From: <john.hufnagel@exeloncorp.com>
To: <dja1@nrc.gov>, <rkm@nrc.gov>
Date: 04/24/2006 6:17:58 PM
Subject: Questions to go over tomorrow...

Roy and Donnie,

These attached questions are those from the database that we currently have statused as Open, but which have responses that should allow closure. Although in the closed status, AMP-071 and AMP-204 were also included because they were updated to reference additional information provided in AMP-072.

Also, we did not send AMP-358, which is the item on Fatigue Analysis. We plan on sending that to you tomorrow.

Hope to talk with you tomorrow PM.

- John.

<<AMP-071.pdf>> <<AMP-072.pdf>> <<AMP-141.pdf>> <<AMP-204.pdf>> <<AMP-209.pdf>> <<AMP-210.pdf>> <<AMP-264.pdf>> <<AMP-356.pdf>> <<AMP-357.pdf>> <<AMP-359.pdf>> <<AMP-360.pdf>> <<AMP-361.pdf>> <<AMP-362.pdf>> <<AMR-164.pdf>> <<AMR-167.pdf>> <<AMR-355.pdf>>

CC: <donald.warfel@exeloncorp.com>, <fred.polaski@exeloncorp.com>

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Subject: Questions to go over tomorrow...
Creation Date: 04/24/2006 6:16:56 PM
From: <john.hufnagel@exeloncorp.com>

Created By: john.hufnagel@exeloncorp.com

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nrc.gov
OWGWPO01.HQGWDO01
DJA1 (D. Ashley)

nrc.gov
TWGWPO01.HQGWDO01
RKM (Roy Mathew)

exeloncorp.com
fred.polaski CC
donald.warfel CC

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MESSAGE	1675	24 April, 2006 6:16:56 PM
TEXT.htm	3304	
AMP-071.pdf	65536	
AMP-072.pdf	84155	
AMP-141.pdf	87076	
AMP-204.pdf	61834	
AMP-209.pdf	74779	
AMP-210.pdf	172997	
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AMP-356.pdf	76361	
AMP-357.pdf	59816	
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AMP-360.pdf	54601	
AMP-361.pdf	57386	
AMP-362.pdf	60783	
AMR-164.pdf	71098	
AMR-167.pdf	107008	
AMR-355.pdf	60948	

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Options

Expiration Date:	None
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Item No
AMP-071

Date Received: 9/23/2005

Source AMP Audit

Status: Closed

Topic:
ASME Section XI, Subsection IWE

Document References:
B.1.27-3

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

(B.1.27-3):In the OCGS AMP B.1.27 discussion of operating experience, the applicant discusses three (3) areas where containment degradation has been observed. These are the upper region of the drywell shell; the sand bed region at the base of the drywell; and the suppression chamber (Torus) and vent system.Sand bed region at the bottom of the drywell - The applicant states that sand was removed and a protective coating was applied to the shell to mitigate further corrosion. The coating is monitored periodically under LRA AMP B.1.33 Protective Coating Monitoring and Maintenance Program. The reader is directed to program B.1.33 for additional details. LRA B.1.33 identifies this coating to be within its scope; the discussion of operating experience in LRA B.1.33 is similar to the discussion of operating experience in LRA B.1.27. Please provide the following information pertaining to aging management of the sand bed region:
(a) At the present time, is monitoring and maintenance of the coating in the sand bed region included in the scope of the current Protective Coating Monitoring and Maintenance Program or is it performed as part of the current IWE program?
(b) Please provide the implementing procedure for this activity, preferably in both hard copy and electronic format.
(c) Does LR aging management of the containment shell in the sand bed region include both the augmented IWE activities (as delineated in question B.1.27-2 above) and the coating monitoring and maintenance activities under B.1.33? If only B.1.33 is credited, please provide the technical basis for concluding that the augmented IWE activities are not necessary.

Assigned To: Ouaou, Ahmed

Response:

a) Monitoring and maintenance of the coating in the former sand bed region is included in the scope of the Protective Coating Monitoring and Maintenance Program (B.1.33)
b) The sand bed region coating is in accordance with specification SP-1302-32-035 and SP-9000-06-003. These documents are included with Program B.1.33.
c) The Protective Coating Monitoring and Maintenance Program is credited for aging management of the sand bed region. It is not included in augmented inspection required by IWE. As stated in IWE program (B.1.27) operating experience, corrective actions that include cleaning and coating of the

sand bed region implemented in 1992 have arrested corrosion. The coated surfaces were inspected in 1994, 1996, 2000, and 2004. The inspection showed no coating failure or signs or degradation. Thus, the region is not subject to augmented inspection in accordance with IWE-1240. The coating will be inspected every other refueling outage during the period of extended operation consistent with NRC commitments for the current term.

Oyster Creek will also perform periodic UT inspections of the drywell shell thickness in the sand bed region as described in response to NRC Questions AMP-141 and AMP-209.

Oyster Creek will also enhance the Protective Coating Monitoring and Maintenance Program (B.1.33) to require inspection of the coating credited for corrosion (Torus internal, vent system internal, sand bed region external) in accordance with ASME Section XI, Subsection IWE. For details of the enhancements refer to response to NRC Question AMP-188 for details.

Revised response to reference AMP-188, and AMP-209 which contain additional commitments and clarification discussed with NRC Staff on 1/26/2006.

Supplemental information - 4/20/2006
As a result of discussions with NRC Staff on April 20, 2006 Oyster Creek provided supplemental information on torus coating. Refer to AMP-072 response for this information.

LRCR #: 229 *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/20/2006

Reviewed By: Muggleston, Kevin 4/20/2006

Approved By: Warfel, Don 4/20/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No
AMP-072

Date Received: 9/23/2005

Source AMP Audit

Status: Open

Topic:
ASME Section XI, Subsection IWE

Document References:
B.1.27-4

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

(B.1.27-4):In the OCGS AMP B.1.27 discussion of operating experience, the applicant discusses three (3) areas where containment degradation has been observed. These are the upper region of the drywell shell; the sand bed region at the base of the drywell; and the suppression chamber (Torus) and vent system.Suppression chamber (Torus) and vent system – The applicant states that the coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion, and refers the reader to program B.1.33 for additional details. Under operating experience in LRA B.1.33, the applicant states that Torus and vent header vapor space Service Level I coating inspections performed in 2002 found the coating in these areas to be in good condition. Inspection of the immersed coating in the Torus identified blistering. The blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters remained intact and continued to protect the base metal. However, several blistered areas included pitting damage where the blisters were fractured. A qualitative assessment of the identified pits was performed and concluded that the measured pit depths were significantly less than the established acceptance criteria. The fractured blisters were repaired to reestablish the protective coating barrier.Please provide the following information pertaining to past operating experience and LR aging management for the suppression chamber (Torus) and vent system:
(a) Please provide the plant documentation that describes the blistering and pitting, the qualitative assessment performed, the established acceptance criteria, and the corrective action taken, preferably in both hard copy and electronic format.
(b) Was ASME Section XI, Subsection IWE applied, to develop the acceptance criteria?
(c) Was the inspection that discovered the blistering and cracking conducted under IWE, a coatings monitoring and maintenance program, or another program? If another program, please identify the program.
(d) Are both the IWE and Coatings AMPs credited to manage loss of material due to corrosion for the suppression chamber (Torus) and vent system, for the extended period of operation? If not, please provide the technical basis for concluding that both AMPs do not need to be credited.

Assigned To: Ouaou, Ahmed

Response:

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a) Inspection of the suppression chamber (Torus) and vent system coating is conducted by divers every other outage in accordance with engineering specification SP-1302-52-120. The specification provides inspection and acceptance criteria for the coating. It also provides inspection and acceptance criteria for pitting, as a contingency to be used in the event failure of the coating results in pitting. The coating is monitored for cracks, sags, runs, flaking, blisters, bubbles, and other defects described in the Protective Coating Monitoring and Maintenance Program (B.1.33).

The specification requires inspection of the torus and vent system surfaces for coating integrity. If pitting is observed, then isolated pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center-to-center distance between the subject pits and neighboring isolated pits or areas of pitting corrosion is greater that 20 inches. Multiple pits that can be encompassed by a 2.5-inch diameter circle are limited to a maximum depth of 0.141 inches provided the center to center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater that 20 inches. Pits that do not meet these criteria are documented and sent to engineering for evaluation and acceptance.

