken place since 1992. This is because the 2006 UT data could not be compared directly with the 1992 data due to the difference in UT instruments and measurement technique used in 2006, and the uncertainty associated with precisely locating the 1992 UT points. A review of the 2006 data for the 106 external locations indicated that the measured local thickness is greater than the local acceptance criteria of 0.490" for pressure and 536 mils for local buckling. (Ref [47])

As stated above, the 2006 UT data of the locally thinned areas (106 points) could not be correlated directly with the corresponding 1992 UT data. This is largely due to using a more accurate UT instrument and the procedure used to take the measurements.. In addition the inner drywell shell surface could be subject to some insignificant corrosion due to water intrusion onto the embedded shell (see discussion below). For these reasons the Oyster Creek ASME Section XI, Subsection IWE Program (B.1.27) will be further enhanced to require UT measurements of the locally thinned areas in 2008 and periodically during the period of extended operation. (Ref [47])

During the 2006 refueling outage (1R21), AmerGen conducted VT-1 inspections of the epoxy coating in all ten bays in accordance with ASME Section XI, Subsection IWE, and AmerGen's Protective Coating Monitoring and Maintenance Program. These inspections would have documented any flaking, blistering, peeling, discoloration, and other signs of degradation of the coating. The VT-1 inspections found the coating to be in good condition with no degradation.

Based on these VT-1 inspections, AmerGen has confirmed that no further corrosion of the drywell shell is occurring from the exterior of the epoxy-coated sandbed region. Monitoring of the coating in accordance with the ASME Section XI, Subsection IWE and AmerGen's Protective Coating Monitoring and Maintenance Program will continue to ensure that the drywell shell maintains its intended function during the period of extended operation. (Ref [47])

A. Aging Management Program for the Extended Period of Operation:

AmerGen is committed to a comprehensive aging management program to ensure that significant corrosion is detected and corrected prior to impacting the intended functions of the drywell (Ref [47]). The program elements for the sandbed region include:

1. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.

2. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage during refueling outages and during the plant operating cycle:

    - The sand bed region drains will be monitored daily during refueling outages. If leakage is detected, procedures will be in place to determine the source of leakage and investigate and address the impact of leakage on the drywell shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.
    - The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:

        - Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region
        - UTs of the upper drywell region consistent with the existing program

- UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred
- UT results will be evaluated per the existing program

Any degraded coating or moisture barrier will be repaired

3. The Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage. Inspection of the coating is accomplished through the Protective Coating Monitoring and Maintenance Program (B.1.33)

4. When the sand bed region drywell shell coating inspection is performed, the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected

5. The reactor cavity seal leakage concrete trough drain will be verified to be clear from blockage once per refueling cycle.

6. UT thickness measurements will be taken from outside the drywell in the sandbed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

7. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sandbed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified.

8. Perform visual inspection of the drywell shell inside the trench in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

After each inspection, UT thickness measurements results will be evaluated and compared with previous UT thickness measurements. If unsatisfactory results are identified, then additional corrective actions will be initiated, as necessary, to ensure the drywell shell integrity is maintained throughout the period of extended operation (Ref [47]).

III. Conclusion

Corrosion of the Oyster Creek outer drywell shell has been investigated since the early 1980's. Corrective actions, implemented beginning in 1986, have arrested corrosion. AmerGen conducted UT thickness inspections of the shell in the sandbed region in 2006 (1R21) to confirm corrosion has been arrested in the outer drywell shell. The results showed that corrosion of the exterior drywell shell has been arrested. AmerGen also conducted VT-1 inspections of the epoxy coating in all ten bays in accordance with ASME Section XI, Subsection IWE, and AmerGen's Protective Coating Monitoring and Maintenance Program. The VT-1 inspections found the coating to be in good condition with no degradation.

Engineering analysis of the drywell using a conservative uniform general thickness of 736 mils for the entire sandbed region concluded that the drywell meets its design requirements during the current term with adequate margin.

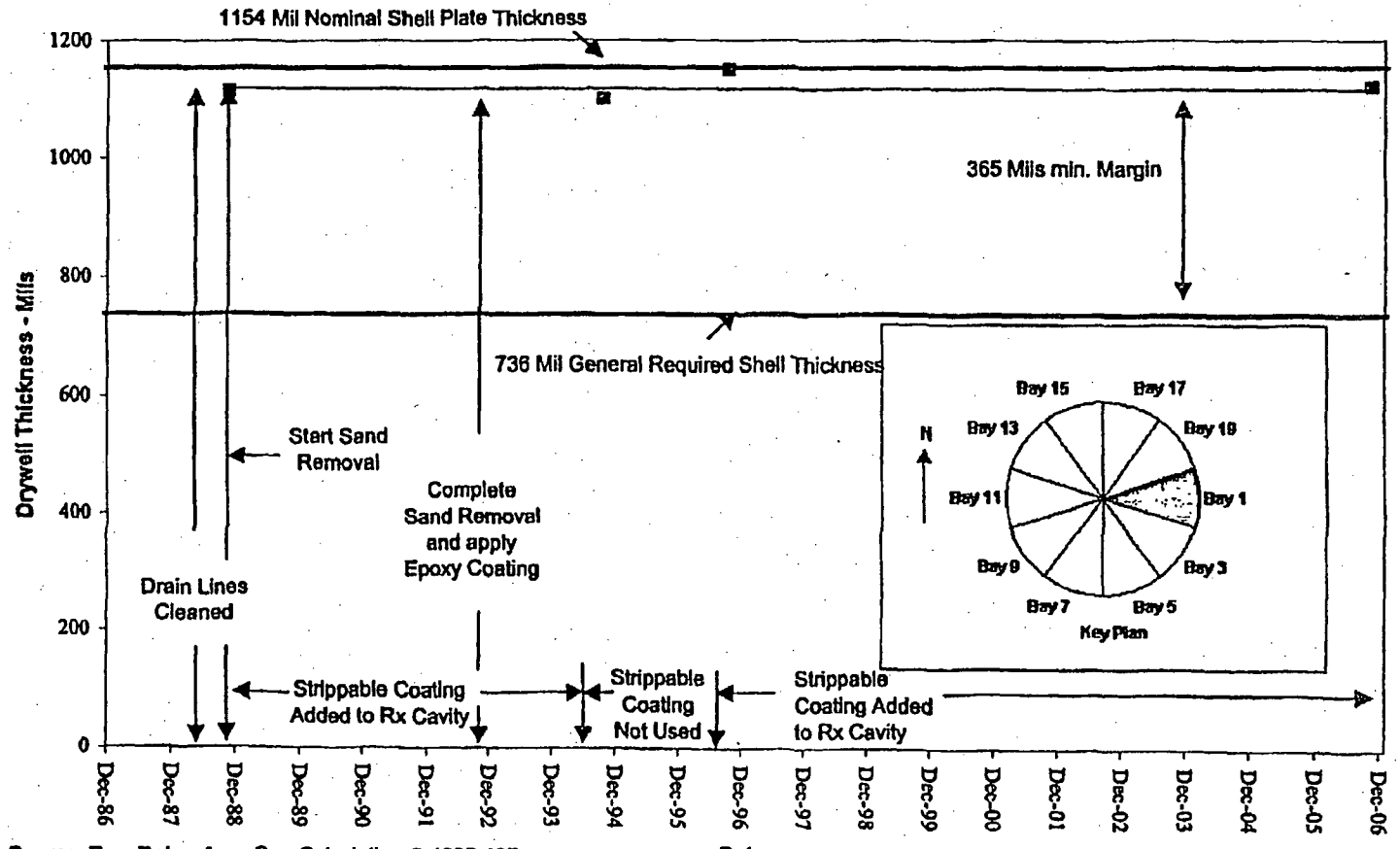
AmerGen is committed to implementing a comprehensive aging management program during the extended period of operation to preserve the existing margin. The program is designed to detect, mitigate, and correct drywell shell degradations. These activities provide reasonable assurance that wall thinning of the drywell will be detected and corrected prior to impacting the intended function of the drywell.

ATTACHMENT 1

GRAPHICAL PRESENTATION OF SANDBED DATA

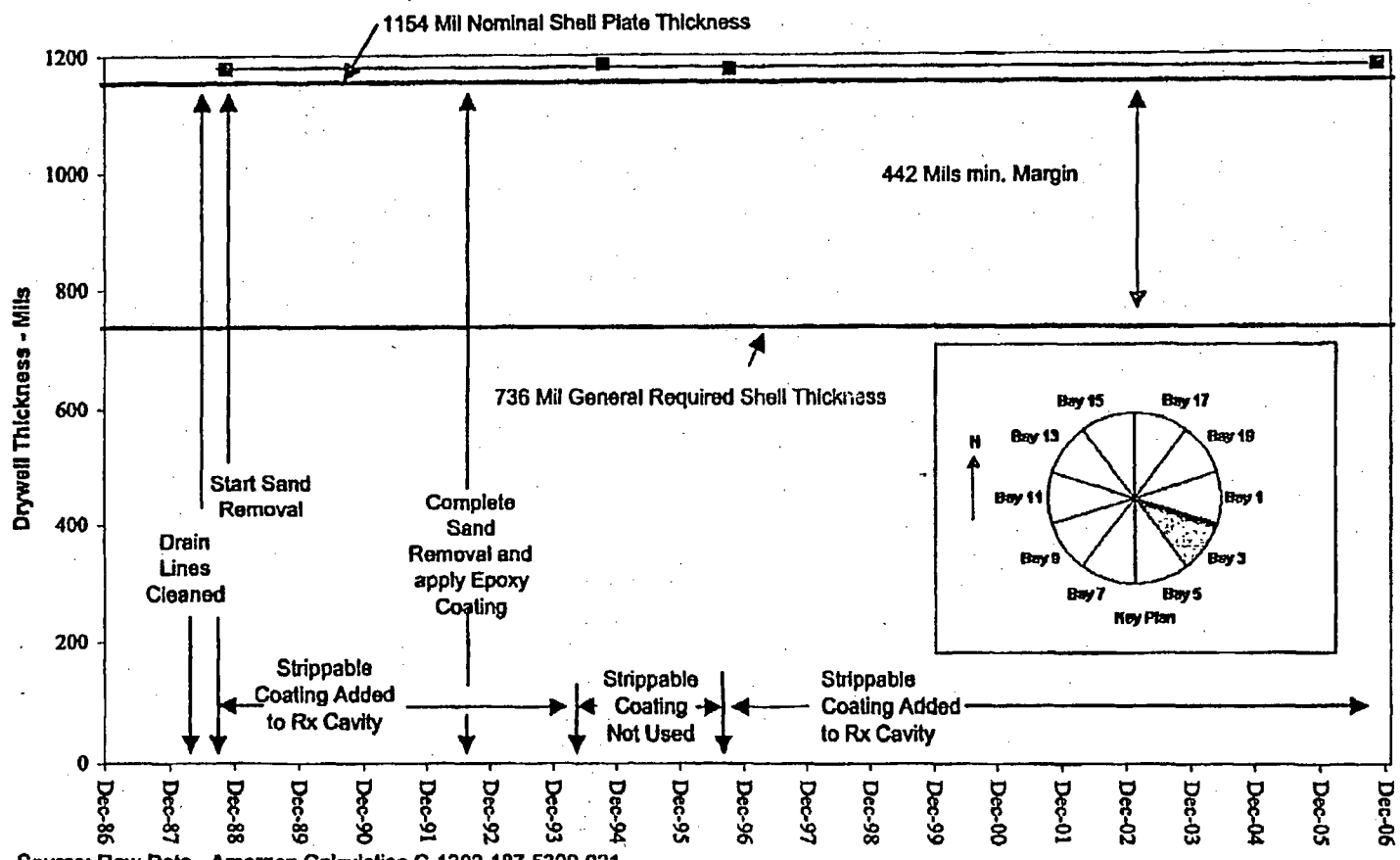
Source of data for the graphs:
Ref. [21], Ref [25], Ref [27], Ref [31], and Ref [47]

Figure 1. Sandbed Bay # 1D



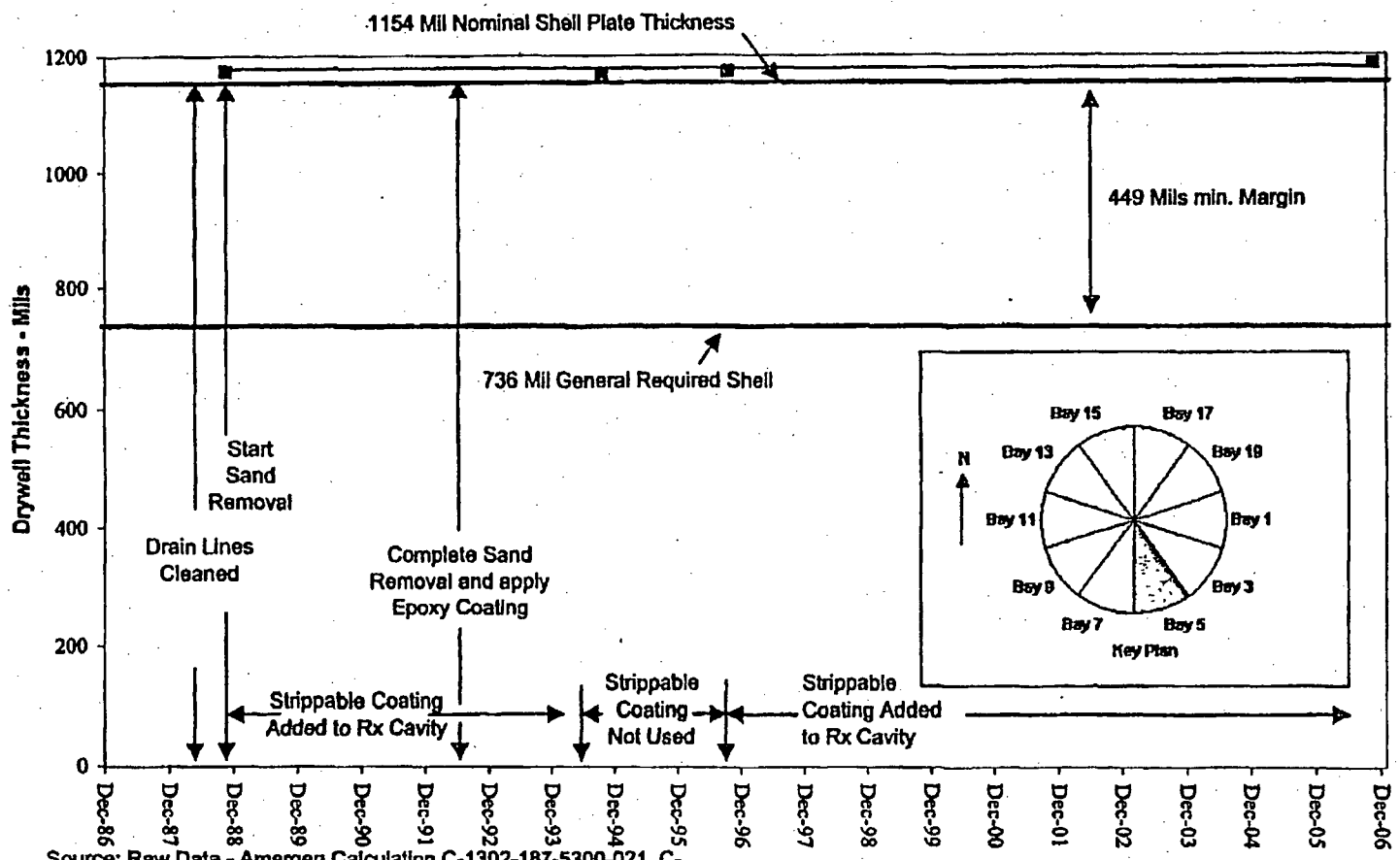
Source: Raw Data - AmerGen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 2. Sandbed Bay #3D



