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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: Exelon Generation Company, LLC Review of the Safety Evaluation Report with Open Items 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 Brian E. Holian (NRC) to Michael P. Gallagher (Exelon), "Safety Evaluation Report with Open Items Related to the License Renewal of Limerick Generating Station, Units 1 and 2 (TAC Nos. ME6555, ME6556)", dated July 31, 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 U.S. Nuclear Regulatory Commission issued the Safety Evaluation Report with Open Items (SER) related to the LGS License Renewal Application and requested Exelon to review the SER and provide comments to the staff within 45 days of the date of that letter.

Exelon has completed its review of the SER. Enclosure A contains the responses to Open items OI 3.0.3.2.13-1 and OI 3.0.5-1. As a result of these responses, Enclosure B provides updates to affected sections of the LRA and Enclosure C provides updates to License Renewal Commitments. During our review of the SER, we also identified that further clarification is required regarding LGS Fire Damper Functional Testing. This update is provided in the form of an LRA Supplement within Enclosure D, with associated LRA changes included in Enclosure B. Enclosure E provides Exelon comments on the SER.

There are no other new or revised regulatory commitments contained in this letter.

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 9-12-2012

Respectfully,

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

Enclosures: A: Responses to Open items OI 3.0.3.2.13-1 and OI 3.0.5-1
B: Updates to affected LGS LRA sections
C: LGS License Renewal Commitment List Changes
D: Fire Damper Functional Testing LRA Supplement
E: Comments Related to the Safety Evaluation Report with Open Items – Limerick Generating Station, Units 1 and 2

cc: Regional Administrator – NRC Region I
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# Enclosure A

## Responses to Open Items

**OI 3.0.3.2.13-1**
**OI 3.0.5-1**

**<u>Open Item 3.0.3.2.13-1</u> ASME Section XI, Subsection IWE**

LGS, Units 1 and 2, have seen corrosion in the suppression pool liner and downcomers. The applicant's proposed aging management of the suppression pool liner and downcomers is within the scope of the ASME Section XI, Subsection IWE program. As described in SER Section 3.0.3.2.13, the staff has an open item for aging management of the suppression pool liner and downcomers. Specifically the open item is related to:

- The applicant has developed an acceptance criterion for the degradation of the downcomers; however, this criterion is not identified in the aging management program or the associated procedures.

- The staff is concerned about the adequacy of the criteria used for selecting locations for recoating (i.e. criteria for coating degradation, general corrosion, and pitting corrosion). In addition, it is not clear how the coating degradation can be effectively identified for each liner plate underwater in the suppression pool. Also, the applicant's proposed criteria for augmented inspection is not consistent with ASME Code, Section XI, Subsection IWE, requirements that detailed visual and ultrasonic thickness measurement be completed on 100 percent of surface areas subjected to accelerated corrosion or areas where the absence or repeated loss of coatings has resulted in substantial corrosion or pitting.

**<u>Exelon Response</u>**

Based on Exelon's review of Open Item 3.0.3.2.13-1 and SER Section 3.0.3.2.13, it is Exelon's understanding that the staff needs additional information regarding aging management of the suppression pool liners and downcomers in the following areas:

1) The incorporation of acceptance criteria for recoating degradation of the downcomers in the aging management program or its associated procedures.

2) The adequacy of the criteria used for selecting liner plates for recoating including how recoats will be prioritized and corrected in a phased approach prior to the period of extended operation.

3) The ability to effectively identify coating degradation for each liner plate underwater in the suppression pool.

4) The consistency with ASME Section XI, Subsection IWE augmented acceptance criteria.

5) The corrosion rates within the suppression pool.

These five items are addressed below. Finally, the open item's use of the terms "general corrosion" and "pitting corrosion" suggests that the staff believes that both general and pitting corrosion mechanisms are (or could be) significant contributors to aging of the submerged portion of the suppression pool and/or downcomers. Because only general corrosion is a significant mechanism in this submerged environment, Exelon also addresses this issue as part of Item 5.

**1) Incorporation of Downcomer Recoat Acceptance Criteria**

Exelon's response to RAI B.2.1.30-2.1 dated April 27, 2012 described the downcomer acceptance criteria used to determine when areas of the downcomers affected by corrosion will be recoated. These criteria will be incorporated into the ASME Section XI, IWE aging management program.

LRA Appendix A.2.1.30 and LRA Appendix B.2.1.30 are revised as shown in Enclosure B to incorporate an enhancement to revise the ASME Section XI, Subsection IWE aging management program to include the criteria used to determine when downcomer areas affected by corrosion will be recoated. LRA Appendix A, Table A.5, Commitment No. 30 is revised as shown in Enclosure C.

**2) Liner Plate Recoating Criteria**

The prioritized Coating Maintenance Plan represents a transition from the existing IWE inspection approach to an aging management approach. This plan will ensure minimum loss of material so that the liner's intended function is maintained both prior to and during the period of extended operation. A prioritized approach is necessary so that the recoating of selected areas can be performed underwater during scheduled outages rather than draining the suppression pool to conduct a total recoat which creates competing safety issues such as offloading the entire core, reduced emergency core cooling system water inventory with a drained suppression pool, radiological and industrial safety hazards. This plan is based on three levels of priority for recoating as discussed below.

The first priority is for spot recoating local areas of general corrosion greater than 50 mils loss of liner metal. These spot recoats will be performed in the outage they are discovered. This immediate priority addresses locations where corrosion is deepest, and helps to sustain the life of the coating. Inorganic zinc depletes starting with small defects and progresses outward. Recoating these areas mitigates the progression of coating depletion. The 50 mil action level ensures that the local acceptance criteria of 187.5 mils would not be exceeded by the next inspection even if unexpected accelerated corrosion were to occur.

The next priority is for recoats of larger areas of general corrosion greater than 25 mils loss of liner metal. A prioritized list of liner locations will be recoated, prior to the PEO, based on surface area affected including any newly identified areas found during the more frequent ASME examinations. The amount of submerged surface area currently exceeding this action level is small, i.e. less than 3 percent submerged surface area on Unit 1 and less than 1 percent on Unit 2. Actions taken at this metal loss value assure that surfaces on liner plates are limited to less than 10 percent wall thickness loss, where structural integrity is not challenged. The intent is to address these areas starting at the next inspection opportunity and to complete recoating these areas prior to the period of extended operation (PEO).

The plan also has provisions to proactively recoat large areas where coating has depleted and is no longer present before significant corrosion occurs. This third priority is proactive because the corrosion levels in the affected areas on such liner plates are small, i.e. less than 25 mils which is less than 10 percent metal thickness loss. For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss. This list will include any newly identified areas with greater than 25 percent surface depletion found during the more frequent ASME examinations, and will be worked off prior to the PEO. More frequent liner examinations provide opportunities for recoating, allowing execution of the prioritized approach to maintain liner coating protection. An ASME IWE examination will be conducted each inservice inspection period (3 times in 10 years)

for 100 percent of the accessible submerged liner surface. De-sludging of the suppression pool floor each refueling outage minimizes potential corrosion sites and also sustains the life of the coating. The Coating Maintenance Plan began in 2012 for Unit 1 and will be initiated in 2013 for Unit 2. Early institution of the Plan - well in advance of the PEO - allows the prioritized actions to be implemented prior to reaching PEO.

During the PEO, the plan will proceed in a similar prioritized fashion. It's expected that the Coating Maintenance Plan will sustain the life of the coating through the PEO. Local areas of general corrosion greater than 50 mils loss of liner metal will continue to be spot recoated in the outage of discovery. In addition, larger area recoats of general corrosion greater than 25 mils loss of liner metal will also be recoated in the outage of discovery. For plates with greater than 25 percent coating depletion, the affected area will be proactively recoated at least by the next inspection opportunity. Since these areas have less than 10 percent metal loss, allowing some time for planning the recoat is acceptable.

This prioritized plan will maintain coating protection of the liners, and maintain thickness margin for structural integrity by continuing to minimize metal wall loss due to general corrosion throughout the PEO.

LRA Appendix A.2.1.30 and LRA Appendix B.2.1.30 are revised as shown in Enclosure B to include this prioritized approach for recoating suppression pool liner plates for both Limerick units prior to the PEO, as well as during the PEO. LRA Appendix A, Table A.5, Commitment No. 30 is revised as shown in Enclosure C.

**3) Liner Plate Coating Inspection**

The requirements for underwater visual inspection of the suppression pool liner plates are defined in LGS engineering specification NE-101, "Nuclear Safety Related Specification for Coating and Liner Inspection and Coating Repair of the Suppression Chambers at Limerick Generating Station Units 1 and 2". The contractor used for underwater inspections maintains a Quality Assurance Program that has been evaluated and approved by Exelon and meets the requirements of 10 CFR 50, Appendix B. Personnel performing underwater inspections are qualified and certified Coating Inspectors, meeting the requirements of ANSI N45.2.6 and ASTM D4537 as a Level II or Level III Inspector.

A visual inspection is performed on wall and floor plates to qualitatively assess the general condition of the coating by performing a VT-3 visual examination. Qualitative inspections identify, classify, and evaluate coating discontinuities and imperfections. In addition to coating discontinuities and imperfections, inspections also identify the complete loss of coating. Once exposed, bare metal will experience corrosion. Therefore, corrosion is indicative of the loss of coating and is the indicator for determining the percentage of surface area with coating depletion.

For the suppression pool liner inspections, results are reported using a unique liner plate designation (e.g., 1-FP-01A-1 is Unit 1 floor plate 01 located in the "A" quadrant of the suppression pool). When a plate consists of a large surface area, the surface area is sub-divided into smaller more manageable identifiable areas as necessary to facilitate data collection and to more accurately describe conditions on different regions of the liner plate. When a manageable inspection area has been established, the inspector performs the visual VT-3 inspection.

Local areas of general corrosion and larger areas of general corrosion are identified and evaluated separately when determining percent affected area. For local areas, the inspector identifies the size of the area containing the indications, the size of the indications, and the

quantity of indications within the area. Depending upon the quantity, the size of the indications may be identified as actual, an average, or the most common size. The quantity is identified as either a fixed number or a distribution (e.g., quantity/$ft^2$). As data is collected, it is entered on a datasheet. The affected area (total square inches) is then calculated based on the inputted data as reported for the inspected area of the plate.

For larger areas, the characterization of the degree of corrosion is performed consistent with the methods described in industry standard ASTM D 610/SSPC-VIS-2, "Standard Practice for Evaluating Degree of Rusting on Painted Steel Surfaces." In these instances, indications are entered into the datasheet by size of the area inspected and percentage of the inspected area affected by the indications. The affected area (total square inches) is then calculated based on the inputted data as reported for the inspected area of the plate.

When determining the percent affected for an entire plate, the cumulative affected area is itemized by plate designation and the percent affected for each plate is calculated by dividing the cumulative affected area by the total plate area.

