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10 CFR 50
10 CFR 51
10 CFR 54

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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Limerick Generating Station, Units 1 and 2
Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Response to NRC Request for Additional Information, dated January 30, 2012, related to the Limerick Generating Station License Renewal Application.

Reference:
1. Exelon Generation Company, LLC letter from Michael P. Gallagher to NRC Document Control Desk, "Application for Renewed Operating Licenses", dated June 22, 2011
2. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station, Units1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)", dated January 30, 2012

In the Reference 1 letter, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Limerick Generating Station, Units 1 and 2 (LGS). In the Reference 2 letter, the NRC requested additional information to support the staffs' review of the LRA.

Enclosed are the responses to these requests for additional information.

Changes to commitments are identified within Enclosure C.

If you have any questions, please contact Mr. Al Fulvio, Manager, Exelon License Renewal, at 610-765-5936.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 02/28/2012

Respectfully,

Michael P. Gallagher

Michael P. Gallagher
Vice President - License Renewal Projects
Exelon Generation Company, LLC

Enclosures: A: Responses to Request for Additional Information
B: Updates to affected LGS LRA sections
C: LGS License Renewal Commitment List Changes

cc: Regional Administrator – NRC Region I
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Project Manager, NRR-Limerick Generating Station
NRC Senior Resident Inspector, Limerick Generating Station
R. R. Janati, Commonwealth of Pennsylvania

Enclosure A

Responses to Request for Additional Information related to various sections of the LGS License Renewal Application (LRA)

RAI B.2.1.30-1
RAI B.2.1.30-2
RAI B.2.1.30-3
RAI B.2.1.30-4
RAI B.2.1.30-5
RAI B.2.1.31-1
RAI B.2.1.31-2
RAI B.2.1.31-3
RAI B.2.1.32-1
RAI B.2.1.32-2
RAI B.2.1.32-3
RAI B.2.1.33-1
RAI B.2.1.35-1
RAI B.2.1.35-2
RAI B.2.1.40-1
RAI B.2.1.40-2
RAI B.2.1.40-3
RAI B.2.1.40-4
RAI B.2.1.41-1
RAI B.2.1.41-2
RAI B.2.1.28-1
RAI B.2.1.37-1

RAI B.2.1.30-1

Background

GALL Report AMP XI.S1, ASME Section XI, Subsection IWE, element 1, “scope of program,” recommends examination of coatings that are intended to prevent corrosion.

Issue

Section 3.1 of the LGS program basis document, LG-AMP-PBD-XI.S1, Revision 1, states that coatings are not credited to prevent corrosion under the scope of ASME Section XI, Subsection IWE program. However, Commitment 30 in Appendix A of the license renewal application (LRA), and Section 2.4 of the program basis document states:

“ASME Section XI, Subsection IWE is an existing program that will be enhanced to:

1. Manage the suppression pool liner and coating system to:
   a. Remove any accumulated sludge in the suppression pool every refueling outage.
   b. Perform an ASME IWE examination of the submerged portion of the suppression pool each Inservice Inspection (ISI) period.
   c. Use the results of the ASME IWE examination to implement a coating maintenance plan to:
      - Perform local recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss.
      - Perform spot recoating of pitting greater than 50 mils deep.
      - Recoat plates with greater than 25 percent coating depletion

The coating maintenance plan will be initiated in the 2012 refueling outage for Unit 1 and the 2013 refueling outage for Unit 2 and implemented such that the areas exceeding the above criteria are recoated prior to the period of extended operation. The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss.”

Request

Explain the apparent inconsistency between the recommendations in the GALL Report, different sections of the program basis document, and Commitment 30 in the LRA. The response should clearly state whether the coating maintenance plan is credited for preventing corrosion of the surfaces of structures which credit the ASME Section XI, Subsection IWE program.

Exelon Response

The Service Level I coating applied to the LGS suppression pool liner includes a license renewal intended function to "maintain adhesion" so as to not adversely affect the operability of ECCS by clogging the ECCS suction strainers. As discussed in Section 3.1 of the LGS program basis document, LG-AMP-PBD-XI.S1, this intended function is maintained through the implementation of GALL Report AMP XI.S8, Protective Coating Monitoring and Maintenance

Program which is described in LRA Appendix B, B.2.1.37. The Service Level I coating does not include a license renewal intended function to prevent the loss of material due to corrosion and additionally, the coating maintenance plan as described in LRA Appendix A, Table A.5, Commitment 30 is not credited for preventing corrosion of the LGS IWE surfaces. As identified in LRA Table 3.5.2-11, "Primary Containment Summary of Aging Management Evaluation", the ASME Section XI, Subsection IWE (B.2.1.30) and the 10 CFR Part 50, Appendix J (B.2.1.33) programs are credited for managing the loss of material in the steel suppression pool liner.

LGS is a Mark II concrete containment where containment strength is derived from the concrete rather than the steel liner. The steel liner ensures a high degree of leak tightness during operating and accident conditions. There is a substantial margin available for liner corrosion. The containment liner plate is constructed of ¼ inch carbon steel and includes a calculated margin of 1/8 inch. The coating maintenance plan ensures that the coating protects the liner to avoid significant material loss and ensures that a sufficient thickness margin continues to be maintained in the suppression pool liner.

Although the Service Level I coating does not include a license renewal intended function to prevent the loss of material due to corrosion, inspection of the suppression pool liner coating is performed to ensure that the coatings intended function to "maintain adhesion" is maintained and to ensure that the coating continues to function as a preventive measure to corrosion. These inspection activities, in addition to suppression pool desludging, more frequent IWE examinations, and the coating maintenance plan as described in LRA Appendix A, Table A.5, Commitment 30 ensure that sufficient thickness margin of the suppression pool liner will be maintained through the period of extended operation. Therefore, there is no inconsistency between the recommendations in the GALL Report, the Program Basis Document for the LGS ASME Section XI, Subsection IWE aging management program, and LRA Appendix A, Table A.5, Commitment 30.

RAI B.2.1.30-2

Background

GALL Report AMP XI.S1, ASME Section XI, Subsection IWE, element 6, “acceptance criteria,” recommends documentation of containment steel shell or liner material loss locally exceeding 10 percent of the nominal wall thickness or material loss that is projected to locally exceed 10 percent of the nominal containment wall thickness before the next examination. Such areas are corrected by repair or replacement in accordance with ASME Code, Section XI, Subsection IWE-3122 or accepted by engineering evaluation.

ASME Code, Section XI, Subsection IWE-3122.3 (b) states that, “When flaws or areas of degradation are accepted by engineering evaluation, the area containing the flaw or degradation shall be reexamined in accordance with ASME Code, Section XI, Subsection IWE-2420(b) and (c).

ASME Code, Section XI, Subsection IWE-2420(b) requires that when examination results require evaluation of flaws or areas of degradation in accordance with ASME Code, Section XI, Subsection IWE-3000, the areas containing such flaws or areas of degradation shall be reexamined during the next inspection period listed in the schedule of inspection program of ASME Code, Section XI, Subsection IWE-2411 or IWE-2412, in accordance with ASME Code, Section XI, Subsection IWE, Table IWE-2500-1, Examination Category E-C. ASME Code, Section XI, Subsection IWE Table 2500-1 designates Examination Category E-C as surfaces requiring augmented examination.

Issue

Section 3.4 of the LGS program basis document LG-AMP-PBD-XI.S1, Revision 1 states that:

ASME Section XI, Subsection IWE is an existing program that will be enhanced to manage the suppression pool liner and coating system to:

a. Remove any accumulated sludge in the suppression pool every refueling outage.
b. Perform an ASME Code, Section XI, Subsection IWE examination of the submerged portion of the suppression pool each ISI period.
c. Use the results of the ASME Code, Section XI, Subsection IWE examination to implement a coating maintenance plan to:
    - Perform local recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss.
    - Perform spot recoating of pitting greater than 50 mils deep.
    - Recoat plates with greater than 25 percent coating depletion.

Section 3.4, detection of aging effects, of LG-AMP-PBD-XI.S1 states that there are no areas identified for augmented inspection in the drywells or suppression pools. Section 3.6, acceptance criteria, also states that the ASME Section XI, Subsection IWE program implementing procedures and references contain the acceptance criteria for containment surface examinations.

LGS implementing procedure MA-LG-793-001, "Visual Examination of Containment Vessels and Internals," has the following acceptance criteria:

Localized areas of corrosion shall not exceed the following:

Drywell	100 mils
Drywell Head	50 mils
Suppression Pool	62.5 mils

Contrary to the GALL Report recommendations and acceptance criteria delineated in the implementing procedure MA-LG-793-001, an Assignment Report, AR 01063631, identified pitting of up to 122 mils in the liner plate, and was dispositioned to be acceptable by the use of the following acceptance criteria:

- For pitting corrosion the area shall be recoated when the metal loss is 1/8 inch (125 mils lost and 125 mils remain)
- For pitting corrosion the area shall be repaired (metal repair) when the metal loss is 3/16 inch (187.5 mils lost and 62.5 mils remain)
- For general corrosion the area shall be repaired (metal repair) when metal loss is 1/8 inch (125 mils lost and 125 mils remain)

- Suppression pool columns recoating criteria is a loss of 60 mils

During the audit, the staff reviewed suppression pool liner plate corrosion records and found that adjacent plate panels had a variation in thickness of up to 50 mils (20 percent) due to general corrosion.

Request

Provide:

1. The basis for the acceptance criteria used for corrosion of liner plate and suppression pool columns.

2. Acceptance criteria used for corrosion of downcomer piping and its basis.

3. The reason for the apparent discrepancy between the acceptance criteria identified in Commitment 30, LGS procedure MA-LG-793-001, and the one used for disposition of AR01063631.

4. Confirm that the acceptance criteria delineated in the implementing procedure MA-LG-793-001 and the one used to disposition AR01063631 was established considering the effect of a variation in plate thickness between two adjacent panels on the liner plate anchors, and is consistent with original design basis that was based on Section 3.3 of the Bechtel Topical Report BC-TOP-1, Revision 1 which states, "In the analysis, a panel with outward curvature which is +16% over nominal thickness will be considered adjacent to a plate with inward curvature of nominal thickness. The preceding condition is highly improbable and therefore, it is not necessary to consider a case of plate which is -4% under the nominal thickness."

5. Reasons for not following the recommendations of the GALL Report and ASME Section XI, Subsection IWE requirements for augmented examinations (Examination Category E-C) of the containment surfaces subject to degradation in accordance with IWE-1240 for areas with material loss in excess of 10 percent of the nominal containment wall thickness.

Exelon Response

This response addresses the acceptance criteria used for inspections of the suppression pool liner plate, suppression pool downcomers and columns, and their basis. Discussion items (a) through (d) below provide background information that will be referred to in the response to the Request questions 1 through 5.

(a) The liner plate is an ASME Section XI, Subsection IWE component. The acceptance criterion used for inspections of the above-water portion of the suppression pool liner is 62.5 mils. This criterion is incorporated in an implementing procedure used during containment ISI inspections and is a threshold for examiners beyond which documented indications shall be reported to Engineering for evaluation and disposition. The technical basis of this owner-established visual examination acceptance criterion is the original construction specification for the primary containment liners which permitted surface defects of less than or equal to 62.5 mils.

(b) The acceptance criterion used for inspections of the submerged portion of the suppression pool liner for general corrosion is less than or equal to 0.125 inch metal loss. In addition, spot corrosion less than or equal to 2.5 inches in diameter may be 0.1875 inches in depth. The specification and analysis contain acceptance criteria which consider variations in plate thickness due to corrosion in the submerged portion of the suppression pool liner plate. The acceptance criteria vary based on the size of corrosion sites and the surrounding wall thickness. The analysis and specification contain figures providing allowable corrosion criteria based on varying defect diameter as well as varying surrounding thickness. These values are owner-established visual examination criteria (per IWE 3510.2) contained within an engineering specification and are based upon design analysis developed in accordance with IWE 3500. The specification and design analysis are based on the reinforcement rules in Section III of the ASME Code. The acceptance criteria for the original design of the liner were: (i) strain in the liner should be less than 0.005 inch per inch; (ii) liner should not buckle under negative pressure; and (iii) the load carrying capacity of the anchorage should be adequate.