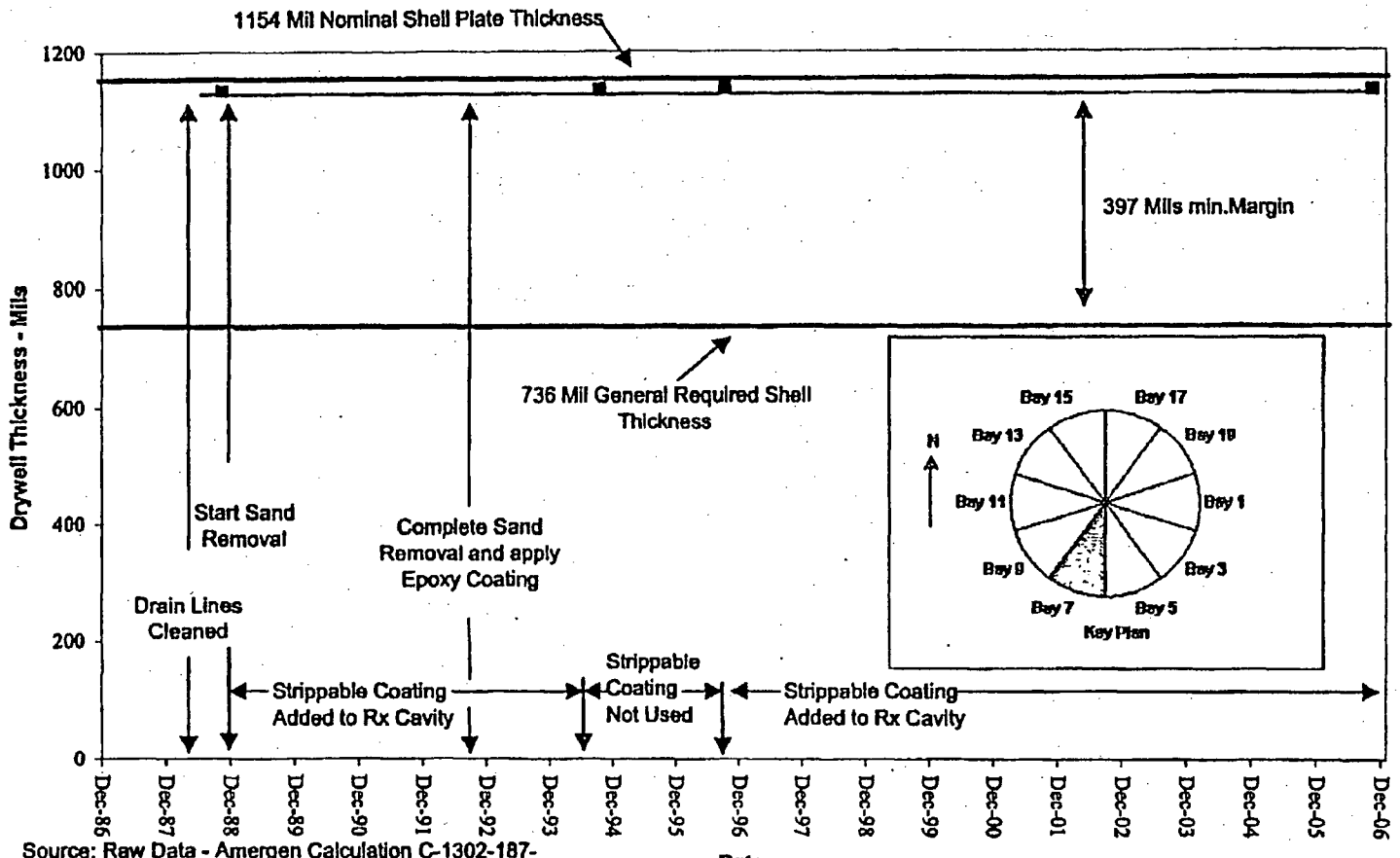
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 3. Sandbed Bay # 5D



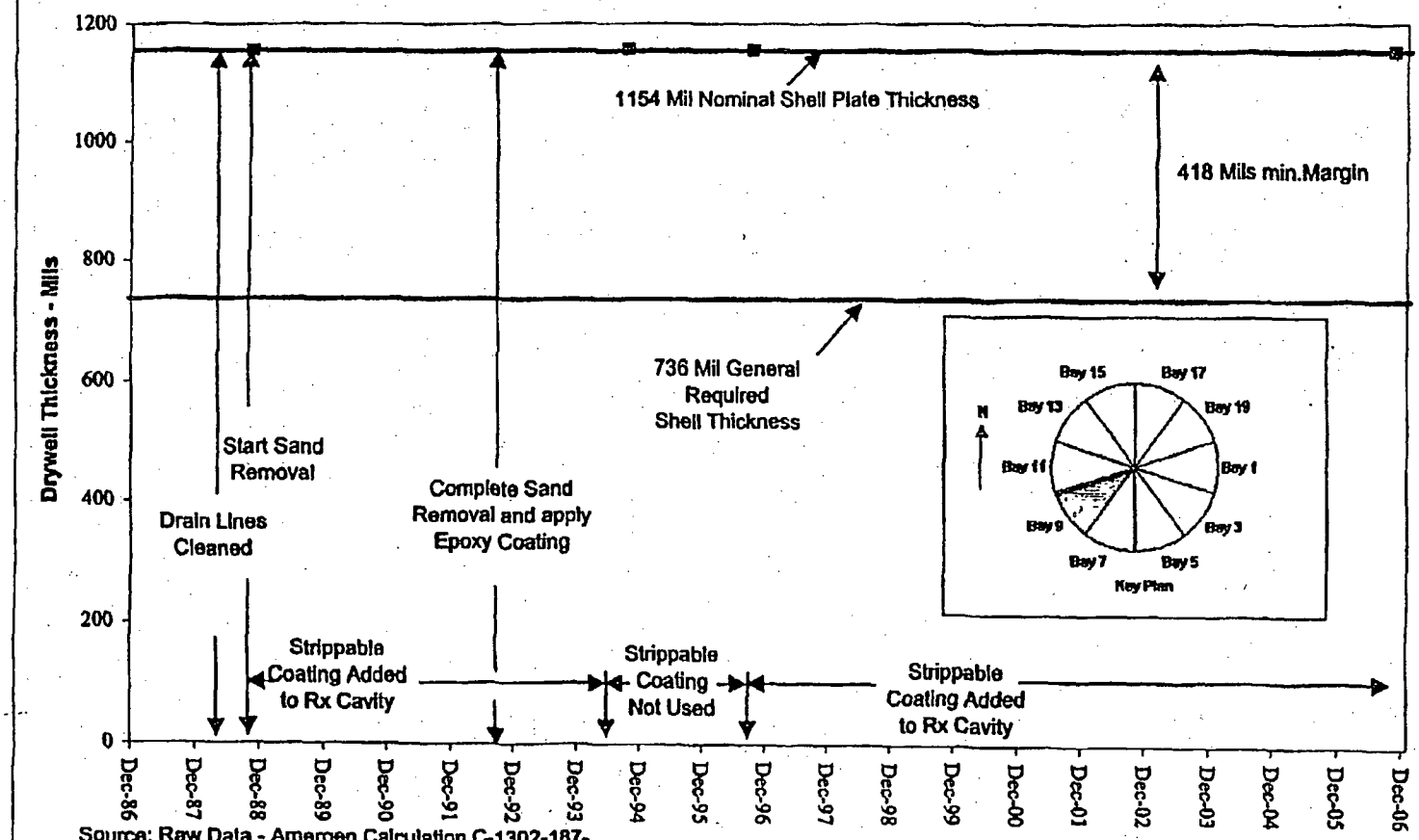
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 4. Sandbed Bay # 7D



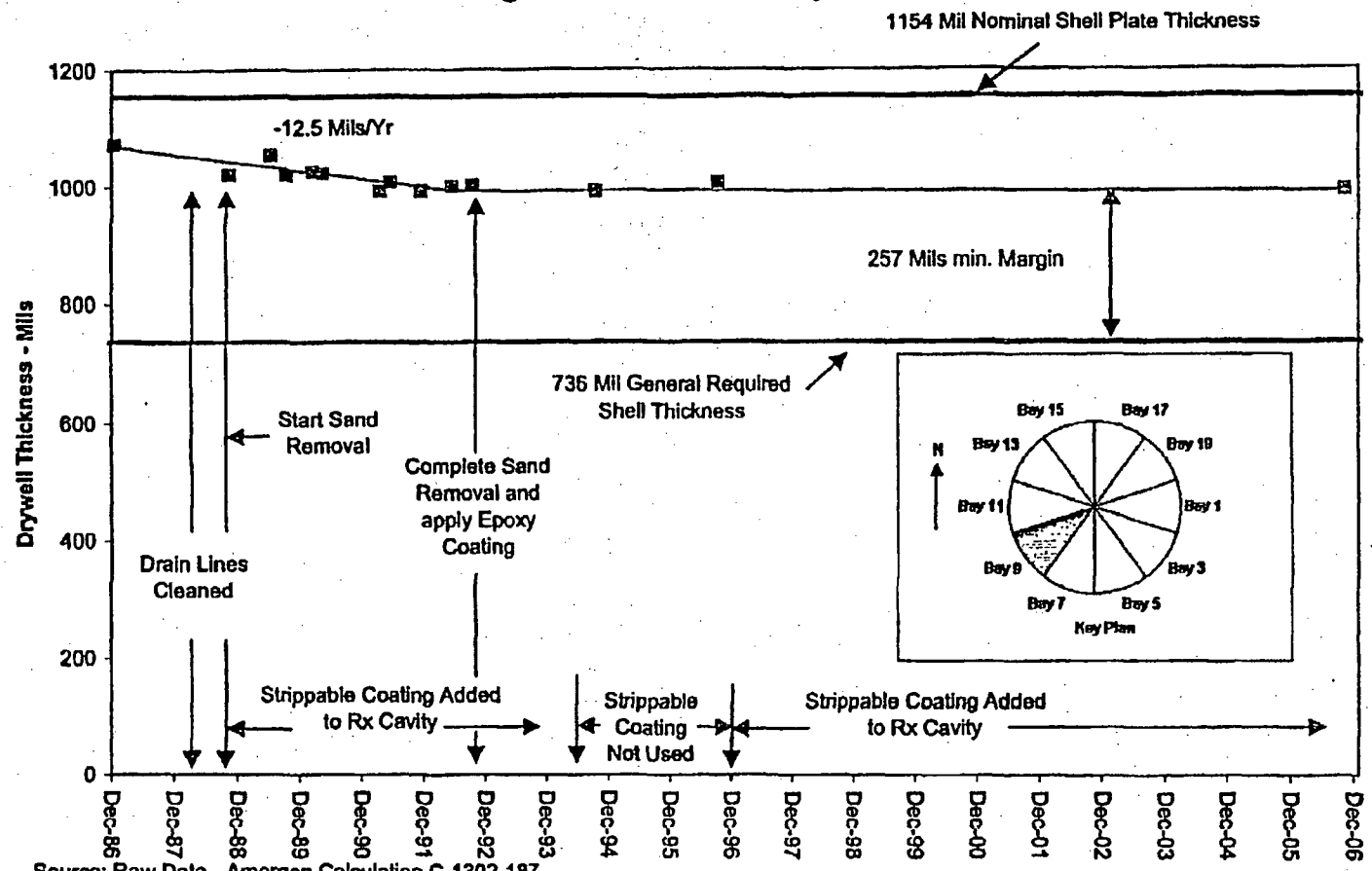
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 5. Sandbed Bay # 9A



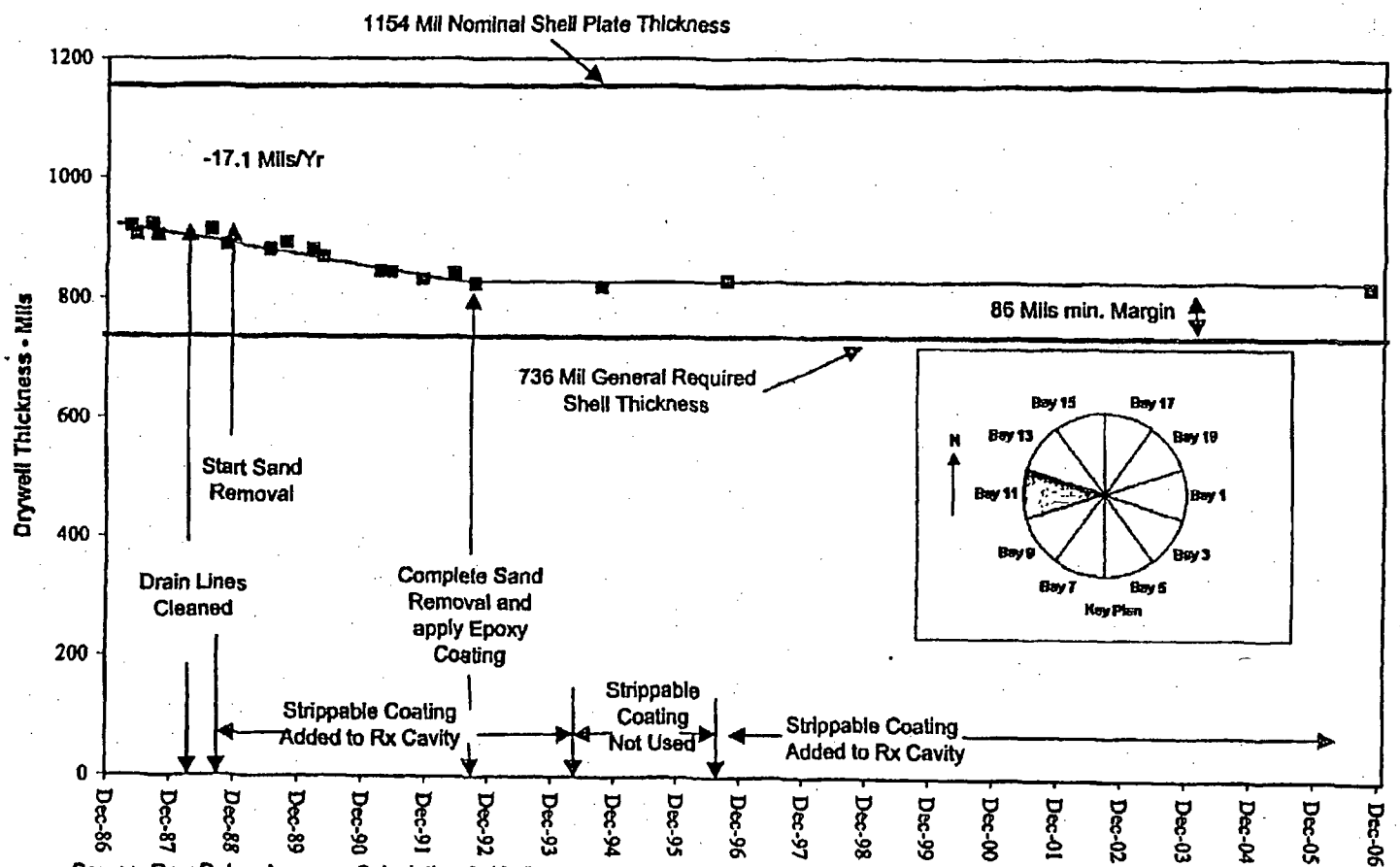
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 6. Sandbed Bay # 9D



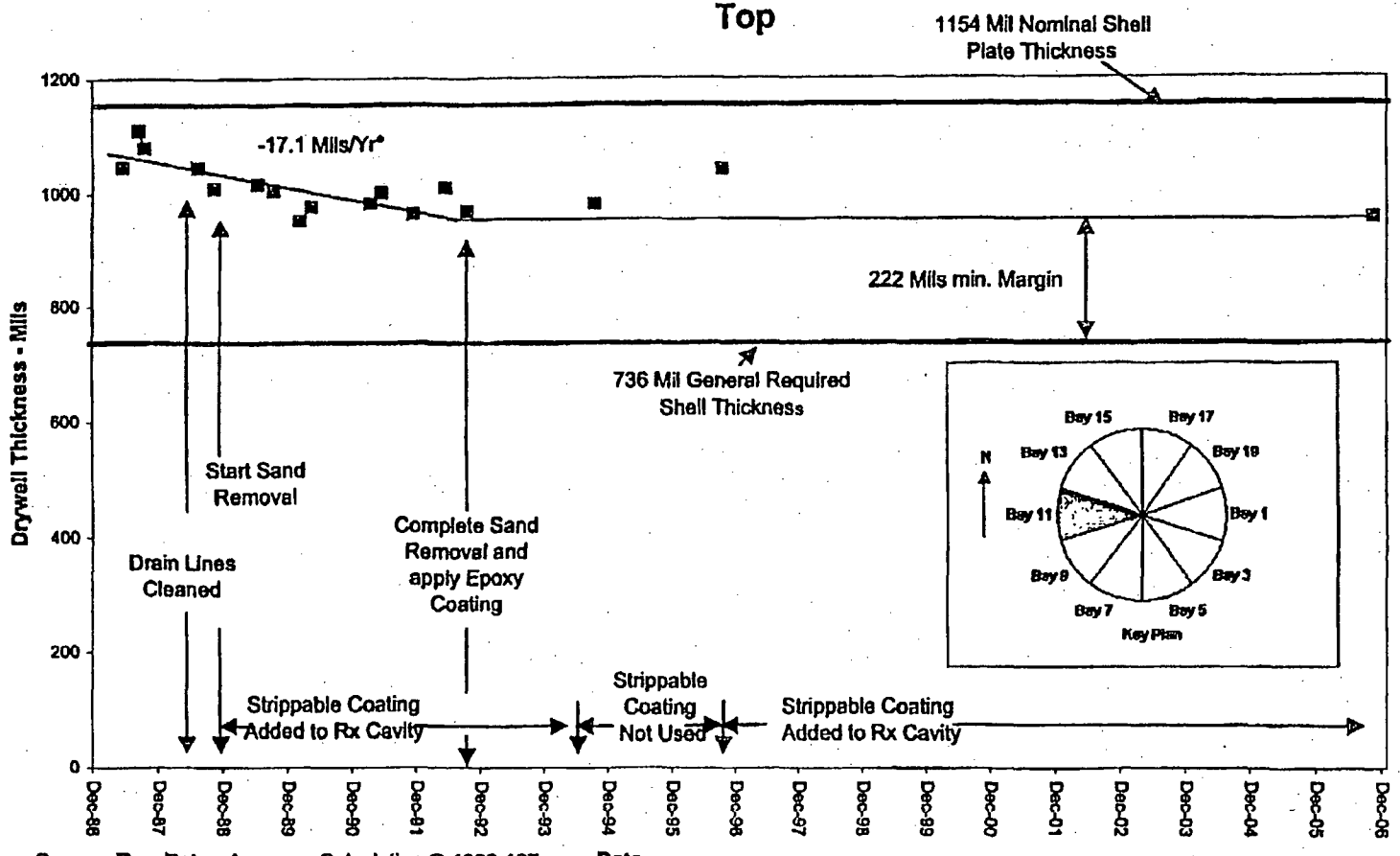
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030.