The qualitative inspection techniques described above, along with the use of qualified Coating Inspectors, ensure the accurate identification of coating degradation such as discontinuities, imperfections, or the complete loss of coating. Therefore, coating degradation can be effectively identified for each liner plate underwater in the suppression pool.

**4) Liner Plate Corrosion Augmented Inspection Criteria**

The LGS acceptance criteria and examination methodology are consistent with ASME Section XI, Subsection IWE, and also specifically with the IWE-1241, IWE-1242, and Table IWE-2500-1 requirement that 100 percent of areas having substantial corrosion require augmented inspection. Substantial liner corrosion is defined by Exelon as general corrosion greater than 25 mils average metal loss, or local areas of general corrosion greater than 50 mils metal loss. The LRA Appendix A, Table A.5, Commitment No. 30 metal loss action levels for recoating are the same as the metal loss criteria for which augmented inspections are required. However, LRA Appendix A, Table A.5, Commitment No. 30 also includes a requirement to recoat plate areas with greater than 25 percent coating depletion which is not a measure of substantial corrosion and will not be used as a criterion to require augmented inspection. The classification of LGS Suppression Pool and downcomer surface areas as ASME Section XI, Subsection IWE, Category E-C, which require augmented inspection, is based on metal loss criteria and not on coating depletion or coating loss. VT-1 detailed visual inspections are performed as required by ASME Section XI, Subsection IWE, Table IWE-2500-1 and 10 CFR 50.55a requirements. Submerged liner surfaces which do not require augmented inspection are examined in accordance with ASME Section XI, Subsection IWE, Table IWE-2500-1 and 10 CFR 50.55a requirements using VT-3 visual examination.

The Exelon examination methodology is also consistent with the ASME Section XI, Subsection IWE, sections IWE-2420(b), and IWE-3122.3 for augmented examinations. IWE-2420(b) requires that when examination results require evaluation of flaws or areas of degradation in accordance with IWE-3000 and the component is acceptable for continued service that the flaws or areas of degradation be reexamined during the next inspection period in accordance with Table IWE-2500-1, Examination Category E-C. Similarly, IWE-3122.3 states that *"A component whose examination detects flaws or areas of degradation that do not meet the acceptance standards of IWE-3500 is acceptable for continued service without a repair / replacement activity if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no unacceptable effect on the structural integrity of the containment. …."* IWE-3122.3 also requires that when flaws or degradation are accepted by an

engineering evaluation the area be reexamined in accordance with IWE-2420(b) and (c). Exelon's response to RAI B.1.30-2 dated February 28, 2012 states in part: *"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."* Similarly, IWE-3511 *"Standards for Examination Category E-C, Containment Surfaces Requiring Augmented Examination"* subparagraph IWE-3511.1 states: *"The Owner shall define acceptance criteria for visual examination of containment surfaces."* Exelon has defined acceptance criteria for the suppression pool liner and downcomers which are described in Exelon responses to RAI B.2.1.30-2 and RAI B.2.1.30-2.1 dated February 28, 2012 and April 27, 2012. LGS examination results have not required engineering evaluation of flaws or areas of degradation, as no areas have been in excess of the Exelon pre-established metal loss criteria for structural integrity.

In addition, Exelon examination methodology is consistent with the ASME Section XI, Subsection IWE for ultrasonic testing. ASME Section XI, Subsection IWE, Table IWE-2500-1 requires detailed visual examination and 10 CFR50.55a requires VT-1 visual examination for category E-C surfaces (containment surfaces requiring Augmented Examination). IWE-2500(b)(1) states: *"Surface areas requiring augmented examination that are accessible for visual examination shall be visually examined using a detailed visual examination method."* Table IWE-2500-1 also includes requirements for ultrasonic thickness examination in certain cases for examination category E-C in accordance with the paragraphs referenced in the Table. Ultrasonic thickness measurements are not required in all cases, but rather per IWE-2500(b)(2), for areas that are not accessible for visual examination on the side requiring augmented examination. IWE-3200 *"Supplemental Examinations"* states in part, that flaws or degradation that require evaluation may be supplemented by other examination methods and techniques to determine the character of the flaw, and that surface flaws or areas that are suspect shall be supplemented by either surface or volumetric examination, when specified as a result of the engineering evaluation performed in IWE-3122.3. As stated above, LGS examination results have not required engineering evaluation of flaws or areas of degradation, as no areas have been in excess of the Exelon pre-established metal loss criteria for structural integrity.

The Exelon methodology for examination of the submerged liner areas is described below. During visual examinations, coating and corrosion conditions are visually assessed and characterized as local areas of general corrosion or general corrosion. Metal loss in local areas of general corrosion is qualitatively assessed during VT-3 examination to report a bounding condition in the reported area using a go/no-go gauge as necessary. During this qualitative assessment, indications identified to be approaching or in excess of the criteria set by Exelon which require augmented examination, are quantitatively assessed during VT-1 inspections to determine metal loss. This is accomplished by measuring the maximum depth of the flaw with a calibrated dial-depth gauge and measuring the thickness of the surrounding coating with a calibrated dry-film thickness (DFT) gauge. Actual metal loss is then calculated by subtracting the average DFT (3-readings minimum) from the maximum dial-depth gauge reading.

General corrosion metal loss for areas larger than several inches in diameter is also visually assessed during VT-3 or VT-1 examinations as required. Metal loss conditions for general corrosion are reported as a bounding condition. Metal loss is typically uniform across a larger area of general corrosion. If there are local areas of general corrosion with greater metal loss within an area of general corrosion the methods described above are combined as necessary. The metal loss in the larger area of general corrosion is assessed using visual techniques or alternately UT may be used, and then the metal loss in local areas of general corrosion with greater metal loss is measured with a go/no-go gauge or dial depth gauge as necessary.

Ultrasonic thickness measurements were performed in 2012 on 27 Unit 1 suppression pool liner plates in unaffected areas where coating is intact to determine baseline wall thickness

(four readings per plate). The plate thickness in the areas unaffected by corrosion ranged from 0.251 inches to 0.285 inches. Ultrasonic thickness measurements were also performed on four liner plates in areas affected by general corrosion to determine remaining wall thickness (two readings per plate). The readings in the areas of general corrosion exceeded the nominal plate thickness of 0.250 inches except for one reading which was 0.244 inches. Ultrasonic thickness readings in the corroded areas of the four plates ranged from 0.244 inches to 0.265 inches. The difference between the average thickness for these plates in areas unaffected by corrosion and average thickness readings in areas affected by corrosion ranged from 1 to 15 mils. The visually assessed general corrosion metal loss for these plates ranged from 8 to 20 mils. Therefore, the visually assessed general corrosion metal loss for these four plates was conservative and correlated well with the ultrasonic thickness measurements.

Ultrasonic examinations are performed as necessary to quantify metal loss and to support engineering evaluations. Although not required by ASME Section XI, Subsection IWE for areas that can be visually inspected the LGS specification for underwater containment liner inspection states that alternatively, the metal loss value may be determined by ultrasonic thickness measurements. Therefore, to confirm visual assessments of general corrosion, when IWE examinations are conducted, an ultrasonic thickness measurement will be performed on an area of submerged suppression pool liner affected by general corrosion. These ultrasonic thickness measurements will be performed in an area of more significant metal loss.

LRA Appendix A.2.1.30 and LRA Appendix B.2.1.30 are revised as shown in Enclosure B to include the additional Ultrasonic Testing thickness measurement in suppression pool areas of general corrosion for both Limerick units as a part of the coating maintenance plan. LRA Appendix A, Table A.5, Commitment No. 30 is revised as shown in Enclosure C.

**5) Liner Plate General and Pitting Corrosion Rate**

SER Section 3.0.3.2.13, page 3-137, in the last paragraph of the section titled “Liner Plate General and Pitting Corrosion Rate,” the staff states that pitting corrosion is unpredictable and can cause a leak in the liner plate over time. The staff also states that the unpredictability and possibility of high pitting corrosion rates is made clear by inspection results: two floor pits of 69 mils and 72 mils were identified in 2010 (1R13), even though these pits were not detected four years earlier in the 2006 (1R11) inspection.

The Exelon response to RAI B.2.1.30-4.1, dated April 27, 2012, includes the most recent evaluation of the LGS suppression pool liner corrosion. This RAI response states:

*“Pitting corrosion is not anticipated to be a major degradation mechanism for the LGS carbon steel suppression pool liner. Pitting corrosion occurs on alloys that form protective passive films in the suppression pool environment and carbon steel does not typically form passive films in low temperature water. Also, the primary pitting corrosion promoting anion, chloride, in the LGS suppression pool water is only present at very low levels of a few parts per billion. Therefore, the carbon steel liner exposed to the suppression pool environment is anticipated to experience general corrosion, not pitting corrosion.*

*A review of the references cited in the “Issue” discussion concludes that they are not representative of the material and water chemistry conditions for the LGS suppression pool liner and the conclusions regarding pitting corrosion are not directly applicable to LGS.*

- *The paper by J. A. Gonzalez, et al., discusses the localized attack on carbon steel reinforcement embedded in chloride contaminated high pH (e. g., 12-14) concrete. This study concludes that the maximum penetration of localized attack is equivalent to about*

*four to eight times the average general penetration. The LGS configuration consists of purified water at neutral pH with only trace amounts of chlorides in contact with the carbon steel liner plate. Therefore, the localized corrosion rates in the chloride contaminated high pH concrete are not considered applicable to the LGS suppression pool liner.*

- *The paper by F. King discusses the potential corrosion of carbon steel spent fuel containers stored in a deep geological repository where the carbon steel containers are placed in contact with compacted bentonite clay. Over long periods of time the bentonite is assumed to become saturated with water containing contaminates at levels not present in the LGS suppression pool water. The study concludes that the pH of the environments plays a key role, with uniform corrosion observed below a critical pH and localized corrosion at higher pH values. The value of this critical pH depends on temperature and the concentration of ions in solution and has been reported to range from 8 to 10.5. This critical pH value is up to four orders of magnitude higher than the LGS suppression pool water pH which is in the average range of 6.5 to 6.8. Therefore, since the environment (bentonite) and water chemistry from the study are not representative of the LGS conditions, the conclusions regarding localized corrosion are not applicable.*

- *The paper by X. Sun, et al., discusses the viability of a coupled multi-electrode sensor array to provide real-time monitoring of corrosion in air-saturated (and not nitrogen blanketed) drinking water systems. The electrochemical testing was conducted over a very short time period (e. g., three hours and eight days) in both distilled water and spring water. The short duration of the test does not provide results that are representative of long term operating conditions for the LGS suppression pool liner. However, if one considers the test results for distilled water, which is more representative of the LGS suppression pool water than spring water, the test indicates that the maximum localized corrosion rate was eight times higher than the average corrosion rate for carbon steel and the maximum localized corrosion rate for carbon steel was 3.5 mil/year. Thus, the average corrosion rate for carbon steel for the test conditions was 3.5 divided by 8 or 0.44 mil/year and is not representative of LGS. The LGS liner general corrosion rate is approximately 2 mil/year based on years of field exposure to the suppression pool environment. Therefore, these electrochemical test results do not appear to be directly applicable to LGS.*

