Exelon Generation®

License Renewal
Exelon Nuclear

200 Exelon Way
Kennett Square, PA 19348
www.exeloncorp.com

10 CFR 50
10 CFR 51
10 CFR 54

RS-14-218

July 18, 2014

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

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: Responses to NRC Requests for Additional Information, Sets 33 and 34, both dated June 23, 2014; and Corrections and Clarifications related to the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application

References:

1. Letter from Michael P. Gallagher, Exelon Generation Company LLC (Exelon) to NRC Document Control Desk, dated May 29, 2013, "Application for Renewed Operating Licenses"

2. Letter from Lindsay R. Robinson, US NRC to Michael P. Gallagher, Exelon, dated June 23, 2014, "Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 33 (TAC NOS. MF1879, MF1880, MF1881, and MF1882)"

3. Letter from Lindsay R. Robinson, US NRC to Michael P. Gallagher, Exelon, dated June 23, 2014, "Request for Additional Information for the Review of the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, License Renewal Application, Set 34 (TAC NOS. MF1879, MF1880, MF1881, and MF1882)"

In Reference 1, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2

(BBS). In References 2 and 3, the NRC requested additional information (Sets 33 and 34, respectively) to support staff review of the LRA.

Enclosure A contains the responses to these requests for additional information.

Enclosure B contains updates to sections of the LRA affected by the Sets 33 and 34 responses.

In addition, Enclosure B contains updates to LRA Appendix A, Section A.2.1.16, Fire Water System, providing additional detail regarding wet pipe sprinkler system testing in response to staff feedback.

Enclosure C provides minor corrections to LRA Summary of Aging Management Evaluation Tables (Table 2s) that were recently identified.

Enclosure D contains clarifications to LRA sections associated with two Aging Management Programs, to make the level of detail consistent with what is contained in the program basis documents, in response to staff feedback. This causes a slight change to the description of license renewal commitment 23, as shown in the commitment table mark-up within Enclosure D.

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

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

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

Executed on 7-18-2014

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 LRA sections
C. Corrections to LRA Summary of Aging Management Evaluation Tables
D. Aging Management Program Clarifications

cc: Regional Administrator – NRC Region III
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Senior Resident Inspector, Braidwood Station
NRC Senior Resident Inspector, Byron Station
NRC Project Manager, NRR-DORL-Braidwood and Byron Stations
Illinois Emergency Management Agency - Division of Nuclear Safety

Enclosure A
Byron and Braidwood Stations (BBS), Units 1 and 2
License Renewal Application

Responses to Requests for Additional Information

RAI B.2.1.28-3b (Set 33)
RAI 2.3.3.12-4 (Set 34)

RAI B.2.1.28-3b

Applicability:

Byron Station (Byron) and Braidwood Station (Braidwood), all units

Background:

1. The response to request for additional information (RAI) B.2.1.28-3a, dated May 15, 2014, stated that soil corrosion probes will not necessarily be installed at each cathodic protection survey test point; but rather, the soil corrosion probe assemblies will most often be installed away from existing cathodic protection test points. The response also stated that:

    - Selection of soil corrosion probe locations and utilization of the data will be subject to assistance in selection of the location(s) by National Association of Corrosion Engineers (NACE) qualified cathodic protection experts.
    - "[g]enerally, both the soil corrosion probes and the permanent reference electrode are installed below-grade and in close proximity to the buried piping of interest."
    - "[i]n such situations, other adjacent convention test points exhibiting values less negative than -850mV could be evaluated, as applicable, in accordance with the criteria described above."
    - A NACE qualified cathodic protection expert will evaluate the difference in the respective locations between the soil corrosion probes and the existing test point to determine whether the difference in the relative data could be reasonably attributed to other significant site features (e.g., exposed large surface area tank bottoms, heavily congested areas of other buried piping, very large diameter pipes).

2. The response to RAI B.2.1.28-3a stated that soil corrosion probe data will only be used in locations where in-scope buried piping has been volumetrically examined.

Issue:

1. The staff noted that:

    a. NACE offers four levels of qualification consisting of cathodic protection tester, cathodic protection technician, cathodic protection technologist, and cathodic protection specialist (NACE Courses CP 1 through CP 4). It is not clear to the staff what level of qualification will be required for individuals who determine locations of soil corrosion probes and the impact of localized site features.

    b. Given the use of the term "generally" in relation to the location of the installation of soil corrosion probes, it is not clear to the staff whether soil corrosion probes will be installed in close proximity to the buried piping of interest.

c. Based on its review of the response to RAI B.2.1.28-3a, the staff understands that a soil corrosion probe could be used to verify that effective cathodic protection has been provided to pipe segment locations remote from the probe. The staff has the following concerns:

   i. A NACE qualified cathodic protection expert will evaluate the impact of significant site features as they could affect cathodic protection effectiveness. However, the response did not state the factors that will be considered when evaluating the impact of local site features.

   ii. The response did not state how local soil conditions (e.g., moisture content, pH, and resistivity) could be impactful. For example, if the soil in the vicinity of the soil corrosion probe were less corrosive than at other pipe segment locations, the soil corrosion probe could under-predict the corrosion rate at other points of interest along the pipe length.

2. The staff noted that license renewal application (LRA) Section B.2.1.28 was not revised to state that soil corrosion probe data will only be used in locations where in-scope buried piping has been volumetrically examined in conjunction with installation of the probes.

Request:

1. State:

   a. the level of NACE cathodic protection qualification of the individuals involved in selecting soil corrosion probe locations and for determining the impact of localized site features

   b. Whether soil corrosion probes will be installed in close proximity to the buried piping of interest, or state the basis for its location if installed remotely from the pipe of interest.

   c. What factors will be considered when evaluating local site features including examples of how the factors would be applied.

   d. How local soil conditions will be factored into use of the soil corrosion probe data.

   In addition, make any applicable changes to LRA Section B.2.1.28.

2. Revise the Buried and Underground Piping program (LRA Section B.2.1.28) to state that soil corrosion probe data will only be used in locations where in-scope buried piping has been volumetrically examined in conjunction with installation of the probes.

Exelon Response:

1.

a. For the purposes of determining future installation locations of soil corrosion probe assemblies at Byron and Braidwood, cathodic protection experts relied upon for expertise and guidance on the selection of locations will possess a NACE CP4, “Cathodic Protection Specialist”, qualification status. Individuals possessing a NACE CP4 level qualification are required to have passed an examination course demonstrating skill and knowledge in the design of complete cathodic protection systems, rectifier and ground bed installations, on-site corrosion analysis, and application of new technologies to existing cathodic protection programs. LRA Appendix B, Section B.2.1.28, is revised, as shown in Enclosure B, to clarify the level of qualification of cathodic protection experts relied upon for guidance in selecting installation locations of new soil corrosion probe assemblies.

b. Based upon a review of the response to RAI B.2.1.28-3a, request 2, it has been determined that the use of the term “generally”, as referenced in the sentence identified in the *Background* section of this RAI, was unnecessary. For the purposes of assessing cathodic protection effectiveness of in-scope buried piping as part of the Buried and Underground Piping (B.2.1.28) aging management program, all soil corrosion probe assemblies will be installed in close proximity to the buried pipe of interest. LRA Appendix B, Section B.2.1.28, is revised to clarify this requirement, as shown in Enclosure B.

c. In the response to RAI B.2.1.28-3a, request 2, contained in Exelon Letter RS-14-143, dated May 15, 2014, it was stated that in certain situations, data obtained from a newly installed soil corrosion (SC) probe assembly may be used to evaluate the cathodic protection effectiveness in areas currently assessed by existing cathodic protection (CP) test points. In these situations the following factors would be considered:

1) The soil corrosion probe assembly would be buried directly adjacent, and electrically connected, to the same buried pipeline of interest being assessed by the existing CP test point.

2) The soil corrosion probe assembly would also be located further from the nearest impressed current anode bed than the existing CP test point.

3) The location of the soil corrosion probe assembly with respect to the existing CP test point would need to be evaluated to determine whether any potential low readings from the CP test point could be attributed to nearby adjacent site features, such as exposed large surface area tank bottoms, heavily congested areas of other buried piping, or very large diameter pipes (e.g., circulating water).