Figure 7. Sandbed Bay #11A



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

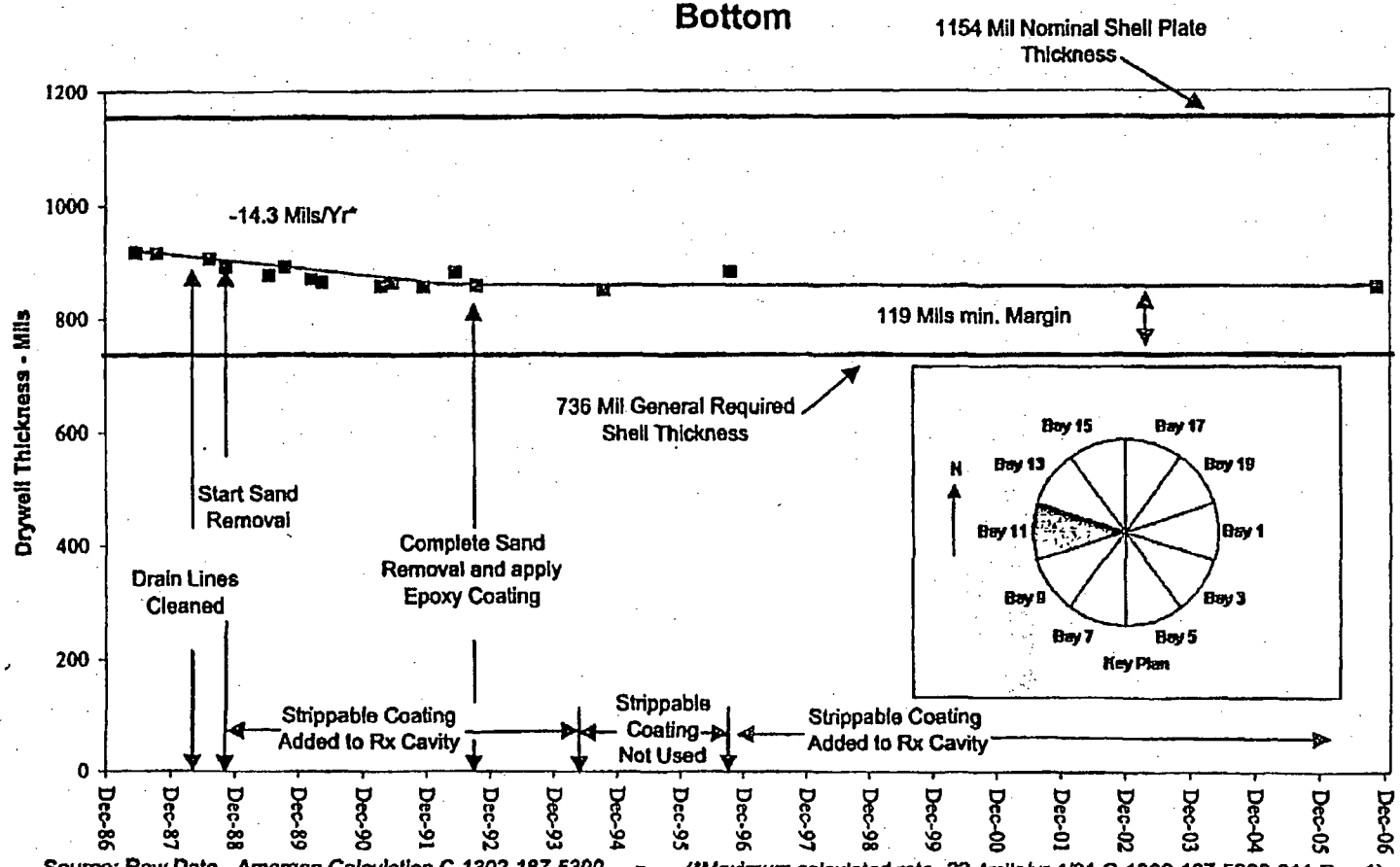
Figure 8. Sandbed Bay #11C
Top



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-

(*Maximum calculated rate -35.2 mils/yr 4/91, C-1302-187-5300-011 Rev. 1)

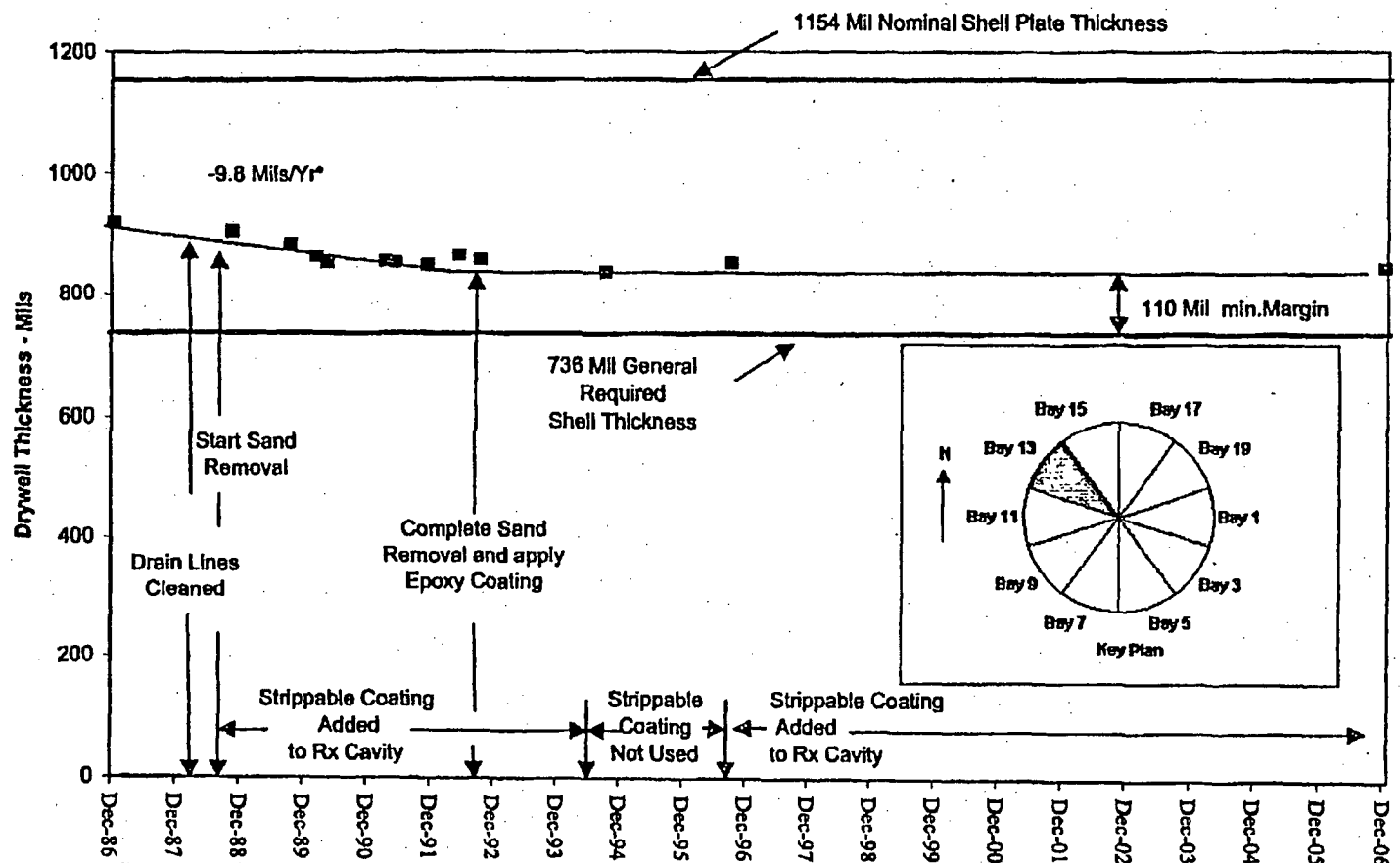
Figure 9. Sandbed Bay #11C Bottom



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

(*Maximum calculated rate -22.4mils/yr 4/91,C-1302-187-5300-011 Rev.1)

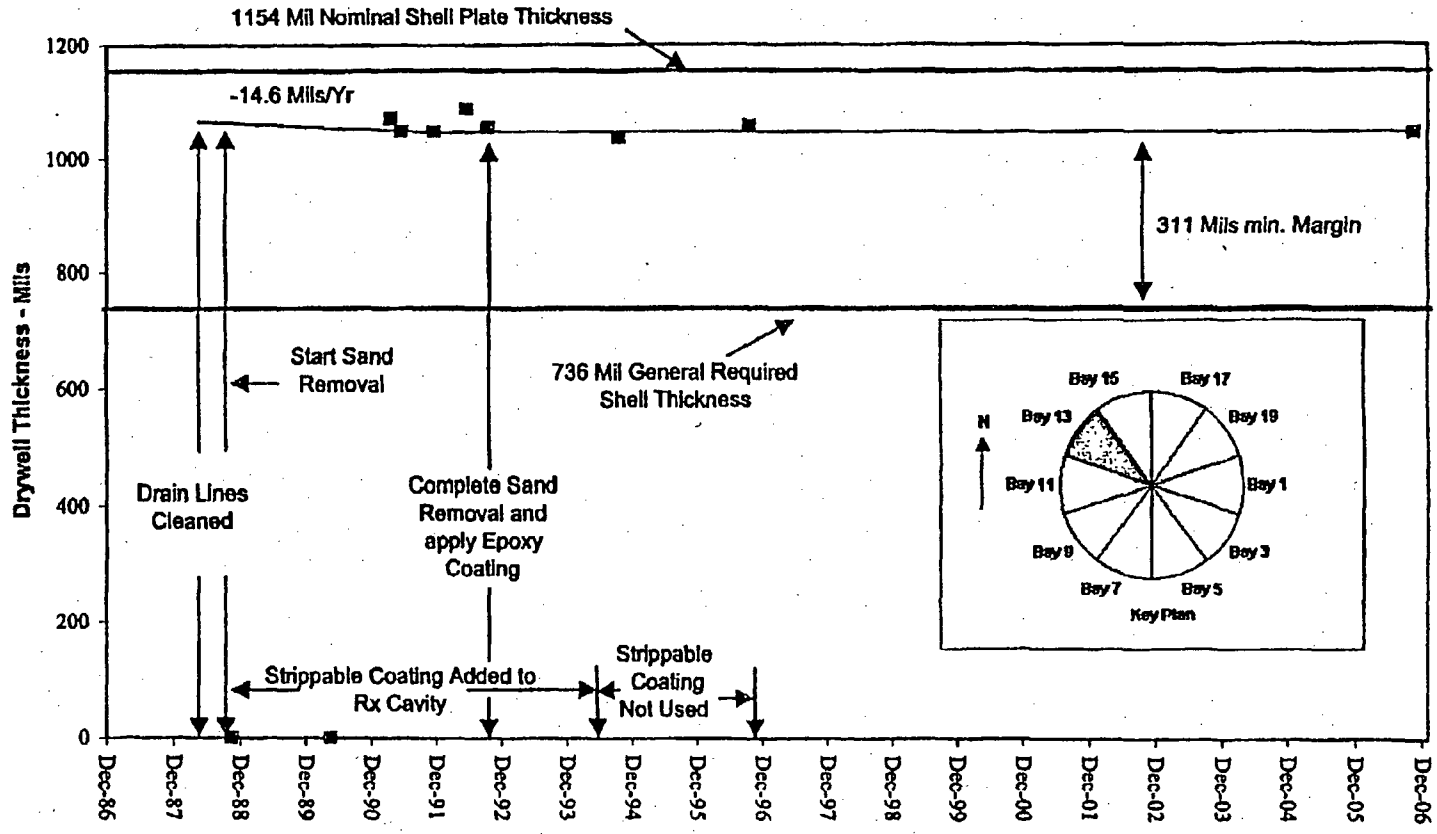
Figure 10. Sandbed Bay #13A



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

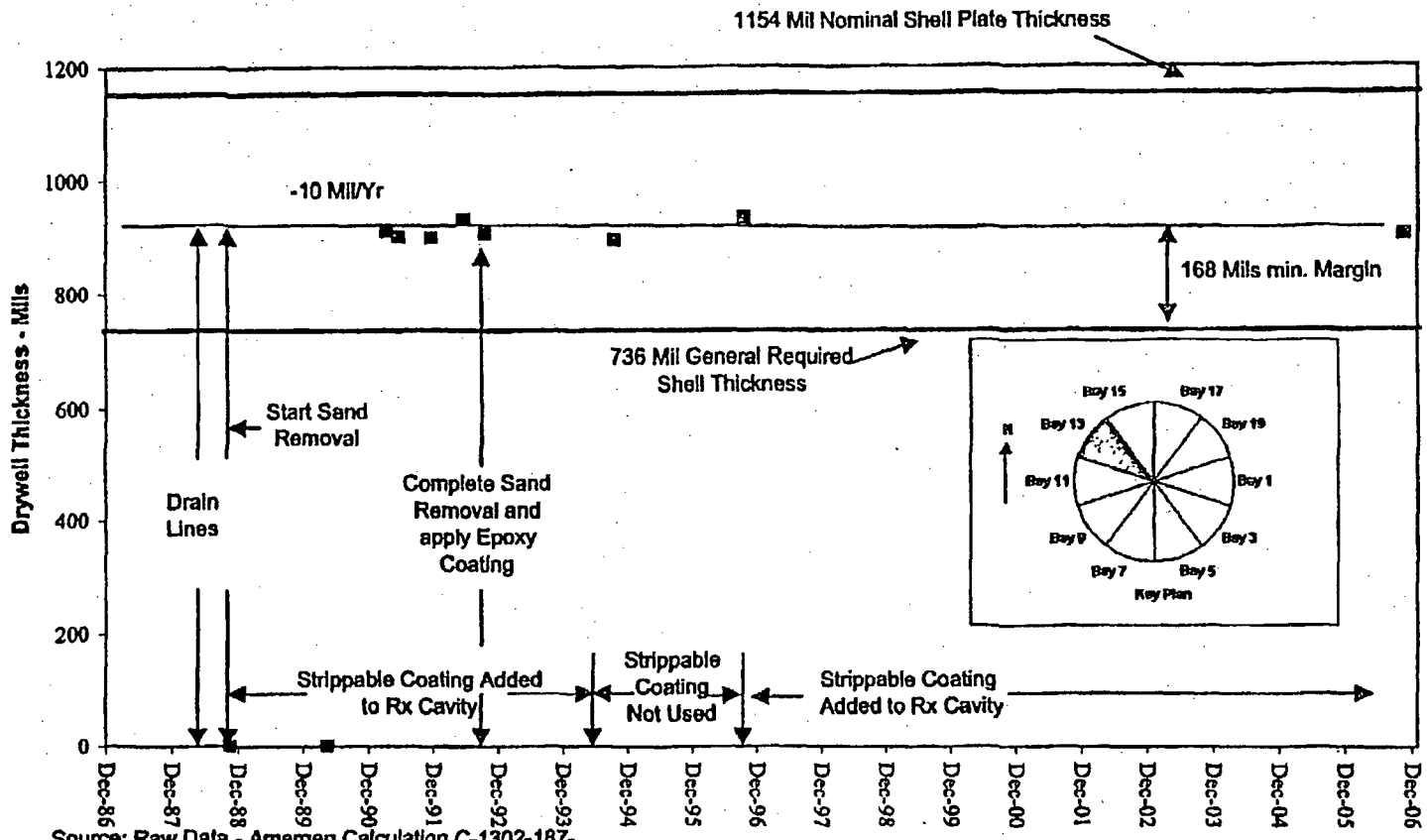
(*Maximum Calculated rate -39.1 mils/yr 4/91, C-1302-187-5300-011 Rev. 1)