*As discussed above, the studies cited in this RAI do not represent the material-environment combination for the LGS suppression pool liner. A study more representative of the LGS suppression pool liner material-environment combination was performed by A. D. Mercer, et al., "Comparative Study of Factors Influencing the Action of Corrosion Inhibitors for Mild Steel in Neutral Solution," Part III, Sodium Nitrite, British Corrosion Journal, Vol. 3, May 1968. In this study, carbon steel was immersed for 100 days in high purity water similar in conductivity to the LGS suppression pool plus water containing various aggressive anions such as sulfate, nitrate, and chloride. This test also quantitatively determined the general corrosion rates of carbon steel, and this information was used for the LGS carbon steel corrosion evaluation. While general corrosion of carbon steel was observed in this high purity water control test environment, there was no evidence of pitting corrosion, which is consistent with what is expected for carbon steel in this environment that closely represents the LGS suppression pool liner environment.*

*Inspections of the suppression pool liner have identified isolated locations where material loss has been identified that is greater than expected for general corrosion. The area with the*

*greatest metal loss, 122 mil, is on a floor plate and was identified during the Unit 1 inspection performed in 2006 and was immediately recoated. The 2006 inspection was the first quantitative inspection of the floor plate. A previous general visual inspection of this area in 1996 identified locations of mechanical damage (nicks, dings, scrapes, etc.) that exposed the liner plate to the suppression pool water. Therefore, it is not known when the corrosion at this location initiated or if some of the wall thickness loss is due to mechanical damage in addition to corrosion. The small number of these locations is indicative of mechanical damage as the initiator of the corrosion. Otherwise, the number of areas that exhibit metal loss greater than expected from general corrosion would be significantly higher and be prevalent in many of the liner plates that have experienced a loss of coating."*

This evaluation cited in the response to RAI B.2.1.30-4.1 supersedes previous evaluations, including Issue Report (IR) 1063631. The RAI response is based on an Exelon corrosion evaluation performed to assess the material and environmental conditions in the suppression pool and determine the corrosion mechanism, the expected corrosion rate, and address the factors that influence corrosion of the carbon steel pool liner. This corrosion evaluation concluded that with the LGS excellent water chemistry, the expected corrosion mechanism was general corrosion with a corrosion rate of less than 2 mils per year. The corrosion evaluation also concluded that due to the non-passive nature of the corrosion film developed on the carbon steel surface in the suppression pool environment, pitting corrosion is not expected and that the presence of sludge in the suppression pool would not be a significant contributor to the type or rate of corrosion.

The term "pitting" is commonly used in LGS suppression pool inspection reports and documentation to identify areas of corrosion that are local in nature. In this context, "pitting" is not intended to describe the corrosion mechanism since the local areas of general corrosion that exist in the suppression pool liner do not exhibit behavior typical of pitting corrosion and pitting is not expected for the LGS suppression pool environment.

The study performed by A. D. Mercer, et al., cited in the response to RAI B.2.1.30-4.1, supports the conclusion that for carbon steel, pitting corrosion is not expected to occur when exposed to water that has similar water chemistry to the LGS suppression pool water. While the A. D. Mercer study did not include consideration of sludge, the Exelon corrosion evaluation did consider the effect of sludge and concluded that the presence of sludge does not have a significant impact on the corrosion of carbon steel exposed to the sludge and is not expected to result in pitting corrosion. The sludge in the LGS suppression pool is a light powdery material that is easily returned to suspension in the pool water when agitated. The sludge would have to adhere to the exposed metal surface of the liner in order to promote corrosion mechanisms other than general corrosion. The sludge in the LGS suppression pools is not dense or tightly adherent to the liner surfaces and is easily removed by vacuuming. Therefore, the presence of sludge in the suppression pool is not expected to produce pitting corrosion and has no significant impact on the general corrosion rate.

The corrosion rate determined in the Exelon corrosion evaluation is consistent with the inspection results for the liner plate evaluation grids initially established in 1995 for Unit 2 and 1996 for Unit 1. These evaluation grids are located on both the liner floor and liner walls for both units and include localized corrosion sites similar to those discussed below for plates 1-WP-07B-3 and 1-FP-01B-2. For each unit, two grids are located on the floor and one grid on the wall. The floor plates containing the evaluation grids become covered with sludge during operation similar to other floor plates. These evaluation grids do not identify any significant difference in average corrosion rates between the floor grids and the wall grids. The maximum individual spot location metal loss rate is 2.1 mils per year and the average metal loss rate for the 114 monitored locations is below 2 mils per year. These data demonstrate that the general

corrosion rate of 2 mils per year is applicable to all locations on the liner and that the presence of sludge has no measurable impact on corrosion rates or the initiation of pitting corrosion.

LRA Appendix A, Table A.5, Commitment 30, includes a commitment to remove any accumulated sludge in the suppression pool every refueling outage, thereby reducing the potential for the formation of tightly adherent sludge deposits that could impact the liner.

The Issue Report (IR 1063631) referenced in the SER on page 3-136 does not represent the most recent evaluation of the LGS suppression pool liner corrosion. The corrosion evaluation discussed in the response to RAI B.2.1.30-4.1 was performed to identify the corrosion mechanisms and determine the corrosion rate for the suppression pool liner and supersedes the IR 1063631 assessment. The Issue Report was written in 2010 to document the condition of the Unit 1 liner following the inspection in 1R13 and makes reference to localized corrosion identified in previous inspections. This assignment report does not perform a detailed evaluation of the corrosion mechanisms or determine corrosion rates. It does, however, cite several local areas of general corrosion, formerly referred to as “pitting”. The local areas of general corrosion identified in the Issue Report are:

- One local area 77 mils deep on a plate identified in the Unit 1 1998 inspection (1R7). The plate is a wall plate (1-WP-07B-3), not a floor plate as identified in IR 1063631.
- One local area 122 mils deep on a floor plate (1-FP-01B-2) identified in the Unit 1 inspection performed in 2006 (1R11).
- Two local areas, one 69 mils deep and another 72 mils deep, identified on a floor plate (1-FP-01B-2) in the Unit 1 inspection in 2010 (1R13).

The local area of 77 mil metal loss was initially identified during underwater inspections performed in 1996. At that time the measured depth was 72 mils. This spot location was inspected again in 1998 with a measured depth of 77 mils and was recoated. The loss of 5 mils of metal over a two year time period is consistent with a general corrosion rate of 2 mils per year and not consistent with pitting corrosion behavior.

The areas of localized corrosion for the 122 mils, 69 mils, and 72 mils metal loss are all on the same floor plate (1-FP-01B-2) that was initially inspected in 1996 and observed to have numerous locations where mechanical damage (dings, scratches) exposed the metal substrate and resulted in corrosion of the steel liner. In the 1996 inspection, two measurements of metal loss were taken in areas that, based on the visual inspection of the plate, appeared to exhibit the most corrosion. The depth of the metal loss at these two locations was 35 mils and 41 mils. Therefore, corrosion of localized areas on this plate began well before the 1996 inspection.

Inspection of the 1-FP-01B-2 floor plate in 2006 identified one location with a metal loss of 122 mils. This location was immediately recoated to arrest any further loss of material. At this time, the inspection and recoat criterion did not require any locations that had less than 125 mils metal loss to be documented or recoated. The identification of the 122 mil deep area does not indicate that a loss of 122 mils of metal occurred between 2006 and the last inspection in 1996.

Inspection of the 1-FP-01B-2 floor plate in 2010 identified the localized areas with 69 mils and 72 mils metal loss. These were recoated to arrest any further metal loss in accordance with the inspection and recoat criteria that required action if a local area was determined to have material loss greater than 60 mils. Although the entire plate was inspected during the prior outage in 2006, these locations were not recorded because they did not meet the 125 mils metal loss criterion in effect during that inspection. Therefore, the identification of these areas in 2010 is not evidence that 69 mils or 72 mils metal loss occurred in the four year period between 2010 and the last inspection in 2006. Corrosion at these locations also likely initiated from mechanical damage, not coating depletion, which was noted during the 1996 inspection.

The inspection results for the LGS suppression pool liners continue to be consistent with a general corrosion rate of 2 mils per year. Local areas of general corrosion behave in a similar manner to general corrosion as evidenced by the plate evaluation grid inspection results and evaluation of the four locations described in IR 1063631. As described in the response to RAI B.2.1.30-4.1, dated April 27, 2012:

*"The inspection scope and frequency described in Commitment 30 provides for the identification of any areas where localized corrosion is occurring at a rate higher than the general corrosion rate, and the recoating criteria will arrest the material loss at these localized corrosion areas prior to reaching the structural integrity acceptance criteria. Exelon's response to RAI B.2.1.30-2 identifies the acceptance criteria for the submerged portion of the suppression pool liner for general corrosion and localized corrosion. Using the general corrosion recoat criterion of 25 mils and a general corrosion rate of 2 mils per year, an uncoated area could experience a reduction in wall thickness of 33 mils ((25 mils) + (2 mils/yr x 4 yr)) due to general corrosion at the next inspection when the degraded area would be recoated. This is well below the 125 mils general corrosion allowance. Even though the X. Sun testing referenced above is not applicable to the LGS environment; if a localized corrosion rate as high as a factor of eight times the general corrosion rate were to occur at LGS, the maintenance plan would arrest the material loss. Using a localized corrosion recoat criterion of 50 mils and a localized corrosion rate as high as 8 times the general corrosion rate, the depth of the localized corroded area would be 114 mils ((50 mils) + (2 mils/yr x 4 yr x 8)) at the next inspection when the degraded area would be recoated or repaired. This is below the 125 mils general corrosion allowance and well below the structural integrity acceptance criterion for metal loss of 187.5 mils for localized corrosion."*

The prioritized approach for recoating liner plates described in the revision to LRA Appendix A, Table A.5, Commitment No. 30, requires that local areas of general corrosion be recoated in the outage they are identified. The commitments for frequent inspections and to recoat local areas with greater than 50 mils metal loss in the same outage as identified assure that these local areas do not encroach upon structural limits. Therefore, the coating maintenance plan as described in the LRA Appendix A, Table A.5, Commitment No. 30, as revised, adequately addresses both general corrosion and local area general corrosion to avoid significant material loss and maintain the suppression pool liner integrity.

**<u>Open Item 3.0.5-1</u> Operating Experience for Aging Management Programs**

LR-ISG-2011-05 states that enhancements to the existing programmatic activities for the ongoing review of operating experience that are necessary for license renewal should be put in place no later than the date the renewed operating licenses are issued. The applicant described several enhancements; however, it plans to implement them after issuance of the renewed licenses. As discussed in SER Section 3.0.5, the staff could not determine whether operating experience related to aging management and age-related degradation will be considered in the period between issuance of the renewed licenses and implementation of the enhancements.