Plant documentation that describes the blistering and pitting, and qualitative assessment performed, the established acceptance criteria, and corrective actions taken, is included in PBD-AMP-B.1.27 Notebook and available for Staff review.

b) The Torus and Vent System coating is classified Service Level I Coating as described in the Protective Coating Monitoring and Maintenance Program (B.1.33). The Program was evaluated against the 10 Element of NUREG-1801 XI.S8, Protective Coating Monitoring and Maintenance Program and found consistent without enhancements or exceptions. Acceptance criteria are evaluated in element 3.6 of the Oyster Creek Protective Coating Monitoring and Maintenance Program (PBD-AMP-B.1.33). The inspection is performed by ASME Section XI Level II and Level III inspectors.

Acceptance criteria for pits is based on engineering analysis that uses the method of Code Case N597 as guidance for calculation of pit depths that will not violate the local stress requirements of either ASME Section III, 1977 Edition or Section VIII, 1962 Edition.

c) The Inspection that discovered the blistering was conducted under the Protective Coating Monitoring and Maintenance Program. Examinations are performed by ASME Section XI Level II and Level III inspectors.

d) Yes, both IWE and Coatings AMPs are credited to manage loss of material due to corrosion for the suppression chamber (Torus) and the vent system for the extended period of operation.

04/19/2006 Supplemental Information Discussed with the NRC Audit Team:
1) The following clarification was provided regarding torus coating inspections. During the period of extended operation, torus coating inspection will be performed in all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME, Subsection IWE. This specific commitment will be added to the LRA

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Appendix A.5 Commitment List, as part of Commitment 33 associated with the Protective Coating Monitoring and Maintenance program.
2) Condition Report No. 373695 Assignments 2 and 3 have been initiated to drive program improvements for the monitoring and trending of Torus design margins and to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the Corrective Action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to entering the period of extended operation. This commitment will be described in a letter to the NRC.
3) The answers provided for question AMP-210 were written to address specific concerns of the AMP audit team and were centered around worse case Torus thickness margins existing on the Torus shell due to corrosion. This supplemental information is being provided to reinforce that based on all available inspection results, the average thickness of the Torus remains at 0.385". Based on the results of the inspections performed through 1993 (14R), it was concluded that the Torus shell thickness had remained virtually unchanged following the repair and recoating efforts performed in 1984. The was communicated to the NRC via letter C321-94-2186 dated November 3, 1994, Amendment No. 177 to DPR-16 and SER dated February 21, 1995 for the EMRV Tech Spec change. Coating inspections performed subsequent to 1993 (14R) continue to confirm that the Torus shell thickness has remained virtually unchanged following the repair and recoating efforts performed in 1984 and that the average thickness of the Torus remains at 0.385". Torus integrity will continue to be evaluated during future inspections (performed every other refueling outage) into the period of extended operation.

Clarity concerning pit corrosion was provided. Pit corrosion less than or equal to 0.040" was not repaired during the 1984 Torus repair and recoating effort based on available margins and was found to be acceptable without any size restriction since it satisfied minimum uniform thickness requirements. Inspection activities subsequent to 1984 have identified 5 isolated pits that exceed 0.040". These areas have been mapped for trending and analysis during future inspections. These areas are as follows:
- 1 pit of 0.042" in bay 1
- 1 pit of 0.0685" in bay 2
- 2 pits of 0.050" in bay 6
- 1 pit of 0.058" in bay 10

Shell thicknesses have been evaluated against code requirements and found to satisfy all Design and Licensing Basis requirements. Therefore, the integrity of the Torus shell has been verified to have adequate shell thickness margins to ensure Design and Licensing Basis requirements can be maintained.
4. Answer b) above is supplemented as follows: In regard to the use of Code Case N-597 for the evaluation of pits, see AMP-210 for additional information.
5. Answer a) above is revised as follows: Pits greater than 0.040 inches in depth shall be documented and submitted to engineering for evaluation.

LRCR #: 296 ***LRA A.5 Commitment #:*** B.1.33

IR#:

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Approvals:

Prepared By:	Ouaou, Ahmed	4/20/2006
Reviewed By:	Miller, Mark	4/20/2006
Approved By:	Warfel, Don	4/20/2006

NRC Acceptance (Date):

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Item No AMP-210	***Date Received:*** 1/24/2006 ***Source*** AMP Audit
Topic: IWE	***Status:*** Open

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

Pages 25 through 31 of the PBD present a discussion of the OCGS operating experience.

(8a)The following statements related to drywell corrosion in the sand bed region need further explanation and clarification:
As a result of the presence of water in the sand bed region, extensive UT thickness measurements (about 1000) of the drywell shell were taken to determine if degradation was occurring. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.
Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning found only in these areas?
After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements.
Please describe the concrete surface below the sand that is discussed in paragraph above.
Please provide the following information:
(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster

Creek sand bed region.

Evaluation of UT measurements taken from inside the drywell, in the in the former sand bed region, in 1992, 1994, and 1996 confirmed that corrosion is mitigated. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.
NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

(8b)The following statement related to drywell corrosion above the sand bed region needs further explanation and clarification:

Corrective action for these regions involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specifications reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the drywell shell and the concrete will allow the upper portion of the drywell to meet ASME code requirements.

Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements". Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

(8c)The following statements related to torus degradation need further explanation and clarification:
Inspection performed in 2002 found the coating to be in good condition in the vapor area of the Torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function.
While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continues to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established

in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to 50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Assigned To: Ouaou, Ahmed

Response:

(8a) Question: Please explain the underlined statement. Were water leaks limited to only a portion of the circumference? Was wall thinning only in these area?

Response:
This statement was not meant to indicate that water leaks were limited to only a portion of the circumference. The statement is meant to reflect the fact that water leakage was observed coming out of certain sand bed region drains and those locations were suspect of wall thinning.
No. Wall thinning was not limited to the areas where water leakage from the drains was observed. Wall thinning occurred in all areas of the sand bed region based on UT measurements and visual inspection of the area conducted after the sand was removed in 1992. However the degree of wall thinning varied from location to location. For example 60% of the measured locations in the sand bed region (bays 1, 3, 5, 7, 9, and 15) indicate that the average measured drywell shell thickness is nearly the same as the design nominal thickness and that these locations experienced negligible wall thinning; whereas bay 19A experienced approximately 30% reduction in wall thickness.

Question: Please discuss the concrete surface below the sand that is discussed in paragraph above.

Response:
The concrete surface below the sand was intended to be shaped to promote flow toward each of the five sand bed drains. However once the sand was removed it was discovered that the floor was not properly finished and shaped as required to permit proper drainage. There were low points, craters, and rough surfaces that could allow moisture to pool instead of flowing smoothly toward the drains. These concrete surfaces were refurbished to fill low areas, smooth rough surfaces, and coat these surfaces with epoxy coating to promote improved drainage. The drywell shell at juncture of the concrete floor was sealed with an elastomer to prevent water intrusion into the embedded drywell shell.

Question: Please provide the following information:

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(1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806 minimum)
(2) What was the projected thickness based on measurements taken from the inside?
(3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733 minimum)
(4) Is the minimum required thickness based on stress or buckling criteria?
(5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the .736 minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster Creek sand bed region.

Response:
1. The minimum recorded thickness in the sand bed region from outside inspection is 0.618 inches. The minimum recorded thickness in the sand bed region from inside inspections is 0.603. These minimum recorded thicknesses are isolated local measurement and represent a single point UT measurement. The 0.806 inches thickness provided to the Staff verbally is an average minimum general thickness calculated based on 49 UT measurements taken in an area that is approximately 6"x 6". Thus the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806".

The 0.806" minimum average thickness verbally discussed with the Staff during the AMP audit was recorded in location 19A in 1994. Additional reviews after the audit noted that lower minimum average thickness values were recorded at the same location in 1991 (0.803") and in September 1992 (0.800"). However, the three values are within the tolerance of +/- 0.010" discussed with the Staff.

2. The minimum projected thickness depends on whether the trended data is before or after 1992 as demonstrated by corrosion trends provided in response to NRC Question #AMP-356. For license renewal, using corrosion rate trends after 1992 is appropriate because of corrosion mitigating measures such as removal of the sand and coating of the shell. Then, using corrosion rate trends based on 1992, 1994, and 1996 UT data; and the minimum average thickness measured in 1992 (0.800"), the minimum projected average thickness through 2009 and beyond remains approximately 0.800 inches. The projected minimum thickness during and through the period of extended operation will be reevaluated after UT inspections that will be conducted prior to entering the period of extended operation, and after the periodic UT inspection every 10 years thereafter.

3.The engineering analysis that demonstrated compliance to ASME code requirements was performed in two parts, Stress and Stability Analysis with Sand, and Stress and Stability Analyses without Sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4, were transmitted to the NRC Staff in December 1990 and in 1991 respectively. Index No. 9-3 and 9-4, were revised later to correct errors identified during an internal audit and were resubmitted to the Staff in January 1992 (see attachment 1 & 2). The analyses are briefly described below.