One factor that will be considered when evaluating the effects of adjacent site features is whether those site features serve as large cathodic protection current collectors. Cathodic protection current collectors are large soil-exposed metallic surfaces of electrically continuous structures or components that effectively use the majority of supplied current density available to an area. This results in less current available to adequately protect nearby components, such as buried piping, and often results in lower cathodic polarization potentials observed in the areas near the exposed metallic structure or component. Examples of structures or components which can act as large cathodic protection current collectors are exposed tank bottom surfaces, uncoated buried pipes, and reinforced concrete structures.

Another example of a factor that will be considered when evaluating the effects of adjacent site features is whether those site features, such as large diameter pipe (e.g., circulating water), could be shielding current from reaching the intended buried pipe of interest. Byron and Braidwood utilize deep anode ground beds where the impressed current moves up toward the plant structures in a fairly uniform pattern from deeper depths, and is picked up on the surfaces by all buried piping that is electrically connected to the cathodic protection system. However, when smaller pipes of interest are routed adjacent to much larger diameter circulating water piping, for example, the circulating water pipes can act as a barrier to the uniform migration of current to the surface. Specifically, the available cathodic protection current is picked up first at the bottom of the large diameter circulating water pipe and subsequently fails to reach the pipe of interest. As a result, the pipe of interest does not receive the impressed current necessary to achieve adequate protection, which is observed through lower polarization potential readings.

In order to further explain the intended use of the soil corrosion probe assemblies with respect to the areas in which they may be used to assess cathodic protection effectiveness, provided below are example scenarios involving Figure 1 contained at the end of this RAI response.

<u>Scenario 1:</u>

- Prior to installation of new SC Probe assembly #1, existing conventional Test Point A would represent CP effectiveness for Zone 1 and Zone 2 for the buried pipe of interest.
- After installation of new SC Probe assembly #1, electrically connected to and physically located in close proximity to the same buried pipe of interest as Test Point A, SC Probe assembly #1 will assess CP effectiveness for Zone 1, and Test Point A will assess CP effectiveness for Zone 2.
- If Test Point A fails to meet -850mV, Zone 2 may still be considered adequately protected based upon a satisfactory reading for SC Probe assembly #1 because:
    - SC Probe assembly #1 is located further from Deep Anode C than Test Point A.
    - No exposed metallic site features are located near Test Point A which could serve as large current collectors or otherwise shield current from reaching the buried pipe to which Test Point A is connected.
    - Soil corrosion probe assemblies provide more accurate data than existing test points, in part, due to the probes and associated reference electrode

being located in close proximity to the buried pipe of interest, while a portable reference electrode used for Test Point A is placed on the soil surface, further from the buried pipe of interest. The loss of material readings from the probes also account for both polarization levels and local soil conditions experienced over the entire surveillance interval.

- Use of SC Probe assembly #1 to assess Zone 1 and Zone 2 is consistent with the previous practice prior to its installation when Test Point A represented both Zones.

Therefore, data from SC Probe assembly #1 may be used to assess CP effectiveness along the lengths represented by Test Point A.

Scenario 2:

- Prior to installation of new SC Probe assembly #2, existing conventional Test Point B would represent CP effectiveness for Zone 3 and Zone 4 for the buried pipe of interest.
- After installation of new SC Probe assembly #2, electrically connected to and physically located in close proximity to the same buried pipe of interest as Test Point B, SC Probe assembly #2 will assess CP effectiveness for Zone 3, and Test Point B will assess CP effectiveness for Zone 4.
- SC Probe assembly #2 is located further from Deep Anode B than Test Point B.
- Test Point B is located in close proximity to 2 tanks with uncoated metallic tank bottoms founded directly on grade. These tanks may behave as current collectors, resulting in potentially less available current in the vicinity of the adjacent buried pipe of interest, and subsequently lower polarization values at the location of Test Point B.

Therefore, data from SC Probe assembly #2 will NOT be used to assess CP effectiveness in the areas represented by Test Point B.

LRA Appendix B, Section B.2.1.28, is revised to provide additional detail on the factors that will be considered when installing and using the soil corrosion probe assemblies, as shown in Enclosure B.

d. Local soil conditions will be factored into the use of soil corrosion probe assemblies by considering existing soil sample data when identifying installation locations of the soil corrosion probe assemblies. Location selection for soil corrosion probe assemblies will consider any existing soil sample data (e.g., moisture content, pH, and resistivity measurements) to identify potentially more corrosive areas of concern in which to install the probe assemblies, including any additional indirect evidence, such as buried pipe inspection results, of more corrosive locations.

Soil sampling during buried pipe excavations and inspections is a best practice identified as part of the Byron and Braidwood buried piping programs and procedures. As an example, six (6) soil samples were collected in 2009 at

Byron, including three (3) locations of existing cathodic protection test points and three (3) excavated buried pipes. Soil parameters associated with these six (6) locations consisted of pH values between 8.5 and 9.2, chloride levels between 2 and 39 ppm, and redox potentials between 260 and 310 mV. Saturated soil resistivity values consisted of 6.8k, 9.2k, 14k, 15k, 21k, and 36k ohm-cm. For Byron, these soil samples, taken from distributed locations, indicate that the soil corrosivity is relatively consistent, such that large variances in local soil conditions are not a significant concern.

At Braidwood, the Service Water system is backfilled in controlled low-strength material, and while soil sampling has not been performed along the condensate system, over 300 feet of buried condensate system piping has been excavated and inspected at eight (8) different locations along the system since 2010. Based on the same controlled compacted backfill specified for the entire length of the system, verification during excavations that the same backfill materials exist, as well as similar pipe surface conditions and extent of material loss identified in locations of coating damage during these inspections, there has been little variability of local soil conditions associated with buried condensate system piping. Future excavations associated with the implementation of Enhancement 6 to the Buried and Underground Piping (B.2.1.28) aging management program will provide additional verification of the minimal effects of local soil conditions on the buried condensate system piping.

While local soil conditions will be factored into the location placement of soil corrosion probe assemblies based on existing soil data available at the time of the installation, the proposed method of assessing cathodic protection (CP) effectiveness along buried pipe segments remote from the probe assemblies themselves is consistent with the existing methodology of assessing CP effectiveness using existing conventional test points. As described in the example provided in Scenario 1 under the Response to ‘1c.’, above, the existing methodology for assessing CP effectiveness during annual surveys, in accordance with the original design of the system, involves evaluating pipe segment locations away from where the physical readings are obtained and without directly considering the effects of local soil conditions along the entire lengths. Therefore, the proposed use of soil corrosion probe assemblies in assessing CP effectiveness along pipe segments away from where the probe assemblies are physically located, specifically pipe segments associated with only the nearest adjacent test point, is consistent with the manner in which the system is currently tested and evaluated by existing conventional test points.

Soil corrosion probe assemblies also provide enhanced data, with respect to existing conventional test points, for soil corrosivity assessment in the areas in which they are installed (i.e., close proximity to the piping they are assessing). Specifically, existing conventional CP test points provide data once each year, during performance of an annual survey, related only to the pipe-to-soil potential of the pipe of interest, thereby representing the degree of polarization and cathodic protection only at the time of surveillance. In contrast, soil corrosion probe assemblies are directly installed in the soil, in close proximity to the buried pipe they are assessing, and provide direct information on the effectiveness of the cathodic protection system in mitigating material loss based upon the actual local soil conditions, including any variances in both soil conditions and CP effectiveness over the entire surveillance interval.