**<u>Exelon Response</u>**

In accordance with its existing, effective processes, LGS will consider operating experience related to aging management and age-related degradation in the period between issuance of the renewed licenses and implementation of the enhancements.

If the operating experience enhancements described in Exelon's March 13, 2012 response to RAI B.1.4-1 are not implemented by the time the renewed licenses are issued, LGS will take the following actions:

1. Review all License Renewal Interim Staff Guidance (LR-ISG) documents issued in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements to gain insights regarding aging management lessons learned for incorporation into LGS aging management activities.

2. Review the first revision of NUREG-1801 issued after the enhancements are implemented, to capture significant aging management lessons learned that occur in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements. This review will identify significant guidance changes driven by industry operating experience that should be incorporated into LGS aging management activities.

Aging management related lessons learned from these review activities will be entered into the plant action tracking database for incorporation into credited LGS AMPs or into new LGS AMPs.

LRA Section A.1.6 (the UFSAR supplement) and Section B.1.4 are updated as shown in Enclosure B. Section A.5 (License Renewal commitments) is updated as shown in Enclosure C.

**Enclosure B**
**LGS License Renewal Application Updates**

Notes:

- To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated.
- Text from the original LRA or previous RAI responses 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 Open Item 3.0.3.2.13-1 provided in Enclosure A of this letter, LRA Sections A.2.1.30 and B.2.1.30 are revised as follows:

**A.2.1.30 ASME Section XI, Subsection IWE**

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55(a). The program consists of periodic inspection of the primary containment liner plate surfaces and components, including its integral attachments, diaphragm slab carbon steel liner, downcomers and bracing, penetration sleeves, pressure retaining bolting, personnel airlock and equipment hatches, drywell head, and other pressure retaining components for loss of material, loss of preload, loss of leak-tightness, and fretting or lockup.

Examination methods include visual and volumetric testing as required by ASME Section XI, Subsection IWE. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action program.

The ASME Section XI, Subsection IWE aging management program 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 ISI period.

   c. Use the results of the ASME IWE examination to implement a coating maintenance plan to ***perform the following prior to the period of extended operation (PEO)***:

      - ~~Perform local recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss.~~ ***Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified.***

      - ~~Perform spot recoating of pitting greater than 50 mils deep.~~ ***Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low.***

      - ~~Recoat plates with greater than 25 percent coating depletion.~~ ***For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss.***

   ***d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO:***

      - ***Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified.***

- ***Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated in the outage they are identified.***

- ***For plates with greater than 25 percent coating depletion, the affected area will be recoated no later than the next scheduled inspection.***

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.

2. ***Include the criteria used to determine when downcomer areas affected by corrosion will be recoated.***

3. ***When IWE examinations are conducted, perform an ultrasonic thickness measurement on an area of submerged suppression pool liner affected by general corrosion.***

~~2.~~**4.** Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.

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

### B.2.1.30 ASME Section XI, Subsection IWE

**Enhancements**

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

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 ISI period.

   c. Use the results of the ASME IWE examination to implement a coating maintenance plan to ***perform the following prior to the period of extended operation (PEO)***:

      - ~~Perform local recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss.~~ ***Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified.***

- ~~Perform spot recoating of pitting greater than 50 mils deep.~~ ***Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low.***

- ~~Recoat plates with greater than 25 percent coating depletion.~~ ***For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss.***

**d.** ***Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO:***

- ***Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified.***

- ***Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated in the outage they are identified.***

- ***Coating depletion greater than 25 percent on any plate will be recoated no later than the next scheduled inspection.***

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. **Program Element Affected: Detection of Aging Effects (Element 4)**

***2. Include the criteria used to determine when downcomer areas affected by corrosion will be recoated. Program Element Affected: Detection of Aging Effects (Element 4)***

***3. When IWE examinations are conducted, perform an ultrasonic thickness measurement on an area of submerged suppression pool liner affected by general corrosion. Program Element Affected: Detection of Aging Effects (Element 4)***

~~2.~~***4.*** Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Program Element Affected: Preventive Actions (Element 2)

As a result of the response to **OI 3.0.5-1** provided in Enclosure A of this letter, LRA Sections A.1.6 and B.1.4 are revised as shown below:

## A.1.6 OPERATING EXPERIENCE

The Operating Experience program is an existing program that will be enhanced to ensure, through the ongoing review of both internal and external operating experience, that the license renewal aging management programs are effective to manage the aging effects for which they are credited throughout the period of extended operation. The programs are either enhanced or new programs developed when the review of operating experience indicates that the existing programs do not provide reasonable assurance that aging effects are being effectively managed.

The Operating Experience program will be enhanced to:

1. Explicitly require the review of operating experience for aging-related degradation.
2. Establish criteria to define aging-related degradation.
3. Establish identification coding for use in identification, trending and communications of aging-related degradation.
4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.
5. Require review of external operating experience for information related to aging management, and evaluation of such information for potential improvements to LGS aging management activities.
6. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management.

These enhancements will be implemented ~~within~~ ***no later than*** two years following receipt of the renewed operating licenses.

***In addition, if the operating experience enhancements described above are not implemented by the time the renewed licenses are issued, LGS will take the following actions:***

1. ***Review all License Renewal Interim Staff Guidance (LR-ISG) documents issued in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements to gain insights regarding aging management lessons learned for incorporation into LGS aging management activities.***

2. ***Review the first revision of NUREG-1801 issued after the enhancements are implemented, to capture significant aging management lessons learned that occur in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements. This review will identify significant guidance changes driven by industry operating experience that should be incorporated into LGS aging management activities.***

***Aging management related lessons learned from these review activities will be entered into the plant action tracking database for incorporation into credited LGS AMPs or into new LGS AMPs.***

## B.1.4 OPERATING EXPERIENCE

Operating experience is used at LGS to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at LGS. Limerick, as part of the Exelon fleet, receives Operating Experience (internal and external to Exelon Nuclear) daily. The Operating Experience process (OPEX) screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The OPEX process reviews operating experience from external (also referred to as industry operating experience) and internal (referred to as in-house operating experience) sources. External operating experience includes INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), and other documents (e.g., 10 CFR Part 21 Reports, etc.). Internal operating experience includes event investigations, trending reports, and lessons learned from in-house events as captured in self-assessments, and in the 10 CFR Part 50, Appendix B corrective action program.

Each AMP summary in this appendix contains a discussion of operating experience relevant to the program. This information was obtained through the review of in-house operating experience captured by the Corrective Action Program, Program Self-Assessments, Program Health Reports, and through the review of industry operating experience. Additionally, operating experience was obtained through interviews with system engineers, program engineers, and other plant personnel. New programs utilized plant and or industry operating experience as applicable, and discussed the operating experience and associated corrective actions as they relate to implementation of the new program. The operating experience in each AMP summary identifies past corrective actions that have resulted in program enhancements and provides objective evidence that the effects of aging have been, and will continue to be, adequately managed.

As described above, the existing Operating Experience process, in conjunction with the Corrective Action Program, has proven to be effective in learning from adverse conditions and events, and improving programs that address aging-related degradation. In order to provide additional assurance that internal and external operating experience related to aging management continues to be used effectively during the period of extended operation, Limerick will enhance its Operating Experience Program to:

1. Explicitly require the review of operating experience for aging-related degradation.

2. Establish criteria to define aging-related degradation. In general, the criteria will be used to identify aging that is in excess of what would be expected, relative to design, previous inspection experience and the inspection intervals.

3. Establish identification coding for use in identification, trending and communications of aging-related degradation. This coding will assist plant personnel in ensuring that, in addition to addressing the specific issue, the adequacy of existing aging management programs is assessed. Station personnel are required to periodically assess the performance of the aging management programs, including insights obtained through operating experience. This could lead to AMP revisions or the establishment of new AMPs, as appropriate.

4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.

5. Require review of external operating experience for information related to aging management, and evaluation of such information for potential improvements to LGS aging management activities. License Renewal Interim Staff Guidance (LR-ISG) documents will be reviewed as part of this external operating experience information as they are issued on an ongoing basis, capturing new insights or addressing issues that emerge from license renewal reviews. Other guidance documents such as GALL Revisions may not be explicitly considered unless communicated in the form of one of the above-listed NRC communication vehicles (e.g., RIS).

6. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging-related degradation to enhance the effectiveness of this aspect of the operating experience process. This training will be commensurate with their role in the process.

These enhancements will be implemented ~~within~~ ***no later than*** two years following receipt of the renewed operating licenses.

***In addition, if the operating experience enhancements described above are not implemented by the time the renewed licenses are issued, LGS will take the following actions:***

1. ***Review all License Renewal Interim Staff Guidance (LR-ISG) documents issued in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements to gain insights regarding aging management lessons learned for incorporation into LGS aging management activities.***

2. ***Review the first revision of NUREG-1801 issued after the enhancements are implemented, to capture significant aging management lessons learned that occur in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements. This review will identify significant guidance changes driven by industry operating experience that should be incorporated into LGS aging management activities.***

***Aging management related lessons learned from these review activities will be entered into the plant action tracking database for incorporation into credited LGS AMPs or into new LGS AMPs.***

As a result of the Fire Damper Functional Testing LRA Supplement provided in Enclosure D of this letter, LRA Sections A.2.1.17 and B.2.1.17 are revised as follows:

**A.2.1.17 Fire Protection**

The Fire Protection aging management program is an existing program that includes fire barrier visual inspections, and halon and carbon dioxide systems visual inspections and functional tests. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors and other materials that perform a fire barrier function. Periodic visual inspection and functional testing of the fire rated doors and ***visual inspection of fire rated*** dampers is performed to ensure that their functionality is maintained. The program also includes visual inspections and periodic operability tests of halon and carbon dioxide fire suppression systems using the National Fire Protection Association Codes and Standards for guidance.

**B.2.1.17 Fire Protection**

**Program Description**

The Fire Protection program is an existing program that manages the identified aging effects for the fire barriers and the halon and carbon dioxide systems and associated components through the use of periodic inspections and functional testing to detect aging effects prior to loss of intended functions. System functional tests and inspections are performed in accordance with guidance from National Fire Protection Association Codes and Standards. The program applies to piping, piping components, and piping elements, curbs, and fire barriers (doors and dampers, penetration seals, walls, and slabs). The environments for fire protection components are: air-indoor (uncontrolled) and air-outdoor.