The drywell shell thickness in the sand bed region is based on Stability Analysis without Sand. As described in detail in attachment 1 & 2, the analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches.

As discussed with the Staff during the AMP audit, the basic approach used in the buckling evaluation follows the methodology outlined in ASME Code Case N-284 revision 0 that was reconciled later with revision 1 of the Code Case. Following the procedure of this Code Case, the allowable compressive stress is evaluated in three steps. In the first step, a theoretical buckling stress is determined, and secondly modified using appropriate capacity and plasticity reduction factors. In the final step, the allowable compressive stress is obtained by dividing the buckling stress calculated in the second step by a safety factor of 2.0 for Design and Level A & B service conditions and 1.67 Level C service conditions.

Using the approach described above, the analysis shows that for the most severe design basis load combinations, the limits of ASME Section III, Subsection NE 3213.10 are fully met. For additional details refer to Attachment 1 & 2.

As described above, the buckling analysis was performed assuming a uniform general thickness of the sand bed region of 0.736 inches. However the UT measurements identified isolated, localized areas where the drywell shell thickness is less than 0.736 inches. Acceptance for these areas was based on engineering calculation C-1302-187-5320-024.

The calculation uses a Local Wall Acceptance Criteria". This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick so long as the small 12" by 12" area is at least 0.536" thick. However the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, the minimum required linear distances between a 12" by 12" area thinner than 0.736" but thicker than 0.536" and another 12" by 12" area thinner than 0.736" but thicker than 0.536" were not provided.

The actual data for two bays (13 and 1) shows that there are more than one 12" by 12" areas thinner than 0.736" but thicker than 0.536". Also the actual data for two bays shows that there are more than one 2 ½'" diameter areas thinner than 0.736" but thicker than 0.490". Acceptance is based on the following evaluation.

The effect of these very local wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load.

To begin the discussion we will describe the buckling of a simply supported cylindrical shell under the influence of lateral pressure and axial load. As described in chapter 11 of the Theory of Elastic Stability, Second Edition, by Timoshenko and Gere, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin walled cylindrical shell both the length and radius would be essentially constants and if the thickness was changed locally the change would have to be significant and continuous over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This approach can be easily extrapolated to any shell of revolution that would experience both an axial load and lateral pressure as in the case of the drywell. This local lobe buckling is demonstrated in The GE Letter Report "Sandbed Local Thinning and Raising the Fixity Height Analysis" where a 12 x 12 square inch section of the drywell sand bed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell. Therefore, to influence the buckling of a shell the very local areas of reduced thickness would have to be contiguous and of the same thickness. This is also consistent with Code Case 284 in Section –1700 which indicates that the average stress values in the shell should be used for calculating the buckling stress. Therefore, an acceptable distance between areas of reduced thickness is not required for an acceptable buckling analysis except that the area of reduced thickness is small enough not to influence a buckling lobe of the shell. The very local areas of thickness are dispersed over a wide area with varying thickness and as such will have a negligible effect on the buckling response of the drywell. In addition, these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region which is located at the midpoint between two vents.

The acceptance criteria for the thickness of 0.49 inches confined to an area less than 2½ inches in diameter experiencing primary membrane + bending stresses is 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.

The implications of these paragraphs are that shell failures at these locations from primary stresses produced by pressure cannot occur provided openings in shells have sufficient reinforcement. The current design pressure of 44 psig for drywell requires a thickness of 0.479 inches in the sand bed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sand bed region exceed the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph are not required for the very local wall thickness evaluation presented in Revision 0 of Calculation C-1302-187-5320-024.

Reviewing the stability analyses provided in both the GE Report 9-4 and the GE Letter Report Sand bed Local Thinning and Raising the Fixity Height Analysis and recognizing that the plate elements in the sand bed region of the model are 3" x 3" it is clear that the circumferential buckling lobes for the

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drywell are substantially larger than the 2 ½ inch diameter very local wall areas. This combined with the local reinforcement surrounding these local areas indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from the GE Letter Report 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 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 indicate there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch thickness used in GE Report 9-4 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%. This leads to the conclusion that the buckling of the shell is 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 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 are centered about the vents, which significantly stiffen the shell. This stiffing effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

The minimum thickness of 0.733" is not correct. The correct minimum thickness is 0.736".

4. The minimum required thickness for the sand bed region is controlled by buckling.

5. We cannot reconcile the difference between the current (lowest measured) of 0.736" in NUREG-1540 and the minimum measured thickness of 0.806 inches we discussed with the Staff. Perhaps the value in NUREG-1540 should be labeled minimum required by the Code, as documented in several correspondences with the Staff, instead of lowest measured. In a letter dated September 15, 1995, GPU provided the Staff a table that lists sand bed region thicknesses. The table indicates that nominal thickness is 1.154". the minimum measured thickness in 1994 is 0.806", and the minimum thickness required by Code is 0.736". These thicknesses are consistent with those discussed with the Staff during the AMP/AMR audit.

Question: NUREG-1540, published in April 1996, includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements. and (page 2) As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically. Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.Please reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent requirement/commitment documented in NUREG-1540.

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Response:

Our review of NUREG-1540, page 2 indicates that the statements appear to be based on 1991, or 1993 GPU commitment to perform periodic UT measurements. In fact UT thickness measurements were taken in the sand bed region from inside the drywell in 1992, and 1994. The trend of the UT measurements indicates that corrosion has been arrested. As results GPU informed NRC in a letter dated September 15, 1995 (ref. 2) that UT measurements will be taken one more time, in 1996, and the epoxy coating will be inspected in 1996 and, as a minimum again in 2000. The UT measurements were taken in 1996, per the commitment, and confirmed corrosion rate trend of 1992 and 1994. The results of 1992, 1994, and 1996 UT measurements were provided to the Staff during the AMP/AMR audits.

In response to GPU September 15, 1995 letter, NRC Staff found the proposed changes to sand bed region commitments (i.e. no additional UT measurements after 1996) reasonable and acceptable. This response is documented in November 1, 1995 Safety Evaluation for the Drywell Monitoring Program.

For license renewal, Oyster Creek was previously committed to perform One-Time UT inspection of the drywell shell in the sand bed region prior to entering the period of extended operation. However, in response to NRC Question #AMP-141, Oyster Creek revised the commitment to perform UT inspections periodically. The initial inspection will be conducted prior to entering the period of extended operation and additional inspections will be conducted every 10 years thereafter. The UT measurements will be taken from inside the drywell at same locations as 1996 UT campaign

(8b) Question: Please describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements. Are these measures to prevent water intrusion credited for LR? If not, how will ASME code requirements be met during the extended period of operation?

Response:
The measures taken to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to maintain the ASME code requirements are,
1. Cleared the former sand bed region drains to improve the drainage path.
2. Replaced reactor cavity steel trough drain gasket, which was found to be leaking.
3. Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.
4. Confirmed that the reactor cavity concrete trough drains are not clogged
5. Monitored former sand bed region drains and reactor cavity concrete trough drains for leakage during refueling outages and plant operation.

Oyster Creek is committed to implement these measures during the period of extended operation.

(8c) Please confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to

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50 mils max; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (.141) and pits as deep as 261 mils (.261) may be acceptable.

Response:
(1) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, specifies repair requirements for coating defects exposing substrate and fractured blisters showing signs of corrosion. The repairs referred to in the inspection report included fractured blisters, as well as any mechanically damaged areas, which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters would be candidates for repair, not those blisters that remain intact. The number and location of repairs are tabulated in the final inspection report prepared by Underwater Construction Corporation.
(2) Coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001. Several blistered areas included pitting corrosion where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

(3) In addition to blistering, random deficiencies that exposed base metal were identified in the torus immersion region coating (e.g., minor mechanical damage) during the 19R (2002) torus coating inspections. They ranged in size from 1/16" to ½" in diameter. Pitting in these areas was qualitatively evaluated and ranged from less than 10 mils to slightly more than 40 mils in a few isolated cases. Three quantitative pit depth measurements were taken in several locations in the immersion area of Bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to be representative of typical conditions found on the shell.

Prior to 2002 inspection 4 pits greater than 0.040" were identified. The pits depth are 0.058" (1 pit in 1988), 0.05" (2 pits in 1991), and 0.0685" (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found to be acceptable.

(4) Specification SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating, includes the pit-depth acceptance criteria for rapid evaluation of observed pitting. The acceptance criteria are supported by a calculation C-1302-187-E310-038. Locations that do not meet the pit-depth acceptance criteria are characterized based on the size of the area, center to center distance between corroded areas, the maximum pit depth and location in the Torus based on major structural features. These details are sent to Oyster Creek Engineering for evaluation.