Figure 11. Sandbed Bay #13D Top



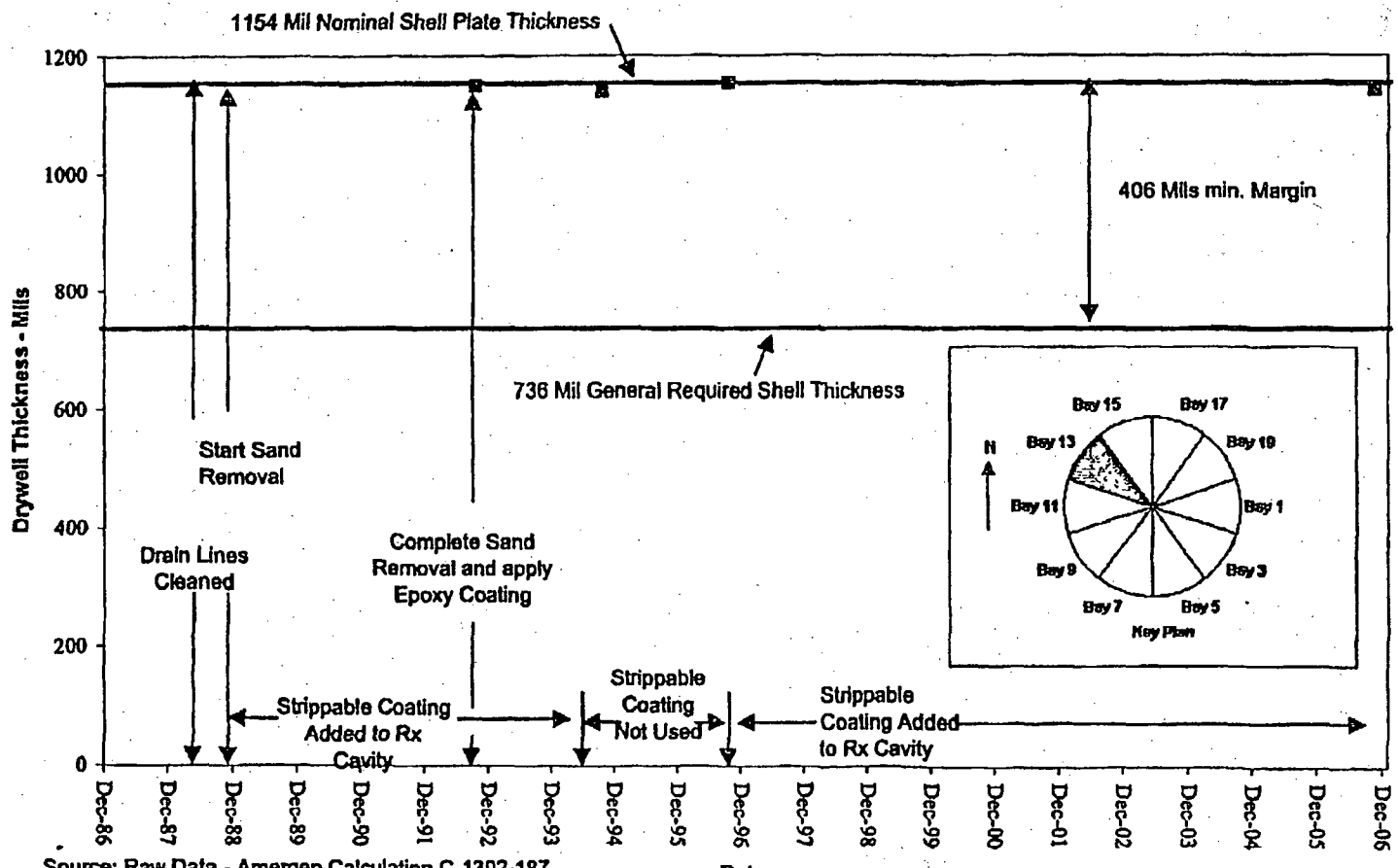
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 12. Sandbed Bay #13 D Bottom



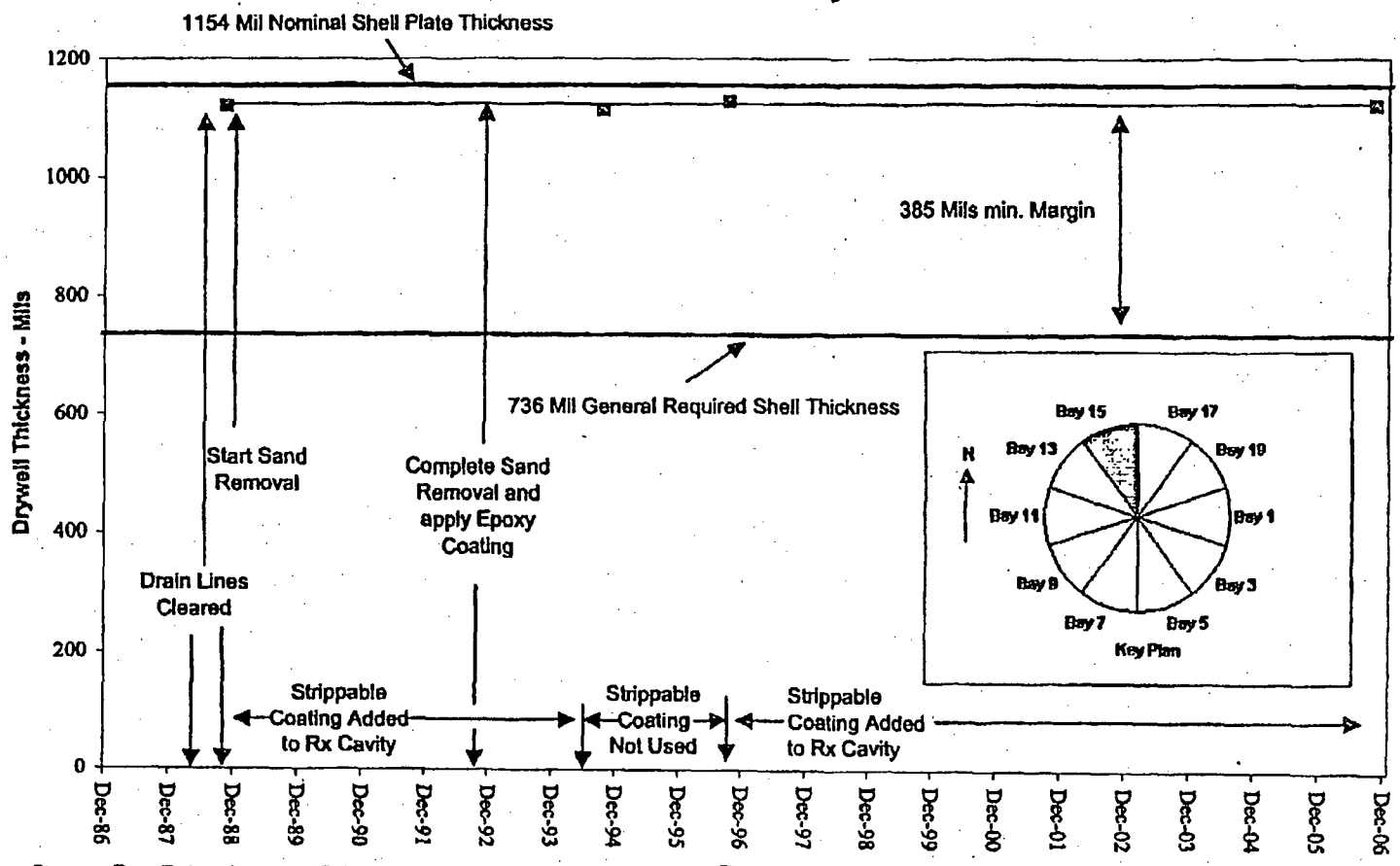
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 13. Sandbed Bay # 13C



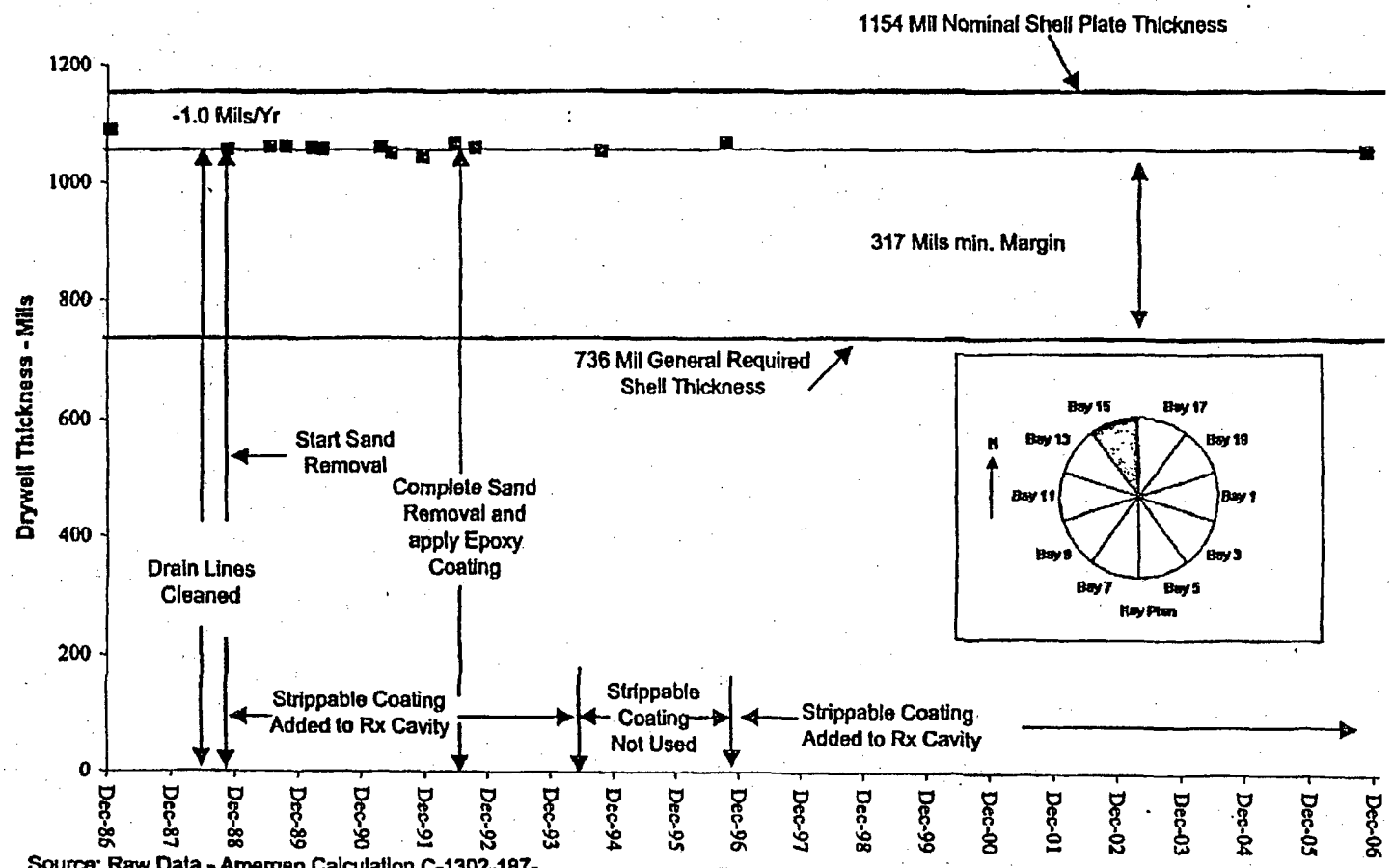
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 14. Sandbed Bay # 15A



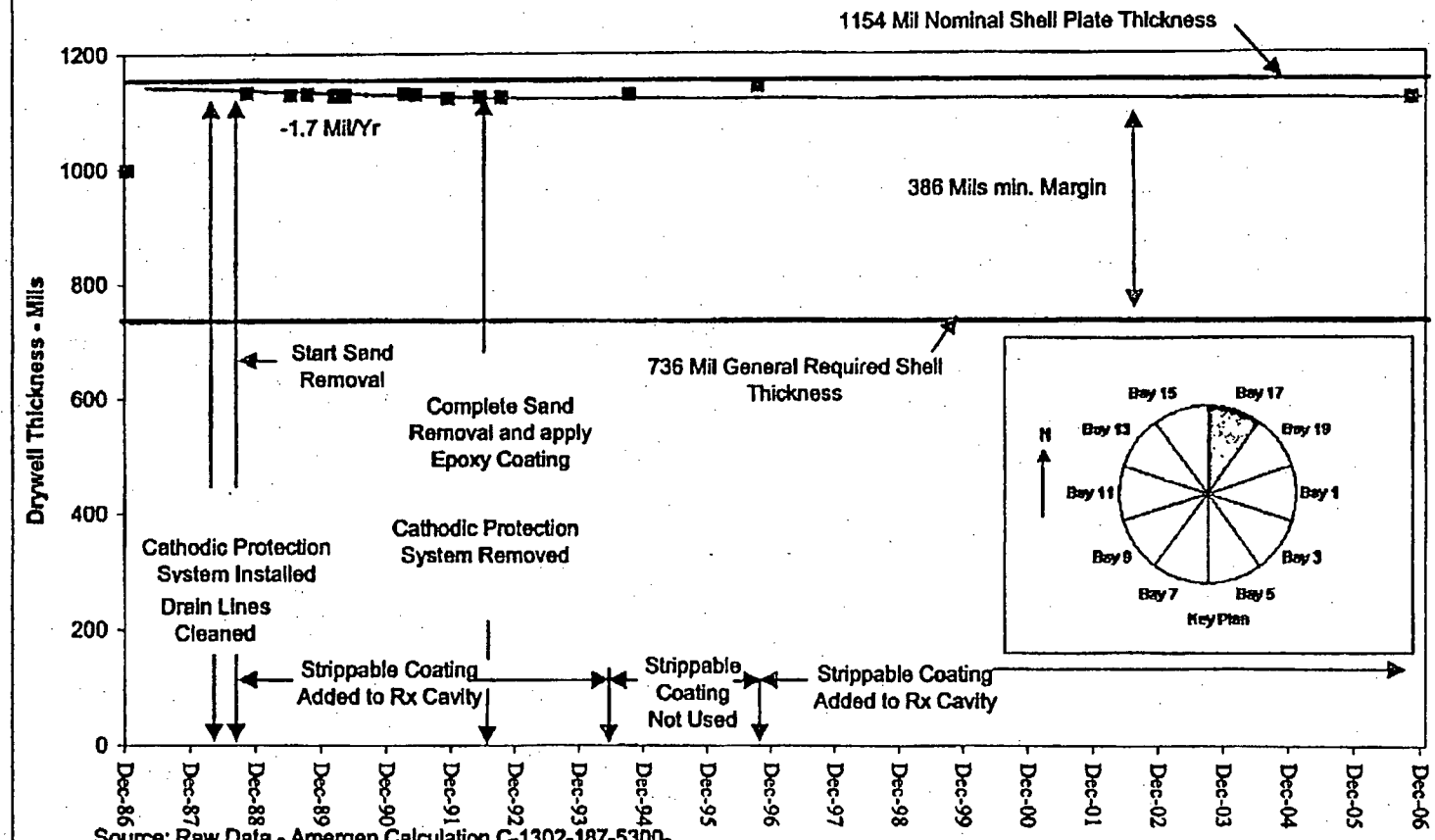
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