The analysis specifically considers strain and buckling under negative pressure loading. The maximum strain developed in the vertical wall of the liner is controlling, and hence is the more limiting condition. The strains are conservatively assumed to change inversely proportional to the thickness of the liner. The model used for buckling of the liner and anchorage system is the same as that used in the original containment design. The minimum thickness based on strain is 0.12 inches; however, a minimum wall thickness of 0.125 inches is used in the analysis. Spot corrosion criteria are developed using the "Limits of Reinforcement" in Paragraph NE-3334 of the ASME Code.

This design analysis was evaluated in the February 20, 2008, NRC Safety Evaluation Report (SER) associated with extension of the test interval for the Type A containment integrated leak rate tests. As stated in the SER, the acceptance criteria are based on allowable strain levels rather than on stress levels, since the liner is not relied upon to resist loads but must be able to withstand the strains experienced by the concrete. Also, the SER states that the acceptance criteria are established "in a manner consistent with the original design basis and industry standards."

(c) The downcomers are ASME Section XI, Subsection IWE components. The downcomers are designed and constructed consistent with ASME Section III, Subsection B, but are not ASME stamped components. The acceptance criterion is less than or equal to 60 mils metal loss. This value is consistent with the 62.5 mils metal loss acceptance criterion used for the above-water portion of the Suppression Pool liner. The technical basis of this owner-established criterion are the design analyses for the downcomers which considered loads including stresses from internal pressure, stresses from external pressure, and stress and fatigue as the result of cyclic loading from seismic events, safety-relief valve discharges, condensation oscillation and chugging. The internal pressure and fatigue analyses were performed consistent with ASME Section III requirements while the analysis for external pressure was performed consistent with ASME Section VIII, Division 2, requirements. These analyses conclude that surface defects of less than or equal to 0.0625 inches are acceptable to meet design requirements.

(d) The suppression pool columns are IWF Class MC supports. The acceptance criterion is incorporated in the inspection procedure and is based on IWF-3410 which states that "roughness or general corrosion which does not reduce the load bearing capacity of the support is a non-relevant condition." The original construction specification permitted surface defects of less than or equal to 0.0625 inch.

The following responses address each of the five requests of this RAI:

1. The bases for the acceptance criteria used for visual examination of the above-water and submerged portions of the suppression pool liner plate, and for the suppression pool columns, are as described in (a), (b), and (d) above. The implementing procedure for column examination states that localized corrosion, which visibly reduces the cross-sectional area of the component, is unacceptable. As discussed in AR01063631, minimal general corrosion and spot corrosion (affecting less than 1.5% of the cumulative surface area inspected) was identified on the 12 Unit 1 columns examined. General loss of material was reported at less than 20 mils, and no localized corrosion exceeding 60 mils was identified. The small areas of minimal general corrosion identified on the 1.25-inch thick columns do not affect load bearing capacity or visibly reduce the cross sectional area, and are therefore acceptable.

2. The acceptance criterion used for the initial visual examination of the Unit 1 downcomers in the 1R13 outage, as reported in AR 1063631, is less than or equal to 60 mils as described in (c) above. The corrosion found on the downcomers during 1R13 outage affected less than 13% of the cumulative surface area examined. Loss of metal in the exposed substrate was generally less than 15 mils.

3. LRA Appendix A, Table A.5, Commitment 30 does not address liner acceptance criteria, but instead addresses an enhancement for managing the suppression pool liner and coating system. The enhancement incorporates new action level criteria for spot recoating and local recoating activities. Procedure MA-LG-793-001 does not address the submerged portions of the suppression pool. The conditions identified in AR01063631 were accepted based on the acceptance criteria for submerged portions of the suppression pool contained in the engineering specification, as described in (b) above.

4. Section 3.0 of BC-TOP-1, "Factors Affecting the Liner Plate and Anchorage System", does not address or apply to corrosion. The discussion in Section 3.0 addresses the effects of curvature, anchor spacing, and variation in plate thickness on loading of the anchor system. Section 3.3 addresses the expected thickness variations associated with standard rolling tolerances during fabrication and erection of the liner plate. For a plate which is 4% under the theoretical thickness, the lower plate stiffness would create a slight increase in loading on the anchor. A plate which is thicker is advantageous – as long as the excess thickness is constant throughout a large area – since a panel with inward curvature would be stiffer resulting in decreased anchor loads. For these reasons, the BC-TOP-1 analysis considers a panel with outward curvature which is 16% over the nominal thickness, and adjacent to a plate with inward curvature of nominal thickness. The LGS implementing procedures and specifications do contain acceptance criteria which consider variations in plate thickness due to corrosion in the submerged portion of the suppression pool liner plate as discussed in (b) above.

   LGS summary records from suppression pool submerged area inspections in 2004 and 2006 for Unit 1 and in 2009 for Unit 2 reviewed during the license renewal audit, contain no instances of 50 mils average metal loss due to general corrosion. The greatest loss of material due to general corrosion for Unit 1 floor plates was an average of 32.5 mils on plate 1-FP-01B-2 affecting 0.48% of the plate area. The greatest loss of material due to general corrosion for Unit 2 floor plates was an average of 35 mils on plate 2-FP-07D-4 affecting 5.54% of the plate area. The conditions identified in AR01063631 were accepted based on the acceptance criteria for submerged portions of the suppression pool contained in the engineering specification, as described in (b) above.

5. The GALL does not recommend augmented examinations (Examination Category E-C) of areas with material loss in excess of 10 percent of the nominal containment wall thickness. ASME Section XI, Subsection IWE, specifically IWE-1240, also does not recommend augmented examinations (Examination Category E-C) of areas with material loss in excess of 10 percent of the nominal containment wall thickness. To accept a component for continued service by examination in accordance with IWE-3122.1, the acceptance standards of IWE-3500 must be met. No mention is made in these paragraphs of a 10% wall loss criterion. For E-A examinations, the examinations must meet the standards of IWE-3510.1 and IWE-3510.2, which indicate the Owner shall define the acceptance criteria. In the past, augmented examinations (Examination Category E-C) would be required if the criteria in (b) above were exceeded. LGS currently utilizes criteria for Augmented Inspections (ASME Section XI, Subsection Examination Category E-C) which are consistent with action levels for spot and local recoating in the engineering specification. Criteria for augmented inspections which are aligned with the coating action levels from LRA Appendix A, Table A.5, Commitment 30 will be implemented starting in 2012, well in advance of the PEO, and are intended to avoid significant material loss in the submerged portions of the suppression pool liner.

   Metallic shells of concrete containments such as those at LGS are able to withstand greater than a 10% loss and satisfy the requirements of the original design specifications and construction code. As stated in (b) above, a design analysis demonstrates that the carbon steel suppression pool liner is twice the necessary thickness.

RAI B.2.1.30-3

Background

GALL Report AMP XI.S1, ASME Section XI, Subsection IWE recommends that containment coatings shall be monitored and maintained in accordance with GALL Report AMP XI.S8.

Issue

1. LGS Specification NE-101, Revision 5, “Specification for Coating and Liner Inspection and Coating Repair of Suppression Chambers at Limerick Generating Station Units 1 and 2,” requires that a floor or wall steel plate or downcomer in the suppression chamber with a loss coating greater than 25 percent of the surface area to be classified as ASME Section IWE, Category E-C, “Containment Surfaces Requiring Augmented Inspection.”

2. The staff review of AR 01063631 during the audit identified extensive general and pitting corrosion of the suppression pool liner plate, downcomers, and columns. This included the following:

   - General corrosion and spot corrosion was recorded on about 13 percent of the cumulative surface area of the 87 downcomers. Seventy-five percent of the underwater coating of one downcomer (number 79) was missing.

- One column had no coating in an area of 42" x 36".
- Four of the 44 floor panels and 2 of the 30 wall panels experienced a loss of greater than 30 percent of the protective coating. One floor panel had a loss of seventy two percent of the underwater coating.

All of these conditions were found to be acceptable in AR 01063631.

3. The carbon steel suppression pools of the LGS containments were coated with zinc primer. The zinc coating was applied to the suppression pool about 30 years ago. Recent operating experience has shown that zinc coatings have a limited lifetime and may not be effective during the period of extended operation if not reapplied.

<u>Request</u>

Explain the following:

1. The basis for accepting the degradation due to corrosion of the suppression pool components as documented in AR 01063631.

2. Basis for using 25 percent loss of coating as a criterion to classify the affected area as ASME Section IWE, Category E-C that require augmented inspection.

3. Reasons for not recoating the entire suppression pool and drywell liner plate, and associated components to manage the aging of the containment during the period of extended operation.

<u>Exelon Response</u>

1. AR Number 01063631 evaluated the results of the inspections performed during 1R13 on the suppression pool liner, downcomers, and columns. The evaluation concluded that none of the conditions identified were outside of the acceptance criteria. The basis for this acceptance criteria is provided in Exelon response to RAI B.2.1.30-2.

2. IWE-1241 includes examples of surface areas requiring augmented examination. IWE-3510 states that the owner shall define acceptance criteria. Exelon has defined the acceptance criteria as greater than 25% coating loss. The greater than 25% coating loss criterion will be implemented as part of LRA Appendix A, Table A.5, Commitment 30. Floor and wall panels exhibiting coating loss greater than 25% will be recoated as part of this new commitment. The value of 25% was selected based on LGS-specific experience and current material condition, and is a reasonable criterion upon which to minimize loss of material. This approach provides for the systematic restoration of the coating on the plates such that no submerged floor or wall panel will have coating depletion in excess of 25% when entering the period of extended operation. LRA Appendix A, Table A.5, Commitment 30 also includes requirements for local area and spot recoating to arrest general corrosion and pitting corrosion when the criteria for a total plate recoat is not met (less than or equal to 25% coating loss).

3. Recoating of the entire suppression pool liner (all at once or in the near future) is not warranted because of the available thickness margin in the containment liner, and as discussed in Exelon response to RAI B.2.1.30-4, excellent water chemistry control and low

overall corrosion rate. LRA Appendix A, Table A.5, Commitment 30 will provide for a systematic re-coating, starting well in advance of the period of extended operation to avoid significant material loss. As discussed in Exelon response to RAI B.2.1.30-1, the Service Level I coating applied to the LGS suppression pool liner includes a license renewal intended function to "maintain adhesion" so as to not adversely affect the operability of ECCS by clogging the ECCS suction strainers. The Service Level I coating applied to the LGS suppression pool liner does not include a license renewal intended function to prevent the loss of material due to corrosion. The inspection of the suppression pool liner coating is performed to ensure that the coating continues to "maintain adhesion" and function as a preventive measure to corrosion.

LRA Appendix A, Table A.5, Commitment 30 is intended to manage the submerged portion of the suppression pool liner through inspections and through the maintenance of coating. This commitment provides for the systematic restoration of the coating on floor and wall panels such that no submerged panel will have coating depletion in excess of 25% when entering the period of extended operation. The commitment also includes requirements for local area and spot recoating to arrest general corrosion and pitting corrosion when the criteria for a total plate recoat is not met. These activities, in addition to suppression pool desludging and more frequent IWE examinations ensure that sufficient thickness margin of the suppression pool liner will be maintained through the period of extended operation.

The drywell liner uses an epoxy coating system, is subject to a less aggressive environment than the submerged regions of the suppression pool, and is currently in good condition on both LGS units. The Unit 1 coating was most recently found to have two small areas of degraded coating (14 inch uncoated square above the personal air lock and a small area around 4 bolts in the bioshield) and is scheduled to be addressed in 2012; the Unit 2 coating was found to have no areas of degraded coating. The drywell coating is not part of LRA Appendix A, Table A.5, Commitment 30.

RAI B.2.1.30-4

Background

GALL Report AMP XI.S1, element 5, “monitoring and trending,” recommends developing a corrosion rate for containment liner plate and associated components that can be inferred from past ultrasonic testing (UT) examinations or establish a corrosion rate using representative samples in similar operating conditions, materials, and environments.

Issue

During the audit, the staff did not find any evidence that the applicant is trending the degradation of the containment drywell and suppression chambers, or has established a corrosion rate using UT examinations or by any other method.

Request

1. Provide trending details related to the thickness of the containment drywell and suppression chamber components that establish a corrosion rate and project the loss of thickness

through the end of the period of extended operation. Specifically, provide the trends in loss of thickness and corrosion rate for the suppression pool floor and wall panels, columns, downcomers, and reactor pedestal.