(5) The acceptance criteria for pit depth is as follows:
-Isolated Pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center to center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated.

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-Multiple Pits that can be encompassed by a 2-1/2" diameter circle shall be limited to a maximum pit depth of 0.141" provided the center to center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or recoated.

Question: Please also provide the following information: nominal design, as-built, and minimum measured thickness of the torus; minimum thickness required to meet ASME code acceptance criteria; the technical basis for the pitting acceptance criteria include in Specification SP-1302-52-120

Response:
Submersed area:
(a) The nominal Design thickness is 0.385 inches
(b) The as-built thickness is 0.385 inches
(c) The minimum uniform measured thickness is,
 0.343 inches - general shell
 0.345 inches - shell - ring girders
 0.345 inches - shell - saddle flange
 0.345 inches - shell - torus straps

(d) The minimum general thickness required to meet ASME Code Acceptance is 0.337 inches.

Technical basis for pitting acceptance criteria included in Specification SP-1302-52-120 is based on engineering calculation C-1302-187-E310-038. At the time of preparation of calculation C-1302-187-E310-038 in 2002 there were no published methods to calculate acceptance standards for locally thinned areas in ASME Section III or Section VIII Pressure Vessel codes. Therefore, the approach in Code Case N-597 was used as guidance in assessing locally thinned areas in the Torus. This is based on the similarity in approaches between Local Thinning Areas described in N597 and Local Primary Stress areas described in Paragraph NE3213.10 of the ASME B&PV Code Section III, particularly small areas of wall thinning which do not exceed 1.0 x (square root of Rt). In addition, the ASME B&PV Code Section III, Subsection NB, Paragraph NB-3630 allows the analysis of pipe systems in accordance with the Vessel Analysis rules described in Paragraph NB-3200 of the same Subsection as an alternate analysis approach. Therefore, the approach used in N597 for local areas of thinning was probably developed using the rules for Local Primary Membrane Stress from paragraph NB-3200 in particular Subparagraph 3213.10. The Local Primary Stress Limits in NB-3213.10 are similar to those discussed in Subsection NE, Paragraph NE-3213.10.

Since the Code Case had not yet been invoked in to the Section XI program, the calculation provided a reconciliation of the results obtained from the code case against the ASME Section III code requirements as discussed above. This reconciliation demonstrated that the approach in N597 used on a pressure vessel such as the Torus would be acceptable since the results are conservative compared to the previous work performed in MPR-953 and Lm(a) (defined in N597 Table- 3622-1) £ (Rmintmin)1/2.

Currently, the maximum pit depth measured in the Torus is a 0.0685" (measured in 1992 in bay 2). It was evaluated as acceptable using the design calculations existing at that time and was not based on

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Calculation C-1302-187-E310-038. This remains the bounding wall thickness in the Torus. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Section III and VIII Code requirements for the Torus.

The Torus inspection program is being enhanced per IR 373695 to improve the detail of the acceptance criteria and margin management requirements using the ASME Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If Code Case N-597-1 is required to develop these criteria for future inspections, NRC review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to periodically monitor to verify they remain bounded.

Supplemental information - 04/19/2006.
This supplements response to item 8a(1) above.
The lowest recorded reading was 0.603 in December 1992. A review of the previous readings for the period 1990 thru 1992 and two subsequent readings taken in September 1994 and 1996 show this point should not be considered valid. The average reading for this point taken in 1994 and 1996 was 0.888 inches.

Point 14 in location 17D was the next lowest value of 0.646 inches recorded during the 1994 outage. A review of readings, at this same point, taken during the period from 1990 through 1992 and subsequent reading taken in 1996 are conistent with this value. Thus the minimum recorded thickness in the sand bed region from inside inspections is 0.646 inches, instead of 0.603 inches.

For additional information on torus coating refer to AMP-072.

LRCR #: *LRA A.5 Commitment #:*

IR#:

__Approvals:__

Prepared By: Ouaou, Ahmed 4/20/2006

Reviewed By: Miller, Mark 4/20/2006

Approved By: Warfel, Don 4/20/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No
AMP-264

Date Received: 1/25/2006
Source AMP Audit

Topic:
One Time Inspection

Status: Open

Document References:
B.1.24

NRC Representative Lofaro, Bob

AmerGen (Took Issue): Hufnagel, Joh

Question

AMP-TBD (Audit2 B.1.24-8): The OCGS Inspection Sample Basis document for the one-time inspection, dated 08/16/2005, states in Section A that the one-time inspection sample size will include 10% of the total butt welds in Class 1 piping under 4", and the actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, etc. and will be determined by the site. Please provide the following information:
a) How will the sample selection process ensure that samples of all different pipe sizes less than 4" are inspected (i.e., 1", 2", 3" etc.)?
b) Are there any Class 1 pipes less than 4" NPS in the scope of this AMP that are not butt welded (e.g., socket welded)? If so, how will these non-butt welded pipes be inspected since UT examination is not suitable for socket welds?
c) What is Oyster Creek's operating experience with Class 1 piping less than 4 inch NPS in terms of cracking?

Assigned To: Miller, Mark

Response:

THIS RESPONSE IS SUPERCEDED as a result of the 4/19/2006 Audit discussions with the NRC. See revised response below this original response:

a) The one-time inspection for Class 1 piping, piping components, and piping elements for cracking initiation and growth due to thermal and mechanical loading, stress corrosion cracking, and intergranular stress corrosion cracking includes a representative sample of the susceptible items, and, where practical, focuses on the bounding or lead items most susceptible to cracking due to time in service, severity of operating conditions, or lowest design margin.

Applying ASME Code Case N-578-1, "Risk Informed Requirements for Class 1, 2, or 3 Piping, Method B Section XI, Division 1" is one method other applicants have used for determining sample size for one-time inspections. With this method, butt welds are evaluated based on risk and "binned" into high, medium, and low risk categories. The selected sample for one-time inspection volumetric examination then included 10 % of the high and medium risk butt welds. Oyster Creek however has not employed risk informed ISI and does not currently have a risk based evaluation that categorizes the Class 1 butt welds into risk categories. This evaluation is extensive and to perform this evaluation at this time is not practical so ASME Code Case N-578-1 will not be utilized. Instead, the one-time inspection sample size will include 10% of the total butt welds in Class 1 piping less than 4" NPS. The actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, etc. and will be determined with site involvement. UT techniques consistent with the ASME Code and 10 CFR Part 50, Appendix B that permit the inspection of the inside surfaces of the item will be used for the inspection of butt welds.

Oyster Creek piping is based upon the ANSI B31.1 (1963) Power Piping specification. The Class 1 piping classification is based upon ASME Section XI. The Oyster Creek line specifications, Piping and Instrument drawings, Isometric Configuration drawings and input from the Oyster Creek ISI coordinator were used to determine the location and population of butt welds less than or equal to four inches. The population includes welds on the Reactor Recirculation System, the CRD return line, the reactor vessel bottom head drain line, the reactor head vent line (Main Steam system), and the Reactor Water Cleanup System. The butt welds less than 4" NPS in these systems are two and three inch in size (there is no 2 ½ inch Class 1 piping; nor are there any butt welds on the 1 inch Class 1 piping). The proposed sample includes a representative sample of welds from these systems and includes both two and three inch NPS pipe.

b) The majority of Class 1 piping less than 4" NPS is socket welded. The ASME Section XI Class 1 piping program requires surface examination of socket welded connections. The One-Time Inspection program will not include in-situ volumetric examination of socket welded connections. The One-Time Inspection program will include opportunistic examinations of Class 1 socket welded connections less than 4" NPS. Socket weld failures will be evaluated in accordance with the Oyster Creek 10 CFR Part 50, Appendix B corrective action program to determine failure mechanisms and corrective actions. In addition, the plant modification process will require that any class 1 socket welded connection less than 4" NPS that has been removed during the installation of a plant modification be examined for cracking and cracking mechanisms.

LRCR #276 has been initiated to
revise the program commitments accordingly.

c) Based on a review of the Oyster Creek CAP System (Corrective Action Program) from 1998 through present, cracking due to SCC, IGSCC, or thermal and mechanical loading has not been found on class 1 piping less than 4" NPS. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue.

