From: Christopher.Wilson2@exeloncorp.com
Sent: Tuesday, March 13, 2012 9:32 AM
To: Kuntz, Robert
Subject: FW: Emailing: 3.13.12 - LIM - Response to RAI dated 2.14.12 & 2.16.12 re. LGS LRA.pdf
Attachments: 3.13.12 - LIM - Response to RAI dated 2.14.12 & 2.16.12 re. LGS LRA.pdf

<<3.13.12 - LIM - Response to RAI dated 2.14.12 & 2.16.12 re. LGS LRA.pdf>> Rob

Letter just sent to DCC

Chris Wilson
Exelon Nuclear
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Hearing Identifier: Limerick_LR_NonPublic
Email Number: 1053

Mail Envelope Properties (9A15F707EB47A04D882D9FEB352EDDF803B62FF0)

Subject: FW: Emailing: 3.13.12 - LIM - Response to RAI dated 2.14.12 & 2.16.12 re. LGS LRA.pdf
Sent Date: 3/13/2012 9:31:42 AM
Received Date: 3/13/2012 9:30:27 AM
From: Christopher.Wilson2@exeloncorp.com

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Recipients:
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Tracking Status: None

Post Office: cccmsxch12.energy.power.corp

Files	Size	Date & Time
MESSAGE	1128	3/13/2012 9:30:27 AM
3.13.12 - LIM - Response to RAI dated 2.14.12 & 2.16.12 re. LGS LRA.pdf	769298	

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

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Nuclear

10 CFR 50
10 CFR 51
10 CFR 54

March 13, 2012

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

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

Subject: Response to NRC Requests for Additional Information, dated February 14 and February 16, 2012, related to the Limerick Generating Station License Renewal Application

Reference: 1. Exelon Generation Company, LLC letter from Michael P. Gallagher to NRC Document Control Desk, "Application for Renewed Operating Licenses", dated June 22, 2011
2. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)", dated February 14, 2012
3. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)", dated February 16, 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 and Reference 3 letters, the NRC requested additional information to support the staffs' review of the LRA.

Enclosed are the responses to these requests for additional information.

Enclosure C identifies commitments made in this letter and is an update to the LGS LRA Appendix A, Table A.5, License Renewal Commitment List. Any other actions discussed in the letter represent intended or planned actions and are described to the NRC for the NRC's information and are not regulatory commitments.

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 03-13-2012

Respectfully,

Michael P. Gallagher

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

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

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

Enclosure A

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

RAI 3.1.1.60-1
RAI 3.2.2.1.1-1
RAI 3.2.2.1.1-2
RAI 3.2.2.1.1-3
RAI 3.3.1.30-1
RAI 3.6.2.3-1
RAI B.1.4-1
RAI A.1-1
RAI 3.4.1.11-1
RAI 3.5.2.11-1

RAI 3.1.1.60-1

Background:

SRP-LR Table 3.1.1, item 3.1.1-60 addresses carbon steel piping components exposed to reactor coolant that are being managed for wall thinning due to flow-accelerated corrosion. License renewal application (LRA) Table 3.1.1 states that this item is not applicable because there are no carbon steel piping components exposed to reactor coolant that are susceptible to this aging effect in the reactor coolant system. The staff noted that EPRI 1013013, "An Evaluation of Flow-Accelerated Corrosion in the Bottom Head Drain Lines of Boiling Water Reactors," concluded that both Limerick Generating Station (LGS) units were viewed as having very limited susceptibility to damage from this concern.

Issue:

Although LGS is viewed as having limited susceptibility to damage from this concern, it is unclear to the staff that it can be stated that there are no components susceptible to wall thinning due to flow-accelerated corrosion in the reactor coolant system, as claimed in the LRA.

Request:

Provide the bases for the determination that there are no steel piping components exposed to reactor coolant that are susceptible to flow-accelerated corrosion in the reactor coolant system. Include in the response a description of the susceptibility analysis performed for the bottom head drain line as well as other piping and components in the reactor coolant system.

Exelon Response

The carbon steel portion of the RPV bottom head drain line (BHDL) includes approximately seven feet of 2-inch carbon steel piping directly connected to the RPV bottom head drain nozzle. Although the carbon steel portion of the BHDL is excluded from inspection requirements, it is considered to be susceptible to FAC. The Flow-Accelerated Corrosion program susceptibility analysis performed for LGS determined that the carbon steel portion of the (BHDL) is susceptible to FAC, but wear rates are predicted to be low. LGS Units 1 and 2 are classified as Category A units where "the rate of FAC wall loss was predicted to be very low and have very limited susceptibility to wall thinning". Consistent with the recommendations of BWRVIP-205, *Bottom Head Drain Line Inspection and Evaluation Guidelines, EPRI 1018428, Final Report, November 2008,* inspection of the BHDL for FAC is not required.

LRA Table 3.1.2-1, Reactor Coolant Pressure Boundary, Summary of Aging Management Evaluation, is revised as shown in Enclosure B, to include an aging management review line item to use the FAC program to manage wall thinning in reactor coolant environment for carbon steel Class 1 Piping, Fittings, and Branch Connections < NPS 4-inch.

An extent of condition review of Class 1 reactor coolant system piping and components was performed to determine any additional components that are susceptible to wall thinning due to FAC and not identified in LRA Table 3.1.2-1 as being managed by the FAC aging management program. The only additional reactor coolant system components identified were piping components and valve bodies within the Feedwater plant system. LRA Table 3.1.2-1 is revised to include aging management review line items to use the FAC aging management program to manage wall thinning of those carbon steel components as shown in Enclosure B. LRA Table

3.1.1, item 3.1.1-60 and Section 3.1.2.1.1 are revised to be consistent with this response as shown in Enclosure B.

RAI 3.2.2.1.1-1

Background:

GALL Report AMP XI.M18, "Bolting Integrity" includes periodic volumetric or surface and visual inspections of closure bolting for leakage, loss of material, cracking, and loss of preload/loss of prestress in accordance with the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code) Section XI Inservice Inspection, Subsections IWB, IWC, and IWD. In addition, GALL Report AMP XI.M18 recommends system walkdowns at least once per refueling cycle to ensure detection of leakage at bolted joints before the leakage becomes excessive.

LRA Section B.2.1.11 states that inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities. The following tables in the LRA contain bolting exposed to an external environment of treated water or raw water (i.e., submerged) and managed for loss of material and loss of preload with the Bolting Integrity program:

- Table 3.2.2-02: Core Spray System
- Table 3.2.2-03: High Pressure Coolant Injection System
- Table 3.2.2-04: Reactor Core Isolation Cooling System
- Table 3.2.2-05: Residual Heat Removal System
- Table 3.3.2-11: Fuel Pool Cooling and Cleanup System
- Table 3.4.2-01: Circulating Water System
- Table 3.4.2-03: Condenser and Air Removal System

Issue:

It is unclear to the staff how inspection of submerged bolting during maintenance activities will be capable of detecting loss of material and loss of preload prior to loss of component intended functions and how often these inspections will be conducted given potentially limited opportunities to drain systems and expose the bolting for inspection.

Request:

1. For each system, state the parameters that will be inspected for during opportunistic inspections of normally submerged bolting and the basis for why these parameters will be capable of assessing the condition of the bolting before loss of intended function occurs.

2. For each system, state the minimum number and frequency of inspections that will be conducted during the period of extended operation.

Exelon Response

1. The parameters inspected for submerged bolting included in the Bolting Integrity program described in LRA Section B.2.1.11 and their bases are as follows:

    - Core Spray System (Table 3.2.2-2) - The submerged bolting is for the attachment of the core spray pump suction strainers to the pump suction piping flange located in the suppression pool below the normal water level. Bolting is also used to join the upper and lower halves of the strainer assemblies and on the blind flange on the unused branch of the penetration tee fitting as shown on drawing LR-M-52 sheets 1 and 3. This bolting is not high strength bolting as defined in GALL Report AMP XI.M18. Carbon steel and stainless steel bolting materials are used. This bolting is visually inspected for loss of material and loss of preload. The visual inspection checks for degradation including corrosion and missing or loose parts. Bolted connections include either staked threads, lock wires, or are double nutted to prevent loosening of the nuts. The parameters inspected, given the design features described above, enable assessment of the condition of the bolting before loss of intended function occurs. This bolting is inspected at least once every 10-year ISI inspection interval and will be inspected a minimum of two times during the period of extended operation.

    - High Pressure Coolant Injection System (HPCI) (Table 3.2.2-3) - The submerged bolting is for the attachment of the HPCI pump suction strainers to the pump suction piping flange located in the suppression pool below the normal water level. This bolting is not high strength bolting as defined in GALL Report AMP XI.M18. Bolting is carbon steel material. This bolting is visually inspected for loss of material and loss of preload. The visual inspection checks for degradation including corrosion and missing or loose parts. The parameters inspected enable assessment of the condition of the bolting before loss of intended function occurs. This bolting is inspected at least once every 10-year ISI inspection interval and will be inspected a minimum of two times during the period of extended operation.

    - Reactor Core Isolation Cooling System (RCIC) (Table 3.2.2-4) - The submerged bolting is for the attachment of the RCIC pump suction strainers to the pump suction piping flange located in the suppression pool below the normal water level. This bolting is not high strength bolting as defined in GALL Report AMP XI.M18. Bolting is carbon steel material. This bolting is visually inspected to detect loss of material and loss of preload. The visual inspection checks for degradation including corrosion and missing or loose parts. The parameters inspected enable assessment of the condition of the bolting before loss of intended function occurs. This bolting is inspected at least once every 10-year ISI inspection interval and will be inspected a minimum of two times during the period of extended operation.

    - Residual Heat Removal System (RHR) (Table 3.2.2-5) - The submerged bolting is for the attachment of the RHR pump suction strainers to the pump suction piping flange located in the suppression pool below the normal water level. Bolting is also used to join the upper and lower halves of the strainer assemblies. This bolting is not high strength bolting as defined in GALL Report AMP XI.M18. The bolting is stainless steel material. This bolting is visually inspected for loss

of material and loss of preload. The visual inspection checks for degradation including corrosion and missing or loose parts. Bolted connections include either staked threads, lock wires, or are double nutted to prevent loosening of the nuts. The parameters inspected, given the design features described above, enable the assessment of the condition of the bolting before loss of intended function occurs. This bolting is inspected at least once every 10-year ISI inspection interval and will be inspected a minimum of two times during the period of extended operation.

During the review of RAI 3.2.2.1.1-1 regarding the bolting for the RHR suction strainers, the detailed materials list was reviewed to identify the location of carbon steel bolting materials. This review identified that only stainless steel bolting materials in a treated water (external) environment are associated with the RHR strainers. Carbon steel bolting materials in a treated water (external) environment are not used for the RHR strainers and are not used elsewhere in the RHR system. Consistent with this finding, LRA Table 3.2.2-5 is revised to remove the line item for "Bolting", "Mechanical Closure", "Carbon and Low Alloy Steel Bolting", in a "Treated Water (External)" environment. LRA Table 3.2.1 is also revised to remove the Residual Heat Removal system from the discussion for line item 3.2.1-16. These page revisions are included in Enclosure B.