Exelon Response

1. The LGS Mark II containment, concrete with steel liner, is inspected in accordance with ASME Section XI. The applicable code for the current LGS ISI ten year inspection interval is ASME Section XI, 2001 Edition including 2003 Addenda. IWE 2420 states: “(a) the sequence of component examinations established during the first inspection interval shall be repeated during each successive inspection interval, to the extent practical. (b) When examination results require evaluation of flaws or areas of degradation in accordance with IWE-3000, and component is acceptable for continued service, the areas containing such flaws or areas of degradation shall be reexamined during the next inspection period listed in the schedule of the inspection program of IWE-2411 or IWE-2412, in accordance with Table IWE-2500-1, Examination Category E-C. (c) When the reexaminations required by IWE-2420(b) reveal that flaws or areas of degradation remain essentially unchanged for the next inspection period, these areas no longer require augmented examination in accordance with Table IWE-2500-1, Examination Category E-C."

   The LGS ASME Section XI, Subsection IWE program as described in LRA Section B.2.1.30 is consistent with GALL Report AMP XI.S1 and ASME Section XI requirements for monitoring and trending. The corrosion of the submerged portion of the suppression pool liner is being trended by the establishment of several corrosion evaluation grids for each unit. Inspections of these areas were performed during outages in 1996 and 2004 for Unit 1 and 1995, 1997, and 2009 for Unit 2. These results are also applicable to the submerged portions of the suppression pool support columns, downcomers, and reactor pedestal that are fabricated of carbon steel. The data obtained from these inspections suggests that the liner metal with no coating is experiencing an average general corrosion rate of approximately 1 to 2 mils per year. This data was obtained during underwater suppression pool liner inspections using depth gauges, including compensation for remaining coating thickness on surfaces adjoining the grid areas with material loss. An evaluation has been performed to determine the corrosion rate for uncoated carbon steel components in the suppression pool for the LGS specific suppression pool water chemistry and operating temperature and concludes that a general corrosion rate of approximately 1.8 mils per year is expected for LGS. The inspection data for the corrosion evaluation grids compares well with the predicted general corrosion rate as the result of the good water chemistry that is maintained in the suppression pool. The expected general corrosion rate, if applied to uncoated steel areas for 60 years, will result in a containment liner thickness that meets the liner engineering acceptance criteria for structural integrity. The inspection plan will continue to verify this corrosion rate is applicable to the LGS containment components submerged in the suppression pool. The evaluation concludes that the recoat criteria described below are adequate to manage the aging affects for the suppression pool liner and maintain sufficient thickness margin.

   LRA Appendix A.5, Commitment 30, for the ASME Section XI, Subsection IWE program includes performing an ASME IWE examination of the submerged portion of the suppression pool each Inservice Inspection (ISI) period. The results from these inspections will be used to implement a coating maintenance plan that requires the recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss, spot recoating of pitting greater than 50 mils deep, and recoating of plates with greater than 25 percent coating depletion as discussed in Exelon response to RAI B.2.1.30-1. These recoat criteria have been established to ensure that sufficient thickness margin of the suppression pool liner will be maintained through the period of extended operation.

The drywell liner uses an epoxy coating system and is normally exposed to an inerted environment. No corrosion or wall thinning is expected. As described in LRA Section B.2.1.30, the ASME Section XI, Subsection IWE program provides for periodic inspections for the presence of age related degradation and repairs are made in accordance with Examination Category E-C.

The suppression pool support columns are addressed for aging management in the ASME Section XI, Subsection IWF program as described in LRA Section B.2.1.32. Additional information is provided in Exelon response to RAI B.2.1.30-2. The reactor pedestal is addressed for aging management in the ASME XI, Subsection IWL program as discussed in LRA Section B.2.1.31. These components are made of the same materials and exposed to the same environmental conditions as the containment liner and downcomers and are expected to experience a corrosion rate similar to the containment liner uncoated steel.

GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE", element 5, "Monitoring and Trending", specifically describes the requirements to develop a corrosion rate and projection of wall thickness loss through the extended period of operation as being applicable only to the BWR Mark I containment design. This is appropriate for a Mark I containment design where the steel containment wall - not backed by a concrete structure - is required to perform the containment function. LGS utilizes a Mark II concrete containment design with a steel liner. Nevertheless, the corrosion rate (from two sets of LGS inspection data on certain control grids) shows a value of 1 to 2 mils per year and a corrosion evaluation for carbon steel under the conditions of the LGS suppression pool water chemistry and temperature indicates a value of 1.8 mils per year. A corrosion rate is more critical for longer periods where inspections or re-coating are not being regularly performed. However, LRA Appendix A.5, Commitment 30, will be performed starting in 2012, twelve years (six operating cycles) prior to PEO, and will also be performed throughout the PEO. Therefore, rather than project the loss of thickness through the end of the period of extended operation, LGS will continue to verify that the expected uncoated steel corrosion rate supports the inspection and coating maintenance plan to avoid significant material loss.

RAI B.2.1.30-5

Background

The GALL Report recommends non-coated surfaces to be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities.

Issue

During the audit, the staff reviewed the ASME IWE (Class MC) Containment Visual Examination NDE Report for different components, including one for the drywell closure head (IWE-20S199-DWH). This report had photographs of the different attachments to the drywell closure head that show extensive corrosion and pitting. However, the examination report found that the condition is acceptable by visual examination.

Request

Explain the basis for acceptance of extensive corrosion and pitting on the different attachments to the drywell closure head (IWE-20S199-DWH). The response should include any records of measurement of loss in thickness due to general and pitting corrosion, and any trends in the loss of thickness to demonstrate that the effects of aging will be adequately managed during the period of extended operation.

Exelon Response

The pictures of the Unit 2 drywell head (IWE-20S199-DWH) included with the Examination Report of this component for the April 2011 outage depict surface corrosion on the ends of a steel support angle and channel support for a ladder and platform that are attachments to the drywell closure head. Corrosion is also evident on the attachment points of these supports to the bolt ring and lifting lug plate on the drywell head. No pitting is depicted in the photograph and none was noted by the examiner. The implementing procedure acceptance criterion for the drywell head states that localized areas of corrosion shall not exceed 0.050 inches. This surface corrosion was determined to be within the acceptance criterion by the examiner as no loss of thickness or pitting was noted. Although the surface corrosion of the ladder and platform supports and their attachment points on the drywell head are acceptable, this condition had been had been entered into the Corrective Action Program for follow up.

RAI B.2.1.31-1

Background

GALL Report AMP XI.S2, ASME Section XI, Subsection IWL, program element 6, “acceptance criteria,” refers to American Concrete Institute (ACI) 349.3R for identification of concrete degradation. Chapter 5, “evaluation criteria,” of ACI 349.3R states that “The application of first-tier evaluation criteria can be overly conservative for massive concrete structures, structures not exposed to certain degradation mechanisms, or structures possessing concrete cover in excess of the minimum requirements of ACI 349, Chapter 7, such as concrete tank foundations, retaining walls, and concrete containment structures.”

Chapter 7.7 of ACI 349, “Code Requirements for Nuclear Safety-Related Concrete Structures,” lists the minimum requirement for concrete protection cover for reinforcement for No. 18 bars as 1.5 inch. LGS Plant drawings: C-866, Revision 5, “Reactor Building Units 1 & 2 Primary Containment Drywell Wall Sections & Detail,” and C-250, Revision 8, “Reactor Building Units 1 & 2 Primary Containment Suppression Pool Wall – Sections,” shows the minimum reinforcement cover as 2.0 inches from the center of 6X6X6/6 Welded-Wire-Fabric.

Issue

The program basis document states that, “Criteria based on the ACI 349.3R-02 Chapter 5 second tier has been used consistent with the following Chapter 5 statements and provisions: ‘The application of first-tier evaluation criteria can be overly conservative for massive concrete structures, structures not exposed to certain degradation mechanisms, or structures possessing concrete cover in excess of the minimum requirements of ACI 349 Chapter 7, such as concrete tank foundations, retaining walls, and concrete containment structures. For these types of structures, it is acceptable to compare the observed conditions with the second-tier evaluation criteria parameters’.”

The difference of ½ inch in reinforcement cover from the ACI code requirement to construction application can be considered as the construction-tolerance. Therefore, the code requirement of ACI 349.3R-02 in Chapter 5 “…..structures possessing concrete cover in excess of the minimum requirements of ACI 349, Chapter 7….” may not be satisfied.

Request

Provide justification for not using first-tier evaluation criteria for containment degradation per the requirements of Chapter 5.1 of ACI 349.3R-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.”

Exelon Response

LGS meets the recommendations of the ACI 349.3R-02 Chapter 5 for use of the second tier criteria because the 6 foot 2 inch thick conventionally reinforced concrete walls of the Primary Containment constitute massive concrete. Further, the Reactor Enclosure encloses the Primary Containment, and protects the Primary Containment from degradation mechanisms. The environment within the Reactor Enclosure is indoor air; therefore, the Primary Containment structures are not exposed to degradation mechanisms, which would be applicable to an outdoor air or seacoast environment, including abrasion and erosion, chemical attack, thermal exposure, fatigue, freezing and thawing, irradiation, and leaching as described in ACI 349.3R-02. In addition, the specified minimum concrete cover is 2 inches which is in excess of the minimum concrete cover specified in ACI 349. A tolerance of minus one-half inch is applicable to both the 2-inch cover and the minimum cover specified in ACI 349. Given that all three factors in ACI 349.3R-02, Chapter 5 are met, the application of the second tier criteria is justified for the purpose of evaluation of observed conditions of the LGS Primary Containment. Usage of first tier criteria is not justified for this structure and would provide no benefit given the design. The use of second tier criteria in ACI 349.3R-02, Chapter 5 is also not limited to only those structures possessing concrete cover substantially in excess of the minimum requirements of ACI 349, chapter 7.

RAI B.2.1.31-2

Background

GALL Report AMP XI.S2, ASME Section XI, Subsection IWL, program element 6, “acceptance criteria,” rely on the determination of the “Responsible Engineer” as defined by the ASME Code. Specifically, IWL-2320 states that, “The Responsible Engineer shall be a Registered Professional Engineer experienced in evaluating the conditions of structural concrete. The

Responsible Engineer shall have knowledge of the design and Construction Codes and other criteria used in design and construction of concrete containments in nuclear power plants.”

Issue

The applicant’s procedures ER-AA-335-001, Revision 5, “Qualification and Certification of Non-Destructive Examination (NDE) Personnel,” and Section 3.3.1 of ER-AA-335-018, Revision 5, do not clearly define the qualification requirements of the Responsible Engineer.

Request

Please clarify if the Responsible Engineer will be qualified in accordance with the requirements of ASME Code, Section IWL-2320.

Exelon Response

ER-AA-330, Rev. 9 "Conduct of Inservice Inspection Activities" defines a Responsible Engineer as "A Registered Professional Engineer as defined in ASME Section XI Subsection IWL experienced in evaluating the inservice condition of structural concrete. The Responsible Engineer shall have knowledge of the design and construction codes and other criteria used in the design and construction of concrete containment structures in nuclear power plants." This definition is in accordance with the requirements of ASME Code, Section IWL-2320, and ER-AA-330 governs conduct of all ASME Section XI inservice inspection activities, and is an implementing procedure for GALL Report AMP XI.S2, ASME Section XI, Subsection IWL.

RAI B.2.1.31-3

Background

GALL Report AMP XI.S2, ASME Section XI, Subsection IWL, program element 10, “operating experience,” states that “Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the period of extended operation.”

Issue

The applicant identified containment boundaries on a drawing in AR 00836350 for the ASME Code, Section XI, Subsection IWL and IWE programs (Drawing #: ISI-C-001, Revision 0 “Limerick Generating Station Units 1& 2”) by responding to an ISI Focus Area Self Assessment (FASA) Report. The ISI Boundary drawing included the ceiling of the suppression pool (Q-deck and diaphragm slab) as part of the IWL Program. The applicant responded to an Issue Report, AR 01048714, regarding the inspection results of the Q-deck installed at the bottom of the 3"-6" thick diaphragm slab. Even though the Q-deck and other abandoned steel structural members serve no structural purpose, the applicant’s discussion/evaluation included surface rust of Q-deck in the corrosion product inventory value used for sizing the Emergency Core Cooling Systems (ECCS) suction strainers. This condition was documented in GE CNF-10-001 inspection report. The staff is concerned that the degradation of the Q deck and abandoned steel structural members may impact ECCS through the period of extended operation.