Mechanical/Vibration Fatigue: Vibration induced socket weld failures is a material degradation issue that can result in crack initiation and growth. Small bore pipe and socket welded vent and drain connections in the immediate proximity of vibration sources tend to be most susceptible to high cycle mechanical fatigue. Vibration fatigue does not lend itself to periodic in-service examinations as a means of managing this aging mechanism. Vibration induced fatigue is fast acting and is typically detected early in a component's life. The nature of this mechanism is such that, generally, almost the entire fatigue life of the component is expended during the initial phase of crack initiation. Once a crack initiates, failure quickly follows. The period of time between crack initiation, i.e. a crack size that is detectable by volumetric examination, and the failure of the pressure boundary is very small and is usually measured in days to months and not years. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue. Based upon the Oyster Creek plant specific operating experience, and rationale provided above, cracking due to vibration-induced fatigue is not considered an aging effect for the period of extended operation.

Thermal Fatigue: A relatively small number of thermal related failures have occurred in small-bore piping (reference: Pacific Northwest National Laboratory report PNNL-13930, "Program Plan for Acquiring and Examining Naturally Aged Materials and Components for Nuclear Reactors," dated December 2001). Fatigue failures in safety related systems and components have been rare and fatigue in pressure-retaining equipment is generally detected as small cracks or leaks, caught before reaching a size that could cause a pressure boundary rupture. Thus fatigue is not considered a safety issue (reference: TR-104534, "EPRI Fatigue Management Handbook," dated December 1994). Of those that have occurred, the more common source of thermal fatigue was either (1) cracking associated with the interaction of valve leakage and cyclic effects and (2) cyclic turbulent penetration effects of isolated small-bore piping or drain lines. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue. The issue of thermal fatigue is the subject of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," dated January 2001 which is referenced in GALL program XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping" in program Element 1 "Scope of Program." As discussed in PBD-B.1.24, EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. These inspection recommendations do not apply to Oyster Creek which is a BWR. However, Oyster Creek has evaluated the potential for cracking in nominally stagnant non-isolable piping attached to reactor coolant systems and it was concluded that there are no systems with unisolable sections that could be subjected to thermal stratification or oscillations. This evaluation is summarized as follows: Information Notice (IN) 97-46 discusses a situation that occurred at Oconee Unit 2 where cracks developed in an unisolable section of a combined makeup (MU) and high-pressure injection (HPI) line. The Information Notice goes on to reference NRC Bulletin 88-08 and its supplements. Bulletin 88-08 describes the circumstances that occurred at Farley 2 where a crack developed in an unisolable section of ECCS piping. The crack resulted from high cycle thermal fatigue caused by relatively cold water leaking through a closed globe valve. Oyster Creek performed a review of systems connected to the Reactor Coolant System in response to NRC Bulletin 88-08 and its Supplements to determine whether unisolable sections of piping connected to the Reactor Coolant System could be subjected to stresses from temperature stratification or temperature oscillations. It was concluded that there are no systems with unisolable sections which could be subjected to thermal stratification or oscillations. The piping system evaluations encompassed both the weldments (as required by Bulletin 88-08) and the base metal (as required by Supplement 1 to Bulletin 88-08).

Stress Corrosion Cracking: Three simultaneous conditions must be present for IGSCC to occur: susceptible material, environment, and tensile stress. Tensile stress at the weld root, which is exposed to impurities in the reactor coolant that can accelerate the initiation and propagation of IGSCC, is typically produced during butt welding of piping components and is less of a concern with socket welded connections. The Oyster Creek One-Time Inspection program for class 1 piping less than 4" NPS will focus on full penetration butt welds which are more susceptible (bounding) than socket welded connections to the stress corrosion cracking aging mechanism.

****************************REVISED RESPONSE*************************

THE FOLLOWING IS THE REVISED RESPONSE as a result of 4/19/2006 discussions with NRC during the Audit. It completely supersedes the information above:

a) The one-time inspection for Class 1 piping, piping components, and piping elements for cracking initiation and growth due to thermal and mechanical loading, stress corrosion cracking, and intergranular stress corrosion cracking includes a representative sample of the susceptible items, and, where practical, focuses on the bounding or lead items most susceptible to cracking due to time in service, severity of operating conditions, or lowest design margin.

Applying ASME Code Case N-578-1, "Risk Informed Requirements for Class 1, 2, or 3 Piping, Method B Section XI, Division 1" is one method other applicants have used for determining sample size for one-time inspections. With this method, butt welds are evaluated based on risk and "binned" into high, medium, and low risk categories. The selected sample for one-time inspection volumetric examination then included 10 % of the high and medium risk butt welds. Oyster Creek however has not employed risk informed ISI and does not currently have a risk based evaluation that categorizes the Class 1 butt welds into risk categories. This evaluation is extensive and to perform this evaluation at this time is not practical so ASME Code Case N-578-1 will not be utilized. Instead, the one-time inspection sample size will include 10% of the total butt welds in Class 1 piping less than 4" NPS. The actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, etc. and will be determined with site involvement. UT techniques consistent with the ASME Code and 10 CFR Part 50, Appendix B that permit the inspection of the inside surfaces of the item will be used for the inspection of butt welds. Results of these inspections will be evaluated in the Oyster Creek 10 CFR Part 50, Appendix B Corrective Action process as necessary.

As discussed in response item b. below, the One-Time Inspection program will also include destructive or non-destructive examination of a susceptible small bore socket weld to confirm the absence of cracking. Destructive or non-destructive techniques proven by past industry experience to be effective for the identification of cracking in small bore socket welds will be used for the inspection. Results of the inspection will be evaluated in the Oyster Creek 10 CFR Part 50, Appendix B Corrective Action process as necessary.

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Oyster Creek piping is based upon the ANSI B31.1 (1963) Power Piping specification. The Class 1 piping classification is based upon ASME Section XI. The Oyster Creek line specifications, Piping and Instrument drawings, Isometric Configuration drawings and input from the Oyster Creek ISI coordinator were used to determine the location and population of butt welds less than or equal to four inches. The population includes welds on the Reactor Recirculation System, the CRD return line, the reactor vessel bottom head drain line, the reactor head vent line (Main Steam system), and the Reactor Water Cleanup System. The butt welds less than 4" NPS in these systems are two and three inch in size (there is no 2 ½ inch Class 1 piping; nor are there any butt welds on the 1 inch Class 1 piping). The proposed sample includes a representative sample of welds from these systems and includes both two and three inch NPS pipe.

b) The Oyster Creek One-Time Inspection program for Class 1 piping less than 4" NPS will focus predominantly on full penetration butt welds and will rely on established ultrasonic NDE techniques performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B.

The One-Time Inspection program will also include destructive or non-destructive examination of one (1) socket welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small bore socket welds. This examination will be an examination of opportunity (e.g., socket weld failure or socket weld replacement). Should an inspection of opportunity not occur prior to entering the period of extended operation, a susceptible small bore socket weld will be examined either destructively or non-destructively prior to entering the period of extended operation. The current plan is to examine a susceptible small bore Class 1 elbow off of an Isolation Condenser System drain line. Results of the inspection will be evaluated in the Oyster Creek 10 CFR Part 50, Appendix B Corrective Action process as necessary.

This specific commitment will be added to the LRA Appendix A.5 Commitment List, as part of Commitment 24 associated with the One-Time Inspection program. LRCR #276 has been initiated to revise the One-Time Inspection program documents regarding socket weld inspection.

c) Based on a review of the Oyster Creek CAP System (Corrective Action Program) from 1998 through present, cracking due to SCC, IGSCC, or thermal and mechanical loading has not been found on class 1 piping less than 4" NPS. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue.

Mechanical/Vibration Fatigue: Vibration induced socket weld failures is a material degradation issue that can result in crack initiation and growth. Small bore pipe and socket welded vent and drain connections in the immediate proximity of vibration sources tend to be most susceptible to high cycle mechanical fatigue. Vibration fatigue does not lend itself to periodic in-service examinations as a means of managing this aging mechanism. Vibration induced fatigue is fast acting and is typically detected early in a component's life. The nature of this mechanism is such that, generally, almost the entire fatigue life of the component is expended during the initial phase of crack initiation. Once a crack initiates, failure quickly follows. The period of time between crack initiation, i.e. a crack size that is detectable by volumetric examination, and the failure of the pressure boundary is very small and is usually measured in days to months and not years. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue. Based upon the Oyster Creek plant specific operating experience, and rationale provided above, cracking due to vibration-induced fatigue is not considered an aging effect for the period of extended operation.