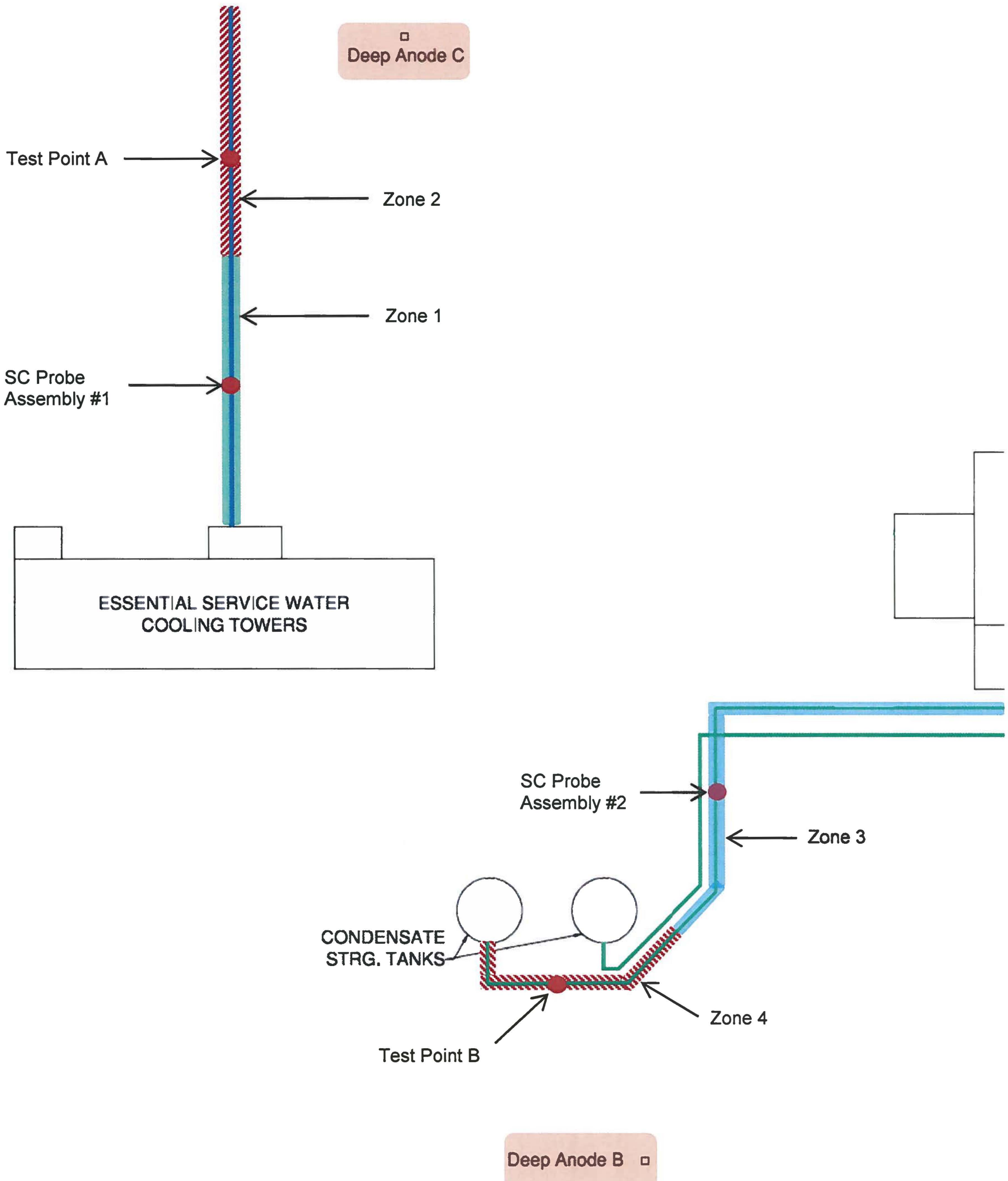
In conclusion, the proposed use of soil corrosion probe assemblies in assessing CP effectiveness along pipe segments away from where the probe assemblies are physically located, specifically pipe segments associated with the nearest adjacent CP test point, is consistent with the manner in which the system is currently tested and evaluated by existing CP test points. Soil corrosion probe assemblies also provide an enhanced ability, with respect to conventional CP test points, to assess the impacts of local soil conditions in close proximity to the buried pipe that the soil corrosion probe assemblies are assessing, over the entire surveillance interval of interest (i.e., one year). In order to further account for local soil conditions, location selection for installing soil corrosion probe assemblies will consider any existing soil data obtained during previous excavations and soil sampling activities in order to identify potentially more corrosive locations. LRA Appendix B, Section B.2.1.28, is revised to include consideration of pre-existing soil sample data when identifying installation locations of soil corrosion probe assemblies, as shown in Enclosure B.

2. In the response to RAI B.2.1.28-3, request b, contained in Exelon Letter RS-14-003, dated January 13, 2014, it was stated that cathodic protection effectiveness may be demonstrated through use of soil corrosion probes. The identified acceptance criteria during annual cathodic protection surveys for use of the soil corrosion probe assemblies would consist of either, a measured corrosion rate observed by a cathodically protected probe exhibiting less than one (1) mil per year material loss over the past one (1) year, or, a remaining life calculation performed at the time of the annual survey which demonstrates that the buried piping of interest would continue to perform its intended function through the end of the period of extended operation. The remaining life calculation would be based on previous volumetric wall thickness measurements taken at the time of the installation of the probes, cumulative loss of material since the initial volumetric examination during installation of the probe, as well as the current years' measured corrosion rate extrapolated through the end of the life of the plant.

   In the response to RAI B.2.1.28-3a, request 3a, contained in Exelon Letter RS-14-143, dated May 15, 2014, it was also clarified that, since the remaining life calculations require as-found pipe wall thickness measurements, the use of remaining life calculations to demonstrate cathodic protection effectiveness would only be utilized where soil corrosion probe assemblies are installed at locations where the associated buried piping has been volumetrically examined. If volumetric examinations of the associated buried pipe of interest were not performed, the acceptance criterion related to the evaluation of a remaining life calculation would not be utilized. However, in locations where soil corrosion probe assemblies are installed without performing volumetric examinations of the buried pipe of interest, data from the soil corrosion probe assemblies would still be evaluated with respect to the one (1) mil per year criterion to determine cathodic protection effectiveness.

   In order to clarify the use of the two (2) acceptance criteria when evaluating cathodic protection effectiveness using soil corrosion probes, LRA Appendix B, Section B.2.1.28, is revised as shown in Enclosure B.

Figure 1 – Soil Corrosion (SC) Probe Simplified Drawing



*Note: This figure is for demonstrative purposes only, and is not intended to represent actual configurations or planned installation locations.

RAI 2.3.3.12-4

Applicability:

Byron Station (Byron) and Braidwood Station (Braidwood), Units 1 and 2

Background:

For Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, the staff reviewed the combined license renewal application (LRA), drawings, and several other applicable documents. LRA Section 2.3.3.12 discusses requirements for the fire water supply system but does not mention suction screens for the fire pump suction water supply. The intake traveling screens were not included in the license renewal boundaries; however, they appear to have fire protection intended functions required for compliance with Title 10 of the *Code of Federal Regulations* (CFR) 50.48, "Fire protection," as stated in 10 CFR 54.4. Intake traveling screens are located upstream of the fire pump suctions to remove any major debris from the fresh or raw water. Intake traveling screens are necessary to remove debris from and prevent clogging of the fire protection water supply system and have a passive intended function of filter.

Issue:

Tables 2.3.3-12 and 3.3.2-12 of the LRA do not include the intake traveling screens.

Request:

The staff requests that the applicant verify whether the intake traveling screens are in the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an aging management review (AMR) in accordance with 10 CFR 54.21(a)(1). If they are excluded from the scope of license renewal and are not subject to an AMR, the staff requests that the applicant provide justification for the exclusion.

Exelon Response:

At both Byron and Braidwood, the fire pumps are equipped with a stainless steel suction strainer to protect the pump from debris in the water supply. The fire pump suction strainers are included within the scope of license renewal and are evaluated with the Fire Protection System for aging management review. The fire pump suction strainers are evaluated as component type "Strainer Element" in Table 3.3.2-12 of the LRA. The fire pump suction strainers perform a "Filter" intended function and are managed for aging by the Fire Water System (B.2.1.16) aging management program.