Request

1. Identify the effects of Q-deck degradation on the concrete diaphragm slab, including potential degradation of rebars.

2. Discuss how the corrosion from the Q-deck and other abandoned steel structures attached to the ceiling of the suppression pool would impact the corrosion-product inventory in the suppression pool and the operation of the current ECCS suction strainers through the period of extended operation.

Exelon Response

1. As stated in Exelon response to RAI 2.1-7 transmitted via Exelon letter dated January 27, 2012, the Q-deck, which is also known as metal decking as well as the abandoned steel on the underside of the concrete diaphragm slab, is included within the scope of license renewal and subject to aging management using the Structures Monitoring aging management program. Engineering evaluated the condition of the Q-deck in Corrective Action Program issue report AR 01048714, and stated that the surface corrosion noted was acceptable. The engineering technical evaluation also stated the surface corrosion of the Q-deck has no effect on the structural integrity concrete diaphragm slab which includes the reinforcing steel (rebars) embedded in the concrete. The reinforcing steel is embedded in the concrete and raised above the metal decking such that concrete separates the reinforcing steel from the surface of the metal decking. The shear studs embedded in the concrete are not attached to the metal decking but rather are attached to the structural steel beams which are within the scope of license renewal and subject to the Structures Monitoring aging management program. Therefore the corrosion noted on the metal decking (Q-deck) will have no effect on the concrete diaphragm slab and reinforcing steel (rebars).

2. The engineering technical evaluation included with AR 01048714, addressed the potential of corrosion particles from the Q-deck and abandoned steel and concluded that the corrosion is bounded by the corrosion product inventory allowance for the ECCS suction strainers. The suppression pool floor and ECCS suction strainers are periodically inspected for sludge and foreign material accumulation. LRA Appendix A.5, Commitment 30 also requires removal of any accumulated sludge from the suppression pool every refueling outage. Therefore, there is no impact on the corrosion product inventory allowance and no impact on the operation of the ECCS suction strainers through the period of extended operation.

RAI B.2.1.32-1

Background

GALL Report AMP XI.S3 states that ASME Code-class MC component supports should be managed for aging using the ASME Section XI, Subsection IWF code. The license renewal application and program basis document state that the ASME Section XI, Subsection IWF program includes ASME Code-class MC component supports.

Issue

The staff reviewed the implementing procedures for the Inservice Inspection, IWF program and noted that the procedure specifically states that examination of ASME Code-classified MC supports is not required at LGS. The staff also noted that LGS has components that are classified as ASME Code-class MC.

Request

Explain how the identified class MC components will be managed for aging during the period of extended operation.

Exelon Response

Exelon procedures have been revised to clarify that ASME Code-classified MC supports are visually inspected in accordance with the ASME Section XI, Subsection IWF aging management program. ASME Section XI, Subsection IWF program is implemented in accordance with the GALL Report AMP XI.S3 aging management program.

RAI B.2.1.32-2

Background

GALL Report AMP XI.S3 program element 2, “preventive actions,” states that if ASTM A325, ASTM F1852, and/or ASTM A490 bolts are used, the preventive actions as discussed in Section 2 of the Research Council for Structural Connections “Specification for Structural Joints Using ASTM A325 or ASTM A490 Bolts” should be followed.

Issue

The staff noted that element 2 of the aging management program basis document states that structural bolting used in ASME Section XI, Subsection IWF supports does not include ASTM A325, ASTM F1852 or ASTM A490 bolts. Element 3 of the program basis document states that, “while the use of high strength bolts in supports is not common at LGS, A490 bolts are used for some larger supports.” It is not clear to the staff whether the applicant uses ASTM A490 bolts, and if so, whether the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts” are followed.

Request

If ASTM A325, ASTM F1852, and/or ASTM A490 bolts are used, explain how the preventive actions discussed in Section 2 of “Specification for Structural Joints Using ASTM A325 or A490 Bolts” are addressed, or why they are unnecessary.

Exelon Response

The structural bolting for IWF supports does not include the use of ASTM A325, ASTM F1852 or ASTM A490 bolts at LGS. Therefore, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts” is not required for the ASME Section XI, Subsection IWF bolting materials used at LGS. Element 3 of the program basis document will be revised to state that the structural bolting for IWF supports does not include the use of ASTM A325, ASTM F1852 or ASTM A490 bolts.

RAI B.2.1.32-3

Background

GALL Report AMP XI.S3 program element 5, “monitoring and trending,” states that examinations of component supports that reveal indications which exceed the acceptance standards and require corrective measures are extended to include additional examinations in accordance with ASME Code Section IWF-2430.

Issue

Upon review of plant-specific operating experience, the staff noted several cases in which conditions were found during ASME Code, Section IWF, examinations that appeared to be degraded. The applicant performed an engineering evaluation and determined that the as-found component was acceptable for continued service (i.e., did not violate the acceptance standards of ASME Code Section IWF-3410) but chose to enter the component into its Corrective Action Program and re-work the component to as-new condition. Since the engineering evaluation determined that the as-found condition did not affect the support’s capability to perform its design function, the licensee did not apply ASME Sections IWF-2420 and IWF-2430 for successive or additional examinations.

The ASME Code, Section XI, Subsection IWF program requires the inspection of the same sample of the total population of component supports each inspection interval. The staff’s concern with respect to aging management is that if IWF supports that are part of the inspection sample are reworked to as-new condition, they are no longer typical of the other supports in the population. Subsequent ASME Code, Section XI, Subsection IWF interval inspections of the same sample would not represent the age-related degradation of the rest of the population.

Request

When corrective actions are not required per the ASME Code, Section IWF, acceptance criteria, but a support within the IWF inspection sample is repaired to as-new condition without an expansion if the ISI sample population size, describe how the ASME Code, Section XI, Subsection IWF Program will be effective in managing aging of similar/adjacent components that are not included in the ISI Program sample population.

Exelon Response

To the extent practical, the same supports selected for examination during the first inspection interval shall be examined during each successive inspection interval. When relevant conditions that exceed the Acceptance Standards defined in IWF-3400 are identified, applicable additional examination requirements of IWF-2430 are applied. LGS also meets the requirements of IWF-3120 (ISI Acceptance Methods).

When component support conditions are found to include minor age-related degradation that does not meet the threshold of "unacceptable for continued service" as defined in IWF-3400, an evaluation may be performed in accordance with the Corrective Action Program. LGS may choose to take actions on the subject component and will evaluate the need to substitute the support in subsequent inspections with a component that may be more representative of the general population. LGS will update the aging management program procedure to incorporate the above guidance, thus ensuring the ASME Section XI, Subsection IWF Program is effective in managing aging of similar/adjacent components that are not included in the ISI Program sample population.

RAI B.2.1.33-1

Background

Through the integrated leak rate test (ILRT) and local leak rate test (LLRT) testing and ASME Code Section XI, Subsection IWE visual examinations, LGS ensures that the structural integrity of the containment structure will be maintained to withstand the maximum calculated pressure in the event of a loss of coolant accident (LOCA). For the period of extended operation these tests as implemented through the 10 CFR Part 50, Appendix J Program also provide for the detection of age-related pressure boundary degradation for loss of material, loss of sealing/degradation of gaskets, leakage, and loss of bolt preload for valves and penetrations.

Pursuant to 10 CFR Part 50 the applicant, through exemptions (per 10 CFR 50.12) and exclusions (per 10 CFR 50.59), excluded certain structures and components (SCs) (valves and penetrations) from Appendix J testing. The GALL Report, however, in its “scope of program,” program element recommends that the scope of the containment LRT program include all containment boundary pressure-retaining components.

Issue

During the on-site audit the applicant identified and presented justification for a number of exemption(s)/exclusions for valves and penetrations from the 10 CFR Part 50, Appendix J testing. The applicant noted, however, that during the period of extended operation it intends to manage the aging effects for the exempted/excluded SSCs through other AMPs than the designated 10 CFR Part 50, Appendix J testing program. The staff indicated that the SRP-LR, specifies the acceptance criteria for 10 CFR 54.21, on the recommended review procedures for AMR items, and on whether or not these are consistent with the GALL Report recommendations. The AMR tables in Chapters II through VIII of the GALL Report provide guidelines for management of the pertinent aging effects.

Request

1. Identify all of the SCs (valves, penetrations, and other components) that have been exempted/excluded from the 10 CFR Part 50, Appendix J testing and the basis for their exemption/exclusion.

2. For those SCs (valves, penetrations, and other components) that have been exempted/excluded identify the selected AMPs to be used for managing aging effects during the period of extended operation.

Exelon Response

1. Systems, structures and components (SSCs) have been exempted or excluded from 10 CFR Part 50, Appendix J testing as discussed below. (*) indicates components are in both LGS Unit 1 and Unit 2.

   (a) The following are exempted from 10 CFR Part 50, Appendix J testing:

   - Traversing Incore Probe (TIP) System shear valves. These valves are the outboard isolation valves for containment penetrations 35C-G. Type C local leak rate testing of the shear valves (XV-*40A-E) is not practical because squib detonation is required for closure. This exemption to 10 CFR Part 50, Appendix J testing was approved by the NRC for LGS in Section 6.2.6.2 of NUREG-0991 and its Supplement 3.

   (b) As identified in LGS UFSAR Table 6.2-25, the following Unit 1 and Unit 2 penetrations are excluded from 10 CFR Part 50, Appendix J Type B penetration local leak rate testing:

   - Penetration Number 240. The isolation provisions for this line consist of a suppression pool water seal inboard isolation barrier, a blind flange outboard isolation barrier, and a closed system outside containment. The flange is not exposed to the primary containment atmosphere because the line terminates below the minimum water level of the suppression pool. Because the line will maintain a water seal following a LOCA, 10 CFR Part 50, Appendix J Type B testing is not required. This penetration is included in the Type A integrated leak rate test.

   (c) As identified in LGS UFSAR Table 6.2-25, the following valves are excluded from 10 CFR Part 50, Appendix J Type C primary containment isolation valve local leak rate testing:

   - Residual Heat Removal (RHR) System pump suction line outboard isolation valves MO-*F004A-D and PSV-*F030A-D (penetration number 203A-D)
   - RHR pump test line and containment cooling line outboard isolation valves MO-*25A,B (penetration number 204A,B)
   - Core Spray (CS) System pump suction line outboard isolation valves MO-*F001A-D (penetration number 206A-D)
   - CS pump test and flush line outboard isolation valves MO-*F015A,B (penetration number 207A,B)

- CS pump minimum recirculation line outboard isolation valve MO-*F031B (penetration number 208B)
- High Pressure Coolant Injection (HPCI) System pump suction line outboard isolation valve MO-*F042 (penetration number 209)
- HPCI turbine exhaust line outboard isolation valve MO-*F072 (penetration number 210)
- HPCI pump test and flush line outboard isolation valve MO-*F071 (penetration number 212)
- Reactor Core Isolation Cooling (RCIC) System pump suction line outboard isolation valve MO-*F031 (penetration number 214)
- RCIC turbine exhaust line outboard isolation valve MO-*F060 (penetration number 215)
- RCIC minimum flow line outboard isolation valve MO-*F019 (penetration number 216)
- RHR minimum recirculation line outboard isolation valves MO-*05A,B (penetration number 226A,B)
- CS pump minimum recirculation line outboard isolation valve MO-*F031A (penetration number 235)
- HPCI pump minimum recirculation line outboard isolation valve MO-*F012 (penetration number 236)
- RHR relief valve discharge line outboard isolation valves PSV-*06B and MO-*F104B (penetration number 238)
- RHR relief valve discharge line outboard isolation valves PSV-*06A and MO-*F103A (penetration number 239)

The isolation provisions for these penetrations consist of a suppression pool water seal inboard isolation barrier, at least one isolation valve outside containment, and a closed system outside containment. The isolation valve is not exposed to the primary containment atmosphere because the line terminates below the minimum water level of the suppression pool. The closed system is missile protected, seismic Category I, Quality group B, and designed to the temperature and pressure conditions that the system will encounter post-LOCA. Because these lines will maintain a water seal following a LOCA, 10 CFR Part 50, Appendix J Type C valve testing is not required. These penetrations are included in the Type A integrated leak rate test.

2. SSCs that have been exempted/excluded from 10 CFR Part 50, Appendix J testing are being managed for aging effects during the period of extended operation as discussed below.

   (a) Traversing Incore Probe (TIP) System shear valves XV-*40A-E are included in the LRA Table 3.3.2-25 Traversing Incore Probe System Summary of Aging Management Evaluation. These valves are managed internally by the Compressed Air Monitoring (B.2.1.15) program. Since these valves bodies are stainless steel, there are no external aging effects and an external surface aging management program is not required.