Thermal Fatigue: A relatively small number of thermal related failures have occurred in small-bore piping (reference: Pacific Northwest National Laboratory report PNNL-13930, "Program Plan for Acquiring and Examining Naturally Aged Materials and Components for Nuclear Reactors," dated December 2001). Fatigue failures in safety related systems and components have been rare and fatigue in pressure-retaining equipment is generally detected as small cracks or leaks, caught before reaching a size that could cause a pressure boundary rupture. Thus fatigue is not considered a safety issue (reference: TR-104534, "EPRI Fatigue Management Handbook," dated December 1994). Of those that have occurred, the more common source of thermal fatigue was either (1) cracking associated with the interaction of valve leakage and cyclic effects and (2) cyclic turbulent penetration effects of isolated small-bore piping or drain lines. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue. The issue of thermal fatigue is the subject of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," dated January 2001 which is referenced in GALL program XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping" in program Element 1 "Scope of Program." As discussed in PBD-B.1.24, EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. These inspection recommendations do not apply to Oyster Creek which is a BWR. However, Oyster Creek has evaluated the potential for cracking in nominally stagnant non-isolable piping attached to reactor coolant systems and it was concluded that there are no systems with unisolable sections that could be subjected to thermal stratification or oscillations. This evaluation is summarized as follows: Information Notice (IN) 97-46 discusses a situation that occurred at Oconee Unit 2 where cracks developed in an unisolable section of a combined makeup (MU) and high-pressure injection (HPI) line. The Information Notice goes on to reference NRC Bulletin 88-08 and its supplements. Bulletin 88-08 describes the circumstances that occurred at Farley 2 where a crack developed in an unisolable section of ECCS piping. The crack resulted from high cycle thermal fatigue caused by relatively cold water leaking through a closed globe valve. Oyster Creek performed a review of systems connected to the Reactor Coolant System in response to NRC Bulletin 88-08 and its Supplements to determine whether unisolable sections of piping connected to the Reactor Coolant System could be subjected to stresses from temperature stratification or temperature oscillations. It was concluded that there are no systems with unisolable sections which could be subjected to thermal stratification or oscillations. The piping system evaluations encompassed both the weldments (as required by Bulletin 88-08) and the base metal (as required by Supplement 1 to Bulletin 88-08).

Stress Corrosion Cracking: Three simultaneous conditions must be present for IGSCC to occur: susceptible material, environment, and tensile stress. Tensile stress at the weld root, which is exposed to impurities in the reactor coolant that can accelerate the initiation and propagation of IGSCC, is typically produced during welding of piping components. The Oyster Creek One-Time Inspection program for class 1 piping less than 4" NPS will focus predominantly on full penetration butt welds. As discussed in response item b. above, the One-Time Inspection program will also include destructive or non-destructive examination of a small bore socket weld to confirm the absence of cracking.

LRCR #: 276 *LRA A.5 Commitment #:* B.1.24

IR#:

Approvals:

Prepared By: Miller, Mark 4/19/2006

Reviewed By: Muggleston, Kevin 4/19/2006

Approved By: Warfel, Don 4/19/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No		*Date Received:*	*Source*
AMP-204		1/24/2006	AMP Audit
Topic:		*Status:*	Closed
IWE			

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

P. 7 of the PBD states Oyster Creek credits the protective coatings on interior surfaces of the suppression chamber (Torus) shell, and the vent system to mitigate corrosion. In addition Oyster Creek also relies on protective coatings on the exterior surfaces of the drywell shell, in the former sand bed region, to mitigate corrosion in accordance with a current licensing basis (CLB) commitment. For the current term, the protective coatings are monitored on frequency of every other refueling outage under the Protective Coating Monitoring and Maintenance Program. These coated areas will be monitored under the Protective Coating Monitoring and Maintenance Program consistent with ASME Section XI, Subsection IWE requirements during the period of extended operation. This constitutes a new enhancement that will be reflected in Protective Coating Monitoring and Maintenance Program." Please explain in more detail this new enhancement. How does it differ from the previous commitment? Where is this addressed in the protective coatings program PBD?

Assigned To: Ouaou, Ahmed

Response:

Response to this question has been provided in response to Audit Question No. AMP-188, related to the Protective Coating Monitoring and Maintenance Program (B.1.33).

Supplemental information - 4/20/2006
As a result of discussions with NRC Staff on April 20, 2006 Oyster Creek provided supplemental information on torus coating. Refer to AMP-072 response for this information.

LRCR #: *LRA A.5 Commitment #:*

IR#:

Approvals:

Prepared By:	Ouaou, Ahmed	4/20/2006
Reviewed By:	Getz, Stu	4/20/2006

NRC Information Request Form

Approved By: Warfel, Don 4/20/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No
AMP-209

Date Received: 1/24/2006

Source AMP Audit

Status: Open

Topic:
IWE

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

P. 17 of the PBD states
As discussed with NRC Staff during the AMP audit, Oyster Creek will perform one-time UT thickness measurements of the drywell shell, in the sand bed region, to confirm that the protective coating is effective. The UT measurements will be taken from inside the drywell at the same or approximate locations measured in 1996. This constitutes a new commitment that will implemented prior to entering the period of extended operation.
Has this been added to the scope of the One Time Inspection program? How will this commitment be tracked and implemented? Are the locations selected for one-time inspection those that had the minimum remaining thickness based on prior UT results? If not, explain why the selected locations are adequate. What steps will be taken if the current conclusion, that corrosion has been arrested, is not confirmed by the one-time inspection?
Also, please discuss the scope of the current coating inspection program and the LR commitment. What % of the total circumference is inspected during each inspection? How many years and how many inspections does it take to complete a 360 degree inspection of the sandbed region? Has a complete 360 degree inspection been completed yet? How many will be completed during the LR period?

Assigned To: Ouaou, Ahmed

Response:

No, the One-Time inspection of the sand bed region commitment has not been added to One-Time Inspection. As discussed with NRC Staff on 1/26/2006, Oyster Creek will perform periodic UT inspections during the period of extended operation instead of One-Time inspection. The initial UT inspections will occur prior to entering the period of extended operation and every 10 years thereafter. Refer to AMP Audit Question No. 141 for additional details. This revised commitment will be tracked in accordance with Oyster Creek commitment tracking process. Additionally the commitment will be included in a revision to Appendix A.5 Commitment List, item #27, which will be submitted to the NRC and incorporated in the UFSAR Supplement. Implementation of the commitment will be through the Oyster Creek ASME Section IX, Subsection IWE.

The locations selected for UT measurements are the same as those inspected using UT measurements in 1996 and include the thinnest measured area.

If the current conclusion that corrosion has been arrested is not confirmed by UT measurements taken prior to entering the period of extended operation, Oyster Creek is committed to take corrective actions defined in response to NRC Question #AMP-357.

Protective coatings on the exterior surfaces of the drywell shell in the sand bed region are monitored in accordance with the Protective Coating Monitoring and Maintenance Program (B.1.33). The current program requires visual inspection of the coating in accordance with engineering specification IS-328227-004. Inspection criteria is not specifically provided by the specification. However inspections are performed by individuals qualified to perform coating inspections. Acceptance criteria provided in the specification is that any identified coating defects shall be submitted for engineering evaluation. The inspection frequency is every other refueling outage.

As discussed with NRC Staff, the existing Protective Coating Monitoring and Maintenance aging management program does not currently invoke the requirements of ASME Section XI, Subsection IWE. Oyster Creek is committed to enhancing the program to incorporate coated surfaces inspection requirements specified in ASME Section XI, Subsection IWE. In response to NRC Question AMP-188, Oyster Creek provided specific enhancements that will be made to the program as follows:

Sand bed Region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1.

a. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.

b. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

c. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation."

The coated surface of the drywell shell in the sand bed region is divided into 10 bays that constitute 360 degrees. The current program requires inspection of coatings in at least 2 bays every other refueling outage. Certain bays were considered critical and have been inspected more than once. Inspection of 5 out of 10 bays (50%) has been completed to date.

For license renewal Oyster Creek is committed to inspect the remaining 5 bays prior to entering the period of extended operation. This will result in a complete (100%) coating inspection of all the 10 bays (360 degree) prior to entering the period of extended operation. Oyster Creek is also committed to inspect the coating in accordance with ASME Section XI, Subsection IWE. Thus inspection of 100% of the coating will be completed during each Containment ISI 10-Year Interval. Inspections will be conducted every other refueling outage during which at least 3 bays (30% of the coating min) will be examined. We therefore expect to inspect 100% of the coating twice during the period of extended operation. The inspections will be conducted in accordance with the enhanced Protective Coating Monitoring and Maintenance Program (B.1.33), including enhancements discussed in NRC Audit Question AMP-188.