- Fuel Pool Cooling and Cleanup System (Table 3.3.2-11) – The submerged bolting is for the adjustable weir gates that regulate the level of the water in the spent fuel pool. The bolting is not high strength bolting as defined in GALL Report AMP XI.M18. The bolting material is stainless steel. The bolting is visually inspected for loss of material and loss of preload. Visual inspections check for degradation including corrosion and missing or loose parts. The parameters inspected enable assessment of the condition of the bolting before loss of intended function occurs. This bolting is inspected whenever the weir plates require adjustment to support refueling operations and to implement the alternate decay heat removal configuration during refueling outages. This configuration aligns the RHR heat exchangers to remove decay heat from the spent fuel pool water to facilitate refueling operations. Adjustment of the weir plate is expected during each refueling outage, at which time the visual inspection is performed. This results in approximately 10 inspections on each unit during the period of extended operation.

- Circulating Water System (Table 3.4.2-1) – The submerged bolting is for the stainless steel removable screens at the cooling tower basin outlet to the main condenser. This bolting is used to hold the screening mesh material onto the structural framework of the screen. The bolting is not high strength bolting as defined in GALL Report AMP XI.M18. The bolting material is stainless steel. The bolting is inspected for loss of material and loss of preload. The bolting inspection checks for corrosion and missing or loose parts. This bolting is inspected each time the screens are removed for cleaning which normally occurs at refueling outages. Therefore, the bolts will be inspected a minimum of 10 times during the period of extended operation.

- Condenser and Air Removal System (Table 3.4.2-3) – The bolting is in the steam space of the main condenser and holds the expansion joint in place between the main turbine exhaust and the main condenser inlet. The bolting material is carbon steel. The bolting material is not high strength as defined in GALL Report AMP XI.M18. The bolting is inspected for loss of material and loss of preload. The visual inspection checks for degradation which includes corrosion and loose or missing bolts. These inspections are performed whenever the expansion joint is replaced, which is planned on a 12-year frequency. Therefore, the minimum number of inspections during the period of extended operation is one.

Consistent with this response, the UFSAR Supplement for Bolting Integrity, A.2.1.11, and Bolting Integrity program description, B.2.1.11, are revised as shown in Enclosure B. The LRA Appendix A, Table A.5 commitment number 11, is also revised as shown in Enclosure C.

During review of the RHR suction strainer stress analysis for bolting information, it was determined that the analysis includes fatigue analyses for the stainless steel bolting materials and for the stainless steel strainer assembly. The Core Spray strainer stress analysis was also reviewed and was determined to include fatigue analyses of the stainless steel bolts and stainless steel strainer assembly. These fatigue analyses were determined to be TLAAs that require evaluation for the period of extended operation. An extent of condition review was performed for ASME Section III Class 2 components, including the HPCI and RCIC strainers, and no fatigue analyses or additional TLAAs were identified.

Consistent with identification of these TLAAs, the following sections of the LRA have been added, as shown in Enclosure B:

- LRA Section 4.6.11, "RHR and Core Spray Strainer Fatigue Analyses"
- Appendix A, Section A.4.6.11, "RHR and Core Spray Strainer Fatigue Analyses"

The following sections of the LRA have also been revised to incorporate the addition of these TLAAs, as shown in Enclosure B:

- LRA Section 3.3.2.2.1, "Cumulative Fatigue Damage"
- LRA Table 3.2.2-2, "Core Spray System, Summary of Aging Management Evaluation"
- LRA Table 3.2.2-5, "Residual Heat Removal System, Summary of Aging Management Evaluation"
- LRA Table 4.1-2, "Summary of Results – LGS Time-Limited Aging Analyses"

2. The Exelon response to this request is contained in the individual system discussions provided above.

RAI 3.2.2.1.1-2

Background

LRA Tables 3.2.2-03 and 3.2.2-04 include aging management review items for gray cast iron turbine lube oil reservoirs exposed internally to lube oil; however, selective leaching is not considered to be an aging effect. The LRA proposes to manage aging of these components with the Lubricating Oil Analysis and One-Time Inspection programs.

According to the LRA, the Lubricating Oil Analysis program directs the condition monitoring activities (sampling, analyses, and trending) to manage loss of material and reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks. The One-Time Inspection program provides inspections focusing on locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. According to the LRA, the inspections will include a representative sample of the system population and will focus on the bounding or lead components most susceptible to aging, due to time in service, and severity of operating conditions.

Selective leaching is known to occur in susceptible materials such as gray cast iron and uninhibited brasses with greater than 15-percent zinc when an electrolyte is present.

Issue

Sufficient information is not available to determine whether susceptible locations (e.g., turbine lube oil reservoirs) will be included in the sample for inspection or not. Moreover, visual inspections alone may not be sufficient to detect selective leaching. Therefore, the staff cannot conclude whether aging of the gray cast iron reservoirs internally exposed to lube oil will be adequately managed or not.

Request

Explain if samples will include susceptible locations to confirm that selective leaching is not occurring in areas where water can accumulate. If it is determined that selective leaching is a relevant aging effect/mechanism to be managed, explain what aging management program and inspection method(s) (e.g., hardness measurement) will be used to manage the loss of material due to selective leaching.

Exelon Response

As stated in GALL Report AMP XI.M39, the Lubricating Oil Analysis program "…maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer." This program performs a check for water and a particle count to detect evidence of contamination by moisture or excessive corrosion. Element 6 of GALL AMP Report XI.M39 states that "Phase-separated water in any amount is not acceptable." Thus, the lack of water in the oil precludes the existence of an electrolyte in this environment, and the aging mechanism of selective leaching is not applicable. In addition, the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) turbine lube oil reservoirs have not exhibited degradation due to water pooling. Both the HPCI and RCIC turbine lube oil reservoirs are sampled quarterly for water and are drained, cleaned and inspected every two years.

Furthermore, the efficacy of the Lube Oil AMP at minimizing the potential for water pooling is verified through the implementation of the One-Time Inspection program which confirms the absence of corrosion in material subject to lube oil.

RAI 3.2.2.1.1-3

Background

In the LRA AMR tables, there are several entries for copper alloy with 15-percent zinc or more or gray cast iron components internally exposed to “air/gas – wetted.” The LRA states that these components will be managed for loss of material by the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting program. This program uses periodic and opportunistic inspections of the internal surfaces of components augmented by physical manipulation of flexible elastomers where appropriate.

The LRA defines “air/gas – wetted” as “air/gas environments containing significant amounts of moisture where condensation or water pooling may occur. This environment includes air with enough moisture to facilitate loss of material in steel caused by general, pitting, and crevice corrosion.”

Selective leaching is known to occur in susceptible materials such as gray cast iron and uninhibited brasses with greater than 15-percent zinc when moisture or water (an electrolyte) is present.

Issue

Visual inspections alone may not be sufficient to detect selective leaching. Therefore, the staff cannot conclude whether aging of the copper alloy with 15-percent zinc or more or gray cast iron components internally exposed to “air/gas – wetted” will be adequately managed or not.

Request

Explain why copper alloy with 15-percent zinc or more or gray cast iron components internally exposed to air/gas – wetted are not being managed for selective leaching. If it is determined that selective leaching is an appropriate aging effect/mechanism to be managed, explain what aging management program and inspection method(s) (e.g., hardness measurement) will be used to manage the loss of material due to selective leaching.

Exelon Response

The copper alloy with 15 percent zinc or more components which are exposed to an internal environment of air/gas – wetted consist of the following ("*" indicates components that are included in the component type "Piping, piping components, and piping elements" in the LRA Summary of Aging Management Evaluation tables):

- Control Enclosure Ventilation (CEV) and Standby Gas Treatment System (SGTS) instrumentation fittings* and valves

- CEV system chiller skid pressure relief valves, fittings* and valves in the CEV and SGTS instrument air purge supply to the charcoal filters
- Residual Heat Removal (RHR) System spray nozzles in the drywell and suppression chamber
- Emergency Diesel Generator (EDG) System dirty fuel oil drain tank level glass valves
- EDG starting air system valves
- Fire Protection (FP) System spray nozzles and foam solution proportioner supply nozzle
- FP System valves

The gray cast iron components which are exposed to an internal environment of air/gas – wetted consist of the following:

- EDG starting air compressor casings
- Primary Containment Instrument Gas (PCIG) System receiver drain traps*
- High Pressure Coolant Injection (HPCI) System barometric condenser vacuum pump flanges*

The design and operating conditions of each component were evaluated to assess the potential for significant moisture to accumulate and water pooling to occur. In two instances, the EDG system dirty fuel oil drain tank level glass valves and the PCIG receiver drain traps, the components accumulate condensation and are exposed to significant moisture. These components are added to the Selective Leaching program and are subject to visual inspection coupled with hardness measurements or mechanical examination as described in LRA Section B.2.1.23 and Exelon's response to RAI B.2.1.23-1.

The design and operating conditions of the other copper alloy with 15 percent zinc or more components and gray cast iron components exposed to an internal environment of air/gas – wetted are such that they are normally dry and not subject to significant amounts of moisture or water pooling. Therefore, selective leaching is not considered to be an applicable aging effect, and they are not included in the Selective Leaching program. A review of plant operating experience since 2000 did not identify the occurrence of selective leaching in the air/gas – wetted environment at LGS.

LRA Table 3.3.2-8 is revised as shown in Enclosure B to include loss of material due to selective leaching for the EDG dirty fuel oil drain tank level glass valves. Additionally, LRA Table 3.3.2-14 and LRA Section 3.3.2.1.14 are revised to include loss of material due to selective leaching for the PCIG receiver drain traps, which are included in the "Piping, piping components, and piping elements" component type.

RAI 3.3.1.30-1

Background

SRP-LR Table 3.3.1, items 3.3.1-30, 3.3.1-31, and 3.3.1-32 address piping components made with concrete, reinforced concrete, asbestos cement, and cementitious material exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” to manage changes in material properties and cracking due to aggressive chemical attack, and cracking due to settling for these component groups. LRA Table 3.3.1 for the corresponding items state that these items are not applicable because there are no cement, reinforced cement or cementitious material piping exposed to raw water with the above aging effects in auxiliary systems. The staff noted that LRA Table 3.3.2-9, “Fire Protection System” cites item 3.3.1-33, which addresses loss of material due to abrasion, cavitation, aggressive chemical attack and leaching in cement piping components exposed to raw water.

Issue

As indicated in LRA Table 3.3.1, item 3.3.1.33, Limerick has cement piping exposed to raw water in the fire protection system. As such, it is unclear to the staff why the aging effects described in LRA Table 3.3.1, items 3.3.1.30 and 31 (i.e., changes in material properties and cracking) would not apply to cement fire protection piping. Additionally, there is insufficient information in the LRA for the staff to conclude that LRA Table item 3.3.1.32 is not applicable to LGS. Specifically, the discussion provided in the LRA table for this item is unclear as to whether the conclusion of applicability was based on the fact that there is no piping at LGS constructed of reinforced concrete or asbestos cement or was based on the fact that such piping is not subject to the aging effects of changes in material properties and cracking.