   (b) SSCs associated with Penetration Number 240 are included in the LRA Table 3.2.2-5 Residual Heat Removal System Summary of Aging Management Evaluation. These SSCs are managed as follows:

- Bolting - Bolting Integrity (B.2.1.11) program
- Piping, piping components, and piping elements - External Surfaces Monitoring of Mechanical Components (B.2.1.25), Water Chemistry (B.2.1.2), and One-Time Inspection (B.2.1.22) programs
- Valves - External Surfaces Monitoring of Mechanical Components (B.2.1.25), Water Chemistry (B.2.1.2), and One-Time Inspection (B.2.1.22) programs

(c) Valves excluded from Type C primary containment isolation valve local leak rate testing are included in LRA Table 3.2.2-5 for the RHR System, Table 3.2.2-2 for the CS System, Table 3.2.2-3 for the HPCI System, and Table 3.2.2-4 for the RCIC System. In all instances, these valves are managed by the External Surfaces Monitoring of Mechanical Components (B.2.1.25), Water Chemistry (B.2.1.2), and One-Time Inspection (B.2.1.22) programs.

RAI B.2.1.35-1

Background

Pursuant to 10 CFR 54.21(c)(1), a license renewal applicant is required to provide a list of Time-Limited Aging Analyses (TLAAs), as defined in 10 CFR 54.3. Calculations/analyses are required for certain structures within the scope of license renewal that are to consider the effects of aging that involve time-limited assumptions based on the proposed operating term. The TLAAs are to provide the basis for conclusions related to the capability of the structure to perform its intended function(s) as delineated in 10 CFR 54.4(b) and are contained by reference in the continuing license basis.

Operating experience associated with trending of prestressing forces involving post-tensioned concrete containment structures, as well as general civil engineering structures, indicates that prestressing tendons could lose their prestressing forces with time due to creep and shrinkage of concrete, and relaxation of the steel. If a prestressing tendon is ungrouted, the level of prestressing force can be monitored and trended by conduct of lift-off tests, and if larger-than-anticipated loss of prestressing force has occurred, the prestressing tendon can be retensioned to the desired prestressing force. The Limerick Generating Station Units 1 and 2 spent fuel pools have grouted tendon systems for which the level of prestressing forces neither can be monitored nor trended by conduct of lift-off tests, nor can the tendons be retensioned to the desired prestressing force.

Issue

The prestressed concrete girders that provide the main support for the Limerick Generating Station Units 1 and 2 spent fuel pools utilized grouted tendons. Since the tendons are grouted, conventional inspection procedures (e.g., lift-off tests to indicate the level of prestressing force) used to evaluate the structural integrity of ungrouted tendon systems cannot be utilized. The continued presence of elevated temperatures, creep and shrinkage of the concrete, and relaxation of the prestressing tendon steel could, through losses of prestressing force, produce increased deflections of the girders and have a negative effect on associated safety-related SCs. Increased deflections also can lead to cracking of the concrete that may impact the structural integrity of the prestressed girders (e.g., provide access for environments that may cause corrosion of the tendon steel) and the spent fuel pools.

Request

Provide a plant-specific TLAA or a plant-specific inspection/monitoring program to provide assurances that the capability of the prestressed concrete girders associated with the spent fuel pool will continue to meet their intended function(s) during the period of extended operation.

Exelon Response

The original design analysis for the fuel pool girders evaluated loss of prestress due to stress relaxation of the steel tendons and due to creep and shrinkage of the concrete. Since stress relaxation of the steel tendons is based upon a time-limited assumption, this analysis has been identified as a TLAA that requires evaluation for the period of extended operation. The TLAA was demonstrated to remain valid in accordance with 10 CFR 54.21(c)(1)(i) because the loss of prestress values used in the analysis are valid for over 60 years.

In addition, the fuel pool girders are included within the scope of the Structures Monitoring Program B.2.1.35. The girders are visually examined once every five years for signs of concrete cracking or other degradation. This program provides additional assurance that the fuel pool girders will continue to perform their intended function(s) during the period of extended operation.

Consistent with the above response, LRA Section 4.6.10, Fuel Pool Girder Loss of Prestress, and UFSAR Supplement, Section A.4.6.10, Fuel Pool Girder Loss of Prestress, are added, as shown in Enclosure B. Also, LRA Sections 3.5.2.1.13 and 3.5.2.3 and LRA Tables 3.5.2-13 and 4.1-2 are revised, as shown in Enclosure B.

RAI B.2.1.35-2

Background

GALL Report, AMP XI.S6, Structures Monitoring Program, element 10 recommends that the Structures Monitoring Program consider operating experience.

Issue

In AR 01198943 it is noted that the turbine building operating floor consists of the turbine pedestal and a concrete slab on steel beams in all other floor areas. The ends of the steel beams adjacent to the turbine pedestal are supported by concrete ledges of the turbine pedestal. The other ends of the beams are supported by steel girders. The beam seat assemblies supported by the turbine pedestal consist of sliding surface plates, backup plates, and elastomeric pads. A walk-down found that the beam ends supported by the turbine pedestal had settled approximately 0.5 inches as a result of deterioration/melting of the elastomeric pads. This condition was observed at almost all locations around the entire turbine pedestal expansion joint of both LGS Units 1 and 2. An extent of condition evaluation determined that the settlement at one end of the beam/slab does not affect the structural integrity of the turbine building operating floor and the structure can still perform its intended function of supporting loads from the operating floor.

Request

Provide the assessment demonstrating that the turbine building operating floor and structure can still perform its intended functions (e.g., supporting loads from the operating floor) and that the resulting change in alignment does not impact attachments or supports (e.g., pipe support anchor for the main steam line attached to a beam web does not induce stress into the pipe).

Exelon Response

The change in alignment of the turbine enclosure operating floor and structure was due to degraded elastomeric pads, included as part of the sliding bearing assemblies located below the turbine operating deck floor beams. The comparatively small change in alignment does not impair the ability of the turbine enclosure operating floor and structure to perform its intended functions (e. g., supporting loads from the operating floor). The alignment change also does not impact attachments or supports (e. g., pipe support anchor for the main turbine sealing steam line attached to a beam web). The degraded elastomeric pads were evaluated within LGS Corrective Action Program. A structural evaluation concluded that the degraded elastomeric pads and settlement at one end of the floor beams and slab did not affect the structural integrity of the turbine enclosure. An initial assessment of this condition was performed in Corrective Action Program issue report IR 01198943. A further assessment of this condition is as follows:

The end of the steel beams adjacent to the turbine pedestal remains supported by a concrete ledge of the turbine pedestal in the same manner as before except that the intervening urethane pad between the beam end bearing plates and the concrete ledge has degraded allowing the beam end to move one-half inch downward. The beams on the north side of the pedestal are 34 feet long while beams on the south side are 24 feet long.

The resulting rotational change in alignment of these beams due to the one half inch downward displacement at one end over the 24 or 34 feet beam length is insignificant and has no adverse structural effect. No specific damping capability was required or relied upon by the design specification or drawings for the elastomeric pad part of the sliding supports. The design calculation for the turbine enclosure states that it is impractical to design the bearings to dampen vibrations, and the calculation does not require or rely on vibration damping from these bearing assemblies. The operating concrete floor and beam structure and turbine pedestal possess inherent damping characteristics which are unaffected by the degraded elastomeric pad.

The turbine-generator units are supported on freestanding reinforced concrete pedestals. The turbine-generator pedestal is a massive reinforced concrete structure which is founded on rock at the same level as the basemat for the turbine enclosure. No adverse structural effects from vibration have been identified on the turbine-generator pedestal concrete or on the adjacent turbine operating floor and steel beams. No resonance, significant vibration, or visible distress has been reported for the turbine operating deck or floor beams. Both the turbine-generator pedestal concrete and the turbine enclosure concrete floors and steel beams are periodically monitored by the Structures Monitoring Program.

Initial piping assessment indicates that the change in alignment does induce some additional secondary stress into the 3-inch diameter main turbine steam seal leakoff piping. Given the inherent flexibility on the 3-inch piping, the effect of the settlement induces stress on the piping and supports and is currently considered to not induce significant additional stresses in the piping. A more extensive evaluation of piping and supports attached to the floor slab or beams is planned and tracked as a Corrective Action Program assignment. There is no impact on safety-related piping and supports in the turbine enclosure. The safety-related portion of main steam piping extends from the reactor enclosure wall penetration to the main turbine stop valves. This piping is supported from structural steel that is not affected by the displacement created by degraded elastomeric pads. The remainder of the main steam supply piping to the main turbine is large diameter piping designed with a support system to accommodate large thermal movements. The support system of the piping between the main turbine stop valves and main turbine is composed of variable supports with a comparatively large distance between supports such that the settlement of 0.5 inches at the end of the turbine pedestal has little impact on design loads and thermal displacements. The main turbine steam supply piping to the low pressure turbines is supported from the turbine pedestal such that loads on the low pressure turbine nozzles are unaffected by the degraded elastomeric pads.

Piping supported from the structural steel affected by the degraded elastomeric pads is conventional piping, i. e. nonsafety-related and nonseismic. The installation tolerances for these piping systems are greater than the maximum displacement due to the degraded pads. Although the displacement is the greatest at the end of the beams supported by the turbine pedestal, the displacement is reduced as a function of distance from the turbine pedestal. Therefore, no significant impact is expected on these piping systems. There have been no leaks or cracks in piping observed in the affected piping systems that are attributed to the alignment change associated with the elastomeric pad degradation.

RAI B.2.1.40-1

Background

GALL Report AMP XI.E3 recommends that periodic actions be taken to prevent inaccessible power cables from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes for water collection, and draining the water, as needed.

Issue

The program description and “preventive actions” program element of the program basis document, LG-AMP-PBD-XI.E3, LRA Appendix A, Section A.2.1.40, LRA Appendix B, Section B.2.1.40 and LRA, Appendix A, Table A.5, “License Renewal Commitment List,” Commitment No. 40 are not consistent in describing how the program will manage inaccessible power cables subject to significant moisture (e.g., at times exposed to significant moisture, minimize exposure and prevent exposing cables to significant moisture). It is not clear to the staff that these statements are consistent with the GALL Report AMP, because the LRA AMP including Sections B.2.1.40, A.2.1.40, and Table A.5, Commitment No. 40 describe the program as minimizing potential exposure to significant moisture.

Request

Verify that LRA AMP is consistent with the GALL Report and revise the program basis document, LG-AMP-PBD-XI.E3, LRA Sections B.2.1.40, A.2.1.40, and Table A.5, Commitment No. 40 to provide consistency with the GALL Report AMP in the program’s purpose to manage inaccessible power cable exposure to significant moisture, as necessary.

Exelon Response

The LGS Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that is consistent with GALL Report AMP XI.E3. The inaccessible power cables in the scope of this program may at times be exposed to significant moisture. These cables will be tested using a proven test for detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence. The Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program LRA sections A.2.1.40, B.2.1.40, and Table A.5 Commitment No. 40 are revised as shown in Enclosure B for A.2.1.40 and B.2.1.40 and as shown in Enclosure C for Table A.5 to clarify that periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. The program basis document will also be revised for this clarification.

RAI B.2.1.40-2

Background

GALL Report, Chapter VI, Table VIA, "Electrical Components - Equipment Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," item VI.A.LP-35 lists the material as various organic polymers and the aging effect/mechanism as reduced insulation resistance due to moisture and recommends managing the effects of aging with GALL Report AMP XI.E3.

Issue

The LRA uses the term "electrical continuity" in describing the intended function in LRA Table 2.5.2-1, for the commodity "Insulation Material for Electrical Cables and Connections." LRA Table 3.6.2-1 uses "electrical continuity" for the intended function for component types, "Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V," "Fuse Holders (Not Part of Active Equipment): Insulation Material," "Insulation Material for Electrical Cables and Connections," "Insulation Material for Electrical Cables and Connections Used in Instrumentation Circuits," and LRA Section 2.5.2.5.2, "Electrical Penetrations." In addition, component type, "Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements," in Table 3.6.2-1 lists the materials "Various Polymeric and Metallic Materials" and therefore should also include the intended function "Insulate (Electrical)." The use of the intended function, "electrical continuity" in the above examples is inconsistent with the material (various organic polymers) listed for the component types referenced.