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General revision of the response to add and clarify commitments. (AMO 4/2/06)

LRCR #: 229/263 ***LRA A.5 Commitment #:*** 27

IR#:

Approvals:

Prepared By:	Ouaou, Ahmed	4/ 2/2006
Reviewed By:	Muggleston, Kevin	4/ 2/2006
Approved By:	Warfel, Don	4/ 3/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No	*Date Received:*	*Source*
AMP-141	10/ 6/2005	AMP Audit
Topic:	*Status:*	Open

Topic:
IWE

Document References:
B.1.27

NRC Representative Morante, Rich

AmerGen (Took Issue): Hufnagel, Joh

Question

AMP B.1.27 IWE

a. Visual inspection of the coatings in the former sandbed region of the drywell is currently conducted under the applicant's protective coatings monitoring and maintenance program; only this AMP is credited for managing loss of material due to corrosion for license renewal. Visual inspection of the containment shell conducted in accordance with the requirements of IWE is typically credited to manage loss of material due to corrosion.

The applicant is requested to provide its technical basis for not also crediting its IWE program for managing loss of material due to corrosion in the former sandbed region of the drywell.

B. During discussions with the applicant's staff on 10/04/05 about augmented inspection conducted under IWE, the applicant presented tabulated inspection results obtained from the mid 1980s to the present, to monitor the remaining drywell wall thickness in the cylindrical and spherical regions where significant corrosion of the outside surface was previously detected.

The applicant is requested to provide (1) a copy of these tabulated inspection results, (2) a list of the nominal design thicknesses in each region of the drywell, (3) a list of the minimum required thicknesses in each region of the drywell, and (4) a list of the projected remaining wall thicknesses in each region of the drywell in the year 2029.

AMP B.1.27 IWE Question on Remaining Wall Thickness in the Former Sandbed Region of the Drywell

c. During discussions with the applicant's staff on 10/05/05, the applicant described the history and resolution of corrosion in the sandbed region. After discovery, thickness measurements were taken from 1986 through 1992, to monitor the progression of wall loss. Remedial actions were completed in early 1993. At that time, the remaining wall thickness exceeded the minimum required thickness. The applicant concluded that it had completely corrected the conditions which led to the corrosion, and terminated its program to monitor the remaining wall thickness. At that time, the remaining years of operation was expected to be no more than 16 years (end of the current license term).

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The applicant's aging management commitment for license renewals is limited to periodic inspection of the coating that was applied to the exterior surface of the drywell as part of the remedial actions. The applicant has not made a license renewal commitment to measure wall thickness in the sandbed region in order to confirm the effectiveness of the remedial actions taken.

Assigned To: Ouaou, Ahmed

Response:

a) Visual inspection of the containment drywell shell, conducted in accordance with ASME Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containment is considered inaccessible by ASME Section XI, Subsection IWE, thus visual inspection is not possible for a typical Mark I containment including Oyster Creek before the sand was removed from the sand bed region in 1992. After removal of the sand, an epoxy coating was applied to the exterior surfaces of the drywell shell in the sand bed region. The region was made accessible during refueling outages for periodic inspection of the coating. Subsequently Oyster Creek performed periodic visual inspection of the coating in accordance with an NRC current licensing basis commitment. This commitment was implemented prior to implementation of ASME Section XI, Subsection IWE. As a result inspection of the coating was conducted in accordance with the Protective Coating Monitoring and Maintenance Program. Our evaluation of this aging management program concluded the program is adequate to manage aging of the drywell shell in the sand bed region during the period of extended operation consistent with the current licensing basis commitment, and that inclusion of the coating inspection under IWE is not required. However we are amending this position and will commit to monitor the protective coating in the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Section XI, Subsection IWE during the period of extended operation. For details related to implementation of this commitment, refer to the response to NRC AMP Question #188.

b) A tabulation of ultrasonic testing (UT) thickness measurement results in monitored areas of the drywell spherical region above the sand bed region and in the cylindrical region is included in ASME Section XI, Subsection IWE Program Basis Document (PBD-AMP-B.1.27) Notebook. The tabulation contains information requested by the Staff and is available for review during AMP audit. The tabulation is also provided in Table -1, and Table-2 below.

1. See Table-1 and Table-2 for UT inspection results.
2. Nominal design thicknesses of each region of the drywell are:
   - Embedded shell below the sand bed region : 0.676 inches
   - Sand bed region shell : 1.154 inches
   - Spherical region El 23' to El. 51' : 0.770 inches
   - Spherical region El. 51' to El. 65' : 0.722 inches
   - Transition from spherical to cylindrical region: 2.625 inches
   - Cylindrical region : 0.640 inches
3. For the minimum required General thicknesses of the drywell shell above the sand bed region, see Table-1. The minimum required general thickness for the sand bed region is 0.736 inches. The

minimum required local thickness is 0.490 inches. For additional details, see Question #AMP-210.
4. Based on 2004 engineering analysis the minimum projected remaining general wall thickness of the drywell shell above the sand bed region through 2029 is shown in Table-1. The minimum projected remaining wall thickness for the sand bed region through 2029 is 0.800 inches. For additional details, see Question #AMP-210

c) In December 1992, with approval from the NRC a protective epoxy coating was applied to the outside surface of the drywell shell in the sand bed region to prevent additional corrosion in that area. UT thickness measurements taken in 1992, and in 1994, in the sand bed region from inside the drywell confirmed that the corrosion in the sand bed region has been arrested. Periodic inspection of the coating indicates that the coating in that region is performing satisfactorily with no signs of deterioration such as blisters, flakes, or discoloration, etc. Additional UT measurements, taken in 1996 from inside the drywell in the sand bed region showed no ongoing corrosion and provided objective evidence that corrosion has been arrested.

As a result of these UT measurements and the observed condition of the coating, we concluded that corrosion has been arrested and monitoring of the protective coating alone, without additional UT measurements, will adequately manage loss of material in the drywell shell in the sand bed region. However to provide additional assurance that the protective coating is providing adequate protection to ensure drywell integrity, Oyster Creek will perform periodic confirmatory UT inspections of the drywell shell in the sand bed region. The initial UT measurements will be taken prior to entering the period of extended operation and then every 10 years thereafter. The UT measurements will be taken from inside the drywell at the same locations where the UT measurements were taken in 1996. This revises the license renewal commitment communicated to the NRC in a letter from C. N. Swenson Site Vice President, Oyster Creek Generating Station to U. S. Nuclear Regulatory Commission, "Additional Commitments Associated with Application for renewed Operating License - Oyster Creek Generating Station", dated 12/9/2005. This letter commits to one-time inspection to be conducted prior to entering the period of extended operation. The revised commitment will be to conduct UT measurements on a frequency of 10 years, with the first inspection to occur prior to entering the period of extended operation.

This response was revised to incorporate additional commitments on UT examinations for the sand bed region discussed with NRC Audit team on 1/26/2006.
This response was revised to reference response to NRC Question #AMP-188 and RAI 4.7.2-1(d). AMO 4/1/2006.
The response was revised to add Table-1, and Table-2, and delete reference to RAI 4.7.2-1(d) AMO 4/5/2006.
The response was revised to add design nominal thickness and clarify response to item B. AMO 4/12/06

Supplemental Information to item c. above - 04/20/2006.
As a result of discussions with NRC Staff on April 20, 2006, Oyster Creek is committed to the following:
During the initial UT inspections of the sand bed region from inside the drywell, conducted prior to entering the period of extended operation, an attempt will be made to locate and evaluate some of

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the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).

LRCR #: 229 *LRA A.5 Commitment #:* 27

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/20/2006

Reviewed By: Muggleston, Kevin 4/20/2006

Approved By: Warfel, Don 4/20/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No	***Date Received:***	***Source***
AMP-359	3/16/2006	AMP Audit
Topic:	***Status:***	Open

Lubricating Oil Analysis Program - FRCT (AMP B.1.39)

Document References:

NRC Representative Davis, Jim

AmerGen (Took Issue): Beck, Chip

Question

This question was received from Donnie Ashley, NRC Project Manager on 3/14/06 as a draft RAI. On 3/16/06 it was agreed that it would be addressed in the Q&A database since it originates from the audit (Roy Matthew). Subsequently included in 3/17/06 email from Donnie Ashley to George Beck

The Lubricating Oil Analysis Program - FRCT (OCGS AMP B.1.39) takes exception to the GALL Report requirement to monitor flash point.

The basis provided for exceptions to GALL, Element 3 (Parameters Monitored or Inspected) is not valid since the Flash Point of an industrial lubricant is an important test to determine if light-end hydrocarbons are getting into the oil through seal leaks or other means. It is an effective way to monitor seal performance in light end hydro-carbon compressors. Low Flash Points pose a safety hazard in the event of component failure that can generate heat above the flash point of the oil, such as bearing failure.

Please justify the reason for not monitoring the flash point of lubricating oil at the FRCT and why this exception is acceptable to manage the effects of aging for which it is credited.