The Fire Protection program is a condition and performance monitoring program whose monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation. The Fire Protection program provides for visual inspections of fire barrier penetration seals for signs of degradation such as loss of material, cracking, and hardening and loss of strength, through periodic inspection and functional testing. The program requires performance of visual inspections of not less than 10 percent of each type of penetration seal (except internal conduit seals which are not accessible for visual inspection) at least once per refueling cycle (24 months). The program specifies visual examinations of the fire barrier walls, ceilings, and floors in structures within the scope of license renewal at a frequency of at least once per 24 months. Periodic visual ***inspections*** and functional tests are used to manage the aging effects of fire doors ~~and dampers~~. The visual inspection frequency for fire doors is at least once per 24 months, and functional tests of closing mechanisms and latches for required doors is at least once per 6 months. Fire dampers shall be verified to be functional by visual inspection at least once per 24 months~~. In addition, a 10 percent sample of fire dampers shall be functionally tested at least once per 24 months.~~

The program also provides for aging management of external surfaces of the halon and carbon dioxide fire suppression system components through periodic functional tests and visual inspections for any loss of material.

These inspections and tests are implemented through station procedures and recurring task work orders. Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for proper disposition.

The program will be enhanced, as noted below, to provide reasonable assurance that the Fire Protection program aging effects will be adequately managed during the period of extended operation.

# Enclosure C

## LGS License Renewal Commitment List Changes

This Enclosure includes an update to the LGS LRA Appendix A, Section A.5 License Renewal Commitment List, as a result of the Exelon responses to Open Items:

**OI 3.0.3.2.13-1**
**OI 3.0.5-1**

- Note: For clarity, portions of the original LRA License Renewal Commitment List text are repeated in this Enclosure. Text from the original LRA or previous RAI responses 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 Open Item 3.0.3.2.13-1 provided in Enclosure A of this letter, LRA, Appendix A, Table A.5, pages A-56 and A-57, is revised as follows:

## A.5 License Renewal Commitment List

| NO. | PROGRAM OR TOPIC | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE |
|---|---|---|---|---|
| 30 | ASME Section XI, Subsection IWE | ASME Section XI, Subsection IWE is an existing program that will be enhanced to:<br><br>1. Manage the suppression pool liner and coating system to:<br>a. Remove any accumulated sludge in the suppression pool every refueling outage.<br>b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period.<br>c. Use the results of the ASME IWE examination to implement a coating maintenance plan to ***perform the following prior to the period of extended operation (PEO)***:<br>• ~~Perform local recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss.~~ ***Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified.***<br>• ~~Perform spot recoating of pitting greater than 50 mils deep.~~ ***Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low.***<br>• ~~Recoat plates with greater than 25 percent coating depletion.~~ ***For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss.***<br>**d.** ***Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO:***<br>• ***Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified.*** | Program to be enhanced prior to the period of extended operation.<br><br>Inspection schedule identified in commitment. | Section A.2.1.30<br><br>***LGS Letter dated 9/12/2012 OI 3.0.3.2.13-1*** |

| NO. | PROGRAM OR TOPIC | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE |
|---|---|---|---|---|
| | | • ***Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated in the outage they are identified.***<br>• ***For plates with greater than 25 percent coating depletion, the affected area will be recoated no later than the next scheduled inspection.***<br><br>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.<br><br>***2. Include the criteria used to determine when downcomer areas affected by corrosion will be recoated.***<br><br>***3. When IWE examinations are conducted, perform an ultrasonic thickness measurement on an area of submerged suppression pool liner affected by general corrosion.***<br><br>~~2.~~***4.*** Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting | | |

As a result of the response to Open Item OI 3.0.5-1 provided in Enclosure A of this letter, LRA, Appendix A, Table A.5, page A-63, is revised as follows:

## A.5 License Renewal Commitment List

| No. | Program Or Topic | Commitment | Implementation Schedule | Source |
|---|---|---|---|---|
| 46 | Operating Experience | The Operating Experience Program is an existing program that will be enhanced to:<br><br>1. Explicitly require the review of operating experience for aging-related degradation.<br>2. Establish criteria to define aging-related degradation.<br>3. Establish identification coding for use in identification, trending and communications of aging-related degradation.<br>4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.<br>5. Require review of external operating experience for information related to aging management, and evaluation of such information for potential improvements to LGS aging management activities.<br>6. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management.<br><br>***In addition, if the operating experience enhancements described above are not implemented by the time the renewed licenses are issued, LGS will take the following actions:***<br><br>***1. Review all License Renewal Interim Staff Guidance (LR-ISG) documents issued in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements to gain insights regarding aging management lessons learned for incorporation into LGS aging management activities.***<br><br>***2. Review the first revision of NUREG-1801 issued after the enhancements are implemented, to capture significant aging management lessons learned that occur in the period between receipt of the renewed LGS licenses and implementation of the operating experience enhancements.*** | Program to be enhanced ~~within~~ ***no later than*** two years following receipt of the renewed operating licenses | Section A.1.6<br><br>LGS Letter dated ***3/13***/~~March 13,~~ 2012<br>RAI B.1.4-1<br>RAI A.1-1<br><br>LGS Letter dated 7/11/2012<br>RAI B.1.4-3<br><br>***LGS Letter dated 9/12/2012 OI 3.0.5-1*** |

| No. | Program Or Topic | Commitment | Implementation Schedule | Source |
|---|---|---|---|---|
| | | ***This review will identify significant guidance changes driven by industry operating experience that should be incorporated into LGS aging management activities.***<br><br>***Aging management related lessons learned from these review activities will be entered into the plant action tracking database for incorporation into credited LGS AMPs or into new LGS AMPs.*** | | |

# Fire Damper Functional Testing LRA Supplement

## Background:

As stated in the SER with Open Items (page 3-105): "The LRA states that the program includes visual inspections of fire barrier walls, ceilings, floors, and penetration seals; and visual inspections and functional testing of fire doors, fire dampers, and halon and carbon dioxide systems." This is no longer correct as within the last year, Limerick surveillance procedures have been revised to only require damper functional testing when a damper failed a visual inspection.

## Exelon LRA Supplement:

The LGS LRA was submitted to the NRC for review on June 22, 2011. At that time, the procedures that implemented the requirements of the NRC-approved fire protection program for visual inspection of fire dampers also included functional testing of a 10 percent sample of the LGS fire dampers. Since the submittal of the LRA, reviews of plant and industry operating experience have been performed. These reviews concluded that routine functional testing of a 10 percent sample of fire dampers is not warranted. Therefore, plant procedures were revised to discontinue functional testing of a 10 percent sample of the fire dampers. However, functional testing of fire dampers is performed if visual inspections identify a condition that could impair its ability to close or, as necessary, after damper maintenance.

NUREG-1801, Revision 2, XI.M26, Fire Protection Program, requires visual inspection of fire barrier walls, ceilings, floors, doors, and other fire barrier materials performed in walkdowns at a frequency in accordance with an NRC-approved fire protection program. Fire dampers are included in this category of fire protection barriers that are subject to visual inspection. NUREG-1801 does not contain any requirement for functional testing of fire dampers.

The LGS NRC-approved fire protection program is described in UFSAR Appendix 9A and the Technical Requirements Manual section 3/4.7.7. As described in these documents, visual inspections of fire dampers shall be performed at least every 24 months; functional testing is not required.

This difference between the LRA and implementing procedures for fire damper inspections was identified during the NRC regional inspection concluded on June 21, 2012. Corrective action issue report 01380253 was issued to re-evaluate functional testing of a 10 percent sample of the LGS fire dampers. This review has been completed. The initial review to support the procedure changes, the re-review performed in issue report 01380253, and our current assessment conclude that functional testing of a 10 percent sample of the LGS fire dampers is not warranted based on the following:

- Functional testing of fire dampers is not required by NUREG-1801.
- Functional testing of fire dampers is not required as part of the NRC-approved fire protection program for LGS.
- Previously performed routine functional testing of 10 percent of the fire dampers has not identified any functional failures at LGS.
- There is no significant industry operating experience to support the continuation of functional tests for a sample of the LGS fire dampers.
- Functional testing is performed for fire dampers when visual inspections identify a condition that could impair the ability of the damper to close.
- LGS implementing procedures will be revised to provide additional detail regarding inspection criteria for drop/curtain type fire dampers.

Therefore, LRA Appendix A.2.1.17, page A-14, and Appendix B.2.1.17, page B-76, are revised, as shown in Enclosure B, to clarify that functional testing of a 10 percent sample of fire dampers at least once per 24 months is not performed. This change is consistent with the recommendations of NUREG-1801, Revision 2.

# Enclosure E

## Comments Related to Safety Evaluation Report with Open Items

## Limerick Generating Station, Units 1 and 2

**The table on the following pages contains comments and suggestions for NRC staff consideration, based upon Exelon's review of the Limerick Generating Station, Units 1 and 2 Safety Evaluation with Open Items (SER).**

**An item number is provided in column 1, the SER Section number is given in column 2, the SER page number is listed in column 3 and the comment is provided in column 4.**

**Exelon Comments on Safety Evaluation Report With Open Items Related to the License Renewal of Limerick Generating Station, Units 1 and 2**

Where suggested changes to the SER are provided, they are highlighted with ***bolded italics*** for inserted text and strikethroughs for deleted text.

| # | Section # | Page # | Comment |
|---|---|---|---|
| 1. | Table 1.4-1 | 1-7 | LR-ISG-2011-05 is final (not a draft) |
| 2. | 2.1.4.2.2 | 2-13 | Recommend that the 2nd sentence in the 2nd full paragraph be revised to: "The staff determined that the applicant, following its review, ~~revised the method and its implementation relative to~~ ***consistently evaluated*** nonsafety-related pipe containing branch connections..." Reference the Exelon response to RAI 2.1-4 which states that that the issue was "a result of not applying the scoping methodology discussed in LRA Section 2.1.5.2 consistently for some piping configurations that include branch connections." |
| 3. | 2.1.4.2.2 | 2-14 | The end of the 1st sentence in the last paragraph should be revised to "...up to and including an ~~identified~~ anchor or bounding condition ***identified on the boundary drawing***." The end of the 2nd sentence should be revised to "....bounding condition ***on the boundary drawing.***" These clarifications are consistent with the Exelon response to RAI 2.1-6. |
| 4. | 2.1.4.2.2 | 2-16 | Recommend deleting the following sentence in the middle of the page, "However, the method the applicant described during the scoping and screening methodology audit was not in agreement with the method described in the LRA or the 10 CFR 54.4(a)(2) implementing procedure." It is also recommended that the following sentence be revised to: "The staff determined that the applicant had confirmed that the method documented in the LRA and the 10 CFR 54.4(a)(2) implementing procedure was correct and performed an extent of condition review to confirm that the method described in the LRA and the 10 CFR 54.4(a)(2) procedure had been applied~~, as opposed to the method the applicant described during the scoping and screening methodology audit~~." This clarification is consistent with the Exelon response to RAI 2.1-6. During the audit, Exelon staff indicated that anchors or bounding conditions were not consistently identified on the LR drawings if they were within the spatial interaction boundary. |
| 5. | 2.3.2.2.1 | 2-36 | Delete the 2nd paragraph in Section 2.3.2.2.1: "The CS system includes the core support subcomponents and other reactor vessel internal components." These components are included in the Reactor Vessel Internals system. |
| 6. | 2.3.2.2.1 | 2-36 | Recommend deleting the 3rd paragraph in Section 2.3.2.2.1: "The following highlighted license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR." There are no license renewal drawings with the SER. |
| 7. | 2.3.2.2.1<br>2.3.2.3.1<br>2.3.2.4.1<br>2.3.2.5.1<br>2.3.3.5.1 | 2-36<br>2-37<br>2-38<br>2-39<br>2-46 | For the Core Spray, HPCI, RCIC, RHR and CRD Systems, the intended function "Maintains the RCPB Integrity" should not be listed. For these plant systems, the LR system boundary was defined as up to the RCPB system boundary, and the RCPB components were subsumed into the license renewal "RCPB System". Also, the intended functions listed should be consistent with those listed in the LRA for each system. |
| 8. | 2.3.3.7 | 2-47 | Recommend revising the 1st sentence in the 2nd paragraph in Section 2.3.3.7.1 to be consistent with the LRA: "The intended function of the EDG enclosure ***ventilation system*** is to maintain…" |
| 9. | 2.4.7.1 | 2-88 | In the 2nd paragraph, recommend revising to: "The purpose of the reinforced concrete cooling tower ***basins….***" |