At Byron, the fire pumps draw suction from the 1A and 2A Circulating Water Pump House (Byron) intake bays. Trash racks are located in the 1A and 2A intake bays to screen the water for debris. The trash racks are included within the scope of license renewal and are evaluated with the Circulating Water Pump House (Byron) for aging management review. The trash racks are evaluated as component type "Steel Components (Trash Rack Bars)" in Table 3.5.2-2 of the LRA. The trash racks perform a "Filter" intended function and are managed for aging by the Structures Monitoring (B.2.1.34) aging management program. The 1A and 2A intake bays at the Circulating Water Pump House (Byron) are not equipped with traveling screens since the water supply is not from an open source where debris from environmental sources is likely.

At Braidwood, the fire pumps draw suction from the 1A and 2A Lake Screen Structures (Braidwood) intake bays. Trash racks are located in the 1A and 2A intake bays to screen the water for debris. The trash racks are included within the scope of license renewal and are evaluated with the Lake Screen Structures (Braidwood) for aging management review. The trash racks are evaluated as component type “Steel Components (Trash Rack Bars)” in Table 3.5.2-9 of the LRA. The trash racks perform a “Filter” intended function and are managed for aging by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.35) aging management program. The 1A and 2A intake bays at the Lake Screen Structures (Braidwood) are also equipped with traveling screens.

The traveling screens for the 1A and 2A Lake Screen Structures (Braidwood) intake bays are not explicitly relied upon in any safety analysis or plant evaluation to perform a function that demonstrates compliance with the NRC’s regulations for Fire Protection (10 CFR 50.48). However, NFPA 20, *Standard for the Installation of Centrifugal Fire Pumps* (1983), specifies that water from an open source (e.g., a lake or river) be screened to remove debris at the suction intake. Compliance with NFPA 20 (1983), with certain deviations as described in the Fire Protection Report, is credited to meet 10 CFR 50.48 requirements. The traveling screens perform the design function specified in NFPA 20 (1983) by filtering the water entering the 1A and 2A intake bays to remove debris that could potentially degrade the performance of the fire pumps. Since the Braidwood 1A and 2A intake bay traveling screens support the functionality of the fire pumps, they will be evaluated with the Fire Protection System for aging management review. The Fire Water System (B.2.1.16) aging management program will provide aging management of the traveling screens for the 1A and 2A Lake Screen Structures (Braidwood) intake bays and will rely on existing periodic diver inspections. LRA Section 2.3.3.12, Table 2.3.3-12, Table 3.3.1, Table 3.3.2-12, Appendix A, Section A.2.1.16, and Appendix B, Section B.2.1.16 are revised as shown in Enclosure B to identify the 1A and 2A intake bay traveling screens at Braidwood as within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) and subject to aging management review.

Enclosure B

**Byron and Braidwood Stations, Units 1 and 2
License Renewal Application (LRA) updates resulting
from the response to the following RAI:**

RAI B.2.1.28-3b (Set 33)
RAI 2.3.3.12-4 (Set 34)

Note: To facilitate understanding, the original LRA pages have been repeated in this Enclosure, with revisions indicated. Existing LRA text, as modified by subsequent submittals, is shown in normal font. Changes are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the response to RAI 2.3.3.12-4 provided in Enclosure A of this letter, the Description and Boundary discussions in LRA Section 2.3.3.12 are revised as shown below. Text inserted as a result of the response to RAI 2.3.3.12-4 is highlighted by ***bolded italics***. Existing text from the LRA is shown in normal font.

2.3.3.12 Fire Protection System

Description

The Fire Protection System is a standby, mechanical system designed for the rapid detection and suppression of a fire at the plant. The Fire Protection System consists of the following plant systems: fire protection & detection system, Halon system, and portions of the carbon dioxide system. In addition, the fire barrier function of structures and structural components (e.g., walls, floors, penetration seals, doors, fuel oil storage tank berm) is evaluated with the Fire Protection System. The Fire Protection System is in scope for license renewal. However, portions of the Fire Protection System are not required to perform intended functions and are not in scope.

The Fire Protection System consists of the fire protection water supply subsystem, deluge subsystems, sprinkler subsystems, foam subsystems, Halon subsystems, carbon dioxide subsystems, fire detection subsystem, and manual fire extinguishing features. These subsystems work in conjunction with the physical plant design features to provide overall protection for Byron and Braidwood Stations. The physical plant features consist of fire barriers, fire doors, fire rated enclosures, and combustible fluid retaining barriers (i.e., curbs and the fuel oil storage tank berm).

The purpose of the Fire Protection System is to prevent fires from starting, promptly detect and suppress fires to limit damage, and in the event of a fire, to allow for safe shutdown to occur. The Fire Protection System accomplishes this purpose by providing fire protection equipment in the form of detectors, alarms, fire barriers, and suppression systems for selected areas of the plant.

Water Supply Subsystem:
The purpose of the fire protection water supply subsystem is to provide a source of water to automatic and manual water based fire suppression subsystems located throughout the plant including; hose stations, deluge subsystems, sprinkler subsystems, and foam subsystems. The fire protection water supply subsystem accomplishes this purpose through the use of pumps, piping, and valves which allow fire water to be distributed throughout the site to the various fire suppression subsystems.

The fire protection water supply subsystem is a direct pumping system with pumps taking suction from the circulating water intake flume at Byron Station or the cooling lake at Braidwood Station. ***The intake bays for the fire pumps at Braidwood Station, located in the lake screen house, are equipped with traveling screens to prevent debris from entering the bays.*** The Fire Protection System is normally kept pressurized by one of the two motor-driven fire protection jockey pumps. If system demand occurs, the system pressure will decrease initiating the automatic start of the motor-driven fire pump. If system demand exceeds the capability of the motor-driven fire pump or in the event of a pump failure, the diesel-driven fire pump will automatically start. The motor-driven fire pump, diesel-driven fire pump, and jockey pumps are located in the circulating water pump house at Byron Station and the lake screen house at Braidwood Station.

The fire pumps at Byron and Braidwood Stations supply the outdoor ring header. The outdoor ring header encircles the entire plant with fire hydrants strategically located approximately 250 feet apart. The fire water enters the power block at several locations from branch headers off the main outdoor ring header. The outdoor ring header also supplies fire water to remote structures away from the power block. Sectionalizing valves of the post indicator type are provided on the outdoor ring header to allow isolation of the various sections for maintenance.

The outdoor ring header supplies the fire suppression water source for the Turbine Building Complex ring header from both the Unit 1 and Unit 2 sides. The Auxiliary Building ring header is fed from the outdoor ring header through the Fuel Handling Building or through cross connections with the Turbine Building Complex ring header. The Containment Structure fire suppression water is fed from the Auxiliary Building ring header. In addition, in the event that both the motor-driven fire pump and the diesel-driven fire pump are unavailable, water can be supplied via the safety-related cross-tie with the Service Water System.

Deluge Subsystems:
The purpose of the deluge subsystems is to discharge water, upon actuation, to provide fire suppression capability, especially in areas where fire spread is likely to be rapid. The deluge subsystems accomplish this purpose through piping, valves, and nozzles which allow large areas to be wetted down at once when a fire is detected. The deluge subsystems provide fire suppression capability to the main, unit auxiliary, and system auxiliary transformers, hydrogen seal oil units, turbine oil reservoir areas, turbine bearings, and various charcoal filters in safety related ventilation systems. Water is supplied to these deluge subsystems via the Turbine Building Complex ring header or the Auxiliary Building ring header. In addition, preaction sprinkler subsystems supplied from the Turbine Building Complex ring header are provided for the main turbine bearings.

Sprinkler Subsystems:
The purpose of the sprinkler subsystems is to provide automatic fire suppression capability to various fire areas throughout the plant. The subsystem accomplishes this purpose through piping and valves from the fire water supply subsystem to sprinkler heads with closure links designed to melt at various temperatures allowing for automatic actuation. The sprinkler subsystems provide fire suppression capability in most areas of the Turbine Building Complex and in other areas where a significant fire hazard exists, such as the component cooling pump areas and the waste oil tank area in the Auxiliary Building. Water supply for the sprinkler subsystems is provided from the Turbine Building Complex ring header. Operation of the sprinkler subsystems is fully automatic.