Request

Clarify the intended function of the insulation material discussed. As necessary, provide revised intended functions for Table 2.5.2-1 Insulation Material for Electrical Cables and Connections and Table 3.6.2-1 component types (Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V, Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements, Fuse Holders (Not Part of Active Equipment)): Insulation Material, Insulation Materials for Electrical Cables and Connections, and Insulation Materials for Electrical Cables and Connections Used in Instrumentation Circuits.

Exelon Response

The intended function for insulation materials subject to aging management review is “Insulate (Electrical).” Section 2.5.2.5.2 of the LRA is revised to remove electrical continuity as the intended function of electrical penetrations. LRA Table 2.5.2-1 is revised to identify the intended function of Insulation Material for Electrical Cables and Connections as “Insulate (Electrical)” and to clarify the name for the fuse holder commodity to “Fuse Holders: Metallic Clamps.” LRA Table 3.6.2-1 is revised to change the intended functions for insulation material component types to “Insulate (Electrical).” The line item changes are for Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V, Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements made of various polymeric materials, Fuse Holders (Not Part of Active Equipment): Insulation Material, Insulation Materials for Electrical Cables and Connections, and Insulation Materials for Electrical Cables and Connections Used in Instrumentation Circuits.

Consistent with this response, LRA Section 2.5.2.5.2 and Tables 2.5.2-1 and 3.6.2-1 are revised as shown in Enclosure B.

RAI B.2.1.40-3

Background

Gall Report AMP XI.E3 recommends that inaccessible power cables which are exposed to significant moisture will be tested at a frequency of at least every 6 years and that test frequencies will be adjusted based on test results and operating experience.

Issue

Draft procedure MA-MA-716-009 specifies a test frequency of every third refueling outage. The “detection of aging effects” program element of the applicant’s AMP (LG-AMP-PBD-XI.E3) states that the testing will be performed every 6 years and does not include a provision that test frequencies are adjusted based on test results and operating experience. It is not clear to the staff that the applicant’s program, when implemented, will be consistent with the GALL Report AMP such that testing will occur at least every 6 years and more frequent testing will occur based on test results and operating experience. In addition, LRA Sections A.2.1.40, and B.2.1.40, and LRA, Appendix A, Table A.5, Commitment No. 40 specify a test interval of at least every 6 years but do not specify that test frequencies are adjusted based on test results and operating experience.

Request

Explain why the “detection of aging effects” program element in the program basis document LG-AMP-PBD-XI.E3 along with draft work order revisions specify only a 6 year test interval but do not specify a test frequency of at least every 6 years and that test frequencies are adjusted based on test results and operating experience. In addition, explain why LRA Sections A.2.1.40, and B.2.1.40, and LRA, Appendix A, Table A.5, Commitment No. 40 only specify a test interval of at least every 6 years but do not specify that test frequencies are adjusted based on test results and operating experience.

Exelon Response

The LGS Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program cable test frequency is stated in the "detection of aging effects" program element and work order revision requests as either a 6 year or every 3 refueling cycle test interval. This program, including implementing work orders, is subject to the Corrective Action Program, in accordance with the "corrective action" program element. Under the Corrective Action Program, unacceptable test results are subject to engineering evaluation. The evaluations will consider the significance of the test results when determining correction actions. One potential corrective action would be more frequent cable testing.

For clarity and alignment with the "detection of aging effects" program element, the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program LRA sections A.2.1.40, B.2.1.40, and Table A.5 Commitment No. 40 are revised as shown in Enclosure B for A.2.1.40 and B.2.1.40 and as shown in Enclosure C for Table A.5 to clarify a cable test frequency of at least every 6 years and that more frequent testing may occur based on test results and operating experience. The program basis document and the work order revision requests will also be revised for this clarification.

RAI B.2.1.40-4

Background

GALL Report AMP XI.E3, program element "preventive actions" recommends that inspections be performed periodically based on water accumulation over time and event driven occurrences, such as heavy rain or flooding.

Issue

The program basis document, LG-AMP-PBD-XI.E3, and LRA Appendix A, Section A.2.1.40, LRA Appendix B, Section B.2.1.40 and LRA, Appendix A, Table A.5, "License Renewal Commitment List," Commitment No. 40 are not consistent with GALL Report AMP XI.E3 in that event driven inspections are not specified to be performed after heavy rain or flooding events.

Request

Explain why the program basis document, LG-AMP-PBD-XI.E3, LRA Sections A.2.1.40, B.2.1.40 and LRA, Appendix A, Table A.5, Commitment No. 40 do not specify inspections will be performed following event driven occurrences.

Exelon Response

The LGS Inaccessible Power Cable Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program preventive actions are stated in the "preventive actions" program element and work order revision requests. The program element states that inspection frequency will be established, performed and adjusted based on plant specific operating experience, but does not state that inspection frequency for manholes will be established and performed based on water accumulation over time and event driven occurrences, such as heavy rain or flooding.

For clarity and alignment with the "preventive actions" program element, the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program LRA sections A.2.1.40, B.2.1.40, and Table A.5 Commitment No. 40 are revised as shown in Enclosure B for A.2.1.40 and B.2.1.40 and as shown in Enclosure C for Table A.5 to clarify that inspection frequency for manholes will be established and performed based on water accumulation over time and event driven occurrences, such as heavy rain or flooding. The program basis document will also be revised for this clarification.

RAI B.2.1.41-1

Background

In the program basis document, LG-AMP-PBD-XI.E4, Revision 1, under the "parameters monitored or inspected" program element, it states that this program element is consistent with the GALL Report AMP XI.E4. The GALL Report AMP recommends that a sample of accessible bolted connections be inspected for increased resistance using thermography. The program will be implemented via procedure M-092-002. This procedure requires bus joint nuts and bolts be retorqued. EPRI TR-104213s, "Bolted Joint Maintenance & Application Guide" states that bolted joints should be inspected for evidence of overheating, signs of burning or discoloration, and indications of loose bolts. The bolts should not be retorqued, unless the joint either requires service or the bolts are clearly loose. Verifying the torque is not recommended. The torque required to turn the fastener in the tightening direction (restart torque) is not a good indicator of the preload once the fastener is in service. Due to relaxation of the parts of the joint, the final loads are likely to be lower than the installed loads. In addition, the program basis document, as well as GALL Report AMP XI.E4, do not recommend to retorque.

Issue

The program implementation procedure is not consistent with the program basis document nor the EPRI recommendations. The program basis document does not reference retorqueing and the EPRI guidance states that bolts should not be retorqued and that the torque required to turn the fastener in the tightening direction (restart torque) is not a good indication of the preload once the fastener is in service.

Request

Provide technical justification of why retorqueing of bus connections are a good engineering practice to check for bolted loosening and clarify the discrepancy between the program basis document and the implementing procedure.

Exelon Response

Retorquing of metal enclosed bus, bolted bus connections is not part of the LGS Metal Enclosed Bus aging management program. The LGS program will perform thermography of a sample of accessible bolted connections, to inspect for increased resistance of bus connections. The LGS program will also perform visual inspections of metal enclosed bus internals, to inspect for debris or moisture intrusion and signs of age degradation. To implement the LGS Metal Enclosed Bus aging management program, existing maintenance procedures and work orders will be revised to specifically annotate included license renewal activities, acceptance criteria, and inspection frequency. These procedures also contain activities that are not part of the LGS

Metal Enclosed Bus aging management program. Drafted revisions to program implementing procedures and work orders do not include annotation of bus connection retorque for license renewal. A search of work order history revealed that LGS metal enclosed bus joint nuts and bolts have not been retorqued to date. This approach is consistent with the GALL Report AMP XI.E4.

The existing maintenance procedure and work order steps for torque checks do not apply to metal enclosed bus connections. Because bolted connection retorque has not been performed for metal enclosed bus connections and is not part of the LGS Metal Enclosed Bus aging management program, technical justification of retorqueing of bus connections is not provided. Additionally, because bolted connection retorque has not been performed for metal enclosed bus connections and is not part of the LGS Metal Enclosed Bus aging management program, there is no discrepancy between the program basis document and the drafted, annotated portions of the maintenance procedure and work orders that implement the LGS Metal Enclosed Bus aging management program.

RAI B.2.1.41-2

Background

In the program basis document, LG-AMP-PBD-XI.E4, Revision 1, under program element "detection of aging effects," it states that a sample of the metal enclosed bus (MEB) accessible bolted connections in each bus section shall be inspected using thermography for increased resistance. GALL Report AMP XI.E4 also recommends inspecting a sample of the accessible bolted connections for increased resistance using thermography or connection resistance measurements. The applicant provided the staff a photograph of thermography showing a heat source from a space heater inside a MEB. However, the applicant did not provide any photograph taken from outside the bus duct showing the temperature difference between the bus connection due to increased resistance.

Issue

The metal enclosed bus cover as well as space heater may mask the heat resulting from loose bus connections. The staff is concerned that temperature differences between bus connections may not be detected using thermography measurements.

Request

Discuss the plant-specific operating experience with thermography taken from outside a bus duct showing the bus connection temperature difference due to bolt loosening. In addition, discuss manufacturer's recommendation for inspecting bolted connections from outside a bus enclosure. Also explain how thermography inspection is effective in detecting MEB bolted connections for increased resistance.

Exelon Response

The Operating Experience (OE) for the in scope metal enclosed bus is documented in Appendix B, section B.2.1.41 of the LGS LRA and in the Metal Enclosed Bus program basis document, element 10, Operating Experience. There have been no failures of the in scope 4 kV metal enclosed bus at LGS. There is no adverse trend in the associated thermography inspection results for the in scope 4 kV metal enclosed bus at LGS. Routine maintenance results do not indicate a loosening of metal enclosed bus connections. Since there is not a thermography picture available of a loose bolted connection for LGS's metal enclosed bus, a picture of thermography showing a heat source from a space heater inside a metal enclosed bus was provided. This picture was provided to demonstrate the sensitivity of the thermography equipment to detect heat through the metal enclosure and the emissivity of the enclosure.

There are physical location differences between the bolted connections and the electric heaters. An electric heater is located within a segment of the enclosure, along the outside edge. In contrast, bolted bus connections are located where sections of the metal enclosed bus are joined together, both the bus and the enclosure. Therefore, electric heaters and bolted connections are not in the same physical location in the metal enclosed bus. The heat signature for an electric heater shows a pinpointed heat source with decreasing temperatures as distance from the center increases. The heat signature for resistance for a loose connection would be ring-like encircling the bolted connection for the bus bar. The heat signature for the electric heater would not mask nor be misinterpreted as a potential degraded connection.

Manufacturer's recommendations for testing include factory tests and post-installation tests to assure no damage from shipping or installation. Manufacturer's recommendations do not include inspecting bolted connections from outside a bus enclosure. An IEEE standard for metal enclosed bus, like manufacturer's recommendations, includes design tests, production tests and field tests. In service routine testing recommendations are provided in EPRI guidance for switchgear and bus maintenance and in EPRI guidance for infrared thermography. This guidance recommends implementing a predictive maintenance program for metal enclosed bus that includes thermal imaging. Thermal imaging relies on line of sight to the bus connection being monitored. Thermography instantly locates hot spots for further evaluation and repair. The standard identifies that there are no installation requirements directly associated with the use of thermography equipment. The standard also identifies that viewing windows in switchgear, may be valuable, if considered economical. There are no cited design installation requirements or thermography use requirements for metal enclosed bus, beyond line of sight. The thermography guidance document provides numerous examples of observable, elevated temperature conditions, detected by thermography taken through equipment enclosures.

The LGS themography procedure follows established industry practices for thermography. The GALL Report AMP XI.E5 and the SRP-LR associated AMP requirements do not present industry OE to counter existing standards and methodology. LGS specific thermography experience with metal enclosed bus electric heaters validates the viability of LGS practices. The current thermography inspection methodology is, and will continue to be, effective in detecting increased resistance of bolted connections.

RAI B.2.1.28-1

Background

The GALL Report AMP XI.M40 states that for neutron absorber materials, gamma irradiation and/or long-term exposure to the wet pool environment may cause loss of material and changes in dimension (such as gap formation, formation of blisters, pits and bulges) that could result in loss of neutron-absorbing capability of the material.

Issue

It appears that the Boral coupon trees in the LGS, Units 1 and 2, spent fuel pools are located in a 'representative' location rather than a 'bounding' location. That is, the coupon tree location is expected to receive a uniform gamma flux that is representative of typical rack exposure. The program is not clear on whether the coupon exposure to the environment is bounding for the Boral material in all racks.