Request:

1. Provide the basis for concluding that LRA Table 3.3.1, items 3.3.1.30 and 31 (and the associated aging effects) do not apply to concrete fire protection piping at LGS.

2. Clarify whether the conclusion of applicability for LRA Table 3.3.1, item 3.3.1.32, was based on the fact that there is no piping at Limerick constructed of reinforced concrete or asbestos cement or was based on the fact that such piping is not subject to the aging effects of changes in material properties and cracking.

Exelon Response

1. LRA Table 3.3.2-9 includes cement material for component type "Piping, piping components, and piping elements" with a loss of material aging effect. Note 5 of Table 3.3.2-9 describes the cement material as the lining of the piping used for the buried Fire Protection system yard fire main loop. The yard fire main loop consists of 12-inch cement-lined cast iron piping as described in UFSAR sections 9.5.1.2.2.3 and 9A.2.1.3. Exelon's response to RAI 3.3.1.33-1, in letter dated February 16, 2012, revised the aging management program for the internal surface of this piping (internal cement lining) from Inspection of Internal surfaces in Miscellaneous Piping and Ducting Components to the Fire Water system program. The external surface of the cast iron piping in contact with soil is managed by the Selective Leaching program and the Buried and Underground Piping and

Tanks program. The aging effects described in LRA Table 3.3.1 items 3.3.1.30 and 3.3.1.31 are not applicable to the cement lining of cast iron piping.

2. LGS does not utilize reinforced concrete or asbestos cement piping for any piping that is in scope for license renewal. Therefore, the LRA Table 3.3.1 aging effects described in item 3.3.1.30 and item 3.3.1.31 are not applicable to LGS.

RAI 3.6.2.3-1

Background

In LRA Table 3.6.2-1, corresponding to Table 1 Items 3.6.1.16 and 17, the applicant indicated, via note A, that the combination of component type, material, environment, and aging effect requiring management of fuse holders not part of active equipment is consistent with the GALL Report. The applicant provided information about how it will manage the aging effects by proposing the Fuse Holders program, LRA AMP B.2.1.42. The LRA states that this program is consistent with GALL Report AMP XI.E5. During the onsite audit, the staff noted that certain fuse holders (metallic clamps) were in scope of license renewal (i.e., fuse holders in the switchyard control house) but were not included in the scope of Fuse Holders program. GALL Report, items VI.A.LP-23 and -31, “Fuse Holders (Not Part of active equipment): Metallic Clamp,” identifies the aging/effect mechanism as increased resistance of connection due to chemical contamination, corrosion, oxidation; fatigue due to ohmic heating, thermal cycling, electrical transients, increased resistance of connection due to fatigue caused by frequent manipulation or vibration. The associated GALL Report AMP XI.E5, “Fuse Holders,” states that fuse holders within the scope of license renewal should be tested to provide an indication of the condition of the metallic clamps of fuse holders.

Issue

The LRA did not provide technical justifications of why these fuse holders which are in the scope of license renewal are excluded from the applicant’s Fuse Holders program.

Request

Provide a list of fuse holders that are within the scope of license renewal and subject to an aging management review (i.e., fuse holders located outside of active equipment). For fuse holders within the scope of license renewal, provide an evaluation that addresses each aging effect/mechanism identified in GALL Report, items VI.A.LP-23 and -31 and identify fuse holders within the scope of license renewal which will be included in the Fuse Holder program (LRA AMP B.2.1.42) and the AMP basis document.

Exelon Response

The LGS metallic clamps of fuse holders, that are not part of an active assembly, were scoped and screened for aging management review in accordance with the scoping and screening methodologies, documented in LGS LRA Sections 2.1.1, 2.1.5, and 2.1.6. The resulting fuse holders: metallic clamps that are subject to aging management review are the fuse holders that are not part of an active component, are long-lived (i.e., not part of the Environmental Qualification program), and perform a license renewal intended function. At LGS there are five

electrical panels that contain fuse holders: metallic clamps that are subject to aging management review:

Two drywell leak detection fuse panels – 12 fuse holders
Toxic chemical detection fuse panel – 6 fuse holders
500 kV substation battery fuse panel – 2 fuse holders
220 kV substation battery fuse panel – 2 fuse holders.

Other LGS fuse holders that are not part of a larger assembly are for circuits that do not perform a license renewal intended function.

The potential aging effects as discussed in the GALL Report items VI.A.LP-23 and VI.A.LP-31 are not applicable to the fuse holders in the toxic chemical detection fuse panels, 500 kV substation battery fuse panel, nor the 220 kV substation battery fuse panel. The evaluation of aging effects is discussed below.

Chemical Contamination, Corrosion and Oxidation

These fuse holders are located in indoor, controlled environments that do not subject them to environmental aging mechanisms. The toxic chemical detection fuse panel is located in the plant's control enclosure in the upper fan room. The substation battery fuse panels are located in the substation control houses in the 500 kV and 220 kV substation yards. These panels and the enclosed fuse holders are located in indoor, controlled environments, are not subject to weather conditions and are therefore not subject to moisture from precipitation. Their indoor, controlled environment locations assure the fuse holders do not experience high relative humidity during normal conditions. A second barrier protecting the fuse holders from exposure to moisture is their location inside closed electrical boxes. The fuse holders are also protected from chemical contamination by their location inside closed electrical boxes. There are no sources of chemicals in the vicinity of the fuse boxes. Oxidation and corrosion are not a concern since the fuse holders are not located in or near humid areas, nor are they exposed to industrial or oceanic environments.

A walkdown of these electrical panels containing the in-scope fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation or corrosion.

Ohmic Heating, Thermal Cycling and Electrical Transients

Fuses for circuits that carry significant current in power applications could potentially be exposed to ohmic heating and thermal cycling. The fuse holders being evaluated are not in circuits that carry significant current in power applications. The fuses in the toxic chemical detection fuse panel provide 120 Vac power to enclosure fans. These circuits are loaded with a small constant current. The substation battery fuse panels are for substation equipment dc control power. The normal supply of power to loads is from the battery charger. The battery is normally on a float charge, thus the fuses are lightly loaded with a small constant current. Therefore, electrical and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

Mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. The corrective action process is used to document adverse conditions

and provides corrective actions associated with electrical faults and transients that cause the actuation of circuit protective devices.

Frequent Manipulation or Vibration

Wear and fatigue is caused by repeated removal and reinsertion of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventative maintenance. Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse holders.

These fuse holders are located in electrical panels that are not mounted on moving or rotating equipment such as motors, compressors, fans or pumps. Because electrical panels are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, these fuse holders will not exhibit aging effects from frequent manipulation or vibration.

The potential aging effects as discussed in the GALL Report items VI.A.LP-23 and VI.A.LP-31 are applicable to the fuse holders for the drywell drain leak detection circuits. Therefore, these fuse holders are included in the LGS Fuse Holders aging management program.

The in-scope fuse holders are:

- Fuse holder for 10TBB122/FU-1 - Fused circuit for Drywell drain leak detection
- Fuse holder for 10TBB122/FU-2 - Fused circuit for Drywell drain leak detection
- Fuse holder for 10TBB122/FU-3 - Fused circuit for Drywell drain leak detection
- Fuse holder for 10TBB122/FU-4 - Fused circuit for Drywell drain leak detection
- Fuse holder for 10TBB122/FU-5 - Fused circuit for Drywell drain leak detection
- Fuse holder for 10TBB122/FU-6 - Fused circuit for Drywell drain leak detection
- Fuse holder for 20TBB122/FU-1 - Fused circuit for Drywell drain leak detection
- Fuse holder for 20TBB122/FU-2 - Fused circuit for Drywell drain leak detection
- Fuse holder for 20TBB122/FU-3 - Fused circuit for Drywell drain leak detection
- Fuse holder for 20TBB122/FU-4 - Fused circuit for Drywell drain leak detection
- Fuse holder for 20TBB122/FU-5 - Fused circuit for Drywell drain leak detection
- Fuse holder for 20TBB122/FU-6 - Fused circuit for Drywell drain leak detection

The Fuse Holders program basis document will be revised to identify these fuses in Element 1, Scope of Program, in the LGS Fuse Holders program basis document.

RAI B.1.4-1

Background

License Renewal Application (LRA) Section B.1.4 states that, during the first 10 years of entering the period of extended operation, the owners of programs credited for license renewal will perform a review of plant-specific and industry operating experience to confirm the effectiveness of the Aging Management Program (AMPs). This review will determine if the AMP is currently effective, requires modification, or identify a need to develop a new AMP. In addition, the LRA states that follow-up actions will be taken as appropriate to provide additional

assurance that aging of systems, structures, and components in the scope of license renewal will be adequately managed throughout the period of extended operation.

Issue

LRA Section B.1.4 describes a plan to review operating experience once for each AMP after entering the period of extended operation. New operating experience information is generated daily; therefore, the proposed one-time review would not result in the timely consideration of operating experience. Further, if the operating experience review occurs only once in the first 10 years of entering the period of extended operation, then there will be a gap between that review and the renewed license expiration date, during which no operating experience will be considered to determine whether the AMPs are effective, require modification, or whether there is a need to develop new AMPs.

Request

Describe programmatic activities that will be used for the ongoing review of plant-specific and industry operating experience to ensure that (a) the license renewal AMPs are and will continue to be effective in managing the aging effects for which they are credited, and (b) the AMPs will be enhanced or new AMPs will be developed when the review of operating experience indicates that the AMPs may not be fully effective.

In this description, address the following:

(a) If crediting existing activities, justify why they would not preclude the consideration of operating experience related to aging.

(b) Describe the sources of plant-specific and industry operating experience that will be reviewed for potential impacts on the aging management activities.

(c) Indicate whether plant-specific and industry operating experience only will be considered from a prescribed list of sources.

(d) Describe how plant-specific and industry operating experience evaluations will be prioritized and completed in a timely manner.

(e) Describe the operating experience evaluation records with respect to what will be considered and recorded on aging. Indicate whether the evaluation records will be maintained in auditable and retrievable form.

(f) When it is determined through an operating experience evaluation that enhancements to the aging management activities are necessary, including the development of new AMPs, describe how the enhancements will be implemented.

(g) Describe how the ongoing operating experience review activities will be administratively controlled. Indicate whether these administrative controls include periodic audits to ensure the effectiveness of the operating experience review activities.

(h) Describe how operating experience issues will be identified and categorized as related to aging. If an identification code is used, provide its definition or the criteria for its application. Also, describe how age-related operating experience will be trended.

(i) Indicate whether guidance documents and other publications are considered as a source of operating experience information. If they are considered as a potential source, provide a plan for considering the content of guidance documents, such as the GALL Report, as operating experience applicable to aging management. If they are not a potential source, justify why they should not be considered as such.

(j) Describe how evaluations of operating experience issues related to aging will consider the following:

- systems, structures, or components
- materials
- environments
- aging effects
- aging mechanisms
- AMPs

(k) Describe criteria for considering when AMPs should be modified or new AMPs developed due to operating experience.