Assigned To: Beck, Chip

Response:

The Lubricating Oil Analysis Program - FRCT (PBD-AMP-1.39) will be revised to include measurement of flash point.

(This is consistent with PBD-AMP-B.2.02 Lubricating Oil Monitoring Activities)

LRCR #: 292 ***LRA A.5 Commitment #:***

IR#:

Approvals:

NRC Information Request Form

Prepared By:	Beck, Chip	3/30/2006
Reviewed By:	Muggleston, Kevin	3/30/2006
Approved By:	Warfel, Don	3/30/2006
NRC Acceptance (Date):		

NRC Information Request Form

Item No		***Date Received:***	***Source***
AMP-361		3/17/2006	AMP Audit
Topic:		***Status:***	Closed

PBD-AMP-B.1.12 Bolting Integrity

Document References:

NRC Representative Davis, Jim

AmerGen (Took Issue): Beck, Chip

Question

This question was received in an email from Donnie Ashley, NRC Project Manager, to George Beck, dated 3/17/06.

PBD -AMP- B.1.12, "Bolting Integrity" identifies an enhancement to NUREG-1801 for elements 1, 2, and 7. This enhancement is not identified in OCGS LRA B1.12. Is the LRA supplemented to reflect this?

Assigned To: Corsi, Lou

Response:

During preparation of PBD we identified the need for enhancement. LRCR-242 was generated to revise Appendix A and B for Bolting Integrity, which contains the enhancement to include reference to EPRI TR-104213 in the site procedure.

LRCR #: 242 ***LRA A.5 Commitment #:*** 12

IR#:

Approvals:

Prepared By: Corsi, Lou 3/17/2006

Reviewed By: Getz, Stu 3/17/2006

Approved By: Warfel, Don 3/17/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No
AMP-357

Date Received: 2/16/2006

Source AMP Audit

Topic:
IWE

Status: Open

Document References:

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

(1) When a new set of point thickness readings is taken is the former sandbed region, prior to entering the LR period, what will be the quantitative acceptance criteria for concluding that corrosion has or has not occurred since the last inspection in 1996.

(2) If additional corrosion is detected in the upcoming inspection, describe in detail the augmented inspections and other steps that will be taken to evaluate the extent of the corrosion, and describe the approach to ensuring the continued structural adequacy of the containment.

Assigned To: Ouaou, Ahmed

Response:

(1).The new set of UT measurements for the former sand bed region will be analyzed using the same methodology used to analyze the 1992, 1994, and 1996 UT data. The results will then be compared to the 1992, 1994,1996 UT results to confirm the previous no corrosion trend. Because of surface roughness of the exterior of the drywell shell, experience has shown that UT measurements can vary significantly unless the UT instrument is positioned on the exact point as the previous measurements. Thus acceptance criteria will be based on the standard deviation of the previous data (+/-11 mils) and instrument accuracy of (+/-10 mils) for a total of 21 mils. Deviation from this value will be considered unexpected and requires corrective actions described in item (2) below.

(2). If additional corrosion is identified that exceeds acceptance criteria described above, Oyster Creek will initiate corrective actions that include one or all of the following, depending on the extent of identified corrosion.
a. Perform additional UT measurements to confirm the readings
b. Notify NRC within 48 hours of confirmation of the identified condition
c. Conduct inspection of the coatings in the sand bed region in areas where the additional corrosion was detected.
d. Perform engineering evaluation to assess the extent of the condition and to determine if additional inspections are required to assure drywell integrity.
e. Perform operability determination and justification for continued operation until next scheduled

inspection.

These actions will be completed before restarting from an outage

LRCR #: 293 ***LRA A.5 Commitment #:***

IR#:

Approvals:

Prepared By: Ouaou, Ahmed 4/ 1/2006

Reviewed By: Muggleston, Kevin 4/ 3/2006

Approved By: Warfel, Don 4/ 3/2006

NRC Acceptance (Date):

NRC Information Request Form

Item No
AMP-356

Date Received: 2/16/2006
Source AMP Audit

Topic:
IWE

Status: Open

Document References:

NRC Representative Morante, Rich

AmerGen (Took Issue):

Question

IWE AMP
Question 4 IWE AMP Revised Feb. 17, 2006 R. Morante (AMP-356)

(1) Identify the specific locations around the circumference in the former sandbed region where UT thickness readings have been and will be taken from inside containment. Confirm that all points previously recorded will be included in future inspections.

(2) Describe the grid pattern at each location (meridional length, circumferential length, grid point spacing, total number of point readings), and graphically locate each grid pattern within the former sandbed region.

(3) For each grid location, submit a graph of remaining thickness versus time, using the UT readings since the initiation of the program (both prior to and following removal of the sand and application of the external coating).

(4) Clearly describe the methodology and acceptance criteria that is applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) evaluation.

Assigned To: Ouaou, Ahmed

Response:

Response:
1. The circumference of the drywell is divided into 10 bays, designated as Bays 1, 3, 5, 7, 9, 11,13, 15, 17, and 19. UT thickness readings have been taken in each bay at one or more locations. The specific locations around the circumference in the former sand bed region where UT thickness reading have been taken from inside containment are Bay 1D, 3D, 5D, 7D, 9A, 9D, 11A, 11C, 13A, 13C, 13D, 15A, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C. For each location, UT measurements were taken centered at elevation 11'-3". These represent the locations where UT measurements were taken in 1992, 1994, and 1996.

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In addition UT measurements were taken one time inside 2 trenches excavated in drywell floor concrete. The purpose of these UT measurements is to determine the extent of corrosion in the lower portions of the sand bed region prior to removing the sand and making accessible for visual inspection.

Future UT thickness measurements will be taken at the same locations as those inspected in 1996 in accordance with Oyster Creek commitment documented in NRC Question #AMP-209.

2. For locations where the initial investigations found significant wall thinning (9D, 11A, 11C, 13A, 13D, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C) the grid pattern consists of 7 x 7 grid centered at elevation 11'-3 (meridian) and centered at the centerline of the tested location within each bay, which consists of 6"x 6" square template. The grid spacing is 1" on center. There are 49 point readings. For graphical location of the grid, refer to attachment 1.

For locations where the initial investigations found no significant wall thinning (1D, 3D, 5D, 7D, 9A, 13C, and 15A) the grid pattern consists of 1 x 7 grid centered at elevation 11'-3" (meridian) on 1" centers. There are 7 point readings. For graphical location of the grid, refer to attachment 1.

3. A graph representing the remaining thickness versus time using UT reading since the initiation of the program (both prior to and following removal of the sand and application of the external coating) for location 9D, 11A, 11C, 13A, 13D,15D,17A,17D,17/19, 19A, 19B, and 19C is included in the attached graph. Other locations (i.e. 1D, 3D, 5D, 7D, 9A, 13C, and 15A) are not included because wall thinning is not significant and the trend line will be essentially a straight line.

4. The methodology and acceptance criteria that is applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) is described in engineering specification IS-328227-004 and in calculation No. C-1302-187-5300-011. These documents were submitted to the NRC in a letter dated November 26, 1990 and provided to the Staff during the AMP/AMR audit. A brief summary of the methodology and acceptance criteria is described below.

The initial locations where corrosion loss was most severe in 1986 and 1987 were selected for repeat inspection over time to measure corrosion rate. For location where the initial investigations found significant wall thinning UT inspection consists of 49 individual UT data points equally spaced over a 6"x 6" area. Each new set of 49 values was then tested for normal distribution.

The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736. In addition each individual reading is compared to the local minimum required criteria of 0.49. The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to NRC Question #AMP-210.

A decrease in the mean value over time is representative of corrosion. If corrosion does not exist, the mean value will not vary with time except for random variations in the UT measurements.

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If corrosion is continuing, the mean thickness will decrease linearly with time. Therefore the curve fit of the data is tested to determine if linear regression is appropriate, in which case the corrosion rate is equal to the slope of the line. If a slope exists, then upper and lower 95% confidence intervals of the curve fit are calculated. The lower 95% confidence interval is then projected into the future and compared to the required minimum uniform thickness criteria of 0.736.

A similar process is applied to the thinnest individual reading in each grid. The curve fit of the data is tested to determine if linear regression is appropriate. If a slope exists, then the lower 95% confidence interval is then projected into the future and compared to the required minimum local thickness criteria of .49.

LRCR #: ***LRA A.5 Commitment #:***

IR#:

Approvals:

Prepared By:	Ouaou, Ahmed	4/ 4/2006
Reviewed By:	Getz, Stu	4/ 5/2006
Approved By:	Warfel, Don	4/ 5/2006

NRC Acceptance (Date):