Figure 15. Sandbed Bay #15 D



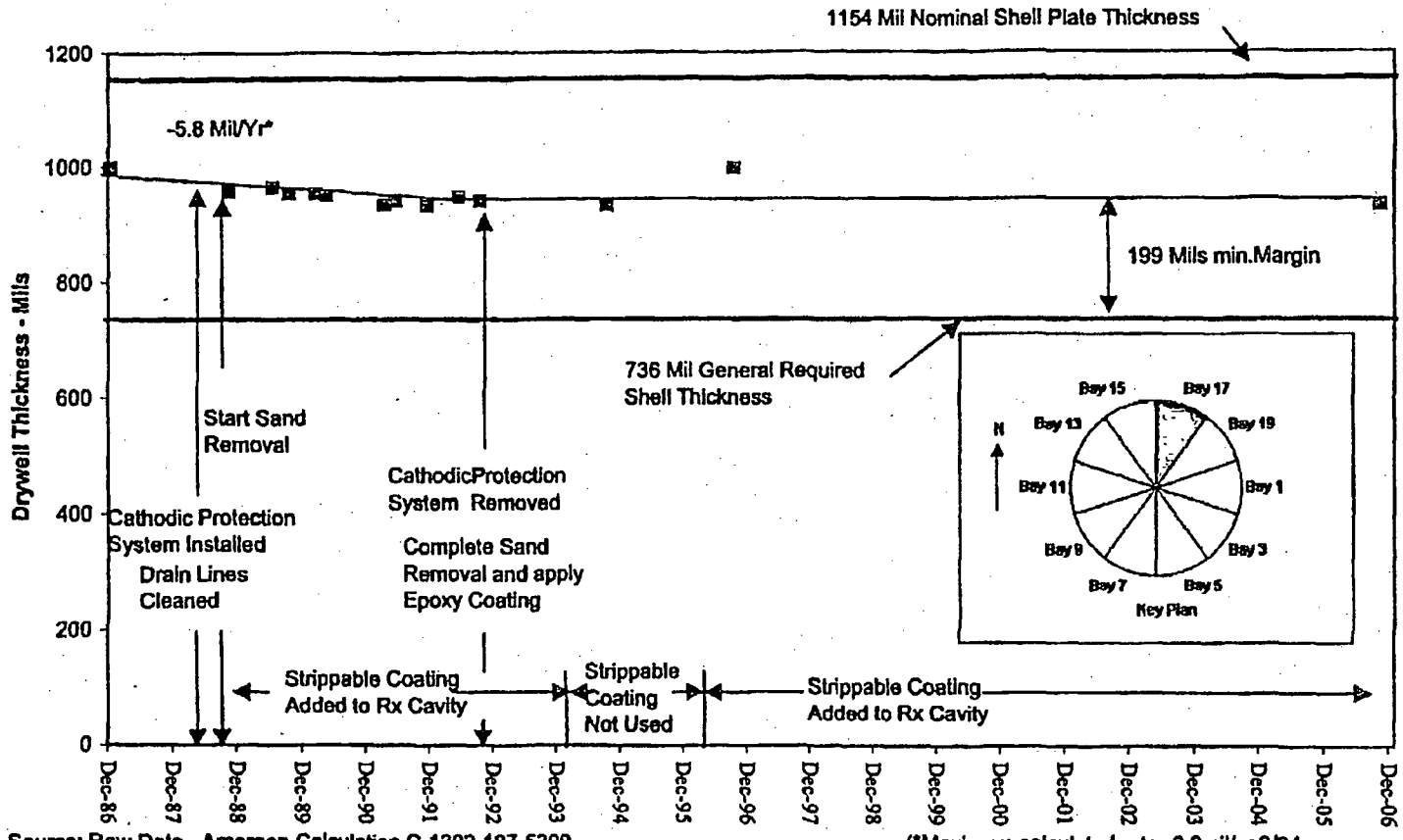
Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-026, C-1302-187-8610-030

Figure 16. Sandbed Bay #17A
Top



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

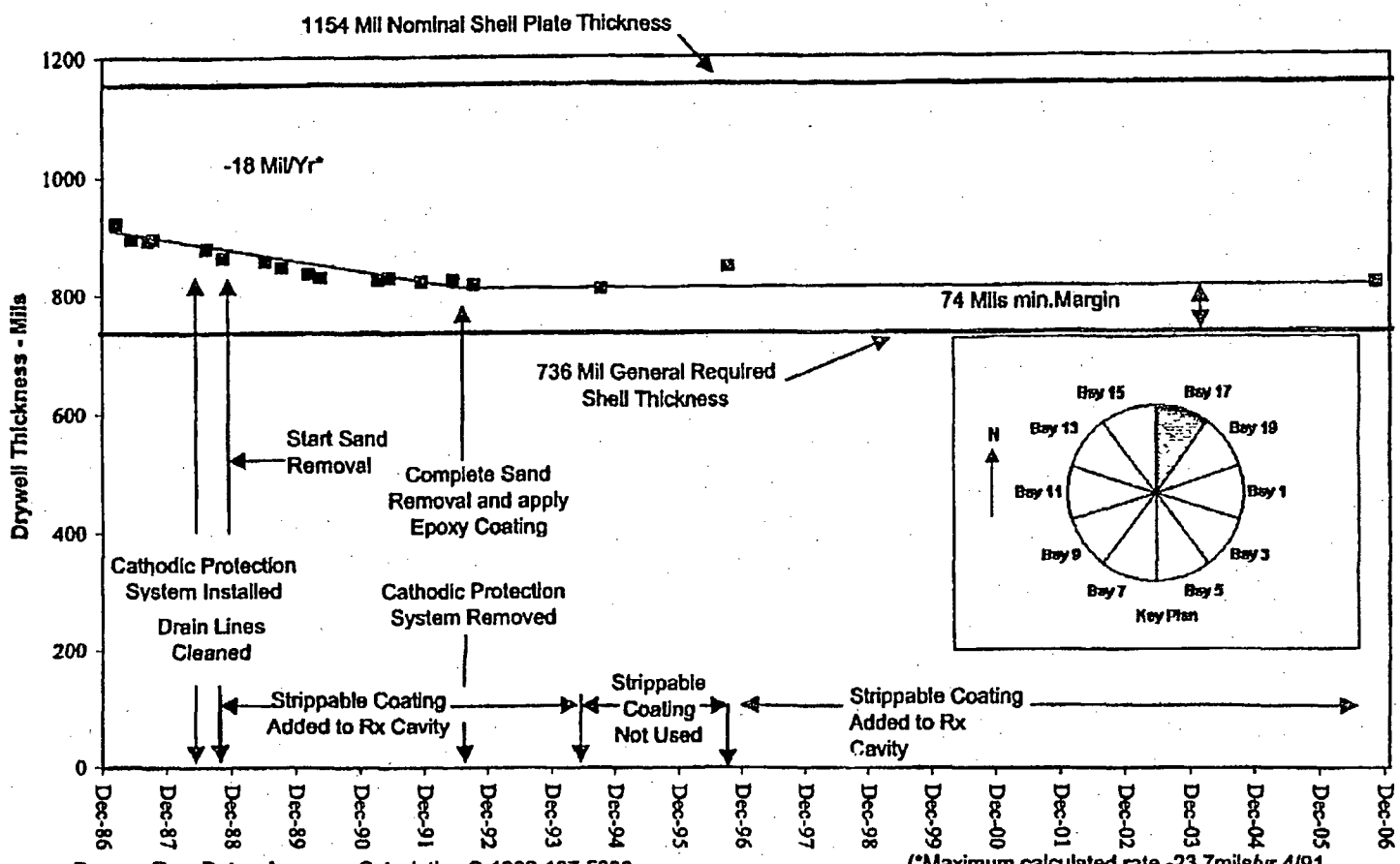
Figure 17. Sandbed Bay #17A Bottom



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

(*Maximum calculated rate -0.3mil/yr 9/94, C-1302-187-5300-028 Rev. 0)

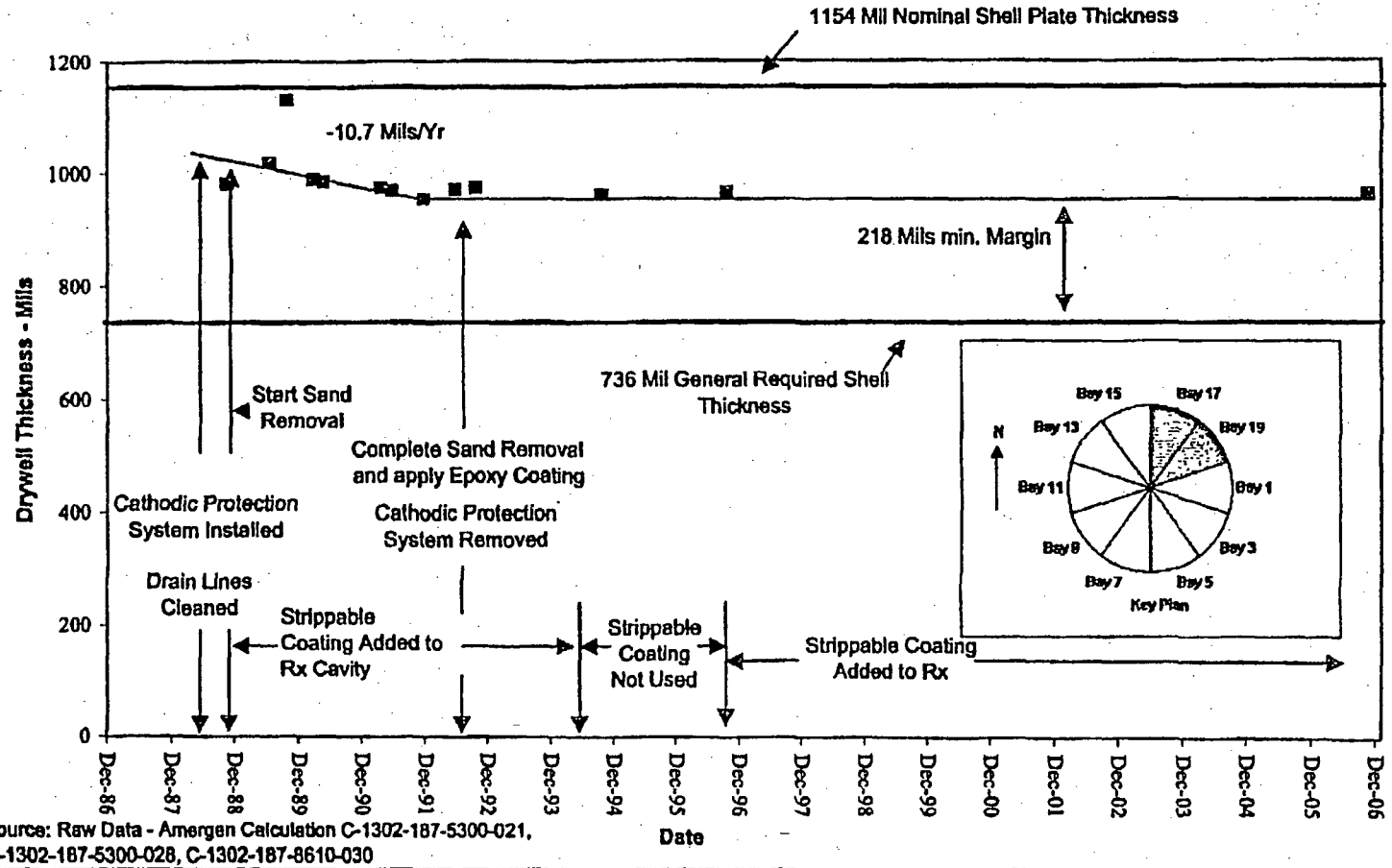
Figure 18. Sandbed Bay #17D



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

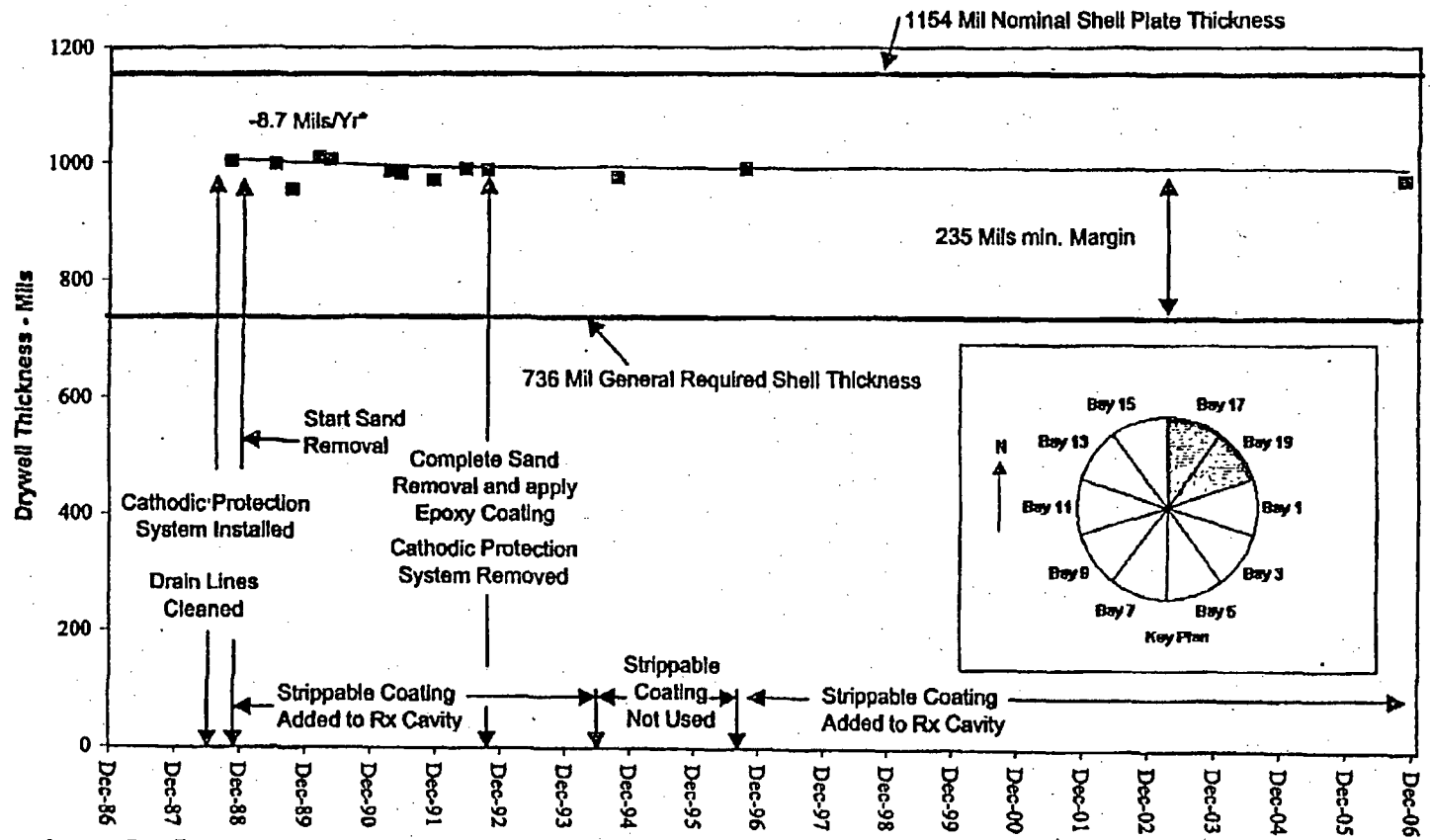
(*Maximum calculated rate -23.7mils/yr 4/91, C-1302-187-5300-011 Rev. 1)