Request

Please discuss how the coupon exposure (i.e., coupon tree location) will provide reasonable assurance that Boral degradation is identified prior to potential loss of neutron-absorbing capability of the material. If the coupon exposure to the environment is not bounding of the material in all racks, discuss how the aging effects of the Boral material will be managed for the unbounded racks.

Exelon Response

The LGS coupon exposure practice was established to meet the spent fuel rack manufacturer recommendations. The original recommendation from the rack manufacturer was to surround the coupon tree in each spent fuel pool by freshly discharged fuel assemblies following each of the first five operating cycles after rack installation. This would assure that the Boral in the coupons experiences a higher radiation dose than the Boral panels in the storage racks. Following the fifth accelerated exposure, the fuel assemblies surrounding the test coupon tree could remain in place for the remaining life of the racks.

This recommendation was initially implemented at LGS, but was discontinued based on an updated recommendation from the rack manufacturer. At the time the practice was discontinued, the coupons in the Unit 2 spent fuel racks had received two cycles of exposure to freshly discharged fuel. A rerack of the Unit 1 spent fuel pool was in progress, and the coupons in the Unit 1 spent fuel pool had not yet been subject to the accelerated exposure condition.

GALL Report AMP XI.M40, Element 4, recommends performing coupon testing and analysis to determine the condition of the spent fuel rack neutron absorbing material capacity and condition. Element 5 recommends that differences in exposure conditions be considered in implementing this program. In order for the condition of the coupons to accurately represent the condition of the Boral in the spent fuel racks, the coupons must be maintained in a bounding condition. The coupons must be exposed to a radiation dose that bounds or exceeds that of the Boral in the racks. Resuming the initial five-cycle accelerated coupon exposure configuration recommended by the rack manufacturer would place the coupons in a bounding condition. Following the five-cycle accelerated exposure sequence, the bounding condition must be maintained by verifying that that the exposure of individual rack cells does not exceed that of the coupons.

The Monitoring of Neutron-Absorbing Materials Other than Boraflex program is enhanced to:

- Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly discharged fuel assemblies) at each of five refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1).

- Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks.

These enhancements ensure that condition of the Boral in the coupons bounds the condition of the Boral in the spent fuel storage racks, which therefore ensures that degradation of the Boral in the spent fuel racks is identified prior to potential loss of neutron-absorbing capability of the material. The UFSAR Supplement LRA Section A.2.1.28 and LRA Section B.2.1.28 are revised as shown in Enclosure B to add these enhancements to the Monitoring of Neutron-Absorbing Materials Other than Boraflex program. In addition, LRA, Appendix A, Table A.5, commitment 28 is revised as shown in Enclosure C.

RAI B.2.1.37-1

Background

The GALL Report AMP XI.S8 recommends using ASTM D 5163, in as much as it defines the inspection frequency to be each refueling outage or during other major maintenance outages, as needed. Although this may be the case, the guidance document also states that the frequency of in-service coating inspection monitoring shall be determined by the licensee or his designee.

Issue

The ASME Section XI, Subsection IWE program described in LRA AMP B.2.1.30 will be enhanced to include inspection of 100 percent of the accessible coating in the immersed region of the suppression pool each ISI period. The applicant does not address inspection techniques or the frequency for inspection of the coating in the immersed region of the suppression pool in the Protective Coating Monitoring Maintenance Program.

Request

Please provide the inspection technique used, and frequency and scope of inspection for the Service Level I immersed coating in the suppression pool. In addition, discuss how the technique and frequency are consistent with GALL Report AMP XI.S8.

Exelon Response

Consistent with GALL Report AMP XI.S8 Element 4 and ASTM D 5163-08, paragraph 6.1, LGS has determined the inspection frequency of Service Level I immersed coating in the suppression pool and has aligned this inspection to the inspection frequency requirements of ASME Section XI, Subsection IWE for containment ISI. To date, the wetted surfaces of the suppression pool submerged areas (Table IWE-2500-1, Category E-A, Item E1.12) had a 100% inspection completed in each 10 year ASME interval. The B.2.1.30 ASME Section XI, Subsection IWE aging management program has been enhanced as described in LRA Appendix A, Table A.5, Commitment 30 to include inspection of 100% of the wetted surfaces of the suppression pool submerged areas each ISI inspection period.

Consistent with GALL Report AMP XI.S8 Element 4 and ASTM D 5163-08, paragraph 10.1, coating inspections will be by visual inspection techniques.

Enclosure B
LGS License Renewal Application Updates

Notes:

- Updated LRA Sections and Tables are provided in the same order as the RAI responses contained in Enclosure A.
- To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and strikethroughs for deleted text.
    - The only exception to this convention is within the response to **RAI B.2.1.35-1** because entirely new sections are provided; therefore for those new sections, text is not shown in bold/italicized font.

As a result of the response to RAI B.2.1.35-1, provided in Enclosure A of this letter, LRA Sections 3.5.2.1.13, Section 3.5.2.3, and Table 3.5.2-13 on pages 3.5-207 and 3.5-217, are revised to add an aging effect requiring management and identifies aging management via TLAA, and a Plant Specific Note as shown below:

3.5.2.1.13 Reactor Enclosure

Aging Effects Requiring Management

The following aging effects associated with the Reactor Enclosure components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Hardening and Loss of Strength
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Increased Hardness, Shrinkage and Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload
- ***Loss of Prestress***
- Loss of Sealing

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Enclosure components:

- Masonry Walls (B.2.1.34)
- Structures Monitoring (B.2.1.35)
- ***TLAA***
- Water Chemistry (B.2.1.2)

3.5.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with Structures and Component Supports.

- Section 4.5, Containment Liner and Penetrations Fatigue Analysis
- Section 4.6, Other Plant-Specific Time-Limited Aging Analyses
- Section 4.6.7, Refueling Bellows and Supports Cyclic Loading Analysis
- Section 4.6.8, Downcomers and MSRV Discharge Piping Fatigue Analyses
- ***Section 4.6.10, Fuel Pool Girder Loss of Prestress***

Table 3.5.2-13 Reactor Enclosure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Concrete: Foundation (inaccessible)	Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.35)	III.A1.TP-67	3.5.1-47	A
Concrete: Interior	Flood Barrier	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
	HELB/MELB Shielding	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
	Missile Barrier	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
	Shelter, Protection	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
	Shielding	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
	Structural Pressure Boundary	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.35)	III.A1.TP-26	3.5.1-66	A
				Loss of Prestress	***TLAA***			***H, 5***
Conduit	Shelter, Protection	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B2.TP-8	3.5.1-95	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.35)	III.B2.TP-6	3.5.1-93	C
			Concrete	None	None	II.B2.2.CP-114	3.5.1-41	C
	Structural Support	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B2.TP-8	3.5.1-95	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.35)	III.B2.TP-6	3.5.1-93	C
			Concrete	None	None	II.B2.2.CP-114	3.5.1-41	C

Notes	**Definition of Note**
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1. The Structures Monitoring (B.2.1.35) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

2. NUREG-1801 does not contain grout penetration seals, however cracking, loss of bond, and loss of material are applicable aging effects for both grout and concrete, and are managed for grout penetration seals by the Structures Monitoring (B.2.1.35) program.

3. The spent fuel pool water level is monitored in accordance with technical specifications. Leakage from the leak chase channels is monitored in accordance with procedures.

4. The Reactor Well water level is monitored in accordance with technical specifications.

5. The fuel pool girders are two interior concrete prestressed girders that are subject to loss of prestress which is managed by a TLAA evaluated in Section 4.6.10.

As a result of the response to RAI B.2.1.35-1, provided in Enclosure A of this letter, LRA Table 4.1-2, specifically the table section on Other Plant-Specific Time-Limited Aging Analyses is revised to add a TLAA for Fuel Pool Girder Stress Relaxation as shown below:

Table 4.1-2
SUMMARY OF RESULTS - LGS TIME-LIMITED AGING ANALYSES

TLAA DESCRIPTION	DISPOSITION	LRA SECTION
OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES		4.6
Reactor Enclosure Crane Cyclic Loading Analysis	§54.21(c)(1)(i)	4.6.1
Emergency Diesel Generator Enclosure Cranes Cyclic Loading Analysis	§54.21(c)(1)(i)	4.6.2
RPV Core Plate Rim Hold-Down Bolt Loss of Preload	§54.21(c)(1)(i)	4.6.3
Main Steam Line Flow Restrictors Erosion Analysis	§54.21(c)(1)(i)	4.6.4
Jet Pump Auxiliary Spring Wedge Assembly	§54.21(c)(1)(i)	4.6.5
Jet Pump Restrainer Bracket Pad Repair Clamps	§54.21(c)(1)(i)	4.6.6
Refueling Bellows and Support Cyclic Loading Analysis	§54.21(c)(1)(i)	4.6.7
Downcomers and MSRV Discharge Piping Fatigue Analyses	§54.21(c)(1)(i)	4.6.8
Jet Pump Slip Joint Repair Clamps	§54.21(c)(1)(i)	4.6.9
Fuel Pool Girder Loss of Prestress	***§54.21(c)(1)(i)***	***4.6.10***

As a result of the response to RAI B.2.1.35-1, provided in Enclosure A of this letter, the LRA is revised to add Section 4.6.10, as shown below: (The entire content within 4.6.10 is new; therefore, text is not shown in bold/italicized font.)

4.6.10 FUEL POOL GIRDER LOSS OF PRESTRESS

TLAA Description:

The original design analysis for the fuel pool girders evaluated loss of prestress due to stress relaxation of the steel tendons, due to creep and shrinkage of the concrete, and other factors. Since stress relaxation of the steel tendons is based upon a time-limited assumption, this analysis has been identified as a TLAA that requires evaluation for the period of extended operation.

TLAA Evaluation:

The prestress losses evaluated in the analysis considered the following elements:

1) Slip at anchorage;

2) Elastic shortening of concrete;

3) Creep and shrinkage of concrete;

4) Stress relaxation of steel after transfer (4 percent assumed based upon testing);

5) Friction; and

6) Hinge-link connection reduction.

Stress relaxation of the steel tendons is based upon a time-limited assumption, where the steel is assumed to relax as a function of time. A steel relaxation value of 4% was assumed in the fuel pool girder design analysis. This was based on stress relaxation tests of three samples that showed the stress relaxation values after 1,000,000 hours (114 years) of 3.24%, 3.57%, and 3.84%. Therefore, a 4% value was considered bounding for the 40-year design life of the girders. These test results also bound the extended service life of the girder from when it was constructed in 1978 through the end of the period of extended operation in 2049, which is approximately 71 years (623,000 hours). Therefore, since the 4% stress relaxation value assumed in the design analysis is bounding for the extended service life of the fuel pool girder, it remains valid for the period of extended operation.

Shrinkage and creep of concrete are also time-dependent, but they essentially reach a limiting value in a matter of a few years. Change in length of a member over time due to concrete shrinkage results in prestress loss. However, this loss is lower for post-tensioned members such as the fuel pool girder than for prestressed members because the prestress loading is applied after much of the shrinkage has occurred. Creep occurs after loading is applied, and proceeds at a continuously diminishing rate such that it approaches a limiting value. Although increasing creep-deformation measurements have been recorded for periods in excess of 10 years, more than half of the ultimate creep usually takes place within the first three months after loading. Creep is accounted for by assigning an overall reduction in prestress that is considered bounding for the life of the component.

The remaining factors that were evaluated are short term effects that are accounted for in the design analysis that will not contribute to further losses of preload during the period of extended operation. Therefore, since the stress relaxation of the steel tendons has been evaluated for a period bounding the service life of the tendons and since the concrete creep has approached a limiting value, the tendon analysis described above provides assurance that the prestressed concrete girders for the fuel pool will continue to maintain adequate prestress to meet their intended function(s) during the period of extended operation.

Since the stress relaxation value for the steel tendons assumed in the fuel pool girder design analysis remains valid through the period of extended operation, and since the other time-limited variables for loss of preload have reached limiting values, the TLAA has been demonstrated to remain valid for the period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The fuel pool girder design analysis remains valid for the period of extended operation.

As a result of the response to RAI B.2.1.35-1, provided in Enclosure A of this letter, the LRA is revised to add Section A.4.6.10, as shown below: (The entire content within A.4.6.10 is new; therefore, text is not shown in bold/italicized font.)