(l) Describe how the results of the AMP inspections, tests, analyses, etc. will be considered as operating experience, both when they meet and do not meet the applicable acceptance criteria.

(m) Describe the training requirements and justify the level of training on aging issues for those plant personnel responsible for screening, assigning, evaluating, and submitting plant-specific and industry operating experience. Also, provide the periodicity of the training and describe how it will account for personnel turnover.

(n) Provide criteria for reporting plant-specific operating experience on age-related degradation to the industry.

Exelon Response

General

Exelon has an established, mature plant Operating Experience (OPEX) Program that has its roots in the Institute of Nuclear Power Operations (INPO) Significant Event Evaluation and Information Network (SEE-IN) Program that was implemented to address Item I.C.5 of NUREG-0737 and was endorsed by the NRC in Generic Letter 82-04. This program, which has undergone numerous improvements over the years, has provided an effective process for LGS to learn from and make improvements to address adverse operating experience, including aging-related degradation. The Exelon Corrective Action Program (CAP) is used at LGS together with the OPEX Program to evaluate and address degraded conditions including plant-specific (internal) and industry (external) operating experience. Moving forward, these programs will provide assurance that (a) the license renewal AMPs are and will continue to be

effective in managing the aging effects for which they are credited, and (b) the AMPs will be enhanced or new AMPs will be developed when the review of operating experience indicates that the AMPs may not be fully effective.

As part of the Aging Management Review (AMR) portion of the License Renewal Application preparation process, the LGS LR team performed extensive reviews of internal operating experience to determine the breadth of aging effects potentially impacting SSCs in the scope of license renewal at LGS. As expected, these reviews did not identify any aging effects that had not been accounted for in previous Exelon LRAs. In addition, the LGS LRA was prepared in accordance with Revision 2 of the GALL report (NUREG-1801), which has incorporated industry-wide operating experience into the guidance for establishing effective AMPs. These factors provide confidence that lessons learned from many years of aging-related operating experience have already been captured, such that the AMPs specified in the LRA to manage aging during the period of extended operation (PEO) are designed to address reasonably expected aging effects.

In addition, the LGS LRA AMP-related documentation and associated NRC staff reviews have already demonstrated the value and capability of the existing OPEX and CAP Programs in identifying and addressing aging-related degradation. As described in Section A.1.2.3.10 of the SRP-LR (NUREG-1800 Revision 2):

> "Operating experience with existing programs should be discussed. The operating experience of AMPs that are existing programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure- and component-intended function(s) will be maintained during the period of extended operation."

The LGS LRA contains several examples, for each existing AMP, demonstrating that the programs have been effective and therefore provides reasonable assurance that it will effectively manage aging during the PEO. The LRA also contains relevant operating experience and Corrective Action Program examples that provide assurance that new aging management programs being implemented for license renewal will also effectively manage aging, and if deficiencies are identified through operating experience, they will be addressed within the CAP. In fact, there were at least two instances where use of internal operating experience by plant personnel had resulted in identification of aging effects (i.e., these involved loss of material on BWR Vessel Internals Steam Dryer components) and incorporation of aging management activities into the existing AMPs. In these cases, the GALL does not specifically address these potential aging effects, but the related plant programs and LGS LRA do, by virtue of aging-related operating experience having been addressed by plant personnel.

During the safety audits associated with the LGS LRA review, the NRC DLR Staff performed an independent search of the LGS Corrective Action Program database, to identify cases of age-related degradation. This activity, performed with Staff-selected keywords, identified operating experience that was later used by the NRC during the AMP audit to evaluate the use of age-related operating experience at LGS relative to the AMPs credited in the LRA. In the AMP Audit

Report, the NRC drew two primary conclusions related to the use of operating experience at LGS:

1. For all 44 LGS AMPs reviewed during the Audit, the Staff determined that the operating experience provided by the applicant (Exelon) and identified by the staff's independent database search is bounded by industry operating experience (i.e., no previously unknown aging effects were identified by the applicant or the Staff), and
2. For 39 of the 44 AMPs reviewed, the Staff determined that the operating experience provided by the applicant (Exelon) and identified by the staff's independent database search is sufficient to allow the Staff to verify that the LRA AMPs, as implemented by the applicant (Exelon), are sufficient to detect and manage the effects of aging. For the five AMPs for which the NRC did not reach this conclusion, the Staff determined that they would issue RAIs for additional information to confirm that these AMPs will be sufficient to detect and manage the effects of aging during the period of extended operation.

The information described above pertaining to NRC audit activities provides additional confidence that the LGS AMPs will effectively manage aging through the period of extended operation.

Even with the previously described, demonstrated performance of the Operating Experience and Corrective Action Programs at LGS, Exelon is enhancing its procedures and training to provide additional assurance that internal and external operating experience continues to be used effectively during the PEO to refine, modify or create new aging management programs as appropriate.

Responses to the specific points that NRC staff requested Exelon to address in RAI B.1.4-1 are provided below. Because of the length of this response, each NRC point (items "a" through "n") is repeated here in italicized font, directly followed by the Exelon response.

(a) If crediting existing activities, justify why they would not preclude the consideration of operating experience related to aging.

Although as discussed above the existing Operating Experience and Corrective Action Programs already consider and address operating experience related to aging, the programs will be enhanced to provide specific direction to identify, evaluate and communicate operating experience related to aging. This will ensure that consideration of such aging-related operating experience is not precluded.

(b) Describe the sources of plant-specific and industry operating experience that will be reviewed for potential impacts on the aging management activities.

The Operating Experience program will be enhanced to ensure that both LGS plant-specific (internal) and industry level (external) operating experience related to aging management are evaluated in order to evaluate potential improvements to aging management programs and activities. The internal operating experience will come from various sources, such as tests, inspections, plant walkdowns, etc. Adverse results are captured in the site Corrective Action Program database, including adverse AMP-related aging management inspection results. In addition, the program will be enhanced to require sharing information related to significant aging-related degradation of SSCs in the scope of license renewal with the industry, through INPO. The program will also require review of external operating experience items that are

made available via the INPO website. Exelon is working with the industry and INPO to establish a process that will ensure that sharing of aging management lessons learned information is an expected ongoing activity.

(c) *Indicate whether plant-specific and industry operating experience only will be considered from a prescribed list of sources.*

In addition to the operating experience that will be reviewed as described in the response to (b) above, other documents will be reviewed during the period of extended operation to learn from operating experience. These additional documents, largely already included in the scope of the Exelon Operating Experience review process, will be based on those document categories defined in the INPO "Guidelines for Use of Operating Experience" document, which defines "Sources of Operating Experience." Included are a broad set of sources beyond specific internal and external plant operating experience items. These include INPO Event Report (IER) operating experience documents, NRC Bulletins, Generic Letters, Information Notices and Regulatory Issue Summaries, as well as Topical Reports and vendor correspondence (including 10CFR Part 21 information). Exelon is also adding License Renewal Interim Staff Guidance (LR-ISG) documents to the scope of documents reviewed under its Operating Experience Program because they are issued on an ongoing basis, capturing new insights or addressing issues that emerge from license renewal reviews. Periodic (e.g., every five years) updates to NUREG-1801 (the GALL) will not be explicitly reviewed under the Program as these updates, as they relate to operating experience, will trail real-time plant operating experience and LR-ISGs. However, if NRC determines it valuable for plants with renewed licenses to review these or other guidance documents, Exelon recommends that NRC communicate these insights generically under the established RIS process or other NRC generic communications.

(d) *Describe how plant-specific and industry operating experience evaluations will be prioritized and completed in a timely manner.*

LGS plant-specific operating experience items are evaluated within the Exelon Correction Action Program. Significance level and investigation class are established in order to assign the appropriate priority and resources. Exelon procedures are being enhanced to specify that aging-related degradation of structures and components within the scope of license renewal is considered a Significance level 3 Issue, which requires assessment of the cause and consideration of Exelon internal (i.e., Nuclear Event Report (NER)) or external communication (i.e., Nuclear Network Operating Experience (NNOE) item.

While it is possible that operating experience involving aging-related degradation could be prioritized in one of the top two categories within the Exelon process based on their significance and risk, it is expected that this type of operating experience will normally be classified as an Exelon Level 3 Item. External operating experience evaluations of this type are generally performed on a 60-day schedule, subject to adjustment based on their significance and risk.

(e) *Describe the operating experience evaluation records with respect to what will be considered and recorded on aging. Indicate whether the evaluation records will be maintained in auditable and retrievable form.*

Internal Operating Experience

Internal operating experience evaluations involving degraded conditions, including those related to aging, are performed in accordance with the existing Station Corrective Action Program and procedures. The scope of what is considered and recorded relative to aging would depend upon the nature of the degradation identified, whether the inspection was driven by aging management program activities that contain specific inspection criteria and other factors. The records associated with these evaluations are captured within the Passport Action Tracking module, making them auditable and retrievable. In addition, all corrective action type action requests within Passport are archived records, stored on microfiche.

External Operating Experience

Evaluation of external operating experience, including that related to aging management, is performed in accordance with the Exelon Operating Experience Program. Among other things, the issue or event is evaluated to determine its applicability to the Station, whether similar conditions or deficiencies have occurred and whether the Station is vulnerable to a similar issue. If the evaluation identifies an issue adverse to quality, the issue is entered into the Corrective Action Program and addressed as appropriate. Although external aging-related issues have been captured and evaluated in the past, the Operating Experience Program procedures will be enhanced to clearly include aging-related issues within the scope of operating experience to be considered. Documentation associated with the initial evaluation of external operating experience is retained within the Passport Action Tracking database in accordance with the Operating Experience Program, making it auditable and retrievable. As noted above, records associated with the activities entered into the Corrective Action Program are, at the minimum, captured in the Passport Action Tracking module, making them auditable and retrievable.

(f) *When it is determined through an operating experience evaluation that enhancements to the aging management activities are necessary, including the development of new AMPs, describe how the enhancements will be implemented.*

If an operating experience evaluation determines that existing aging management activities are inadequate, the issue is entered into the Station's 10 CFR Appendix B Corrective Action Program for further evaluation and action. An appropriate owner is established to evaluate the deficiency to determine whether an existing aging management program (AMP) should be enhanced, or whether a new program is needed. The Corrective Action Program drives the creation of additional actions in Passport to revise the existing AMP or create a new AMP. In addition, the Corrective Action Program tracks the development of specific implementing activities (e.g., recurring work orders or inspections) within the Station work management system that would be used to schedule, perform and document future inspections, tests, etc.

(g) *Describe how the ongoing operating experience review activities will be administratively controlled. Indicate whether these administrative controls include periodic audits to ensure the effectiveness of the operating experience review activities.*

Exelon has a series of procedures that prescribe the methods and requirements associated with implementation of the Operating Experience Program. Enhancements to these existing procedures will be incorporated to ensure that significant internal and external operating experience that relates to aging management is considered and evaluated under this process. The Operating Experience Program undergoes periodic assessments including a program level self assessment that is conducted on a biennial basis.