Foam Subsystems:
The purpose of the foam subsystems is to provide fire suppression capability to the diesel oil storage tanks. The subsystem accomplishes this purpose by utilizing tanks, piping, valves, and nozzles to mix a protein foam concentrate with fire water from the fire water supply subsystem and expand the mixture in a foam-maker chamber for injection into the hazard area. Manual foam subsystems are provided for the 50,000 gallon diesel oil storage tank rooms in the Auxiliary Building at both Byron and Braidwood Stations. The fire water to the foam subsystems is supplied from the Turbine Building Complex ring header. When actuated, the foam subsystems spray fire suppression foam into the diesel oil storage tank rooms.

Halon Subsystems:
The purpose of the Halon subsystem is to provide fire suppression capability in areas where water suppression systems cannot be used. The subsystem accomplishes this purpose by utilizing Halon storage cylinders, piping, valves, and nozzles to deliver the Halon gas to the fire hazard area. Fire suppression for the upper cable spreading room and the QA vault is provided by the automatic Halon subsystems. Actuation of the Halon subsystems for the QA vault is provided by ionization detectors. The Halon subsystem serving the upper cable spreading room requires signals from both ionization detectors and thermal detectors to actuate. Halon systems have been selected for fire suppression in these areas due to distance from the carbon dioxide storage tank, protection of equipment from water damage, or personnel protection. Following automatic activation of the Halon subsystems, a solenoid valve releases Halon from a storage cylinder into the manifold header. The Halon gas is then discharged through the distribution nozzles onto the fire.

Carbon Dioxide Subsystems:
The purpose of the carbon dioxide subsystems is to provide fire suppression capability to areas where equipment damage would occur should a water based fire suppression system be used. The subsystem accomplishes this purpose by utilizing distribution piping, valves, and nozzles to allow carbon dioxide gas to be transported from the carbon dioxide storage tank to the various fire hazard areas. The carbon dioxide fire suppression subsystem is supplied from a refrigerated 10-ton carbon dioxide storage tank. A single carbon dioxide storage tank, located in the turbine building, supplies carbon dioxide to both units for fire suppression and for main generator hydrogen purging. The portion of the carbon dioxide system that supports the main generator is evaluated with the Main Generator and Auxiliaries System. Actuation of the carbon dioxide subsystem is achieved manually by local pushbuttons or automatically by rate compensated detectors in areas other than cable spreading and cable tunnel areas, and by both ionization and compensated detectors in the cable spreading and cable tunnel areas. Upon actuation, the 10 ton carbon dioxide storage tank supplies carbon dioxide through the master selector valve to the four inch distribution headers and area selector valves. The distribution header provides a flow path to the various fire areas protected by the carbon dioxide subsystem. At Byron Station there is a second carbon dioxide subsystem, including a 2-ton carbon dioxide storage tank, serving the River Screen House. The features of this subsystem are identical to the main carbon dioxide system except that the distribution header, gate valves, master valves, and selector valves are three inch.

Fire Detection Subsystem:
The purpose of the fire detection subsystem is to detect fires, actuate fire protection equipment, inform the main control room of fire location, activate local fire alarms, and monitor status of fire protection components. The subsystem accomplishes this purpose by utilizing ionization, ultraviolet, and thermal detectors to detect fires and activate the fire suppression subsystems.

Manual Fire Extinguishing Features:
The purpose of the manual fire extinguishing features is to allow for manual fire fighting capability throughout the plant. The purpose is accomplished through strategically placed hose stations and portable extinguishers located throughout the site.

Portions of the Fire Protection System perform a primary containment boundary function. The Fire Protection System accomplishes this function through the use of qualified piping and valves that ensure primary containment integrity.

Portions of the Fire Protection system support the Spent Fuel Cooling System in ensuring spent fuel stored in the spent fuel pool remains within acceptable temperature limits. The Fire Protection System includes seismically qualified piping and components in the Auxiliary Building and Fuel Handling Building, including a cross-tie with the safety-related Service Water System, which can be used to provide a make-up water supply source to the spent fuel pool.

For more detailed information, see UFSAR Section 9.5.1.

Boundary

The license renewal scoping boundary of the Fire Protection System consists of the fire water systems, Halon systems, and carbon dioxide system, as follows:

Fire Water Systems:
The fire water systems include the water supply subsystem, the deluge subsystems, the sprinkler subsystems, and the foam subsystems. The water supply system scoping boundary begins at the intake to the motor-driven and diesel-driven fire pumps and the motor driven jockey pumps located in the Circulating Water Pump House at Byron Station and the Lake Screen Structures at Braidwood Station. ***At Braidwood Station only, the scoping boundary also includes the intake bay traveling screens located upstream of the fire pumps.*** The system flowpath continues to the outdoor ring header which supplies fire suppression water to deluge, sprinkler, foam, and manual fire suppression features throughout the site, including to remote structures away from the power block. The water supply system boundary continues from the outdoor ring header to the Turbine Building Complex ring header. The outdoor ring header also supplies the Fuel Handling Building and Radwaste and Service Building Complex fire water headers. The Turbine Building Complex ring header terminates at the various water based fire suppression subsystems throughout the Turbine Building Complex, the cross-ties to the Auxiliary Building ring header, and the nonessential service water system. The Auxiliary Building ring header is also supplied from the Fuel Handling Building fire water header. The Auxiliary Building ring header terminates at the various water based fire suppression subsystems throughout the Auxiliary Building, the fire water headers supplying the Containment Structures and the Fuel Handling Building, and the cross-tie to the essential service water system. The Containment Structure and Fuel Handling Building water supply systems terminate at the various water based fire suppression subsystems throughout these structures.

Halon Subsystems:
There are two separate Halon fire suppression subsystems at Byron and Braidwood Stations. One subsystem protects the upper cable spreading room and the other subsystem protects the QA vault. The scoping boundary for both Halon subsystems begins at the Halon storage cylinders. The Halon subsystem boundary continues through the cylinder manifold and deluge valve to the discharge piping and valves. The Halon subsystem scoping boundary terminates at the distribution nozzles.

Carbon Dioxide Subsystems:
The carbon dioxide subsystem scoping boundary begins at the 10-ton carbon dioxide storage tank, located in the turbine building. The subsystem scoping boundary

continues through the carbon dioxide supply header to the various fire areas served by the subsystem. The subsystem terminates at the distribution nozzles located in the fire areas served by the carbon dioxide fire suppression subsystem. At Byron Station there is a second carbon dioxide subsystem providing fire suppression capability to the River Screen House. The system scoping boundary of the Byron Station River Screen House carbon dioxide subsystem begins at the 2-ton carbon dioxide storage tank and continues through the supply header terminating at the distribution nozzles located in the fire areas served by this subsystem.

All associated piping, components, and instrumentation contained within the flow path described above are included in the system evaluation boundary.

Portable fire extinguishers are also included within the scoping boundary of this license renewal system, however, a flow path description is not applicable for this self-contained portable equipment. Portable fire extinguishers are provided in accordance with NML, NFPA 10, and OSHA regulations and recommendations. These extinguishers are routinely inspected and replaced by station procedures and are, therefore, not subject to aging management review.

The racks, reels, and supports that make up the hose stations are also included within the scoping boundary of the Fire Protection System. These components are required to provide structural support of fire suppression equipment to demonstrate compliance with fire protection requirements. Hoses are considered consumables and are, therefore, not subject to aging management review.

Also included within the scoping boundary of the Fire Protection System are the physical plant design features that consist of fire barrier walls and slabs, fire barriers, fire doors, fire rated enclosures, and combustible fluid retaining barriers located in structures within the scope of license renewal. These structures include: the Auxiliary Building, Circulating Water Pump House (Byron only), Containment Structure, Fuel Handling Building, Lake Screen Structures (Braidwood only), Turbine Building Complex, Radwaste and Service Building Complex, and River Screen House (Byron only). In addition, since the earthen berm that surrounds the fuel oil storage tanks prevents the spread of combustible fluid, the fire barrier function of this structure is included within the scoping boundary of the Fire Protection System. The fire barrier function of all fire damper housings is evaluated with the Fire Protection System for license renewal aging management review. The pressure boundary function of fire damper housings, if applicable, is evaluated with the appropriate ventilation system.