Figure 19. Sandbed Bay #17/19
Frame Top



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

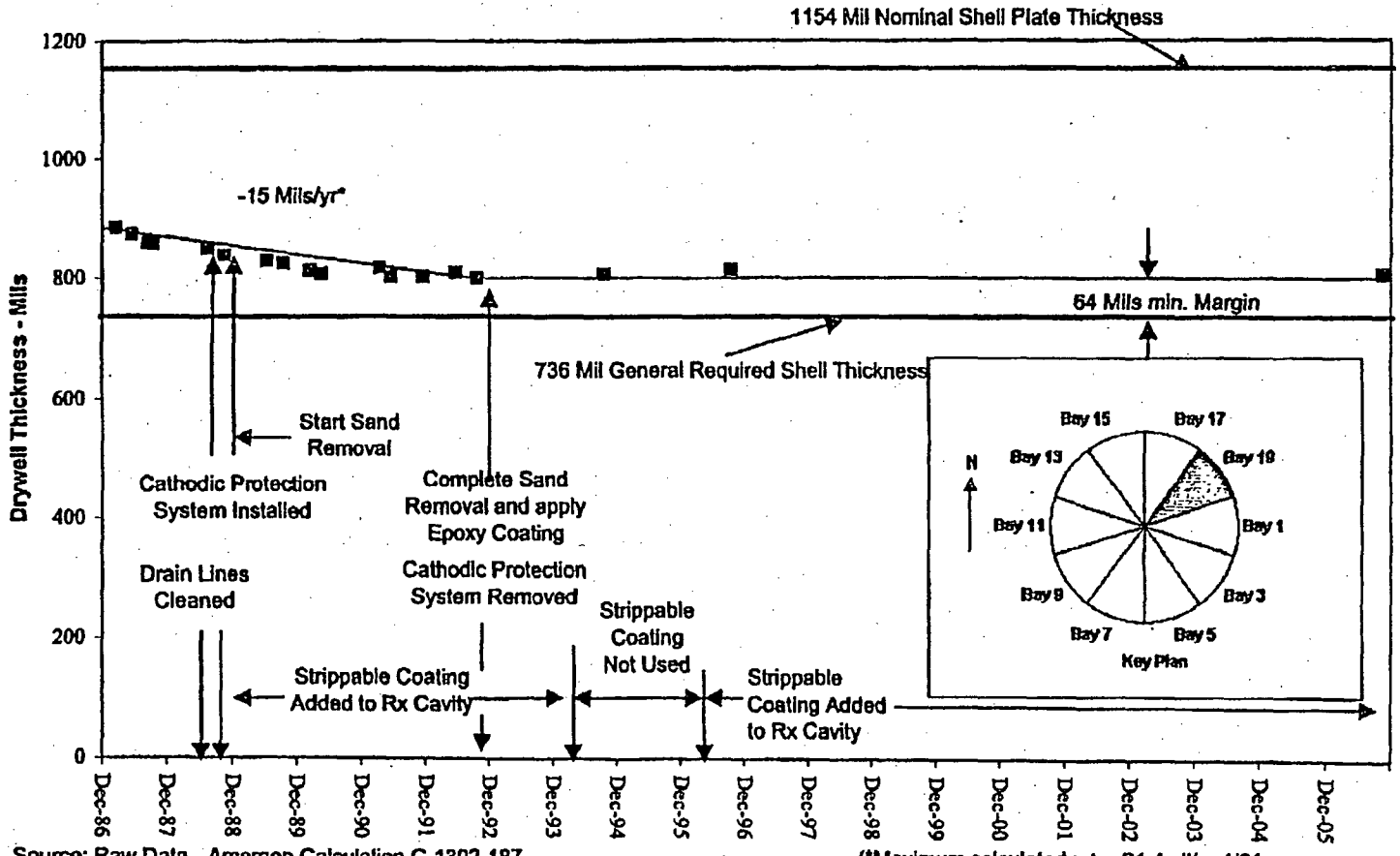
Figure 20. Sandbed Bays # 17/19
Frame Bottom



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

(*Maximum calculated rate -13.1mil/yr 4/90, C-1302-187-5300-011 Rev. 0)

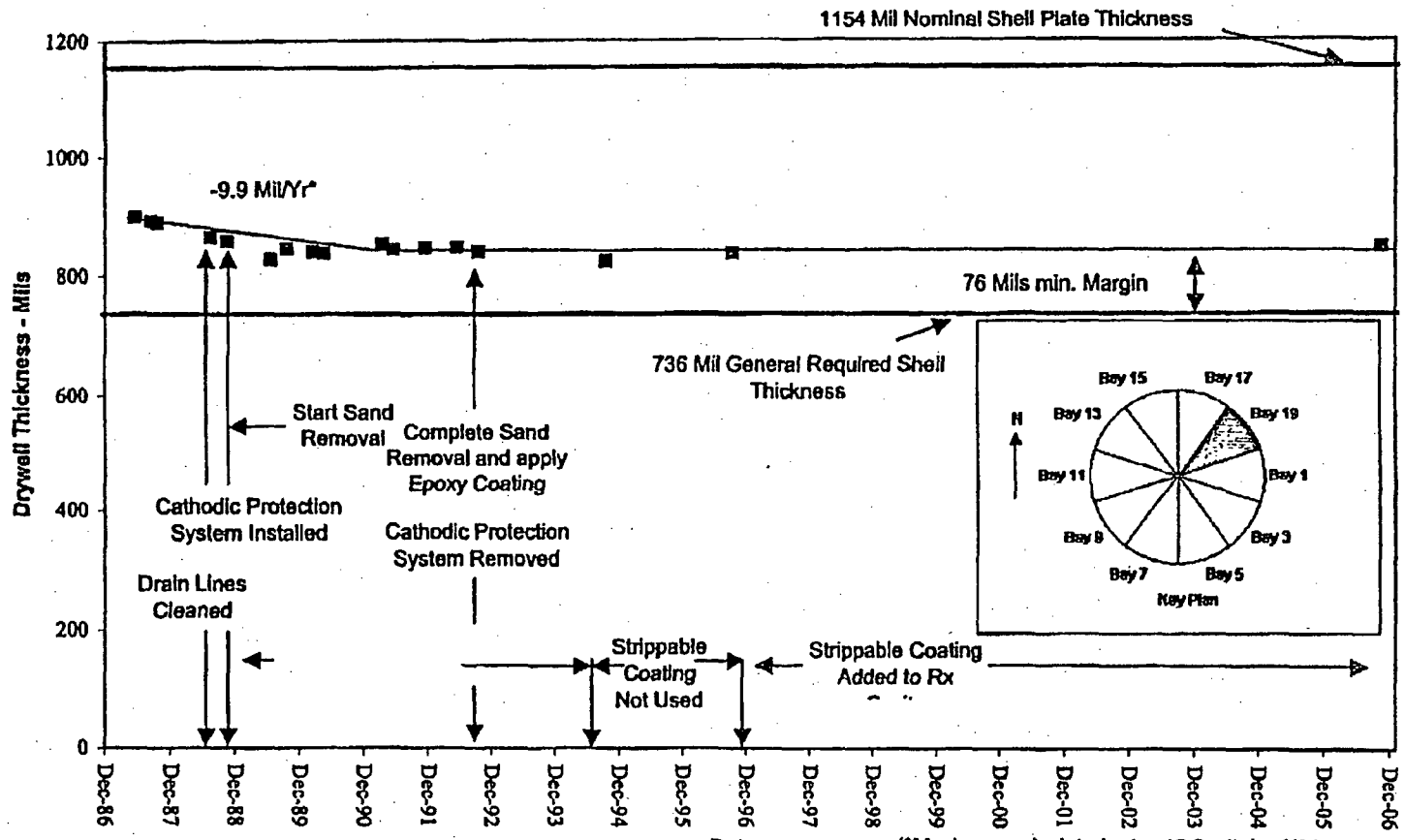
Figure 21 Sandbed Bay # 19A



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

(*Maximum calculated rate -21.4mil/yr 4/91, C-1302-187-5300-011 Rev. 1)

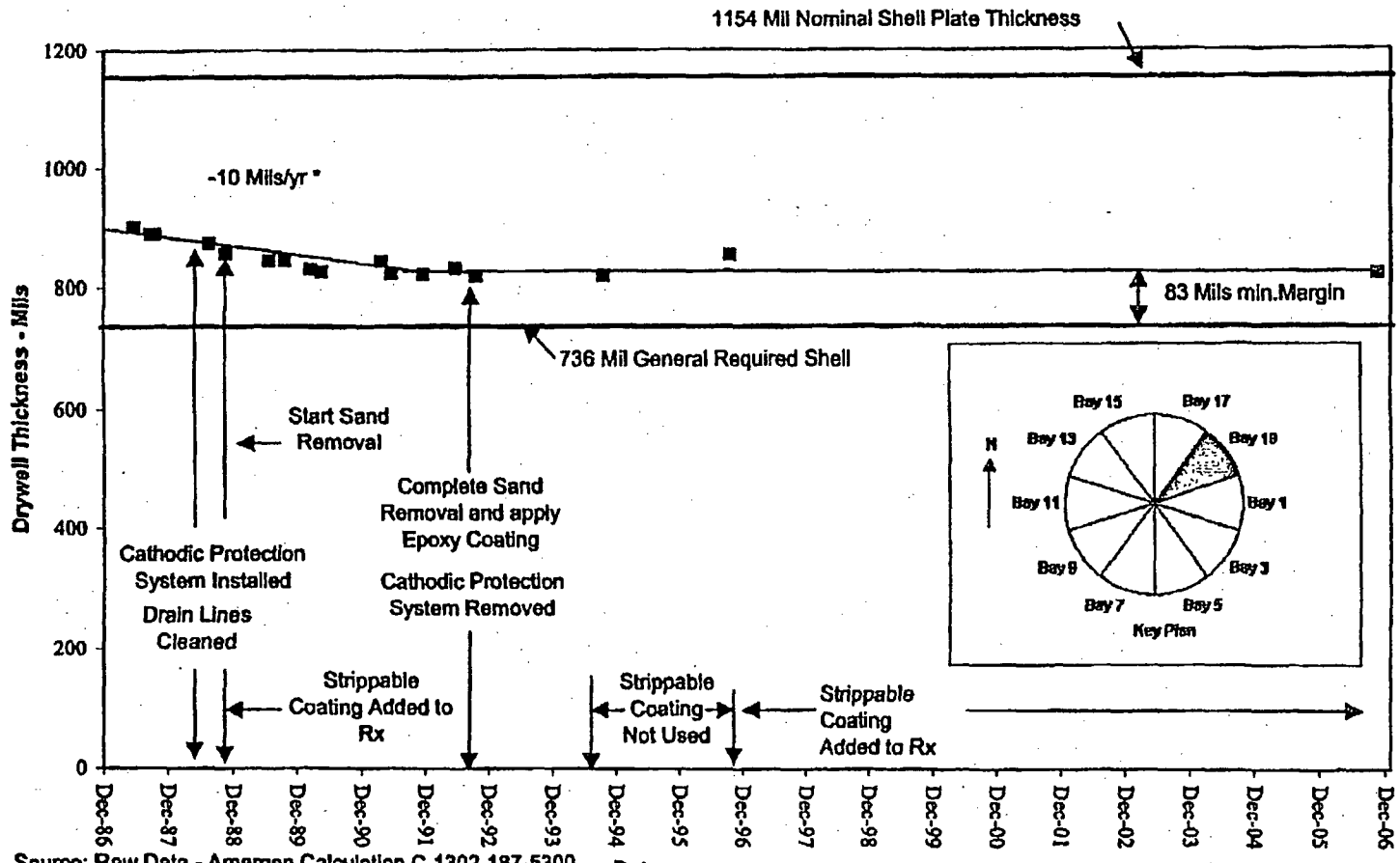
Figure 22. Sandbed Bay #19 B



Source: Raw Data - Amergen Calculation C-1302-187-5300-021, C-1302-187-5300-028, C-1302-187-8610-030

(*Maximum calculated rate -19.0 mils/yr 4/91, C-1302-187-5300-011 Rev. 1)

Figure 23. Sandbed Bay # 19C

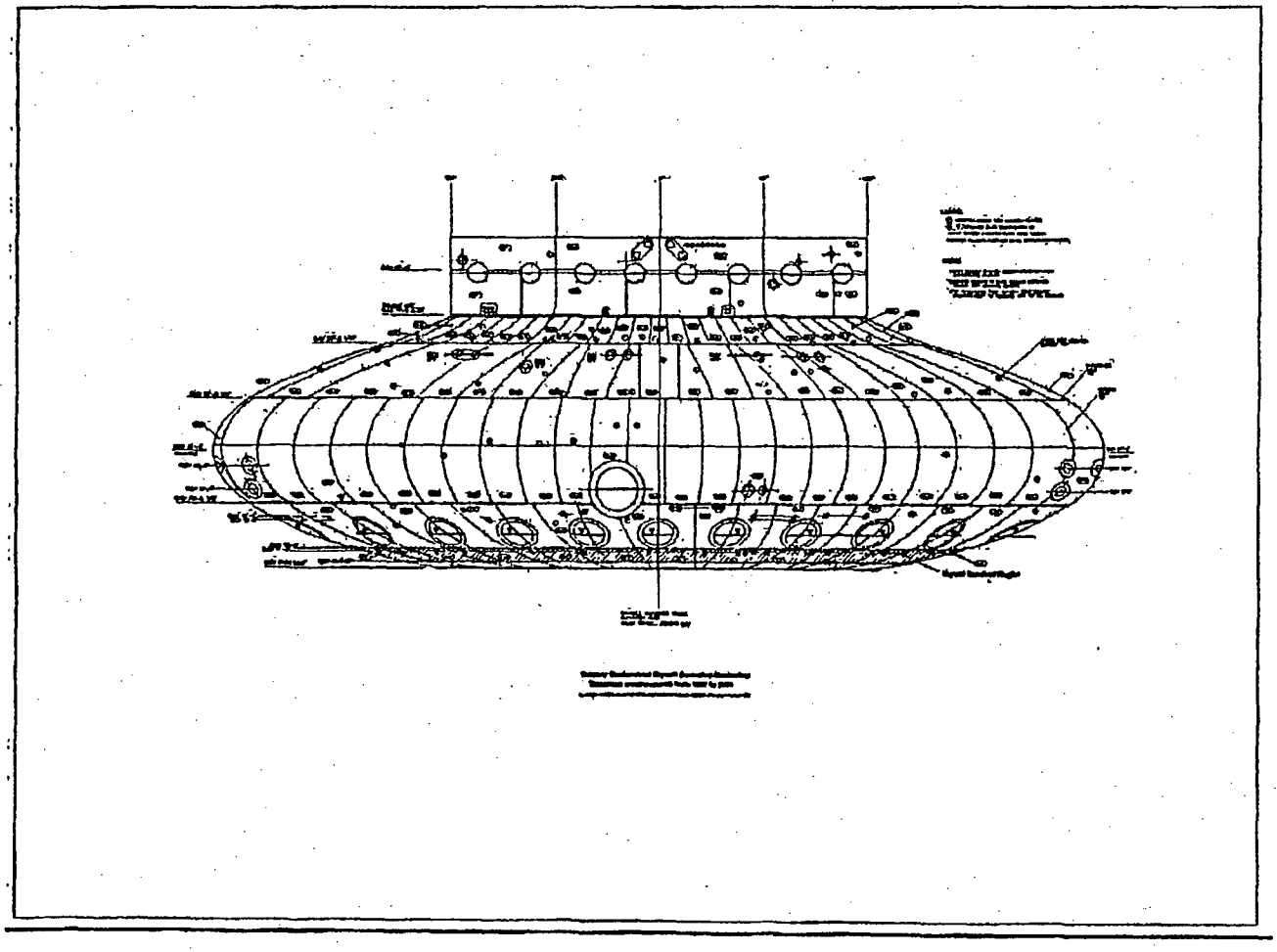


Source: Raw Data - Amergen Calculation C-1302-187-5300 021, C-1302-187-5300-028, C-1302-187-8610-030

(*Maximum calculated rate -24.3mils/yr 4/91, C-1302-187-5300-011 Rev.1)

ATTACHMENT 2

LOCATION OF UT MEASUREMENTS



Attachment 3 – Sandbed Region Epoxy Coating Specification

DEVOE Epoxy Coating System	• Pre-Prime 167 (Epoxy Primer) • Devran 184 (Epoxy paint) • Demat 124S (Epoxy caulk) • DevPrep 88 (Cleaner)
Service Life	The specification requirement for ideal service life is at least 20 years. However, it was recognized that practical coatings may require maintenance sooner than 20 years. The service life is determined by periodic inspection to ensure degradations are detected and corrected before failure of the coating.
Environmental Conditions	• The coating is qualified for temperature Up 250 degree F • Wetting & Drying
Abrasion Resistance	• The material should be sufficiently abrasion resistant to avoid damage from video cameras, temperature probes, radiation monitors, and other similar devices.
Adhesion	• The coating should remain intact and attached to the drywell for the full range of general operating conditions and for the expected light abrasion during inspections and maintenance
Direct Impact Resistance	• The coating should remain intact and attached to the drywell for the full range of general operating conditions and for the expected light abrasion during inspections and maintenance
Weathering Resistance	• N/A. The area to be coated is not exposed to weathering or direct light
Decontaminability	• N/A
Thermal Conductivity	• N/A
Maintenance	• Periodic inspection to determine if maintenance is required
Repairability	• Repairable in the limited access area using equipment available on site
Color	• Color or tint for one coat should provide a good visual contrast with previous coat or substrate • Light gray to provide good light reflectance and easy detection of surface contamination and color changes indicating deterioration, and to make the need to repair a damaged or abraded area more evident
Gamma Radiation	• DEVOE coatings have not been tested for resistance to gamma radiation. Degradation due to exposure to Gamma radiation is determined by periodic inspection.