(h) *Describe how operating experience issues will be identified and categorized as related to aging. If an identification code is used, provide its definition or the criteria for its application. Also, describe how age-related operating experience will be trended.*

Identification coding will be established within the Corrective Action Program database to assist in the identification and trending of aging-related degradation, such that in addition to addressing the specific issue, the adequacy of existing aging management programs can be assessed and adjustments can be made. In addition to establishing coding within the corrective Action process, Exelon is working with industry and INPO to determine coding that can be used for identification and sharing of industry level operating experience related to aging management. The precise definition of this coding is not known at this time, since these activities are currently in progress.

Upon implementation, Station personnel are also 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. The LGS Station Aging Management Coordinator, put in place as part of license renewal implementation prior to the period of extended operation, will serve a lead role in these activities. In addition, existing procedures for engineering programs require performance trending.

(i) *Indicate whether guidance documents and other publications are considered as a source of operating experience information. If they are considered as a potential source, provide a plan for considering the content of guidance documents, such as the GALL Report, as operating experience applicable to aging management. If they are not a potential source, justify why they should not be considered as such.*

Please refer to the response to item (c) above. As noted, while Exelon is normally familiar with and informally reviews many industry guidance documents through its involvement with industry and regulatory groups and committees, for the most part, guidance documents are not formally reviewed as part of the Exelon Operating Experience Program. Guidance documents such as GALL (NUREG-1801) revisions provide invaluable input and insights during the license renewal application process and do contain updated operating experience information on aging management issues. However, GALL revisions occur only approximately every five years, making them impractical for a plant with a renewed license to gain timely insights. Exelon is enhancing its Operating Experience Program to require review of License Renewal Interim Staff Guidance (LR-ISG) documents, as they are issued on an ongoing basis, capturing new insights or addressing issues that emerge from license renewal reviews.

(j) *Describe how evaluations of operating experience issues related to aging will consider the following:*

- *systems, structures, or components*
- *materials*
- *environments*
- *aging effects*
- *aging mechanisms*
- *AMPs*

Evaluation of operating experience that relates to aging management will consider, as appropriate:

- Systems, structures or components that are similar or identical to those involved with the identified operating experience issue, to gain relevant lessons learned
- Materials of construction, operating environment and aging effects associated with the identified aging issue so that lessons learned can be applied to susceptible SSCs in the scope of license renewal
- Aging mechanisms associated with the operating experience to confirm that LGS has appropriate AMPs in place to manage aging that could be caused by these mechanisms.
- AMPs involved with this operating experience so that if the AMPs have been demonstrated to be ineffective, similar AMPs in place at LGS can be evaluated to determine if AMP changes are appropriate, or if a new AMP is needed

If the operating experience issue reveals site-specific vulnerabilities at LGS, the Exelon process directs that an Issue Report be initiated and the issue is then further evaluated for appropriate action, including things such as extent of condition, within the Corrective Action Program. The evaluation would consider applicability to other systems, structures and components, as appropriate.

(k) *Describe criteria for considering when AMPs should be modified or new AMPs developed due to operating experience.*

An evaluation as to whether AMPs should be modified or new AMPs created would be conducted within the Corrective Action Program if a deficient condition related to aging is identified and determined to be applicable to SSCs in the scope of license renewal for LGS. For internal operating experience, this would occur directly as part of the evaluation activities that stem from the Issue Report that gets initiated within the Corrective Action Program after a degraded condition is identified (e.g., acceptance criterion associated with an aging management activity is exceeded). For external operating experience, if the operating experience review determines vulnerability at LGS, then an Issue Report is initiated and an evaluation performed to specify appropriate corrective actions, potentially including the modification of existing AMPs or the creation of new AMPs, if appropriate.

(l) *Describe how the results of the AMP inspections, tests, analyses, etc. will be considered as operating experience, both when they meet and do not meet the applicable acceptance criteria.*

The results of AMP inspections, tests, analyses, etc. are documented and captured within Exelon work management system records, whether or not they meet the applicable acceptance criteria. If the results do not meet the acceptance criteria, an Issue Report within the Corrective Action program is generated and corrective actions taken, such as correcting the specific condition, considering extent of condition, evaluating the adequacy of existing AMPs, etc. If the results of the AMP activity are satisfactory, the results are documented and captured so they are available for future reference as needed.

(m) *Describe the training requirements and justify the level of training on aging issues for those plant personnel responsible for screening, assigning, evaluating, and submitting plant-specific and industry operating experience. Also, provide the periodicity of the training and describe how it will account for personnel turnover.*

Exelon has an established Operating Experience (OPEX) Program with individuals that are assigned and trained in the functions of screening, assigning, evaluating and submitting plant-specific (internal) or industry (external) operating experience. Key personnel include the Exelon Fleet OPEX Coordinator, who is the central input for all operating experience for the Exelon Fleet, and LGS Site OPEX Coordinator, who is the operating experience champion at LGS. The LGS Site OPEX Coordinator, among other things, is responsible for processing both internal Fleet OPEX and outgoing OPEX notifications to the industry.

Recognizing the increased emphasis on aging management with license renewal, Exelon will enhance the existing Operating Experience Program procedures and the Fleet and LGS Station OPEX coordinator training will be updated to ensure that both internal and external aging-related operating experience is properly reviewed and disseminated for evaluation by the appropriate LGS and/or corporate personnel.

As noted in the response to item (h) above, LGS will establish the role of the Station Aging Management Coordinator (AMC) as part of license renewal implementation. Throughout the period of extended operation, the individual fulfilling this position will be the LGS lead for overseeing the effective implementation of activities related to license renewal. The review of internal and external operating experience for lessons learned applicable to LGS, as well as aging-related OE that should be shared external to LGS, will be part of this responsibility. These responsibilities will be captured in the Exelon Aging Management Program implementation procedure. The LGS AMC will be trained in the concepts of license renewal such that he/she is proficient in screening and evaluating aging-related OE.

The LGS AMP owners for existing and new AMPs were selected based upon having appropriate educational background, work experience or duties. The AMP owners have been involved with development, review and approval of the aging management programs credited for aging management in the LGS License Renewal Application, and are therefore familiar with the aging management approach for their AMPs. Currently, most of the owners are part of the Engineering Support Personnel (ESP) population, and as such, have received some classroom training that includes information on component

aging. Training enhancements will be made to periodically include information related to aging management. Documentation showing that these individuals have been trained is retrievable. The AMP owners that are not part of the ESP population have relevant experience and knowledge in their areas of expertise and share information and knowledge with their Exelon and industry peers. Examples include the owners of the Water Chemistry and Lube Oil Analysis AMPs, who have specialized knowledge in these areas.

LGS will provide appropriate training for those personnel performing key license renewal roles, including the Aging Management Coordinator and AMP owners to provide greater assurance that they will effectively fulfill their license renewal related duties. With regard to accounting for personnel turnover, personnel newly assigned to these roles will be required to go through these training activities in order to perform the job function. Associated records will be retained, making them auditable and retrievable.

(n) Provide criteria for reporting plant-specific operating experience on age-related degradation to the industry.

Exelon Operating Experience Program procedures will be enhanced to include direction and criteria for reporting LGS plant-specific operating experience on aging-related degradation to the industry. It is expected that the criteria will include:

1. Observation of aging-related degradation significantly beyond what was expected, based upon an existing AMP inspection frequency, methodology, etc.
2. Aging effects or mechanisms not previously seen or accounted for in LGS AMPs
3. Other significant changes required or being made to AMPs that may be of interest to the industry

LGS LRA Section B.1.4 is updated to be consistent with the above response, as shown in Enclosure B of this letter. Commitment Item 46 of LRA Appendix A, Table A.5 is also revised as shown in Enclosure C to capture the enhancements that will be made to the Operating Experience Program.

Note that the original proposed commitment to perform a review, during the first 10 years of entering the period of extended operation (PEO), of plant specific and industry operating experience to confirm the effectiveness of the aging management programs, is deleted as part of this response. This is because the enhancements being made to ensure aging-related operating experience will be reviewed on an ongoing basis through the PEO will provide reasonable assurance that the effects of aging will be managed through the period of extended operation.

The response to RAI A.1-1 describes the creation of new LRA Section A.1.6, which becomes part of the UFSAR Supplement. This is provided in Enclosure B of this letter.

RAI A.1-1

Background

Section 54.21(d) of 10 CFR requires the application to contain a final safety analysis report supplement. This supplement must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation.

LRA Appendix A contains the applicant's updated final safety analysis report (UFSAR) supplement. This supplement contains Commitment No. 46, which is to, "Perform a review of plant-specific and industry operating experience to confirm the effectiveness of the aging management programs." The implementation schedule for this commitment is "[d]uring the first 10 years of entering the period of extended operation."

Issue

As discussed above in RAI B.1.4-1, the implementation schedule would not provide for the timely consideration of operating experience. Further, this commitment does not adequately describe how operating experience will be considered to determine whether the AMPs are effective, require modification, or whether there is a need to develop new AMPs.

Request

Consistent with the response to RAI B.1.4-1 above, provide a summary description of the ongoing operating experience review activities for the final safety analysis report (FSAR) supplement required in accordance with 10 CFR 54.21(d). If enhancements are necessary, identify them in the FSAR supplement and include the schedules for their implementation.

Exelon Response

Provided in Enclosure B of this letter is a summary description of the Operating Experience program for the UFSAR supplement required in accordance with 10 CFR 54.21(d), including a description of the enhancements that Exelon will make. This summary description becomes LRA Appendix A, Section A.1.6 (new). This UFSAR supplement summary description is partly based upon page A-1 of Appendix A to NRC's updated "Draft License Renewal Interim Staff Guidance LR-ISG-2011-05, Ongoing Review of Operating Experience," issued for public comments (see Federal Register Notice 76 FR 72725, dated November 25, 2011). Exelon provided the NRC with comments on the original NRC draft of ISG 2011-05 in a letter dated October 18, 2011. The essence of comment 2 from that Exelon letter has also been incorporated into the new LRA Appendix A, Section A.1.6.

As indicated in new LRA Section A.1.6 and also in modified LRA commitment # 46, which is shown in Enclosure C, certain enhancements are being made to the existing Operating Experience program. These enhancements will be implemented prior to the period of extended operation. This schedule is consistent with enhancements being made to other existing aging management programs and establishment of new AMPs for license renewal. As stated in Section 3.0.1 of NUREG-1800 Revision 2 (SRP-LR), "Enhancements are revisions or additions to existing aging management program(s) that the applicant commits to implement prior to the period of extended operation."

RAI 3.4.1.11-1

Background

LRA item 3.4.1-11 addresses cracking due to stress corrosion cracking (SCC) of stainless steel piping, piping components, and piping elements, tanks, heat exchanger components exposed to steam or treated water greater than 60°C (140°F). LRA item 3.4.1-11 indicates that cracking due to SCC of the components is managed by the Water Chemistry and One-Time Inspection programs.

LRA Table 3.1.2-1 addresses the aging management review results for the reactor coolant pressure boundary. More specifically, LRA Table 3.1.2-1 addresses the stainless steel piping, piping components, and piping elements exposed to steam (internal), indicating that these components are related to LRA item 3.4.1-11 and cracking due to SCC of these stainless steel components are managed by the Water Chemistry and One-Time Inspection programs.