Not included within the Fire Protection System scoping boundary are the fire detection and signaling and associated circuitry. The fire detection and signaling and associated circuitry are evaluated separately as electrical commodities.

Not included within the Fire Protection System scoping boundary are the diesel oil storage tank and supply piping to the diesel-driven fire pump diesel engine. The diesel oil storage tank and associated supply piping up to diesel engine are evaluated with the Fuel Oil System.

Not included within the Fire Protection System scoping boundary are the reactor coolant pump oil collection systems. The reactor coolant pump oil collection systems are evaluated with the Radioactive Drain System.

Also included in the license renewal scoping boundary of the Fire Protection System are those water filled portions of nonsafety-related piping and equipment located in proximity to equipment performing a safety-related function. This includes the nonsafety-related portions of the system drains located within the Auxiliary Building and Containment Structure. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this portion of the system. For more information, refer to the license renewal boundary drawing for identification of this boundary, shown in red.

Not included within the scope of license renewal is the fire protection equipment located in areas that do not contain safety-related equipment or equipment required for safe shutdown. This includes fire protection features in the Containment Access Facilities, Electrical/Instrument Maintenance Building, FIN Team/Records Management Vault Building (Braidwood), Contractors Facility (Byron), Receiving Building, Receiving Building Warehouse, Security Gatehouse, Training Facilities, and Waste Treatment Building. These areas do not contain safety-related components and are not required to perform or support system intended functions of the Fire Protection System. Therefore, these portions of the Fire Protection System are not included in the scope of license renewal.

As a result of the response to RAI 2.3.3.12-4 provided in Enclosure A of this letter, LRA Table 2.3.3-12 is revised as shown below. Text inserted as a result of the response to RAI 2.3.3.12-4 is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

Table 2.3.3-12 Fire Protection System
Components Subject to Aging Management Review

Component Type	Intended Function
Bolting	Mechanical Closure
Concrete Curbs	Direct Flow
Damper Housing	Fire Barrier
Doors	Fire Barrier
Earthen water-control structures (Fuel Oil Storage Tank Berm)	Direct Flow
Fire Barriers (Insulation and Wraps)	Fire Barrier
Fire Barriers (Masonry Walls)	Fire Barrier
Fire Barriers (Penetration Seals)	Fire Barrier
Fire Barriers (Structural Steel Fireproofing)	Fire Barrier
Fire Barriers (Walls, Ceilings, and Floors)	Fire Barrier
Fire Hydrant	Pressure Boundary
Gas Bottles (Halon)	Pressure Boundary
Hose Stations (Racks, Reels, and Supports)	Structural Support
Insulated piping, piping components, and piping elements	Pressure Boundary
Odorizer	Pressure Boundary
Piping, piping components, and piping elements	Leakage Boundary
	Pressure Boundary
Pump Casing (Jockey Pump)	Pressure Boundary
Pump Casing (Motor and Diesel Driven Fire Pumps)	Pressure Boundary
Restricting Orifice	Pressure Boundary
	Throttle
Silencer/Muffler	Pressure Boundary
Spray Nozzles (Carbon Dioxide)	Spray
Spray Nozzles (Charcoal Filters)	Spray
Spray Nozzles (Deluge)	Spray
Spray Nozzles (Halon)	Spray
Sprinkler Heads	Pressure Boundary
	Spray
Strainer Body	Pressure Boundary
Strainer Element	Filter
Tanks (10 Ton Carbon Dioxide)	Pressure Boundary
Tanks (2 Ton Carbon Dioxide)	Pressure Boundary
Tanks (Foam Concentrate Storage)	Pressure Boundary
Tanks (Retard Chamber)	Pressure Boundary
Traveling Screen (Braidwood only)	***Filter***
Valve Body	Pressure Boundary

As a result of the response to RAI 2.3.3.12-4 provided in Enclosure A of this letter, LRA Table 3.3.1 is revised as shown below. Text inserted as a result of the response to RAI 2.3.3.12-4 is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-64	Steel, Copper alloy Piping, piping components, and piping elements exposed to Raw water	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Consistent with NUREG-1801. The Fire Water System (B.2.1.16) program will be used to manage loss of material of steel and copper alloy piping, piping components, piping elements, ***traveling screens,*** and tanks exposed to raw water in the Fire Protection System.
3.3.1-66	Stainless steel Piping, piping components, and piping elements exposed to Raw water	Loss of material due to pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Consistent with NUREG-1801. The Fire Water System (B.2.1.16) program will be used to manage loss of material of stainless steel piping, piping components, and piping elements***, and traveling screens*** exposed to raw water in the Fire Protection System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-72	Gray cast iron, Copper alloy (>15% Zn or >8% Al) Piping, piping components, and piping elements, Heat exchanger components exposed to Treated water, Closed-cycle cooling water, Soil, Raw water, Waste water	Loss of material due to selective leaching	Chapter XI.M33, "Selective Leaching"	No	Consistent with NUREG-1801. The Selective Leaching (B.2.1.21) program will be used to manage loss of material of copper alloy with 15% zinc or more and gray cast iron heat exchanger components, structural members, piping, piping components, and piping elements***, and traveling screens*** exposed to closed cycle cooling water, waste water, and raw water in the Auxiliary Feedwater System, Chilled Water System, Demineralized Water System, Emergency Diesel Generator & Auxiliaries System, Essential Service Water Cooling Towers (Byron), Fire Protection System, Heating Water and Heating Steam System, Sampling System, and Service Water System.

As a result of the response to RAI 2.3.3.12-4 provided in Enclosure A of this letter, LRA Table 3.3.2-12 is revised as shown below. Text inserted as a result of the response to RAI 2.3.3.12-4 is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

Table 3.3.2-12
Fire Protection System
Summary of Aging Management Evaluation

Table 3.3.2-12 Fire Protection 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.2.1.9)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-124	3.3.1-15	A
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.9)	VII.I.AP-126	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-263	3.3.1-15	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-102	3.3.1-9	A
					Bolting Integrity (B.2.1.9)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-124	3.3.1-15	A
			Soil (External)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.I.AP-241	3.3.1-109	B
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-242	3.3.1-14	A
		Copper Alloy with less than 15% Zinc (Braidwood only)	***Raw Water***	***Loss of Material***	***Bolting Integrity (B.2.1.9)***			***H, 16***
				Loss of Preload	***Bolting Integrity (B.2.1.9)***	***VII.I.AP-261***	***3.3.1-15***	***A***
		Galvanized Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.9)	VII.I.AP-125	3.3.1-12	A

Table 3.3.2-12 Fire Protection System (continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Galvanized Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-124	3.3.1-15	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-102	3.3.1-9	A
					Bolting Integrity (B.2.1.9)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-124	3.3.1-15	A
		Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.9)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-124	3.3.1-15	A
			Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.9)			H, 1
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-264	3.3.1-15	A
Traveling Screen (Braidwood only)	***Filter***	***Carbon Steel***	***Raw Water (External)***	***Loss of Material***	***Fire Water System (B.2.1.16)***	***VII.G.A-33***	***3.3.1-64***	***C***
		Gray Cast Iron	***Raw Water (External)***	***Loss of Material***	***Fire Water System (B.2.1.16)***	***VII.G.A-33***	***3.3.1-64***	***C***
					Selective Leaching (B.2.1.21)	***VII.G.A-51***	***3.3.1-72***	***C***
		Stainless Steel	***Raw Water (External)***	***Loss of Material***	***Fire Water System (B.2.1.16)***	***VII.G.A-55***	***3.3.1-66***	***C***

Plant Specific Notes:

16. The aging effects for copper alloy with 15% zinc or more closure bolting in a raw water environment include loss of material. Inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities.