A.4.6.10 Fuel Pool Girder Loss of Prestress

The design analysis of the LGS Fuel Pool Girders has been identified as a plant-specific TLAA because it includes a time-limited evaluation of loss of prestress of the fuel pool girders. The girder analysis used a 4% stress relaxation value that is based upon stress relaxation test data, projected for 1,000,000 hours (114 years), which is a time-limited assumption. The TLAA remains valid in accordance with 10 CFR 54.21(c)(1)(i) because the loss of prestress values used in the analysis were demonstrated to remain valid through the period of extended operation.

As a result of the response to RAIs B.2.1.40-1, B.2.1.40-3, and B.2.1.40-4, provided in Enclosure A of this letter, the UFSAR Supplement for the aging management program in Appendix A, Section A.2.1.40, on pages A-30 and A-31 and the Program Description for the aging management program in Appendix B, Section B.2.1.40, on page B-157, are revised for clarification as shown below:

A.2.1.40 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope, inaccessible power cables. For this program, power is defined as greater than or equal to 400 V. These ***inaccessible power*** cables may at times be exposed to significant moisture. ~~Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable wetting or submergence in water). Periodic exposures that last less than a few days (e.g., normal rain and drain) are not significant.~~ Power cable exposure to significant moisture may cause reduced insulation resistance that can potentially lead to failure of the cable's insulation system.

The cables in the scope of this aging management program will be tested using a proven test for detecting ~~deterioration~~***reduced insulation resistance*** of the ***cable's*** insulation system due to wetting ***or submergence***, such as Dielectric Loss (Dissipation Factor or Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the test is performed. The cables will be tested at least once every 6 years. ***More frequent testing may occur based on test results and operating experience.*** The first tests will be completed prior to the period of extended operation.

Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this aging management program will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant specific ~~inspection results~~ ***operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding***. ~~The frequency of inspection will recognize that the objective of the inspections, as a preventive action, is to minimize potential exposure of in scope cables to significant moisture.~~ Operation of dewatering devices will be verified prior to any known or predicted heavy rain or flooding event. The first inspections will be completed prior to the period of extended operation. During the period of extended operation, the inspections will occur at least annually.

B.2.1.40 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that manages non-EQ, in scope, inaccessible power cables that are exposed to significant moisture. For this program, power is defined as greater than or equal to 400 V. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable wetting or submergence in water). Periodic exposures that last less than a few days (e.g., normal rain and drain) are not significant. Power cable exposure to significant moisture may cause reduced insulation resistance that can potentially lead to failure of the cable's insulation system.

The cables in the scope of this aging management program will be tested using a proven test for detecting ~~deterioration~~ ***reduced insulation resistance*** of the ***cable's*** insulation system due to wetting ***or submergence***, such as Dielectric Loss (Dissipation Factor or Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the test is performed. The cables will be tested at least once every 6 years. ***More frequent testing may occur based on test results and operating experience.*** The first tests will be completed prior to the period of extended operation.

Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this aging management program will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant specific ~~inspection results~~ ***operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding***. ~~The frequency of inspection will recognize that the objective of the inspections, as a preventive action, is to minimize potential exposure of in scope cables to significant moisture.~~ Operation of dewatering devices will be verified prior to any known or predicted heavy rain or flooding event. The first inspections will be completed prior to the period of extended operation. During the period of extended operation, the inspection will occur at least annually.

As a result of the response to RAI B.2.1.40-2 provided in Enclosure A of this letter, Section 2.5.2.5.2, Table 2.5.2-1 and pages 3.6-21 and 3.6-22 of Table 3.6.2-1 of the LRA, are revised as shown below:

2.5.2.5.2 Electrical Penetrations

Electrical penetrations at LGS are environmentally qualified. They are evaluated as a time-limited aging analysis, Section 2.5.2.4, and ultimately managed by the Environmental Qualification (EQ) of Electric Components (B.3.1.2) program. The ~~electrical continuity of~~ electrical penetration pigtails that could potentially be exposed to an adverse localized environment is included in the evaluation for Insulation Material for Electrical Cables and Connections, Section 2.5.2.5.5. The shelter, protection and pressure boundary intended functions of electrical penetrations are included in the evaluation for Primary Containment, Section 2.4.11.

Table 2.5.2-1 **<u>Electrical Commodities Subject to Aging Management Review</u>**

Commodity	Intended Function
Cable Connections (Metallic Parts)	Electrical Continuity
Fuse Holders***: Metallic Clamps***	Electrical Continuity
High Voltage Insulators	Insulate (Electrical)
Insulation Material for Electrical Cables and Connections	~~Electrical Continuity~~ ***Insulate (Electrical)***
Metal Enclosed Bus	Electrical Continuity
	Insulate (Electrical)
	Shelter, Protection
Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors	Electrical Continuity

Table 3.6.2-1

Electrical Commodities

Summary of Aging Management Evaluation

Table 3.6.2-1 **Electrical Commodities**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Cable Connections (Metallic Parts)	Electrical Continuity	Various Metals Used for Electrical Contacts	Air - Indoor, Controlled or Uncontrolled, or Air - Outdoor	Increased Resistance of Connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)	VI.A.LP-30	3.6.1-18	A
Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V	~~Electrical Continuity~~ ***Insulate (Electrical)***	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced Insulation Resistance	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)	VI.A.LP-35	3.6.1-10	A
Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements	Electrical Continuity	Various ~~Polymeric and~~ Metallic Materials	Adverse Localized Environment Caused by Heat, Radiation, Oxygen, Moisture, or Voltage	Various Aging Effects	Environmental Qualification (EQ) of Electric Components (B.3.1.2)	VI.B.L-05	3.6.1-1	A
	Insulate (Electrical)	***Various Polymeric Materials***	***Adverse Localized Environment Caused by Heat, Radiation, Oxygen, Moisture, or Voltage***	***Various Aging Effects***	***Environmental Qualification (EQ) of Electric Components (B.3.1.2)***	***VI.B.L-05***	***3.6.1-1***	***A***
Fuse Holders (Not Part of Active Equipment): Insulation Material	~~Electrical Continuity~~ ***Insulate (Electrical)***	Various Organic Polymers	Air - Indoor, Controlled or Uncontrolled	None	None	VI.A.LP-24	3.6.1-21	A
Fuse Holders (Not Part of Active Equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air - Indoor, Controlled or Uncontrolled	Increased Resistance of Connection	Fuse Holders (B.2.1.42)	VI.A.LP-31	3.6.1-17	A
			Air - Indoor, Uncontrolled	Increased Resistance of Connection; Fatigue	Fuse Holders (B.2.1.42)	VI.A.LP-23	3.6.1-16	A
High Voltage Insulators	Insulate (Electrical)	Cement	Air - Outdoor (External)	None	None	VI.A.LP-32	3.6.1-2	I, 1

Table 3.6.2-1 **Electrical Commodities** **(Continued)**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
High Voltage Insulators	Insulate (Electrical)	Cement	Air - Outdoor (External)	None	None	VI.A.LP-28	3.6.1-3	I, 2
		Metal	Air - Outdoor (External)	None	None	VI.A.LP-32	3.6.1-2	I, 1
		Metal	Air - Outdoor (External)	None	None	VI.A.LP-28	3.6.1-3	I, 2
		Porcelain	Air - Outdoor (External)	None	None	VI.A.LP-32	3.6.1-2	I, 1
		Porcelain	Air - Outdoor (External)	None	None	VI.A.LP-28	3.6.1-3	I, 2
Insulation Material for Electrical Cables and Connections	~~Electrical Continuity~~ ***Insulate (Electrical)***	Various Organic Polymers	Adverse Localized Environment Caused by Heat, Radiation, or Moisture	Reduced Insulation Resistance	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38)	VI.A.LP-33	3.6.1-8	A
Insulation Material for Electrical Cables and Connections Used in Instrumentation Circuits	~~Electrical Continuity~~ ***Insulate (Electrical)***	Various Organic Polymers	Adverse Localized Environment Caused by Heat, Radiation, or Moisture	Reduced Insulation Resistance	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.39)	VI.A.LP-34	3.6.1-9	A
Metal Enclosed Bus: Bus/Connections	Electrical Continuity	Various Metals Used for Electrical Bus and Connections	Air - Indoor, Controlled or Uncontrolled, or Air - Outdoor	Increased Resistance of Connection	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-25	3.6.1-12	A
Metal Enclosed Bus: Enclosure Assemblies	Shelter, Protection	Elastomers	Air - Indoor, Controlled or Uncontrolled, or Air - Outdoor	Surface Cracking, Crazing, Scuffing, Dimensional Change, Shrinkage, Discoloration, Hardening and Loss of Strength	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-29	3.6.1-11	A

As a result of the response to RAI B.2.1.28-1 provided in Enclosure A of this letter, LRA Sections A.2.1.28 and B.2.1.28 are revised as follows:

A.2.1.28 Monitoring of Neutron-Absorbing Materials Other than Boraflex

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex program is an existing condition monitoring program that periodically analyzes test coupons of the Boral material in the Unit 1 and Unit 2 spent fuel racks to determine if the neutron-absorbing capability of the material has degraded. This program ensures that a 5 percent sub-criticality margin is maintained in the spent fuel pool.

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program will be enhanced to:

1. Perform test coupon analysis on a ten-year frequency.
2. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded prior to the next scheduled test coupon analysis.
3. ***Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly discharged fuel assemblies) at each of five refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1).***
4. ***Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks.***

These enhancements will be implemented prior to the period of extended operation.

B.2.1.28 Monitoring of Neutron-Absorbing Materials Other than Boraflex

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform test coupon analysis on a ten-year frequency. **Program Element Affected: Detection of Aging Effects (Element 4)**
2. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded prior to the next scheduled test coupon analysis. **Program Element Affected: Corrective Actions (Element 7)**
3. ***Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly discharged fuel assemblies) at each of five refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1). Program Element Affected: Monitoring and Trending (Element 5)***
4. ***Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks. Program Element Affected: Monitoring and Trending (Element 5)***

Enclosure C
LGS
License Renewal Commitment List Changes

This Enclosure identifies commitments made in this document and is an update to the LGS LRA Appendix A, Table A.5 License Renewal Commitment List. Any other actions discussed in the submittal represent intended or planned actions and are described to the NRC for the NRC's information and are not regulatory commitments. Changes to the LGS LRA Appendix A, Table A.5 License Renewal Commitment List are as a result of the Exelon response to the following RAIs:

RAI B.2.1.40-1
RAI B.2.1.40-3
RAI B.2.1.40-4
RAI B.2.1.28-1

Notes:

- Updated LRA Sections and Tables are provided in the same order as the RAI responses contained in Enclosure A.
- To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and strikethroughs for deleted text.

As a result of the response to RAIs B.2.1.40-1, B.2.1.40-3, and B.2.1.40-4, provided in Enclosure A of this letter, Commitment No. 40 in LRA, Appendix A, Table A.5, on page A-62, is revised for clarification as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
40	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope, inaccessible power cables. Cables will be tested using a proven test for detecting ~~deterioration~~ ***reduced insulation resistance*** of the ***cable's*** insulation system. The cables will be tested at least once every 6 years. ***More frequent testing may occur based on test results and operating experience.*** ***Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture.*** Manholes associated with the cables included in this aging management program will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant specific ~~inspection results~~ ***operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding***. ~~The frequency of inspection will recognize that the objective of the inspections, as a preventive action, is to minimize potential exposure of in scope cables to significant moisture.~~ Operation of dewatering devices will be verified prior to any known or predicted heavy rain or flooding event. During the period of extended operation, the inspections will occur at least annually.	Program and initial tests and inspections to be implemented prior to the period of extended operation. Test and Inspection schedule identified in commitment.	Section A.2.1.40 LGS Letter dated 2/28/12 RAI B.2.1.40-1 RAI B.2.1.40-3 RAI B.2.1.40-4

As a result of the response to RAI B.2.1.28-1 provided in Enclosure A of this letter, LRA, Appendix A, Table A.5, pages A-54 and A-55, is revised as follows:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
28	Monitoring of Neutron-Absorbing Materials Other than Boraflex	Monitoring of Neutron-Absorbing Materials Other than Boraflex is an existing program that will be enhanced to: Perform test coupon analysis on a ten-year frequency. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded prior to the next scheduled test coupon analysis. ***Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly discharged fuel assemblies) at each of five refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1).*** ***Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks.***	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.28 LGS Letter dated 2/28/12 RAI B.2.1.28-1