In comparison, GALL Report item IV.C1.R-20 and SRP-LR Table 3.1-1, ID 97 recommend GALL Report AMP XI.M7, “BWR Stress Corrosion Cracking,” and GALL Report AMP XI.M2, “Water Chemistry,” to manage cracking due to SCC and intergranular stress corrosion cracking (IGSCC) of stainless steel piping, piping components, and piping elements greater than or equal to four nominal pipe size (NPS) exposed to reactor coolant. GALL Report, Section IX.D, “Selected Definitions & Use of Terms for Describing and Standardizing Environments,” states that reactor coolant is treated water in the reactor coolant system and connected systems at or near full operating temperature, including steam associated with BWRs.

Issue

The LRA credits the One-Time Inspection program to manage cracking due to SCC of the reactor coolant pressure boundary stainless steel piping, piping components, and piping elements exposed to steam (internal), which are addressed in LRA Table 3.1.2-1. The staff needs clarification as to whether any of these stainless steel components is included in the scope of the BWR Stress Corrosion Cracking program or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, which includes periodic inspections. The staff also needs clarification as to the adequacy of the One-Time Inspection program.

Request

1. Provide information to clarify why any of these stainless steel components exposed to steam is not included in the scope of the BWR SCC program or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, which includes periodic inspections (for example, describe the nominal pipe sizes, more specific component types, locations, and applicable inspection requirements of ASME Code, Section XI).

2. Justify why the One-Time Inspection program, which does not include periodic inspections, is adequate to manage cracking due to SCC of these stainless steel components.

   As part of the response, clarify whether SCC has been observed in these components to demonstrate that the LGS operating experience supports the adequacy of the One-Time Inspection program to manage the aging effect.

3. Revise the LRA, consistent with the response to items 1 and 2 above.

Exelon Response

1. The only stainless steel piping, piping components and piping elements exposed to steam (internal) within the Reactor Coolant Pressure Boundary that are addressed in LRA Table 3.1.2-1 are the Reactor Core Isolation Cooling (RCIC) steam supply flow elements. The stainless steel RCIC flow elements are welded into the 4-inch carbon steel portion of the Class 1 RCIC steam supply piping. The piping to flow element welds are currently within the scope of the components managed by the BWR SSC program, which is an augmented program within the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD program.

2. Based on the responses to request 1 and 3, the One-Time Inspection program is not being used to manage cracking due to SCC of these stainless steel components. The BWR SSC program provides for periodic inspections to manage cracking of these components.

3. LRA Table 3.1.2-1 is revised to manage cracking of stainless steel Reactor Coolant Pressure Boundary piping, piping components and piping elements exposed to a steam (internal) environment with the BWR SSC aging management program as shown in Enclosure B.

RAI 3.5.2.11-1

Background:

LRA Table 3.5.1, item 3.5.1-78 states that the spent fuel pool liner is managed for loss of material and cracking by the Water Chemistry program and monitoring of the leak chase channel drainage system.

LRA Tables 3.5.2-11 and 3.5.2-13 include several stainless steel components that reference item 3.5.1-78, but do not line the spent fuel pool. These include, but are not necessarily limited to, the debris screens in the primary containment system in LRA Table 3.5.2-11 and the integral attachments in the reactor enclosure system in LRA Table 3.5.2-13.

For stainless steel components other than the spent fuel pool liner that are exposed to treated water, the GALL Report typically recommends the One-Time Inspection program to verify the effectiveness of the Water Chemistry program (e.g., GALL Report item VII.A4.AP-110).

Issue:

Monitoring of the leak chase channel drainage may not be an appropriate activity to verify the effectiveness of the Water Chemistry program for all of the components in LRA Tables 3.5.2-11 and 3.5.2-13 that reference item 3.5.1-78.

Request:

Identify those items in LRA Tables 3.5.2-11 and 3.5.2-13 that reference LRA item 3.5.1-78 for which monitoring of the leak chase channel drainage system would not be expected to detect degradation. For those items, propose an alternative activity to verify the effectiveness of the Water Chemistry program.

Exelon Response

Table 3.5.2-11, Primary Containment, identifies the refueling bellows assembly and debris screens, grating and bars as stainless steel components in a treated water environment and reference Table 1 item 3.5.1-78. However the refueling bellows assembly is normally exposed to air. The bellows assembly would only be exposed to treated water during refueling outages. The debris screens, grating and bars are associated with the suppression pool purge supply and exhaust line. These components are located above the high water level and therefore are normally exposed to air. The air – indoor, uncontrolled environment is already identified for these components in Table 3.5.2-11 and therefore only the treated water environment is deleted.

Table 3.5.2-13 identifies the spent fuel pool gates, fuel pool liners, integral attachments and the Reactor Well, Dryer and Separator Pool, and Cask Loading Pit liners, integral attachments as stainless steel components in a treated water environment and reference Table 1 item 3.5.1-78. The Reactor Well, Dryer and Separator Pool, and Cask Loading Pit liners, integral attachments are not filled during normal operation and are exposed to air. These areas are only filled during refueling outages. The air – indoor, uncontrolled environment is already identified for these components in Table 3.5.2-13 and therefore only the treated water environment is deleted.

The spent fuel pool gates, fuel pool liners, integral attachments are associated with the spent fuel pool and are exposed to treated water. Therefore Table 1 item 3.5.1-78 is applicable and NUREG-1801 Item III.A5.T-14 aligns the aging management program as "Chapter XI.M2, Water Chemistry and Monitoring of the spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels". LRA Table 3.5.2-13 credits the Water Chemistry program and includes a Plant Specific Note that states "The spent fuel pool water level is monitored in accordance with technical specifications. Leakage from the leak chase channels is monitored in accordance with procedures."

Consistent with this response, LRA Tables 3.5.2-11 and 3.5.2-13 are revised as shown in Enclosure B.

Enclosure B
LGS License Renewal Application Updates

Notes:

- Updated LRA Sections and Tables are provided in the same order as the RAI responses contained in Enclosure A.
- To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and strikethroughs for deleted text.
    - The only exception to this convention is within the responses to RAIs 3.2.2.1.1-1 and A.1-1 because entirely new sections are provided; therefore for those new sections, text is not shown in bold/italicized font.

As a result of the response to RAI 3.1.1-60-1 provided in Enclosure A of this letter LRA Section 3.1.2.1.1, Reactor Coolant Pressure Boundary, on page 3.1-2 is revised as follows:

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Coolant Pressure Boundary components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- BWR Stress Corrosion Cracking (B.2.1.7)
- Bolting Integrity (B.2.1.11)
- Closed Treated Water Systems (B.2.1.13)
- External Surfaces Monitoring of Mechanical Components (B.2.1.25)
- ***Flow-Accelerated Corrosion (B.2.1.10)***
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)
- Lubricating Oil Analysis (B.2.1.27)
- One-Time Inspection (B.2.1.22)
- One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.24)

As a result of the response to RAI 3.1.1.60-1 provided in Enclosure A of this letter LRA Table 3.1.1, item 3.1.1-60 on page 3.1-24 is revised as follows:

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

3.1.1-60	Steel piping, piping components, and piping elements exposed to reactor coolant	Wall thinning due to flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	~~Not applicable.~~ ~~There are no steel piping, piping components or piping elements exposed to reactor coolant that are susceptible to wall thinning due to flow-accelerated corrosion in the Reactor Vessel, Internals and Reactor Coolant System.~~ ***Consistent with NUREG-1801. The Flow-Accelerated Corrosion (B.2.1.10) program will be used to manage wall thinning of steel piping, piping components and piping elements exposed to reactor coolant and treated water in the Reactor Coolant Pressure Boundary.***

As a result of the responses to RAIs 3.1.1.60-1 and 3.4.1.11-1 provided in Enclosure A of this letter, LRA Table 3.1.2-1, pages 3.1-35, 37 and 40, is revised as follows:

Table 3.1.2-1 Reactor Coolant Pressure Boundary (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Class 1 Piping, Fittings and Branch Connections < NPS 4"	Pressure Boundary	Carbon Steel	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	IV.C1.RP-39	3.1.1-31	E, 2
					Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-31	C
				Wall Thinning	***Flow-Accelerated Corrosion (B.2.1.10)***	***IV.C1.R-23***	***3.1.1-60***	***A***
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A
			Reactor Coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-39	A
					One-time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.24)	IV.C1.RP-230	3.1.1-39	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-39	A
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	IV.C1.RP-158	3.1.1-79	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-79	A
Flow Device (Instrumentation Flow Orifices)	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
Flow Device (Main Steam Flow Elements)	Throttle	Carbon Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	A

Table 3.1.2-1 Reactor Coolant Pressure Boundary (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-1	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A
				Wall Thinning	***Flow-Accelerated Corrosion (B.2.1.10)***	***IV.C1.R-23***	***3.1.1-60***	***A***
		Nickel Alloy	Reactor Coolant	Cracking	One-Time Inspection (B.2.1.22)	IV.C1.R-21	3.1.1-97	E, 2
					Water Chemistry (B.2.1.2)	IV.C1.R-21	3.1.1-97	C
				Loss of Material	One-Time Inspection (B.2.1.22)	IV.C1.RP-158	3.1.1-79	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-79	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A
			Reactor Coolant	Cracking	BWR Stress Corrosion Cracking (B.2.1.7)	IV.C1.R-20	3.1.1-97	A
					Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-97	A
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	IV.C1.RP-158	3.1.1-79	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-79	A
			Steam (Internal)	Cracking	~~One-Time Inspection (B.2.1.22)~~ ***BWR Stress Corrosion Cracking (B.2.1.7)***	~~VIII.B2.SP-98~~ ***IV.C1.R-20***	~~3.4.1-11~~ ***3.1.1-97***	A
					Water Chemistry (B.2.1.2)	~~VIII.B2.SP-98~~ ***IV.C1.R-20***	~~3.4.1-11~~ ***3.1.1-97***	A

Table 3.1.2-1 Reactor Coolant Pressure Boundary (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Recirc Motor Driver Mount	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	VIII.B2.SP-160	3.4.1-14	A
					Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-14	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 1
				Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A
				Wall Thinning	***Flow-Accelerated Corrosion (B.2.1.10)***	***IV.C1.R-23***	***3.1.1-60***	***A***
		Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A
			Reactor Coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-20	3.1.1-97	E, 5
					Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-97	A
				Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-6	A, 1
				Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1.1-38	A
				Loss of Material	One-Time Inspection (B.2.1.22)	IV.C1.RP-158	3.1.1-79	A
					Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-79	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.E.RP-04	3.1.1-107	A

As a result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Table 3.2.1, page 3.2-16, is revised as shown below:

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-16	Steel Containment isolation piping and components (Internal surfaces), Piping, piping components, and piping elements exposed to Treated water	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Consistent with NUREG-1801. The Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.22) programs will be used to manage loss of material of the carbon steel, ductile cast iron, and gray cast iron piping, piping components and piping elements, heat exchanger components, and tanks exposed to treated water and steam in the Core Spray, High Pressure Coolant Injection, Reactor Coolant Pressure Boundary, Reactor Core Isolation Cooling, and Residual Heat Removal systems. The Bolting Integrity (B.2.1.11) program has been substituted and will be used to manage loss of material of the carbon and low alloy steel bolting exposed to treated water in the Condenser and Air Removal, Core Spray, High Pressure Coolant Injection~~,~~ ***and*** Reactor Core Isolation Cooling~~, and Residual Heat Removal~~ systems.