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| # | Section # | Page # | Comment |
|---|---|---|---|
| 10. | 2.5.1.1 | 2-97 | The 2nd bullet on list, the last line on the page, should read: "fuse holders***: metallic clamps*** - electrical continuity" per the Exelon response to RAI B.2.1.40-2. |
| 11. | 2.5.1.1 | 2-98 | The 2nd bullet at top of page, should read: "insulation material for electrical cables and connections – ~~electrical conductivity~~ ***insulate (electrical)***" per the Exelon response to RAI B.2.1.40-2. |
| 12. | 2.5.1.2 | 2-98 | Following the 2nd paragraph, the indented, "quoted" paragraph is from the April 1, 2002 letter attachment. The words in Section 2.5.2.1.1 of the SRP are slightly different. Recommend that this paragraph be revised to use precise wording from Revision 2, Section 2.5.2.1.1 of the SRP. |
| 13. | 2.5.1.2 | 2-99 | The 1st sentence at the top of the page should read: "The applicant included the ~~complete~~ circuits between the plant electrical ***distribution system and the electrical*** transmission network up to and including the circuit breakers between the switchyard bus and the offsite transmission lines." This is consistent with the LRA. |
| 14. | 3.0.1.2 | 3-3 | The 1st first paragraph lists system groupings and system names that are not LGS groupings or license renewal systems. Recommend revising the paragraph to list correct LGS license renewal system names. |
| 15. | 3.0.1.2 | 3-3 | The 2nd second bullet references LRA Table 2.0-1, but should instead reference Table 2.1-1. |
| 16. | Table 3.0.3-1 | 3-8<br>3-9 | Programs B.2.1.3 and B.2.1.15 should not reference SER Sections 3.0.3.1.3 and 3.0.3.1.9 respectively; they should be relocated to SER Section 3.0.3.2 because they have an exception or enhancements. |
| 17. | 3.0.3.1 | 3-11 | Program B.2.1.3 has an exception and program B.2.1.15 has enhancements. These programs are incorrectly listed in this Section (consistent with the GALL Report) and should be moved to Section 3.0.3.2 (consistent with GALL Report with exceptions or enhancements). |
| 18. | 3.0.3.1.1 | 3-12 | In the 4th line up from the bottom of the page, following "emergency service water", the (SW) should be deleted. (***ESW***) is the proper abbreviation. |
| 19. | 3.0.3.1.2 | 3-14 | The 1st paragraph under "Operating Experience" states that there was an issue with the stability of soluble iron. It should be ***insoluble*** iron. |
| 20. | 3.0.3.1.3 | 3-15 | Program B.2.1.3 should be relocated to Section 3.0.3.2 because it includes an exception. |
| 21. | 3.0.3.1.4 | 3-21 | In the 1st paragraph of the Operating Experience Section, the 4th line should be revised to "...brace support pad~~s~~ welds, the feedwater sparger~~, the~~ ***attachment welds***, ..." |
| 22. | 3.0.3.1.6 | 3-25 | From the middle to the end of the 3rd paragraph, the references to LRA Item 3.2.1-54 should be revised to be "LRA ***Table 3.2.1***, Item 3.2.1-54" to provide easier reference to LRA location. |
| 23. | 3.0.3.1.7 | 3-34 | The 3rd sentence from the bottom of the last paragraph should be revised to " ...(i.e., CRD housing and incore monitor penetrations) are addressed in LRA Section 4.3.3 and LRA Table~~s~~ 4.3.3-1~~ and 4.3.3-2~~." LRA Table 4.3.3-2 addresses Environmental Fatigue Analysis Results for Piping and not RPV components. |
| 24. | 3.0.3.1.8 | 3-36 | The Operating Experience Section should be revised to: "The LRA also described additional inspections ***performed*** during outage***s***. These inspections led to replacement of selected 1~~.25 percent chromium,~~ large- and small-bore piping~~,which is not susceptible to this aging mechanism~~ ***with FAC resistant material containing 1.25 percent chromium.***" |

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| # | Section # | Page # | Comment |
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| 25. | 3.0.3.1.9 | 3-37 | Program B.2.1.15 should be relocated to Section 3.0.3.2 because it includes enhancements. |
| 26. | 3.0.3.1.16 | 3-51 | "***Lube oil***" is missing from the list of environments in the middle of the last paragraph. Lube oil is included in LRA Section B.2.1.26, and is discussed in the Exelon response to RAI B.2.1.26-2. |
| 27. | 3.0.3.1.16 | 3-51 | "***Loss of fracture toughness, reduction of heat transfer, and cracking"*** are missing from the list of aging effects in the middle of the last paragraph where aging effects are listed. These aging effects were added to the list of applicable aging effects in the Exelon response to RAI B.2.1.26-1. |
| 28. | 3.0.3.1.17 | 3-55 | Recommend revising the first OE example discussed to: ~~The applicant stated that as~~ "***As*** a result, the RCIC pump bearings were flushed and the oil replaced." The LRA OE discussion states that a recommendation was made to flush the bearings and replace the oil but does not state that the flush and refill were actually performed. A check of the Issue Report revealed that the bearings were actually flushed and refilled per the recommendation. |
| 29. | 3.0.3.1.18 | 3-58 | Recommend revising the 3rd sentence in the 2nd paragraph to: "... the CS system isolation valves associated with 206A-D, 207A and B, 208B***, and 235***; the HPCI system isolation valves associated with penetrations 209, 210, 212, ~~235,~~ and 236; and the RCIC..." As discussed in the Exelon response to RAI B.2.1.33-1, penetration 235 is associated with the Core Spray system. |
| 30. | 3.0.3.1.18 | 3-58 | Revise the first sentence of the 3rd paragraph as follows: "The staff reviewed Table 6.2-25 of the UFSAR ***and the Exelon response to RAI B.2.1.33-1,*** and verified that for all penetrations (with the exception of penetration~~s 238, 239 and~~ 240) ~~it states that~~ the isolation provisions consist of ..." Reference the Exelon response to RAI B.2.1.33-1. |
| 31. | 3.0.3.1.19 | 3-61 | The 2nd sentence in the 1st paragraph for "Operating Experience" states that "... LGS performs periodic insulation resistance tests and has replaced several cables before failures." This sentence is not applicable to the LGS Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program and should be deleted. |
| 32. | 3.0.3.1.19 | 3-61 | Recommend that the 3rd sentence in the 1st paragraph be revised to: "... inspections have identified ~~insulation cracking,~~ ***cable jacket cracking and*** embrittlement~~, and bubbling~~ that were repaired with no loss of function." Per the operating experience discussion in LGS LRA Section B.2.1.38, inspections have identified cable jacket cracking and embrittlement. There has been no observed damage to cable insulation or bubbling of cable jackets. |
| 33. | 3.0.3.1.20 | 3-63 | Section on "Staff Evaluation," 2nd paragraph, 2nd line should read: "… to 10 CFR 50.49 Environmental Qualification Requirements ***Used In Instrumentation Circuits*** program, the staff finds that …" |
| 34. | 3.0.3.2 | 3-79 | Programs B.2.1.3 and B.2.1.15 should be listed on this page and included in this Section because they contain an exception or enhancements. |
| 35. | 3.0.3.1.25 | 3-79 | Under "UFSAR Supplement" paragraph, the reference to SRP-LR Table 3.0-1 should be changed to SRP-LR Section 4.4.3.2. SRP-LR Table 3.0-1 does not include recommended UFSAR Supplement wording for GALL Report AMP X.E1. |

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| # | Section # | Page # | Comment |
|---|---|---|---|
| 36. | 3.0.3.2.2 | 3-84 | Recommend revising the 2nd sentence in the paragraph below the list of BWRVIP Reports to: "In addition, Appendix C addresses the applicant's response to ~~other~~ ***the*** license renewal action items." There are no "other" action items. |
| 37. | 3.0.3.2.2 | 3-85 | Recommend that the 2nd sentence in the evaluation of Enhancement 2 be revised to: ".... because when it is implemented it will have reviewed ~~the CMTR for~~ each CASS component and the neutron exposure of the component for the period of extended operation." The 3rd sentence can be deleted because chemical composition, and therefore CMTRs, is not evaluated in determining susceptibility to neutron embrittlement. Chemical composition is only required to determine susceptibility to thermal aging embrittlement as discussed in the evaluation of Enhancement 1. This is consistent with the Exelon response to RAI 3.1.1.99-1. |
| 38. | 3.0.3.2.2 | 3-85 | Recommend revising the last sentence in the evaluation of Enhancement 3 to: ".... will be inspected for evidence of subcritical cracking ~~or wear~~ that could cause failure...." This is consistent with GALL Report AMP XI.M9 Element 3, which states that the program does not directly monitor for loss of fracture toughness ... monitors for cracking. |
| 39. | 3.0.3.2.2 | 3-87 | Recommend revising the 1st sentence in the 1st paragraph to "... address the aging effects on the reactor vessel ~~internal~~ components." Also correct the last sentence in the 1st paragraph to: "The following paragraphs address the TLAAs and the AMP related to reactor vessel ~~internal~~ components specified in the ..." BWRVIP-74-A Report addresses RPV components, not internal components. |
| 40. | 3.0.3.2.4 | 3-94 | Revise the discussion for Enhancement No. 1, 2nd paragraph, last sentence to: "The applicant committed (Commitment No. 12), to inspect ~~non~~safety-related SW system piping at a minimum of ~~five~~ ***ten*** locations ~~per unit~~ each refueling outage interval, which will result in 50 inspections in 10 years." Also, within the discussion for Enhancement No. 1, the 1st sentence in the third paragraph should be revised to read: "…similar operating conditions (see discussion of applicant's response in Enhancement ~~2~~***5***)…" These changes are consistent with the Exelon response to RAI B.2.1.12-3. |
| 41. | 3.0.3.2.4 | 3-95 | Recommend revising the discussion of Enhancement 3, 2nd sentence to: "In this enhancement, the applicant stated that it will replace the supply and return piping for the core spray pump compartment coolers with stainless steel piping ~~by the end of 2014~~ ***prior to the PEO***." This is consistent with the revision to LRA Table A-5, commitment 12, provided with the Exelon response to RAI B.2.1.12-1. |
| 42. | 3.0.3.2.4 | 3-95 | Recommend revising the discussion of Enhancement 4, 2nd sentence to: "In this enhancement, the applicant stated that it will replace the degraded RHRSW piping in the pipe tunnel ~~by the end of 2015~~ ***prior to the PEO***." This is consistent with the revision to LRA Table A-5, commitment 12, provided with the Exelon response to RAI B.2.1.12-1. |