Source: Ref [19]

This discussion addresses the embedded external Oyster Creek drywell shell ("embedded shell"). Part I, below, provides an overview of commitment information regarding the embedded shell prior to the October 2006 outage. The discussion in Part II sets forth information discovered and analyzed as a result of the October 2006 outage. Overall conclusions about the embedded shell, and continued performance of its intended function during the proposed twenty-year renewal term, are summarized in Part III.

A question regarding the embedded shell was posed to AmerGen at a June 1, 2006 NRC public meeting, and later documented in Ref [36]:

> "Inspection of Inaccessible Regions:
> It is not clear to the NRC whether the junction between the 1.154 inch plate and the 0.676 inch plate at the elevation 6 foot 10¼ inches is represented in the UT sampling plan. This area is below the bottom of the sand-pocket area, and is in contact with the concrete alkaline environment. However in the past, before sealing of the junction between the steel and the concrete, this area would have been subjected to the same type of contaminated water as the drywell shell in the sand-pocket area. The NRC considers this junction to be an area for possible corrosion. The NRC requested the applicant to incorporate this area in the sampling plan or justify why it should not be part of the sampling plan."

In October 2006, the ACRS License Renewal Subcommittee also asked about possible corrosion in the embedded region and AmerGen's confidence that corrosion there would be no greater than in the sandbed region, due to the inability to inspect the shell embedded in the concrete. (Ref [44], Pages 84 & 85)

In answer to these inquiries, AmerGen provides the historical information in Part I of this document.

I. Historical Summary - The Embedded Shell

The condition of the embedded shell was communicated in a response to the NRC dated June 20, 2006 (Ref [37]):

"Response:
A review of the drywell construction and fabrication details shows that the drywell skirt is welded to the 1.154 inch thick plate below the sand bed floor before the end of the 1.154" thick plate. This thick plate is welded to the 0.676" plate at elevation 6 foot 10 1/4 inches. One of the purposes of the skirt, which is also now embedded in concrete, was to support the drywell during construction. The presence of the skirt prevents moisture intrusion into the 0.676" plate. Reference Figure 7 in Section 3 of this Enclosure.

Both the 1.154" thick plate and the 0.676" thick plate are embedded in concrete and are inaccessible for inspection as recognized by ASME Section XI, Subsection IWE-1232 and NRC Guidance (NUREG-1801 Rev. 1) for license renewal. These documents credit pressure testing performed in accordance with 10 CFR Part 50 Appendix J, Type A test, for managing aging effects of inaccessible portions of the drywell shell. NUREG-1801 and Ref [30] indicate that corrosion of embedded steel is not significant if the following conditions are satisfied:

1. Concrete meeting the specifications of ACI 318 or 349 and the guidance of 201.2R was used for the containment shell or liner.
2. The concrete is monitored to ensure that it is free of cracks that provide a path for water seepage to the surface of the containment shell or liner.
3. The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements.
4. Water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner."

The Response also indicated:

"The corrosion of the drywell shell in the sand bed region was caused by the moisture trapped in the sand bed due to water leakage into the region. The source of leakage was determined to be the reactor cavity, which is filled with demineralized water during refueling outages. The water passed over the Firebar-D coating that was applied to the drywell shell to allow for formation of the required seismic gap between the drywell shell and the encircling concrete shield wall. The Firebar-D material is a magnesium oxychloride compound. The drywell was erected onsite and exposed to salt air environment during construction, which could also introduce contaminants to the sandbed environment. Chemistry test results on wet sand conducted in 1986 indicated that the leachate from the moist sand had a pH of 8.46 and contained only 45 ppb chlorides and <17 ppb sulfates.

As noted in Ref [30], this water is not aggressive to concrete since the pH is greater than 5.5, the chlorides are less than 500 ppm and sulfates are less than1500 ppm. This means that the wetted concrete environment will provide a high pH environment that will protect the embedded shell from corrosion. Additionally, the corrosion rates calculated for the carbon steel plugs removed from the drywell shell in the sand bed region were comparable to carbon steel exposed to typical waters over a similar temperature range. While an increase in the salinity and impurity of the water will increase the kinetics of the corrosion reaction by increasing the electrolyte conductivity and can alter the form of corrosion experienced by steel (e.g., from general corrosion to pitting corrosion), impurities such as chloride and sulfate are not fundamentally involved in the corrosion anodic and cathodic reactions. In fact, increasing the salinity of the water decreases the dissolved oxygen content of the water and, thus, reduces the concentration of cathodic reactant present for the corrosion reaction." (Ref [37])

The removal of the sand from the sandbed region in 1992 afforded the first opportunity to inspect the sandbed floor and evaluate its condition. There were a number of bays in which the sandbed floor was noted as being unfinished (i.e., the floor lacked a smooth surface with appropriate slope that would direct any water entering the sandbed region away from the drywell shell to the drain). This was documented in Update 10 (4/97) to the Oyster Creek FSAR, Section 3.8.2.8 (Drywell Corrosion) (Ref [46]).

The condition of the sandbed floor also was noted in a May 5, 1993 meeting between GPU Nuclear Corporation and the NRR Staff on the Oyster Creek Drywell Corrosion Mitigation Program (Ref [24]). The presentation slides used during that meeting identified the sandbed floor in some bays to be "cratered with some craters adjacent to the shell. A few craters were big, about 12-13 feet long, 12-20 inches deep and 8-12 inches wide." AmerGen believes that the small quantity, low velocity and non-aggressive chemistry of the water that entered the sandbed region while the sand was present could not have eroded concrete to the extent identified and, therefore, the craters have existed since original construction. (Ref [48])

Several corrective actions were implemented to mitigate corrosion of the drywell shell. These mitigative actions were designed to minimize water intrusion into the sand bed region, provide for an effective drainage of the region in the event of water leakage, and monitor the drains to detect leakage. (See Sections 4 & 6 of this Enclosure). Specifically, as part of the corrosion mitigation activities performed in 1992, the outer shell of the drywell was cleaned and then coated with an epoxy coating including portions of the shell below the current level of the sandbed floor in those bays where the floor was unfinished. The unfinished floors in the sandbed regions were then built up using the same epoxy that was used to coat the shell, and reshaped to allow drainage through the sandbed floor drain of any water that may leak into the region. At that time, the joint between the sandbed floor and the external drywell shell was sealed with a caulk compatible with the epoxy coating to prevent any water from coming in contact with any portion of the drywell shell embedded below the level of the sandbed floor. (Ref [19], Section 6.12).

II. Confirmatory Actions During The 2006 Outage

AmerGen visually inspected the sandbed regions in all 10 bays during the 2006 outage. As part of these inspections, the integrity of the epoxy floor and the caulk sealant between the external drywell shell and the floor of the sandbed region were inspected. No degradation of the caulking between the coated drywell shell and the epoxy coating on the sand bed regions floors was observed. Accordingly, no repairs were required. (Ref [47])

AmerGen observed in 8 of 10 bays separation/cracking of the floor epoxy coating. These areas had no impact on the exterior drywell shell epoxy coating or the caulk seal between the drywell shell and the sand bed floors because the cracks were in areas of the floor away from the shell. The separation/cracking was repaired prior to the conclusion of the October, 2006 outage.

The 1.154 inch thick plate of the external drywell shell between the embedded support skirt and the floor of the sandbed region likely experienced some historical corrosion. However, AmerGen expected such corrosion to be bounded by the corrosion in the non-embedded regions due to the formation of a thin protective oxide passive film over the shell from the highly alkaline concrete. (Ref [29]). During the October 2006 outage, AmerGen implemented a commitment to inspect the drywell shell from the inside of the drywell in two trenches excavated in 1986 in the concrete floor (Discussed in more detail in Section 8 of this Enclosure). An additional portion of one of the trenches was further excavated to expose a small portion of the drywell shell that had, up until October 2006, been embedded in concrete on both sides. An average thickness of 1.113 inches was ultrasonically measured which, when compared with a nominal wall thickness of 1.154 inches, indicates an average total wall loss of 41 mils since construction in the late 1960s (approximately 40 years). AmerGen assumes that the majority of this wall loss occurred from the exterior of the shell and prior to 1992 (Ref [47]), when the sand and standing water was removed from the sandbed region. However, assuming that the 41 mils wall loss occurred over the first 40 years, and that there is an ongoing corrosion of about 1 mil per year, there is still adequate margin for the proposed 20-year period of extended operation.

For the reasons stated below, the exterior of the 0.676 inch thick plate embedded in the concrete below the attachment point of the steel support skirt has been protected from contact with water on the outside of the drywell shell and, therefore, likely did not (and does not now) experience corrosion. The weld that attaches the skirt to the drywell shell is continuous around the exterior of the drywell shell preventing water on the exterior of the drywell from continuing into the 0.676 inch plate region. Although there are cutouts in the skirt to facilitate initial construction, these cutouts are at least 2 feet below the attachment weld. Notes on installation drawings indicate that other openings in the skirt were closed as concrete placement proceeded. For water on the outside of the shell to contact the 0.676 inch plate, it would need to migrate downward through the concrete, through the opening in the skirt and then over two feet upward to the shell. The water on the outside of the shell that may have entered the space between the exterior drywell shell and the sandbed floor prior to the joint being caulked lacks the driving force (including wicking) necessary to navigate such a tortuous path through the concrete.

Also, although the bottom of the drywell is below the level of the groundwater table, it is not credible that groundwater could have migrated through the concrete under this portion of the shell and caused external corrosion in the 0.676 inch plate. The Reactor Building Foundation floor is a 10 ft thick reinforced concrete slab. The bottom elevation of the slab is minus 29' 6" and its top elevation is minus 19' 6". There is a waterproof membrane at the bottom of the mat that extends up the outside of the exterior walls to an Elevation of 5' 0". The concrete pedestal that supports the Containment shell is located at the center of the mat. The containment shell is spherical in shape at the base and has a bottom elevation of 2' 3". The Torus Room completely surrounds this concrete pedestal with a floor elevation of minus 19' 6" (top of mat). (A more detailed description of the drywell is provided in Section 3 of this Enclosure)

In order for ground water to reach the lowest point of the containment shell it would need to penetrate the waterproof membrane then migrate through the 10 ft concrete mat then

migrate through the pedestal concrete. Since there is no waterproofing on this interior concrete pedestal, or other interior walls, any water contained or migrating in the pedestal would seek the path of least resistance and flow into the Torus Room. This path would be through the concrete itself or along construction joints in the pedestal. If water was able to make its way along the path outlined above, and actually reach the base of the containment shell, the Torus Room would be flooded. There are sumps in the basement of the Reactor Building that collect any water in leakage and would prevent significant accumulation of water in the Torus Room.

Periodic testing of the drywell integrity is required by 10CFR50, Appendix J. In particular, the Type A test measures the containment system overall integrated leakage rate and must be conducted under conditions representing design basis loss-of-coolant accident containment peak pressure. The most recent Appendix J, Type A test of the drywell shell (Nov. 2000) confirmed the integrity of the shell in the embedded region and satisfied all Code acceptance criteria.

III. Conclusions

From the above discussion, the conclusions are as follows:

- The corrosion of the external embedded drywell shell is bounded by the corrosion in the sandbed region. This is a reasonable conclusion for two primary reasons:

  1. The carbon steel in the embedded region is in contact with high pH concrete that allows the creation of a passive film on the steel surface. That is, the presence of abundant amounts of calcium hydroxide and relatively small amounts of alkali elements, such as sodium and potassium, gives concrete a very high alkalinity (e.g., pH of 12 to 13). In fact, thermodynamic calculations reveal no corrosion of iron (steel) above pH 10 at room temperature.

  2. Uniform corrosion will tend to occur when some surface regions become anodic for a short period, but their location and that of the cathodic regions constantly change. For example, general corrosion/rusting of mild steel will occur when there is a uniform supply of oxygen available across the surface of the steel and there is a uniform distribution of defects in the oxide film as is usually the case in the non-protective films formed on unalloyed steel. In the absence of areas of high internal stress (e.g., cold-worked regions) or segregated zones (e.g., non-uniform distributions of sulfide inclusions), a number of anodic regions will develop across the surface. Some areas will become less active while new anodic regions become available. Therefore, overall attack takes place at a number of anodic sites whose positions may change, leading to general rusting across the surface.

     If the supply of oxygen is not uniform across a surface, then any regions that are depleted in oxygen will become anodic as the case of moist sand in contact with the drywell steel. The remainder of the drywell surface including the embedded steel has oxygen available to it and therefore acts as a large cathodic area. When the cathodic area is larger, local attack will occur in the

smaller anodic region. This phenomenon is referred to as differential aeration.

Therefore, due to the creation of a differential aeration cell, the adjacent carbon steel in contact with the moist sand bed acts as an anode that sacrifices itself to the benefit of the steel in the embedded region. That is, the corrosion of the sand cushion steel preferentially corrodes as galvanically coupled to the embedded steel." (Ref [37])

- "Craters" identified in the sandbed region floors when the sand was initially removed were created during initial construction (pre-1969). (Ref [48])

- Measures taken to prevent water from entering the sandbed region and any further water intrusion into the area between the concrete and the external drywell shell are effective because they preclude "two of the four necessary fundamental parameters necessary for any form of corrosion to occur, an electrolyte, (i.e., moisture) and the cathodic reactant (i.e., oxygen), while only the lack of one fundamental parameter is sufficient to prevent corrosion. Sealing off the embedded steel prevents refreshment of moisture in the embedded region." (Ref [37]) The ultrasonic measurements taken during the October, 2006 outage of a section of the drywell shell previously embedded on both sides since initial construction indicate the effectiveness of preventive measures in that, on average, in excess of 96% of the nominal wall remains in the embedded portion of the drywell shell immediately below the sandbed region.

- Any oxygen trapped by the caulk sealant would most likely have been consumed and a thin protective oxide passive film would have been formed from contact with the highly alkaline concrete thereby minimizing further corrosion because "residual moisture will not support any subsequent corrosion once all the dissolved oxygen is consumed in the cathodic corrosion reaction. The cessation of the corrosion reaction will occur regardless of the presence of contaminants that may be dissolved in the water (e.g., chloride, sulfate, etc.) since although these impurities can affect the kinetics of the corrosion reaction, they do not participate in the cathodic reduction reaction. Once the cathodic reaction is stopped, corrosion is stopped. Intermittent wetting and aeration of the embedded steel would produce only minimal additional corrosion." In addition, "[t]he presence of concrete in contact with the embedded steel will mitigate corrosion even if sufficient moisture and oxygen are available due to the spontaneous formation of a thin protective oxide passive film on the embedded steel surface in the highly alkaline solution of the concrete. As long as this film is not disturbed, it will keep the steel passive and protected from corrosion." (Ref [37])

- The sandbed floor was reshaped in 1992 to route water to the sandbed drains and away from the drywell shell and caulk sealant.

- Continued inspections of the caulk sealant have confirmed its integrity.

- Appendix J, Type A testing confirmed the integrity of the drywell shell in the embedded region.