As a result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Table 3.2.2-2, pages 3.2-35 and 3.2-38, is revised as shown below:

Table 3.2.2-2

Core Spray System

Summary of Aging Management Evaluation

Table 3.2.2-2 Core Spray System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
			Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.D2.EP-60	3.2.1-16	E, 1, 2
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-122	3.2.1-15	A, 1
		Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.D2.EP-73	3.2.1-17	E, 1, 2
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-122	3.2.1-15	A, 1
				Cumulative Fatigue Damage	***TLAA***	***VII.E4.A-62***	***3.3.1-2***	***C,6***
Flow Device	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A
		Glass	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-60	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-60	A
	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A

Table 3.2.2-2 Core Spray System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing (Safeguard Fill)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
Pump Casing (Suppression Pool Cleanup)	Leakage Boundary	Gray Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A
					Selective Leaching (B.2.1.23)	V.D1.E-43	3.2.1-35	C
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A, 1
				Cumulative Fatigue Damage	***TLAA***	***VII.E4.A-62***	***3.3.1-2***	***C,6***
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A

As a result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Table 3.2.2-5, pages 3.2-62 and 3.2-66, is revised as shown below:

Table 3.2.2-5

Residual Heat Removal System

Summary of Aging Management Evaluation

Table 3.2.2-5 Residual Heat Removal System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
			~~Treated Water (External)~~	~~Loss of Material~~	~~Bolting Integrity (B.2.1.11)~~	~~V.D2.EP-60~~	~~3.2.1-16~~	~~E, 1, 2~~
				~~Loss of Preload~~	~~Bolting Integrity (B.2.1.11)~~	~~V.E.EP-122~~	~~3.2.1-15~~	~~A, 1~~
		Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
			Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.11)	V.D2.EP-73	3.2.1-17	E, 1, 2
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-122	3.2.1-15	A, 1
				Cumulative Fatigue Damage	***TLAA***	***VII.E4.A-62***	***3.3.1-2***	***C,4***
Flow Device	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A
		Glass	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-60	A
			Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-60	A
	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A

Table 3.2.2-5 Residual Heat Removal System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing	Pressure Boundary	Ductile Cast Iron	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A, 3
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A, 3
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A, 3
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A, 3
Spray Nozzles	Spray	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-57	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.AP-143	3.3.1-89	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A, 1
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A, 1
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A, 1
				Cumulative Fatigue Damage	***TLAA***	***VII.E4.A-62***	***3.3.1-2***	***C,4***
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-73	3.2.1-17	A
					Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-17	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	V.D2.EP-60	3.2.1-16	A
					Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-16	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-18	3.2.1-63	A

As a result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Section 3.3.2.2.1, page 3.3-30, is revised as shown below:

3.3.2.2.1 Cumulative Fatigue Damage

Fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of metal fatigue as a TLAA for the Auxiliary Steam System, ***Core Spray System,*** Radwaste System, ~~and~~ Reactor Water Cleanup System ***and Residual Heat Removal System*** is discussed in Section 4.3.2. The evaluation of crane load cycles as a TLAA for the Cranes and Hoists system is discussed in Sections 4.6.1 and 4.6.2.

As the result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Sections A.2.1.11 and Section B.2.1.11 are revised as shown below:

The Bolting Integrity aging management program will be enhanced to:

1. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, storage, and installation torque or tension to prevent or mitigate degradation and failure of closure bolting for pressure retaining components.

2. Prohibit the use of lubricants containing molybdenum disulfide for pressure retaining components.

3. Minimize the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High strength bolting, if used, will be monitored for cracking.

4. ***Perform visual inspection of bolting for the Residual Heat Removal System, Core Spray System, High Pressure Coolant Injection System, and Reactor Core Isolation Cooling System suppression pool suction strainers for loss of material and loss of preload during each ISI inspection interval.***

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

Enhancements

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

1. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, storage, and installation torque or tension to prevent or mitigate degradation and failure of closure bolting for pressure retaining components. **Program Elements Affected: Preventive Actions (Element 2), Detection of Aging Effects (Element 4), Corrective Actions (Element 7)**
2. Prohibit the use of lubricants containing molybdenum disulfide for closure bolting for pressure retaining components. **Program Element Affected: Preventive Actions (Element 2)**
3. Minimize the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High strength bolting, if used, will be monitored for cracking. **Program Elements Affected: Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4)**
4. ***Perform visual inspection of bolting for the Residual Heat Removal System, Core Spray System, High Pressure Coolant Injection System and Reactor Core Isolation Cooling System suction strainers in the suppression pool for loss of material and loss of preload during each ISI inspection interval. Program Elements Affected: Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4)***

As a result of the response to RAI 3.2.2.1.1-1, provided in Enclosure A of this letter, LRA Table 4.1-2 is revised as shown below:

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

TLAA DESCRIPTION	DISPOSITION	LRA SECTION
IDENTIFICATION OF TIME-LIMITED AGING ANALYSES		4.1
Identification of LGS Time-Limited Aging Analyses		4.1.1
Evaluation of LGS Time-Limited Aging Analyses		4.1.2
Acceptance Criteria		4.1.3
Summary of Results		4.1.4
Identification and Evaluation of LGS Exemptions		4.1.5
REACTOR PRESSURE VESSEL NEUTRON EMBRITTLEMENT ANALYSIS		4.2
Neutron Fluence Projections	§54.21(c)(1)(ii)	4.2.1
Upper-Shelf Energy	§54.21(c)(1)(ii)	4.2.2
Adjusted Reference Temperature	§54.21(c)(1)(ii)	4.2.3
Pressure – Temperature Limits	§54.21(c)(1)(iii)	4.2.4
Axial Weld Inspection	§54.21(c)(1)(ii)	4.2.5
Circumferential Weld Inspection	§54.21(c)(1)(iii)	4.2.6
Reactor Pressure Vessel Reflood Thermal Shock	§54.21(c)(1)(ii)	4.2.7
METAL FATIGUE		4.3
ASME Section III, Class 1 Fatigue Analyses	§54.21(c)(1)(iii)	4.3.1
ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Calculations	§54.21(c)(1)(iii) and §54.21(c)(1)(i)	4.3.2
Environmental Fatigue Analyses for RPV and Class 1 Piping	§54.21(c)(1)(iii)	4.3.3
Reactor Vessel Internals Fatigue Analyses	§54.21(c)(1)(iii)	4.3.4
High-Energy Line Break (HELB) Analyses Based Upon Fatigue	§54.21(c)(1)(i)	4.3.5
ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC COMPONENTS		4.4
Environmental Qualification (EQ) of Electric Components	§54.21(c)(1)(iii)	4.4.1
CONTAINMENT LINER AND PENETRATIONS FATIGUE ANALYSIS		4.5
Containment Liner and Penetrations Fatigue Analysis	§54.21(c)(1)(i)	4.5.1
OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES		4.6
Reactor Enclosure Crane Cyclic Loading Analysis	§54.21(c)(1)(i)	4.6.1
Emergency Diesel Generator Enclosure Cranes Cyclic Loading Analysis	§54.21(c)(1)(i)	4.6.2
RPV Core Plate Rim Hold-Down Bolt Loss of Preload	§54.21(c)(1)(i)	4.6.3
Main Steam Line Flow Restrictors Erosion Analysis	§54.21(c)(1)(i)	4.6.4
Jet Pump Auxiliary Spring Wedge Assembly	§54.21(c)(1)(i)	4.6.5
Jet Pump Restrainer Bracket Pad Repair Clamps	§54.21(c)(1)(i)	4.6.6
Refueling Bellows and Support Cyclic Loading Analysis	§54.21(c)(1)(i)	4.6.7
Downcomers and MSRV Discharge Piping Fatigue Analyses	§54.21(c)(1)(iii)	4.6.8
Jet Pump Slip Joint Repair Clamps	§54.21(c)(1)(i)	4.6.9
Fuel Pool Girder Loss of Prestress	§54.21(c)(1)(i)	4.6.10
RHR and Core Spray Strainer Fatigue Analyses	***§54.21(c)(1)(iii)***	***4.6.11***

As a result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Section 4.6.11, "ECCS Suction Strainer Fatigue Analyses" and Appendix A, Section A.4.6.11, "ECCS Suction Strainer Fatigue Analyses," are provided as shown below: (Since the section is new, the text is not shown in bold italics).

4.6.11 RHR AND CORE SPRAY SUCTION STRAINER FATIGUE ANALYSES

TLAA Description:

The original RHR and Core Spray suction strainers were replaced with larger passive strainer designs. The design stress analyses for the replacement strainers include fatigue analyses for the stainless steel bolting and strainer assemblies. These fatigue analyses have been identified as TLAAs that require evaluation for 60 years.

TLAA Evaluation:

The replacement RHR and Core Spray suction strainers were designed in accordance with ASME Section III, NC-3200 requirements. This includes fatigue analyses of the stainless steel bolting and strainer assembly, with resulting fatigue usage values less than 1.0. These analyses were based upon 34,200 MSRV stress cycles (11,400 actuations), 10 SSE stress cycles (1 event), 50 OBE cycles (5 events) and condensation oscillation and chugging cycles that would result from LOCA events. These are the same types of transients analyzed for the downcomers, as described in the revised LRA Section 4.6.8 provided in the Exelon response to RAI 4.6.8-1, transmitted via Exelon letter dated February 29, 2012.

TLAA Disposition: –**10 CFR 54.21(c)(1)(iii) –** The effects of aging on the intended functions of the RHR and Core Spray strainer bodies and bolting will be managed by the Fatigue Monitoring (B.3.1.1) program for the period of extended operation.

As a result of the response to RAI 3.2.2.1.1-1, provided in Enclosure A of this letter, the LRA is revised to add Section A.4.6.11, as shown below: (Since the section is new, the text is not shown in bold italics).

A.4.6.11 RHR and Core Spray Suction Strainer Fatigue Analyses

The design analyses for the RHR and Core Spray suction strainers have been identified as TLAAs because they include a time-limited fatigue analysis of the stainless steel bolting and stainless steel strainer assembly. These analyses were based upon 34,200 MSRV stress cycles (11,400 actuations), 10 SSE stress cycles (1 event), 50 OBE cycles (5 events), and condensation oscillation and chugging cycles that would result from LOCA events. These are the same types of transients analyzed for the downcomers described in LRA Section 4.6.8.

The Fatigue Monitoring program is credited for managing fatigue of the RHR and Core Spray strainer assemblies and bolting, in accordance with 10 CFR 54.21(c)(1)(iii).