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| # | Section # | Page # | Comment |
|---|---|---|---|
| 43. | 3.0.3.2.5 | 3-99 | Recommend revising the 4th paragraph in the Staff Evaluation to: "... the applicant stated that SCC is not applicable because ~~the temperature of the closed cooling water environment is below 60° C (140° F) for all of the systems managed by the Closed Treated Water Systems program~~ ***there are no stainless steel components in these systems exposed to closed-cycle cooling water > 60°C (140°F).***" This change is consistent with the Exelon response to RAI B.2.1.13-1. |
| 44. | 3.0.3.2.7 | 3-105 | The Summary of Technical Information in the Application should be revised to read: "The LRA states that the program includes visual inspections of fire barrier walls, ceilings, floors, ***fire dampers,*** and penetration seals; and visual inspections and functional testing of fire doors~~, fire dampers,~~ and the halon and carbon dioxide systems." This change is consistent with the LRA Supplement within Enclosure D of this letter. |
| 45. | 3.0.3.2.9 | 3-112 | Recommend revising the 2nd paragraph to: "...(c) the first inspection will be conducted ***within*** 5 years prior to entering the period of extended operation..." This is consistent with LRA Table A-5 commitment 19, as revised by the Exelon response to RAI B.2.1.19-1. |
| 46. | 3.0.3.2.9 | 3-113 | Recommend revising the discussion of Enhancement 1, 2nd sentence, to "... backup water storage tank once ***within*** 5 years prior to the period of extended operation..." and the 5th sentence to: "...and noted that the "detection of aging effects" program element recommends that the inspection of the tank should occur within 5 years of entering the period of extended operation.~~ rather than 5 years prior to the period of extended operation."~~ This is consistent with LRA Table A-5 commitment 19 as revised by the Exelon response to RAI B.2.1.19-1. |
| 47. | 3.3.3.2.9 | 3-114 | Recommend revising the UFSAR Supplement discussion to: "...(a) conduct UT measurements of the backup water storage tank's bottom ***within*** 5 years prior to entering..." This is consistent with LRA Table A-5 commitment 19. |
| 48. | 3.0.3.2.10 | 3-117 | In the discussion of enhancement 4, revise the 1st line on page 3-117 to: "...microbiological organisms for the diesel generator ~~day~~ ***diesel oil storage*** tanks." This is consistent with LRA Table A-5, commitment 20. |
| 49. | 3.0.3.2.11 | 3-120 | In the first paragraph, delete the sentence "The coupons in each spent fuel pool (SFP) were subsequently relocated to a representative location." This is consistent with the Exelon response to RAI B.2.1.28-2. |
| 50. | 3.0.3.2.11 | 3-120 | Revise the last sentence in the bottom paragraph as follows: "The applicant stated that the coupon testing proposed for LGS ***is consistent with GALL*** and will monitor ..." This is consistent with the Exelon response to RAI B.2.1.28-3. |
| 51. | 3.0.3.2.11 | 3-121<br>3-122 | This Section currently reflects the original two enhancements from the LRA. Enhancement 1 has been revised and enhancements 3 and 4 have been added per the Exelon responses to RAIs B.2.1.28-1 and B.2.1.28-2. The enhancement discussion and UFSAR Supplement discussion should be updated accordingly. |
| 52. | 3.0.3.2.12 | 3-124 | The continued sentence at the top of the page should be revised to: "…..by NACE SP0169-2007, and the ***plant drainage*** piping is not cathodically protected because….." |

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| # | Section # | Page # | Comment |
|---|---|---|---|
| 53. | 3.0.3.2.12 | 3-126 | Under Enhancement 2, the staff stated that they saw before and after pictures of the EDG fuel oil piping. The before and after pictures that were provided to the staff during the audits were the underground Safety Related Service Water system pipes that were inspected and coated. This discussion should be removed from Enhancement 2 and placed in the discussion under Enhancement 4 or 5. |
| 54. | 3.0.3.2.14 | 3-142 | In paragraph 4, under enhancement, the 2nd sentence should be revised to: "In this enhancement, the applicant stated that the ASME Code, Section XI, Subsection IWL program will be enhanced to ~~start the implementation of the evaluation criteria of the primary containments' concrete from~~ ***include*** the second tier acceptance criteria of ACI 349.3R***.***" This is consistent with LRA Table A-5, commitment 31. |
| 55. | 3.0.3.2.14 | 3-144 | In paragraph 2, the last sentence should be revised to: "Additional degradation, if any, of the Q-deck and ~~shear studs~~ ***structural steel beams*** will be managed by the Structures Monitoring program during the period of extended operation." This is consistent with the Exelon response to RAI B.2.1.31-3. |
| 56. | 3.0.3.2.15 | 3-145 | In paragraph 4, the 1st sentence should be revised to: "In its response dated February 28, 2012, the applicant stated that its procedures have been revised to ~~include~~ ***clarify that*** ASME Code Class MC supports ~~for visual inspection~~ ***are visually inspected*** in accordance...." This is consistent with the Exelon response to RAI B.2.1.32-1. |
| 57. | 3.0.3.2.17 | 3-152 | Under staff evaluation, paragraph 4, the 3rd sentence should be revised to: "The staff also noted that girders are visually examined as recommended by ACI 349.3R-02 once every five years for signs of deterioration, rust stains, and ~~volumetric increase~~ ***concrete cracking***." |
| 58. | 3.0.3.2.17 | 3-153 | The discussion of Enhancement #3, the 2nd sentence should be revised to: "In this enhancement, the applicant stated that the ground water chemistry will be monitored on a frequency not to exceed 5 years for pH, chlorides and sulfates***, and*** ~~to~~ verify that it remains non-aggressive, or ***evaluate*** results ~~that~~ exceed***ing*** criteria ~~will be evaluated~~ to assess ~~the~~ impact, if any, on below-grade concrete." This is consistent with LRA Table A-5, commitment 35. |
| 59. | 3.0.3.2.17 | 3-157 | In paragraph #4, the 4th sentence should be revised to: "A further assessment of this condition indicated that the degraded urethane elastomeric bearing pads between the beam end bearing plates and the concrete ledge resulted in ~~both a settlement and~~ a rotation***al change in alignment*** ~~and changes in the alignment~~ of the beams ~~with the pedestal support~~ ***due to the one-half inch downward displacement at one end***." This is consistent with the Exelon response to RAI B.2.1.35-2. |
| 60. | 3.0.3.2.20 | 3-166 | In the 5th paragraph, line 4 should be revised to: "The TLAA evaluations in LRA Sections ~~4.3.4~~, 4.3.5, 4.6.5 and 4.6.7 are dispositioned ..." The disposition to the TLAA evaluated in LRA Section 4.3.4 was changed from 10 CFR 54.21(c)(1)(i) to 10 CFR 54.21(c)(1)(iii) per the Exelon response to RAI 4.3-10. |
| 61. | 3.0.5.2 | 3-174 | The 2nd-to-last sentence in the 1st full paragraph should be revised to: "The applicant also states that these enhancements will be completed ~~during the first 10 years of~~ ***prior to*** entering the period of extended operation (PEO)." This is consistent with the revision to LRA Table A-5 commitment 46, provided within the Exelon response to RAI A.1-1. |

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| 62. | 3.0.5.2 | 3-175 | Recommend revising the 8th sentence of the 1st full paragraph to: "The applicant further states that NRC License Renewal Interim Staff Guidance (LR-ISG) documents ~~have been~~ ***will be*** added to the scope of documents." This is consistent with the Exelon response to RAI B.1.4-1. |
| 63. | 3.0.5.2 | 3-176 | The 5th sentence in the 1st paragraph should be revised to: "~~The response further states that CAP~~ ***The applicant further stated that*** personnel ~~are~~ ***will be*** required to periodically assess..." As described in the Exelon response to RAI B.1.4-1, this is part of the enhancement package that will become effective upon implementation of the enhancements, not a current requirement. |
| 64. | 3.0.5.2 | 3-177 | Recommend that the 3rd sentence of the final paragraph be revised to: "The applicant stated that guidance ~~will~~ ***is expected to*** include the following:" Also, the 2nd sentence should be revised to: "....the Operating Experience program will be enhanced to include guidance ~~to~~ ***for*** reporting plant-specific operating experience to the industry." This is consistent with the Exelon response to RAI B.1.4-1. |
| 65. | 3.0.5.3 | 3-178 | The 1st sentence of the 2nd paragraph of Section 3.0.5.3 incorrectly refers to Exelon's response to RAI B.1.4-1 as having provided the new UFSAR supplement Section A.1.6. It should refer to Exelon's response to RAI A.1-1. |
| 66. | Table 3.1-1 | 3-181 | For Item Number 3.1.1-2, the Column "AMP in LRA, Supplements, or Attachments" should indicate "***Not applicable.***" |
| 67. | Table 3.1-1 | 3-182 | For Item Number 3.1.1-5, the Column "AMP in LRA, Supplements, or Attachments" should indicate "***Not applicable***." |
| 68. | Table 3.1-1 | 3-183 | For Item Number 3.1.1-7, the Column "AMP in LRA, Supplements, or Attachments" should indicate "***TLAA***." |
| 69. | Table 3.1-1 | 3-191 | For Item Number 3.1.1-41, the "Staff Evaluation" column should state "Not applicable ***to LGS*****"** to be consistent with the other Item Numbers evaluation statements that are applicable to BWRs, but not to LGS. |
| 70. | Table 3.1-1 | 3-193 | For Item Number 3.1.1-50, the "Staff Evaluation" column should state "***Not applicable to LGS*** (see SER Section 3.1.2.1.1)" to be consistent with the other Item Numbers evaluation statements that are applicable to BWRs, but not to LGS. |
| 71. | 3.1.2.1.1 | 3-206 | The last paragraph should reference CASS valve bodies as well as pump casings as components that use AMR line item number 3.1.1-50 in Table 3.1-1. The last 2 sentences should be revised to: "As addressed in GALL Report AMP XI.M12, ~~the~~ pump casing***s and valve bodies*** do~~es~~ not require material screening for susceptibility to thermal aging embrittlement and the existing ASME Code Section XI inspection requirements are adequate to manage loss of fracture toughness due to thermal aging embrittlement ~~of the pump casing~~. In addition, LRA Table 3.1.1, item 3.1.1-38 addresses the applicant's aging management for loss of fracture toughness of the Class 1 CASS pump casing***s and valve bodies***." |
| 72. | 3.1.2.1.1 | 3-207 | Revise the 1st line in the 3rd paragraph to: "... because there are no ***stainless*** steel or high-strength ..." This is consistent with the response to RAI 3.1.2.1.1-1. |