"In summary, AmerGen has extensively investigated drywell corrosion, including the embedded shell. A review of plant operating and industry experience indicates that corrosion of embedded steel in concrete is not significant because it is protected by the high alkalinity in concrete. Corrosion could only become significant if the concrete environment is aggressive. Historical data shows that the environment in the sand bed region is not aggressive, and thus any water in contact with the embedded shell is not aggressive. The data also shows that corrosion of the drywell shell in the sand bed region is due to galvanic corrosion and impurities such as chlorides and sulfates are not fundamentally involved in the corrosion anodic and cathodic reactions. Thus, only limited corrosion would be anticipated for the drywell embedded shell

AmerGen has also committed to a comprehensive drywell corrosion-monitoring program for the period of extended operation. The program includes mitigative measures to prevent water intrusion into the sand bed region. The sand bed region concrete floor is sealed with epoxy coating. The junction between the sand bed region concrete floor and the drywell shell was sealed in 1992 to prevent moisture from impacting the embedded shell. Thus, additional significant corrosion of the embedded shell is not expected because of lack of moisture and depleted oxygen. AmerGen is committed to taking specific corrective actions, described in item 3 of Enclosure 1 to Ref. [39], prior to exceeding any design requirements, if water leakage is detected in the sand bed region drains.

For all of the above reasons, the corrosion rate for the embedded drywell shell is less than the corrosion rate of the sand bed region of the drywell shell. Also, direct monitoring of the drywell shell in the sand bed region adequately bounds any corrosion in the drywell embedded shell." (Ref [37])

This discussion addresses the potential for corrosion of the interior surface of the drywell shell that is embedded in the concrete floor inside the drywell (i.e., below the concrete floor at Elevation 10' 3"). See Figure 4 in Section 3 of this Enclosure. This area includes the shell behind the concrete curb at the edge of the concrete floor. All elevations of the interior drywell shell were presumed to be coated with primer (except those areas to be embedded in concrete) that was applied following fabrication of the material to protect the steel prior to and during installation.

Part I, below, provides an overview of historic information pre-dating the October 2006 outage. The discussion in Part II sets forth information discovered and analyzed as a result of the October 2006 outage. Overall conclusions about the drywell, and its continued operation during the proposed twenty-year renewal term, are summarized in Part III.

I. Historical Summary

The drywell is described in Section 3 of this Enclosure. Figure 1 (Section 3) shows a cross-section of the drywell. Figure 4 (Section 3) shows an elevation view of the construction of the drywell foundation including the configuration of the Torus Room. Figure 5 (Section 3) provides the details of the drywell floor including the drainage trough located in the area under the reactor vessel (referred to as the Sub-Pile Room). The two areas addressed in this discussion are the embedded portions of the 1.154" thick section internal to the drywell and the 0.676" thick section at the bottom of the drywell all of which is embedded internally (See Figure 4 in Section 3). Section 6 of this Enclosure identifies the minimum required average general thickness of the 1.154" thick section as 0.736". Since the 0.676" thick section is completely encased in concrete, it is only required to contain the maximum drywell pressure (44 psig) and is not required to withstand buckling or membrane stresses. The minimum required thickness for this section required due to the maximum drywell pressure is 0.479" per Reference [42].

In 1986, as part of an ongoing effort at the Oyster Creek Generating Station to investigate the impact of water on the outer drywell shell, concrete was excavated at two locations inside the drywell (referred to as trenches) to expose the drywell shell below the Elevation 10' 3" concrete floor level to allow ultrasonic (UT) measurements to be taken to characterize the vertical profile of corrosion in the sand bed region outside the shell. The trenches (approximately 18 inches wide) were located in Bays 5 and 17 (See Figure 3 in Section 3 of this Enclosure) with the bottom of the trenches at Elevations 8' 9" and 9' 3" respectively (The elevation of the sand bed region floor outside the drywell is approximately 8' 11").

Following UT examinations in 1986 and 1988, the exposed shell in the trenches was prepped and coated and the trenches were filled with Dow Corning 3-6548 silicone RTV foam covered with a protective layer of promatic low density silicone elastomer to the height of the concrete floor (Elevation 10' 3"). At that time, it was expected that these materials would prevent water that might be present on the drywell concrete floor from entering the trenches. Before the 2006 outage (discussed in Part II below), these materials had not been removed from the trenches since 1988.

During the preparation of a response to an NRC question (Ref [33]) during the Aging Management Review Audit, an internal memo was identified that indicated the intermittent presence of water in the two trenches inside the drywell. This was not an expected condition. That memo, dated January 3, 1995 was referenced in a 1996 Structural Walkdown Report but was not entered into the Corrective Action Process and was not considered as Operating Experience input to the Aging Management Program reviews.

Based on activities performed under the Structures Monitoring Program and IWE inspection program, and the reviews performed in support of the License Renewal Application, the water on the drywell floor and potentially inside the trenches was previously considered a temporary outage condition and not an operating environment for the embedded shell. However, in its response to an NRC Aging Management Review Audit question (Ref [33]), AmerGen committed to inspect the condition of the drywell interior shell in the trench areas and to evaluate any identified degradations prior to entering the period of extended operation (Commitment 27.5 in Ref. [39]). The results of these inspections and associated corrective actions are described in Section II below.

II. Confirmatory Actions During the October 2006 Refueling Outage

As noted above, AmerGen planned visual and ultrasonic (UT) inspections of the drywell shell in the trench areas during the 2006 refueling outage. The filler material in the trenches was removed and water was identified in the trenches (Bay 5 had 5 inches of standing water and Bay 17 had dampness but no standing water). (Ref: [47]) This condition was entered into the Corrective Action Process.

The presence of water in the trenches was indicative of water beneath the drywell floor surface, being in contact with both the drywell shell and drywell concrete. Following removal of the water from the trenches, visual inspections and UT measurements were performed in each trench. AmerGen has concluded (Ref. [47]) that most of the material loss occurred between 1986 and 1992 when sand and water remained in the sandbed region located adjacent to the exterior of the drywell shell and significant corrosion of the external shell was known to have occurred.

The following additional corrective/confirmatory actions related to the discovery of water in the trenches were taken during the October, 2006 Refueling Outage (Details may be found in Reference [47] transmitting a supplement to the License Renewal Application):

- Walkdowns, drawing reviews, tracer testing and chemistry samples were performed to identify the potential sources of water in the trenches.
- An engineering analysis was performed to evaluate the impact of the water on the drywell shell integrity.
- Field repairs/modifications were implemented to mitigate/minimize future water intrusion into the area between the shell and the concrete floor. These repairs/modifications consisted of (1) Repair of the trough concrete in the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell, (2) Caulking the interface between the

drywell shell and the drywell concrete floor/curb to prevent water from reaching the embedded shell and (3) Grouting/caulking the concrete/drywell shell interface in the trench areas.

- Additional concrete was removed from the Bay 5 trench to expose an additional 6 inches of drywell shell to allow visual inspection and UT measurements to be performed in the area of the shell that had been embedded in concrete (on both sides) until the 2006 outage.

III. Conclusions

An engineering evaluation of the Oyster Creek inner drywell shell condition was prepared by a structural engineer and reviewed by an industry corrosion expert and independent third-party expert to determine the impact of the as-found water on the continued integrity of the drywell shell. The evaluation utilized water chemical analysis, visual inspections and UT examinations to conclude that the measured water chemistry values and the lack of any indications of rebar degradation suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact and significant corrosion of the interior embedded drywell shell would not be expected as long as this benign environment is maintained. Therefore, since the concrete environment complies with the EPRI (Ref [30]) concrete structure guidelines, corrosion would not be considered "an applicable aging mechanism for nuclear power plant concrete structures and structural members" at Oyster Creek. The industry corrosion expert concluded that the water could remain in contact with the interior drywell shell indefinitely without adverse impacts.

More specifically, the results of this engineering evaluation indicate that no significant corrosion of the inner surface of the embedded drywell shell would be anticipated for the following reasons:

- The existing water in contact with the drywell shell has been in contact with the adjacent concrete. The concrete is alkaline which increases the pH of the water and, in turn, inhibits corrosion. This high pH water contains levels of impurities that are significantly below the EPRI embedded steel guidelines action level recommendations. (See Section 7 of this Enclosure)
- Any new water (such as reactor coolant) entering the concrete-to-shell interface (now minimized by repairs/modifications implemented during the 2006 outage) will also increase pH due to its migration through and contact with the concrete creating a non-aggressive, alkaline environment.
- Minimal corrosion of the wetted inner drywell shell surface in contact with the concrete is only expected to occur during outages since the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant since the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also, repairs/modifications implemented during the 2006 outage will further minimize exposure to oxygen.

Based on the UT measurements taken during the 2006 outage of the shell area in the trench in Bay 5 that has not been exposed since it was encased in concrete during initial construction (pre-1969), it was determined that the total

metal lost based on a current average thickness measurement of 1.113" versus a nominal plate thickness of 1.154" is only 0.041" (total wall loss for both inside and outside of the drywell shell). Although no continuing corrosion is expected, but conservatively assuming that a similar wall loss could occur between now and the end of the period of extended operation, a margin of 336 mils to the 0.736" required wall thickness would exist. Using a similarly conservative approach for the 0.676" embedded bottom head plate (0.479" required thickness for pressure retaining capability only as noted above) provides a margin of 115 mils to the end of the period of extended operation.

The engineering evaluations summarized above confirmed that the condition identified during the 2006 outage will not impact safe operation during the next operating cycle. Also, a conservative projection (noted above) of wall loss for the 1.154 and 0.676 inch thick embedded shell sections indicates that margin is provided in both sections through the period of extended operation.

Although a basis is established that ongoing corrosion of the shell embedded in concrete should not be expected and repairs/modifications have been performed to limit or prevent water from reaching the internal surface of the drywell shell, AmerGen has now established that the existence of water in contact with the internal surface of the drywell shell and concrete at and below the floor elevation will be assumed to be a normal operating environment. Therefore, aging management reviews have now been performed and new aging management activities are being specified to confirm that corrosion that could impact the ability of the drywell shell to perform its design functions for the period of extended operation is appropriately managed (Details may be found in Ref. [47]).

Ref. No.	Document	Document Date
	VOLUME 1	
1	Letter 5000-86-1116, GPU to NRC, Oyster Creek Drywell Containment with attached SE No. 000243-002 Rev. 0	12/18/86
2	Restart Analysis Report – Drywell Analysis Sand Transition Zone	2/9/87
3	GE Report No. 87-178-003, GE report "Corrosion Evaluation of the Oyster Creek Drywell" Rev. 1	3/6/87
4	Drawings	
	a) 3E-SK-S-85, Drywell Plan Elev. 11' – 3" 1986 Plots	12/16/86
	b) 3E-SK-S-89, Ultrasonic Testing Drywell Level 50' 2" & 87' 5"	10/16/87
	c) 3E-SK-M-275, Ultrasonic Testing Drywell Level 50' 2" March 1990	4/8/90
	d) 3E-SKM-358, Ultrasonic Testing Drywell Level 51' 10" April 1990	12/27/90
5	Memo, Oyster Creek Reactor Cavity Leakage	1/28/88
6	SE No. 328257-002, Temporary Repair of Reactor Cavity	10/19/88
7	TDR-851, Rev 0, Assessment of Oyster Creek Drywell Shell	12/27/88
8	Calculation C-1302-187-5300-005, "Statistical Analysis of Drywell Thickness Data Thru 12-31-88" Rev. 0	1/31/89
9	TDR-948, "Statistical Analysis of Drywell Thickness Data," Revision 1	2/1/89
10	Calculation C-1302-187-5300-011, "Statistical Analysis of Drywell Thickness Data Thru 4/24/90"	6/13/90
	VOLUME 2	
11	IS-402950-001, "Functional Requirement for Augmented Drywell Inspection," Rev. 0	10/4/90
12	TDR-1027, "Design of a UT Inspection Plan for the Drywell Containment Using Statistical Inference Methods," Rev. 1	11/1/90
13	Letter 5000-90-1995, GPU to NRC, Oyster Creek Drywell Containment	12/5/90
14	Letter, GPU to NRC, Oyster Creek Drywell Containment, dated November 26, 1990	11/26/90
15	Calculation GE Index 9-3 "An ASME Section VIII Evaluation of Oyster Creek Drywell for Without Sand Case Part 1 Stress Analysis"	2/91
16	Calculation GE Index 9-4 "An ASME Section VIII Evaluation of Oyster Creek Drywell for Without Sand Case Part 2 Stability Analysis"	2/91

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17	MPR Report 1275, Selection of Candidate Coatings and Steel Cleaning/Preparation Methods for the Oyster Creek Drywell Exterior in the Sand Bed Area	3/10/92
18	MPR-TP-83161-001, Test Plan for Qualifying the Painting Process for the Exterior Surface of the Drywell, Rev. 2	6/19/92
19	OC-MM-402950-010, "Cleaning and Coating the Drywell Exterior in the Sand Bed Area;" Rev. 0	7/29/92
20	MPR Report 1322 – Results of Painting Process Qualification Tests for the Drywell Exterior in the Sand Bed Area at Oyster Creek, Rev. 0	8/7/92
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21	Calculation C-1302-187-5300-021, "Statistical Analysis of Drywell Thickness Data Thru May 1992" Rev. 0	8/26/92
22	Letter from H.S. Mehta (GE) to Dr. S. Tumminelli (GPU), "Sandbed Local Thinning and Raising the Fixity Height Analyses (Line Items 1 and 2 in Contract # PC-0391407)"	12/11/92
23	SE No. 402950-011, "Clean and Coat Drywell Ext. in Sand Bed," Revision 2	1/5/93
24	NRC Letter, "Summary of May 5, 1993, Meeting with GPU Nuclear Corporation (GPUN) to Discuss Matters Related to the Oyster Creek Drywell Corrosion Mitigation Program	5/17/93
25	Calculation C-1302-187-5300-028, "Statistical Analysis of Drywell Thickness Data Thru September 1994" Rev. 0	12/2/94
26	SE No. 000243-002, "Drywell Steel Shell Plate Thickness Reduction," Rev. 14	8/2/95
27	Calculation C-1302-187-8610-030, "Statistical Analysis of Drywell Thickness Data Thru September 1996" Rev. 1	7/12/00
28	SE No. 320006-003, Application of Strippable Coating on Equipment Pool & Rx Cavity Liner, Rev. 2	8/16/00
29	S. Jäggi, H. Böhni and B. Elsener, "Macrocell Corrosion of Steel in Concrete - Experiments and Numerical Modeling," paper presented at Eurocorr 2001, Riva di Gardi, Italy	10/1/01
30	EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1	8/03
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32	Letter 2130-06-20289, Response to RAI 4.7.2-1	4/7/06
33	Response to NRC Aging Management Review Inspection Team Question No. AMR-164	4/19/06
34	Response to NRC Aging Management Review Inspection Team Question No. AMP-071	4/20/06
35	Response to NRC Aging Management Review Inspection Team Question No. AMP-210	4/20/06
36	NRC Letter, Summary of June 1, 2006 Meeting	6/9/06
37	Letter 2130-06-20353, Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application	6/20/06
38	Letter 2130-06-20354, Updated FSAR Supplement Information Supporting the Oyster Creek Generating Station License Renewal Application	6/23/06
39	Letter 2130-06-20358, Additional Information Concerning FSAR Supplement Supporting the Oyster Creek Generating Station License Renewal Application	7/7/06
40	Letter 2130-06-20360 (CB&I drawing 9-0971 sheet 1)	7/7/06
41	IS-328227-004, "Functional Requirements for Drywell Containment Vessel Thickness Examination," Rev. 13	9/15/06
42	Calculation C-1302-187-5320-024, "OC Drywell Ext. UT Evaluation in Sandbed," Revision 1	9/21/06
43	Calculation C-1302-243-5320-071, Revision 2, "Drywell Thickness Margins"	9/21/06
44	ACRS Subcommittee Transcript Excerpts	10/3/06
45	Letter 2130-06-20414, AmerGen Response to Open Items Associated with the NRC Draft Safety Evaluation for the Oyster Creek Generating Station Application for License Renewal	10/20/06
46	Oyster Creek FSAR Section 3.8.2.8	Rev. 14
47	Letter 2130-06-20426, Information from October 2006 Refueling Outage Supplementing AmerGen Energy Company, LLC (AmerGen) Application for a Renewed Operating License for Oyster Creek Generating Station	12/3/2006
48	MNCR 92-0188, Sandbed Floor	12/28/92
49	MNCR 87-0240, Cavity Liner Defects	11/2/87