As a result of the response to RAI 3.2.2.1.1-3 provided in Enclosure A of this letter, LRA Section 3.3.2.1.14, page 3.3-18, is revised as follows:

3.3.2.1.14 Primary Containment Instrument Gas System

Aging Management Programs

The following aging management programs manage the aging effects for the Primary Containment Instrument Gas System components:

• Bolting Integrity (B.2.1.11)

• Compressed Air Monitoring (B.2.1.15)

• External Surfaces Monitoring of Mechanical Components (B.2.1.25)

• Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)

• Selective Leaching (B.2.1.23)

As a result of the response to RAI 3.2.2.1.1-3 provided in Enclosure A of this letter, LRA Table 3.3.2-8, pages 3.3-137 and 3.3-141, is revised as follows:

Table 3.3.2-8 Emergency Diesel Generator System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.20)	VII.H1.AP-105	3.3.1-70	A
					One-Time Inspection (B.2.1.22)	VII.H1.AP-105	3.3.1-70	A
			Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.A-33	3.3.1-64	E, 5
		Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.AP-143	3.3.1-89	A
					Selective Leaching (B.2.1.23)			***H, 7***
			Fuel Oil (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.H1.AP-132	3.3.1-69	E, 3
	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
			Air - Outdoor (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.H1.A-24	3.3.1-80	E, 1
					External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.H1.A-24	3.3.1-80	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.H2.A-23	3.3.1-89	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.13)	VII.H2.AP-202	3.3.1-45	A

5. These components are associated with the engine exhaust silencer drain piping. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.

6. Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.

7. Component is exposed to an environment containing significant amounts of moisture where condensation or water pooling may occur, resulting in the loss of material due to selective leaching. The Selective Leaching (B.2.1.23) program is used to manage the aging effects applicable to this component type, material and environment combination.

As a result of the response to RAI 3.2.2.1.1-3 provided in Enclosure A of this letter, LRA Table 3.3.2-14, pages 3.3-179 and 3.3-182, is revised as follows:

Table 3.3.2-14 Primary Containment Instrument Gas System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Ductile Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.D.A-80	3.3.1-78	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.A-23	3.3.1-89	A
					Selective Leaching (B.2.1.23)			***H, 3***
		Gray Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.D.A-80	3.3.1-78	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.A-23	3.3.1-89	A
		Nickel Alloy	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-16	3.3.1-118	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.E5.AP-274	3.3.1-95	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.F1.AP-99	3.3.1-94	C
	Pressure Boundary	Aluminum	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-135	3.3.1-113	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-37	3.3.1-113	A
		Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-14	3.3.1-117	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-98	3.3.1-117	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A

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

Plant Specific Notes:

1. The Compressed Air Monitoring program (B.2.1.15) is substituted to manage the aging effect applicable to this component type, material, and environment combination.

2. Component is a zinc die cast and has no aging effects in an air-indoor, uncontrolled (external) or air/gas-dry (internal) environment.

3. Component is exposed to an environment containing significant amounts of moisture where condensation or water pooling may occur, resulting in the loss of material due to selective leaching. The Selective Leaching (B.2.1.23) program is used to manage the aging effects applicable to this component type, material and environment combination.

As a result of the response to RAI B.1.4-1 provided in Enclosure A of this letter, LRA section B.1.4 is revised as shown below:

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 ~~may~~ include***s*** ~~such things as~~ 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 ~~may~~ include***s*** event investigations, trending reports, and lessons learned from in-house events as captured in~~ program notebooks~~, 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 prior to the period of extended operation.

~~During the first 10 years of entering the period of extended operation, the AMP owners of programs credited for license renewal will perform a review of plant-specific and industry operating experience to confirm the effectiveness of the aging management programs. This review will determine if the AMP is currently effective, requires modification or identify a need to develop a new AMP. Follow-up actions will be taken as appropriate to provide additional assurance that aging of SSCs in the scope of license renewal will be adequately managed throughout the period of extended operation.~~

As a result of the response to RAI A.1-1 provided in Enclosure A of this letter, a new section is added to Appendix A of the LRA as shown below: (Since this section is new, the text is not shown in bold italics).

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 effects of aging may not be adequately 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 prior to the period of extended operation.

As a result of the response to RAI 3.5.2.11-1 provided in Enclosure A of this letter, LRA Table 3.5.2-11 pages 3.5-177 and 3.5-178 and LRA Table 3.5.2-13 pages 3.5-215 and 3.5-217, are revised as shown below:

Table 3.5.2-11 Primary Containment (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Steel Components (Steel Columns in Suppression Pool)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.32)	III.B1.3.TP-226	3.5.1-81	C
			Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.32)	III.B1.1.TP-10	3.5.1-90	C
					Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-90	C
Steel elements: diaphragm slab liner, liner anchors, integral attachments	Direct Flow	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B2.2.CP-117	3.5.1-31	C
Steel elements: (Refueling Bellows Assembly)	Flood Barrier	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9
		Stainless Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-9	C
				None	None	III.B5.TP-8	3.5.1-95	C
			~~Treated Water~~	~~Loss of Material~~	~~Water Chemistry (B.2.1.2)~~	~~III.A5.T-14~~	~~3.5.1-78~~	~~C~~
	Shelter, Protection	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9
		Stainless Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-9	C
				None	None	III.B5.TP-8	3.5.1-95	C
			~~Treated Water~~	~~Loss of Material~~	~~Water Chemistry (B.2.1.2)~~	~~III.A5.T-14~~	~~3.5.1-78~~	~~C~~
	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9
		Stainless Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-9	C
				None	None	III.B5.TP-8	3.5.1-95	C
			~~Treated Water~~	~~Loss of Material~~	~~Water Chemistry (B.2.1.2)~~	~~III.A5.T-14~~	~~3.5.1-78~~	~~C~~
	Water retaining boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9

Table 3.5.2-11 Primary Containment (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Steel elements: (Refueling Bellows Assembly)	Water retaining boundary	Stainless Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-9	C
				None	None	III.B5.TP-8	3.5.1-95	C
			~~Treated Water~~	~~Loss of Material~~	~~Water Chemistry (B.2.1.2)~~	~~III.A5.T-14~~	~~3.5.1-78~~	~~C~~
Steel elements: (Seal Plate)	Flood Barrier	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9
	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9
	Water retaining boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C, 9
Steel elements: (debris screens, grating and bars)	Filter	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.35)	III.A4.TP-302	3.5.1-77	C
		Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B5.TP-8	3.5.1-95	C
		Stainless Steel	Air - Indoor, Uncontrolled	None	None	III.B5.TP-8	3.5.1-95	C
			~~Treated Water~~	~~Loss of Material~~	~~Water Chemistry (B.2.1.2)~~	~~III.A5.T-14~~	~~3.5.1-78~~	~~C~~
Steel elements: Downcomers and Bracing	Direct Flow	Carbon Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B2.2.C-48	3.5.1-9	A. 5
				Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B2.2.CP-117	3.5.1-31	A
			Treated Water	Cumulative Fatigue Damage	TLAA	II.B2.2.C-48	3.5.1-9	A, 5
				Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B2.2.CP-117	3.5.1-31	A
Steel elements: Vacuum Breaker Valves and Piping (Connected to Downcomer)	Pressure Relief	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.30)	II.B2.2.CP-117	3.5.1-31	C

Table 3.5.2-13 Reactor Enclosure (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Seismic Gap Filler	Expansion/ Separation	Elastomer	Air - Outdoor	Increased Hardness, Shrinkage, and Loss of Strength	Structures Monitoring (B.2.1.35)	VII.G.A-20	3.3.1-57	E, 1
Spent fuel pool gates	Water retaining boundary	Stainless Steel	Air - Indoor, Uncontrolled	None	None	III.B5.TP-8	3.5.1-95	C
			Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-78	A, 3
Steel elements: (birdscreen)	Filter	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B2.TP-8	3.5.1-95	C
			Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.35)	III.B2.TP-6	3.5.1-93	C
Steel elements: Fuel pool liners, integral attachments	Structural Support	Carbon Steel	Concrete	None	None	II.B2.2.CP-114	3.5.1-41	C
	Water retaining boundary	Stainless Steel	Air - Indoor, Uncontrolled	None	None	III.B5.TP-8	3.5.1-95	C
			Concrete	None	None	VII.J.AP-19	3.3.1-120	C
			Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-78	A, 3
Steel elements: Reactor Well, Dryer and Separator Pool, and Cask Loading Pit liners, integral attachments	Structural Support	Carbon Steel	Concrete	None	None	II.B2.2.CP-114	3.5.1-41	C
	Water retaining boundary	Stainless Steel	Air - Indoor, Uncontrolled	None	None	III.B5.TP-8	3.5.1-95	C
			Concrete	None	None	VII.J.AP-19	3.3.1-120	C
			~~Treated Water~~	~~Loss of Material~~	~~Water Chemistry (B.2.1.2)~~	~~III.A5.T-14~~	~~3.5.1-78~~	~~A, 4~~
Steel elements: Sump liners, integral attachments	Water retaining boundary	Stainless Steel	Air - Indoor, Uncontrolled	None	None	III.B5.TP-8	3.5.1-95	C

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

Plant Specific Notes:

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

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

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

4. ~~The Reactor Well water level is monitored in accordance with technical specifications.~~ ***(Deleted)***

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

Enclosure C

LGS
License Renewal Commitment List Changes

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

RAI 3.2.2.1.1-1
RAI B.1.4-1
RAI A.1-1

Notes:

- To facilitate understanding, portions of the original commitments have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and strikethroughs for deleted text.

As the result of the response to RAI 3.2.2.1.1-1 provided in Enclosure A of this letter, LRA Appendix A, Table A.5, is revised as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
11	Bolting Integrity	Bolting Integrity is an existing program that will be enhanced to: 1. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, storage, and installation torque or tension to prevent or mitigate degradation and failure of closure bolting for pressure retaining components. 2. Prohibit the use of lubricants containing molybdenum disulfide for closure bolting for pressure retaining components. 3. Minimize the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High strength bolting, if used, will be monitored for cracking. ***4. Perform visual inspection of bolting for the Residual Heat Removal System, Core Spray System, High Pressure Coolant Injection System and Reactor Core Isolation Cooling System suppression pool suction strainers for loss of material and loss of preload during each ISI inspection interval.***	Program to be enhanced prior to the period of extended operation.	Section A.2.1.11 ***LGS letter dated 3/12/2012*** ***RAI 3.2.2.1.1-1***

As the result of the responses to RAI B.1.4-1 and RAI A.1-1 provided in Enclosure A of this letter, LRA Appendix A, Table A.5, is revised as shown below:

A.5 License Renewal Commitment List

NO.	*PROGRAM OR TOPIC*	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
46	Operating Experience	~~Perform a review of plant-specific and industry operating experience to confirm the effectiveness of the aging management programs~~ **The Operating Experience Program is an existing program that 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.**	~~During the first 10 years of entering~~ ***Program to be enhanced prior to*** the period of extended operation	~~Section B.1.4~~ ***Section A.1.6*** ***LGS Letter dated 3/12/2012*** ***RAI B.1.4-1*** ***RAI A.1-1***