As a result of the response to RAI 2.3.3.12-4 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.16 is revised as shown below. In addition, LRA Appendix A, Section A.2.1.16 is revised, as shown below, to specify the extent and frequency of flow blockage inspections of wet pipe sprinkler systems. Inserted text is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

A.2.1.16 Fire Water System

The Fire Water System aging management program is an existing condition monitoring program that provides for system pressure monitoring, system header flushing, buried ring header flow testing, pump performance testing, hydrant full flow flushing and full flow verification, sprinkler and deluge system flushing and flow testing, hydrostatic testing, and inspection activities. Major component types managed by this program include sprinklers, fittings, valves, hydrants, hose stations, standpipes, tanks, pumps, and aboveground and buried piping and components. There are no underground (i.e., below grade but contained within a tunnel or vault) piping and components within the scope of the Fire Water System aging management program. This program manages aging effects of loss of material due to corrosion (including MIC), reduction in heat transfer due to fouling, and flow blockage due to fouling.

Opportunistic visual inspections, performed when the internal surface of the system is made accessible due to normal plant maintenance activities, and existing volumetric non-destructive examinations (i.e., guided wave and ultrasonic inspections) will be credited to ensure age related degradation is identified prior to loss of system intended function. At Byron only, the program will be enhanced to require a minimum of 30 volumetric examinations during each three year interval. In addition, the program will be enhanced to perform additional inspections as described in the Enhancements below. ***Internal visual inspections or radiographic testing will be performed at the end of one (1) fire main and the end of one (1) branch line on half of the wet pipe sprinkler system every five (5) years. The wet pipe sprinkler systems that are not inspected during a five (5) year period will be inspected during the subsequent five (5) year period.*** Internal visual inspections are primarily relied upon for detection of flow blockage. Internal visual inspections are only capable of providing qualitative assessments of the internal condition of system piping with respect to loss of material. If unexpected levels of degradation are identified then the condition is entered into the corrective action program for evaluation. Unexpected levels of degradation include excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer.

At Braidwood only, periodic visual inspections of the traveling screens located upstream of the fire pumps are performed during diver inspections of 1A and 2A intake bays.

Buried ring header flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner.

System functional tests, flow tests (including air flow tests), flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. The program will be enhanced to include annual main drain testing in accordance with NFPA 25, Section 13.2.5. These activities are performed periodically to ensure that the loss of material due to corrosion aging effect is managed such that the system and component intended functions are maintained.

In addition, the program will be enhanced to require portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect be subjected to augmented testing beyond that specified in NFPA 25. The augmented testing will include: (1) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (2) volumetric wall-thickness examinations. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5) year frequency thereafter.

In addition, the internal coatings of components within the scope of this program are periodically visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Inspections of internal coatings will be performed by qualified coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. If peeling, blistering, or delamination is detected and the coating is not repaired, then physical testing will be conducted to ensure that the remaining coating is tightly bonded to the base metal and the as-left condition of the coating will be such that the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered). The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). Evidence of unacceptable coating degradation is entered into the corrective action program. The results of inspections of internal coatings are trended and used to adjust inspection frequencies as determined by the ASTM D7108 qualified Site Coating Coordinator.

The Fire Water System aging management program will be enhanced to:

1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2002 Edition), Section 5.3.1.1.1. This testing will be performed at the 50-year in-service date and every 10 years thereafter.

2. Provide for chemical addition, accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion (Byron only).

3. Perform main drain testing annually, in accordance with NFPA 25, “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems,” Section 13.2.5.

4. Perform air flow testing of deluge systems that are not subject to periodic full flow testing on a three (3) year frequency to verify that internal flow blockage is not occurring (Byron only).

5. Perform inspections of Fire Protection System strainers when the system is reset after automatic actuation for signs of internal flow blockage (e.g., buildup of corrosion particles) (Braidwood only).

6. Increase the frequency of visual inspections of the internal surface of the foam concentrate tanks to at least once every ten (10) years. At least one (1) inspection will be performed within the ten (10) year period prior to entry into the period of extended operation, with subsequent inspections performed every ten (10) years thereafter.

7. Perform radiographic testing or internal visual inspections every five (5) years at the end of one (1) fire main and the end of one (1) sprinkler system branch line in half of the wet pipe sprinkler system within the scope of license renewal. If internal flow blockage that could result in failure of the system to deliver the required flow is identified, then perform an obstruction investigation.

8. Perform augmented testing beyond that specified in NFPA 25 on those portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect. The augmented testing will include: (1) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (2) volumetric wall-thickness examinations. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5) year frequency thereafter.

9. Perform a minimum of 30 volumetric examinations of Fire Protection System piping during each three year interval (Byron only).

10. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54.

11. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program.

12. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07).

13. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component.

14. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.

These enhancements will be implemented prior to the period of extended operation, with the testing and inspections performed in accordance with the schedule described above.

As a result of the response to RAI 2.3.3.12-4 provided in Enclosure A of this letter, the Program Description section of LRA Appendix B, Section B.2.1.16 is revised as shown below. Text inserted as a result of the response to RAI 2.3.3.12-4 is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

B.2.1.16 Fire Water System

Program Description

The Fire Water System aging management program is an existing condition monitoring program that manages the loss of material aging effect for the water-based fire protection system and associated components, through the use of system pressure monitoring, system header flushing, buried ring header flow testing, pump performance testing, hydrant full flow flushing and full flow verification, sprinkler and deluge system flushing and flow testing, hydrostatic testing, and inspection activities. This program manages aging effects of loss of material due to corrosion (including MIC), reduction in heat transfer due to fouling, and flow blockage due to fouling. In addition, the Fire Water System aging management program manages the loss of coating integrity aging effect for the components with internal coatings within the scope of the program.

The program applies to water-based fire protection systems that consist of sprinklers, fittings, valves, hydrants, hose stations, standpipes, tanks, pumps, and aboveground and buried piping and components. The program manages aging of fire protection components exposed to outdoor air and raw water. There are no underground (i.e., below grade but contained within a tunnel or vault) piping and components within the scope of the Fire Water System aging management program at Byron and Braidwood Stations. Aging of the external surfaces of buried fire main piping is managed as described in the Buried and Underground Piping (B.2.1.28) aging management program.

The fire water system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated. The program ensures that testing and inspection activities are performed and the results are documented and reviewed by the Fire Protection system manager for analysis and trending. These monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation.

Opportunistic visual inspections, performed when the internal surface is made accessible due to normal plant maintenance activities, and existing volumetric non-destructive examinations (i.e., guided wave and ultrasonic inspection) of piping will be credited to ensure age related degradation is identified prior to loss of system intended function. Selected portions of the fire protection system piping located aboveground and exposed to water will be inspected by non-intrusive volumetric examinations, to ensure that aging effects are managed and that pipe wall thickness is within acceptable limits. Pipe wall thickness inspections will be performed before the end of the current operating term and continued at a frequency of at least once every 3 years during the period of extended operation. At Byron only, as a result of operating experience, the program will be enhanced to require a minimum of 30 volumetric examinations during each three year interval. These inspections will be capable of evaluating pipe wall thickness to ensure against loss of system intended function. Wall thickness evaluations will not be used in lieu of conducting flow tests or inspections for flow blockage. The program will be enhanced to perform additional inspections as described in the Enhancements below. Internal visual inspections or radiographic testing will be performed at the end of one (1) fire main and the end of one (1) branch line on half of the wet pipe sprinkler system every five (5) years. The wet pipe sprinkler systems that are not inspected during a five (5) year period will be inspected during the subsequent five (5) year period. Internal visual inspections are primarily relied upon for detection of flow blockage. Internal visual inspections are only capable of providing qualitative assessments of the internal condition of system piping with respect to loss of material. If unexpected levels of degradation are identified then the condition is entered into the corrective action program for evaluation. Unexpected levels of degradation include excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer.