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| # | Section # | Page # | Comment |
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| 73. | 3.1.2.1.3 | 3-209 | The 2nd sentence in the 2nd paragraph should be revised to: " ...ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD***, One-Time Inspection of ASME Code Class 1 Small-bore Piping, and Water Chemistry programs,*** consistent with the GALL Report." The next sentence should also be revised to: "The staff's evaluations of the ***ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD,*** One-Time Inspection ***of ASME Code Class 1 Small-bore Piping,*** and the Water Chemistry programs are documented in SER Sections **3.0.3.1.1**, 3.0.3.1.~~12~~***14*** and 3.0.3.1.2, respectively." |
| 74. | 3.1.2.1.4 | 3-210 | The middle of the 2nd paragraph should be revised to: "...(RWCU B and C pump casings) on both LGS, Units 1 and 2~~, RWCU pumps since 2000 does not indicate~~ ***have not had*** any indication of flaws, cracking or leakage from the pump casings. In its response ~~to the applicant's aging management methods~~, the applicant ~~indicicted~~ ***indicated*** that***,*** consistent with the ....." |
| 75. | 3.1.2.3.3 | 3-228<br>3-229 | The last 2 paragraphs on page 3-228 and the 1st paragraph on page 3-229, are in conflict with the discussion in Section 3.1.2.1, page 3-206 that references the Exelon responses to RAIs 3.1.2.3-1 and 4.6.9-1 which resulted in revising the AMR to delete reference to the BWR Vessel Internals program and Note 5 in LRA Table 3.1.2-3, and to only credit use of TLAA to manage loss of preload of jet pump slip joint clamp components. The NRC staff found this approach acceptable as documented in SER Sections 3.1.2.1 and 4.6.9. |
| 76. | 3.2.2.1 | 3-243 | Revise the 1st paragraph (to be consistent with the Exelon response to RAI 3.2.2.1.1-1) as follows: "are visually inspected for loss of material and loss of preload ***whenever the expansion joint is replaced, which is planned on a*** ~~at least once every~~ 12-year ~~replacement interval~~ ***frequency***. The applicant further stated that the submerged bolts in the fuel pool cooling and cleanup system, and the circulating water system are visually inspected for loss of material and loss of preload ***when the fuel pool weir plates are adjusted and when the circulating water screens are removed, which normally occurs during*** ~~every~~ refueling outage***s*** ~~during planned maintenance~~." |
| 77. | 3.2.2.3.2 | 3-253 | Revise the last sentence in the 5th paragraph as follows: "cite plant-specific note 5, which states that ***although*** NUREG-1801 does not provide a line ~~in which~~ ***for*** zinc piping components***, they are susceptible to loss of material and*** are inspected per the Lubricating Oil Analysis program." |
| 78. | Table 3.3-1 | 3-258 | For Item 3.3.1-4 the Staff Evaluation column should be revised to: "~~Not applicable to LGS~~ ***Consistent with the GALL Report*** (see Section 3.3.2.2.3)." SER Section 3.3.2.2.3 concludes that, consistent with Exelon response to RAI B.2.1.25-1.1, that aging management is consistent with the GALL Report. Also, the column for "AMP in LRA, Supplements or Amendments" should list the "**External Surfaces Monitoring of Mechanical Components.**" |
| 79. | Table 3.3-1 | 3-259 | For Item 3.3.1-13 the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 80. | Table 3.3-1 | 3-261 | For Items 3.3.1-23 and 3.3.1-24, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |

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| 81. | Table 3.3-1 | 3-262 | For Items 3.3.1-30 and 3.3.1-31, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 82. | Table 3.3-1 | 3-263 | For Items 3.3.1-34 and 3.3.1-35, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 83. | Table 3.3-1 | 3-264 | For Items 3.3.1-37 and 3.3.1-39, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 84. | Table 3.3-1 | 3-265 | For Item 3.3.1-47, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 85. | Table 3.3-1 | 3-270 | For Item 3.3.1-79, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 86. | Table 3.3-1 | 3-273 | For Item 3.3.1-96, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 87. | Table 3.3-1 | 3-274 | For Item 3.3.1-107, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 88. | Table 3.3-1 | 3-275 | For Items 3.3.1-108, 3.3.1-109x, and 3.3.1-110 the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.3-1 that are applicable to BWRs, but not LGS. |
| 89. | 3.3.2.1 | 3-280 | The 1st line in the last paragraph should be revised to: "... the applicant ~~performed and~~ assessed the design and operating conditions..." |
| 90. | 3.3.2.1 | 3-284 | The 2nd to last sentence in the 2nd paragraph, revise to: "... pitting, crevice ***corrosion***, and MIC....." |
| 91. | 3.3.2.1.5 | 3-290 | The 1st sentence in the 1st paragraph in Section 3.3.2.1.5, revise to: "... pitting, crevice ***corrosion***, and MIC." |
| 92. | 3.3.2.1.8 | 3-292 | The 1st sentence in the 1st paragraph in Section 3.3.2.1.8, revise to: "... pitting, crevice ***corrosion***, and MIC; ..." |
| 93. | 3.3.2.1.8 | 3-292 | In the last sentence in the 1st paragraph in Section 3.3.2.1.8, the title of GALL Report AMP XI.M27 should be revised to: "Fire Water ***System***." |
| 94. | 3.3.2.1.10 | 3-293 | In the 2nd paragraph in Section 3.3.2.1.10, the date of the letter containing the Exelon response to RAI B.2.1.26-2 is not correct. Correct to February 15, 2012. |
| 95. | 3.3.2.1.10 | 3-293 | In the 2nd paragraph in Section 3.3.2.1.10, recommend that the 2nd sentence be revised to: "... the applicant stated, the ~~fuel oil~~ environment associated with these components i~~n~~***s*** dirty fuel oil, ***which*** has similar attributes to..." |
| 96. | 3.3.2.1.11 | 3-294 | In the 3rd paragraph in Section 3.3.2.1.11, recommend that the 2nd sentence be revised to: "... the applicant stated that t~~)~~he ~~fuel oil~~ environment associated with these components i~~n~~***s*** dirty fuel oil, ***which*** has similar attributes to..." |
| 97. | 3.3.2.1.18 | 3-299 | In the 1st sentence in the 1st paragraph in Section 3.3.2.1.18, revise to: "... pitting, crevice ***corrosion***, and MIC." |
| 98. | 3.3.2.2.1 | 3-300 | In the 1st paragraph in Section 3.3.2.2.1, recommend that the 1st sentence be revised to: "... exposed to indoor, uncontrolled air ~~externally~~, and ..." |

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| 99. | 3.3.2.2.3 | 3-302 | In the 1st full paragraph, recommend that the last 2 sentences in the paragraph be deleted since they are redundant to the 1st sentence in the paragraph. |
| 100. | 3.3.2.3.4 | 3-306 | Recommend rewording the end of the 3rd sentence in the last paragraph to: "... found to manage this aging ***effect*** in GALL Report AMP XI.M12 ~~but which could not be applied with these ASME Code, Class 3 components~~. Also, add a space between "than" and "140$^{o}$ F" in the second to last line in the last paragraph. |
| 101. | 3.3.2.3.13 | 3-313 | The last sentence in the 4th paragraph, revise to: "... pitting, crevice ***corrosion***, and MIC; ..." |
| 102. | 3.3.2.3.19 | 3-316 | Recommend rewording the end of the 3rd sentence in the last paragraph to: "... found to manage this aging ***effect*** in GALL Report AMP XI.M12 ~~but which could not be applied with these ASME Code, Class 3 components~~. Also, the reference to LRA AMP is incorrect. Revise to: "... applicant stated that LRA AMP B.2.1.~~1~~26 and..." |
| 103. | Table 3.4-1 | 3-321 | For SRP-LR Item No. 3.4.1-2 the AMP in LRA, Supplements or Amendments column should indicate the "***External Surfaces Monitoring of Mechanical Components***" program. Also, the Staff Evaluation column should indicate "***Consistent with the GALL Report***", as discussed in SER Section 3.4.2.2.2. |
| 104. | Table 3.4-1 | 3-321 | For Item 3.4.1-9, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.4-1 that are applicable to BWRs, but not LGS. |
| 105. | Table 3.4-1 | 3-323 | For Item 3.4.1-20, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.4-1 that are applicable to BWRs, but not LGS. |
| 106. | Table 3.4-1 | 3-326 | For Item 3.4.1-38, the Staff Evaluation column should include the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.4-1 that are applicable to BWRs, but not LGS. |
| 107. | Table 3.4-1 | 3-327 | For Item 3.4.1-50x, the Staff Evaluation column should the statement "***Not applicable to LGS***" to be consistent with other line items in Table 3.4-1 that are applicable to BWRs, but not LGS. |
| 108. | 3.4.2.1 | 3-330 | Recommend revising the 3rd Paragraph to: "… piping elements, and tanks exposed to treated ~~borated~~ water greater than 60$^{o}$C ...." The item description does not include borated water, only treated water. |
| 109. | 3.5.2.3 | 3-389 | In discussing the Radwaste Enclosure, the last sentence in the first paragraph should be revised to: "....lead ~~permanent drywell shielding plugs~~ ***penetration seals*** exposed to ... " |
| 110. | 3.6.2.2.2 | 3-406 | In the 1st full paragraph, the first sentence references revision 0 of the EPRI LR Electrical Handbook - 1003057. Recommend referencing Revision 1 to this handbook, 1013475, issued in February 2007. |
| 111. | 3.6.2.2.2 | 3-406 | Recommend revising the 1st sentence in the 2nd new paragraph, to "~~programs identified~~ ***evaluations*** above." There are no plant specific programs for the high voltage insulators. |
| 112. | 3.6.2.2.3 | 3-409 | Recommend revising the 1st sentence In the 2nd paragraph, to "~~programs identified~~ ***evaluations*** above." There are no plant specific programs for the transmission conductors, transmission connectors and switchyard bus and connections. |

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| 113. | 4.7 | 4-93 | In the 1st paragraph, line 10: The last sentence concludes that no plant-specific, TLAA-based exemptions are in effect. However, the Exelon response to RAI 4.1-3 revised LRA Section 4.1.5 and described two exemptions based on TLAAs that were justified for continuation through the period of extended operation. |
| 114. | Appendix B | B-1 | Missing correspondences:<br>• AMP Audit report dated 2/28/12<br>• Summary of conference call held 2/23/12, dated 4/11/12<br>• Summary of conference call held 1/4/12, dated 7/16/12 |