In addition, periodic visual inspections of components with internal coatings are performed. The visual inspections ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Inspections of internal coatings will be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. The as found condition of the coating is documented in inspection reports and the results of prior inspections are reviewed to determine changes in the condition of the coating over time. The program provides for inspections for signs of coating failures and precursors to coating failures including erosion, cracking, flaking, peeling, blistering, delamination, rusting, and mechanical damage. Evidence of unacceptable coating degradation is entered into the corrective action program. Coating inspection acceptance criteria will specify that peeling, blistering, and delamination is not acceptable. Signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program. If peeling, blistering, or delamination is detected and the coating is not repaired or replaced, then physical testing will be conducted to ensure that the remaining coating is tightly bonded to the base metal and the as-left condition of the coating will be such that the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered). The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). A minimum of three (3) sample points adjacent to the defective area will be tested. Indications of blisters, cracking, flaking, or rusting will be assessed by a certified coatings inspector and documented in a post-inspection report. Areas or items exhibiting coating degradation will be documented, photographed, and reported to the ASTM D7108 qualified Site Coating Coordinator in a post-inspection report. Recommendations for immediate coating repair or replacement prior to returning the system to service or postponement of coating repair or replacement to the next inspection window will be provided in the post-inspection report. The results of the inspection contained in the post-inspection report will be evaluated by the ASTM D7108 qualified Site Coating Coordinator. Evaluations used to determine whether repair or replacement of coatings exhibiting signs of peeling, blistering, or delamination are required prior to returning the component to service will consider the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material of the coated component. The results of inspections of internal coatings are trended and used to adjust inspection frequencies as determined by the ASTM D7108 qualified Site Coating Coordinator. 100% of the coated surfaces that are accessible upon component disassembly or entry are inspected. At least one inspection of each of the coated foam concentrate tanks within the scope of this program will be performed during the ten (10) years prior to the period of extended operation to establish a baseline. Evaluations are performed for inspections that do not satisfy established criteria and the conditions are entered into the 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include performing coating repairs or replacements prior to the component being returned to service.

At Braidwood only, periodic visual inspections of the traveling screens located upstream of the fire pumps are performed during diver inspections of 1A and 2A intake bays.

Buried ring header flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner.

50-year sprinkler head testing will be conducted using the guidance provided in NFPA 25. Performance of the initial 50-year tests will be determined based on the date of the sprinkler system installation. Subsequent inspections will be performed every 10 years after the initial 50-year testing.

At Byron only, as a result of operating experience, an enhancement to allow for chemical addition, accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion has been included in the Fire Water System aging management program. In addition, the program is enhanced to require a minimum of 30 volumetric examinations during each three year interval to address Byron operating experience.

System functional tests, flow tests (including air flow tests), flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. The program will be enhanced to include annual main drain testing in accordance with NFPA 25, Section 13.2.5. These activities are performed periodically to ensure that the loss of material due to corrosion aging effect is managed such that the system and component intended functions are maintained.

For portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect the Fire Water System (B.2.1.16) aging management program will be enhanced to require augmented testing beyond that specified in NFPA 25. Augmented testing of these portions of the water-based fire protection system will be performed as follows:

a. Full flow testing at the design pressure and flow rate or internal visual inspections of the internal surface of portions of the system that meet the above criteria will be periodically performed to ensure flow blockage is not occurring. In addition, volumetric examinations will be performed to verify that significant loss of material is not occurring.
b. Flow testing and visual inspections will be capable of detecting flow blockage. Volumetric examinations will measure wall thickness and detect age-related loss of material.
c. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5) year frequency thereafter.

d. Flow testing and visual inspections will monitor for flow blockage in 100% of the applicable portions of the water-based fire protection system. Volumetric examinations will be performed on 20% of the applicable portions of the water-based fire protection system. The 20% of piping that is inspected in each five year interval will be in different locations than previously inspected.
e. Reduction in flow such that the system is not capable of performing its intended function will be entered into the corrective action program. Wall thickness measurements below nominal wall thickness will be entered into the corrective action program.

As a result of the response to RAI B.2.1.28-3b provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.28, Program Description sub-section, is revised as shown below. Existing text associated with the LRA and the response to RAI B.2.1.28-3a (Exelon Letter RS-14-143) is shown in normal font. Changes associated with the response to RAI B.2.1.28-3b are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

B.2.1.28 Buried and Underground Piping

Program Description

The Buried and Underground Piping aging management program is an existing preventive, mitigative, and condition monitoring program that manages the external surface aging effects for buried and underground piping. The program manages aging through preventive, mitigative, and inspection activities for piping and components within the scope of license renewal. It manages the aging effects of loss of material at Byron and Braidwood Stations, as well as cracking and change in material properties (e.g., cracking, blistering, and change in color) at Braidwood Station only.

The Buried and Underground Piping aging management program includes preventive and mitigative techniques, such as external coatings for external corrosion control, the application of cathodic protection, and the quality of backfill utilized. The program also relies on periodic inspection activities, including visual examination of buried and underground piping, manual examination of polymeric materials, and electrochemical verification of the effectiveness of the cathodic protection system. Directed inspections of buried and underground piping are planned based on categorization criteria contained in LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks.'" Buried and underground piping are opportunistically inspected by visual means whenever they become accessible.

In assessing and verifying the effectiveness of the cathodic protection system, soil corrosion probe assemblies may ~~also~~ be used to verify the effectiveness during annual surveys. Data from the soil corrosion probe assemblies may ***also*** be used to evaluate cathodic protection effectiveness at locations already assessed by existing conventional test points. Placement of the soil corrosion probe assemblies will ***be in close proximity to the buried pipe of interest and*** consider factors such as ***existing soil sampling data (e.g., moisture content, pH, and resistivity measurements),*** the location of the nearest anode beds, proximity of the buried in-scope piping of interest and respective ***existing*** test points to the anode beds, and adjacent site features ***(e.g., exposed large surface area tank bottoms, heavily congested areas of other buried piping, adjacent large diameter piping)*** which could affect the measurements taken from both the ***existing*** test points and the soil corrosion probe assemblies. ***Factors such as cathodic shielding and structures or components serving as large current collectors will be considered when evaluating the effects of adjacent site features. Cathodic protection may be proven effective by soil corrosion probe assemblies during the annual cathodic protection survey based on observations of less than one (1) mil per year material loss from the probe, or a remaining life calculation demonstrating the component intended function will be maintained through the period of extended operation. The remaining life calculation methodology may only be used when the pipe being assessed was volumetrically examined at the time the soil corrosion probe assembly was installed.*** Information provided in National Association of Corrosion Engineers (NACE) Internal Publication 05107, "Report on Corrosion Probes in Soil or

Concrete" will be considered during the application, installation, and use of soil corrosion probes. Additional specific details on the installation and use of the probes will be in accordance with vendor, manufacturer, and NACE qualified cathodic protection expert ***(i.e., NACE CP4, "Cathodic Protection Specialist" qualification)*** recommendations.

The Fire Protection System was installed in accordance with National Fire Protection Association (NFPA) Standard 24. Aging management of the buried Fire Protection System piping will be accomplished through performance of annual system leakage surveillances. Any abnormal system leakage beyond baseline acceptance criteria will be investigated, and the location, source, and cause of the abnormal leakage identified in the system. Therefore, directed inspections of fire protection piping are not required.

Byron and Braidwood Stations do not have any buried or underground tanks within the scope of license renewal.

The program will be enhanced as described below to provide reasonable assurance that buried and underground piping and components, constructed of steel, stainless steel, and polymeric materials at Byron and Braidwood Stations will perform their intended function during the period of extended operation.

Enclosure C

Corrections to LRA Summary of Aging Management Evaluation Tables

Exelon letter RS-14-162, dated May 23, 2014, provided a number of minor corrections to the LRA. As part of Change # 6, related to the Sampling System, an incorrect reference to NUREG-1801 and the corresponding Table 1 line item were inadvertently introduced into LRA Table 3.3.2-21, Sampling System - Summary of Aging Management Evaluation. LRA Table 3.3.2-21 is updated as shown below to restore the proper information in this LRA table.

As a result of this finding, Exelon has performed an extent of condition review of correspondence submitted to the NRC as part of the Byron and Braidwood license renewal project to identify any similar discrepancies. Based on this review, it has been determined that three additional minor discrepancies exist in LRA Summary of Aging Management Evaluation tables (Table 2s). These discrepancies are summarized as follows:

1. Exelon letter RS-14-143, dated May 15, 2014 inadvertently used a plant specific note number that was used previously in RS-14-003, dated January 13, 2014 in the revision to Table 3.3.2-2, Chemical & Volume Control System – Summary of Aging Management Evaluation. The plant specific note number added to Table 3.2.2-2 in Exelon letter RS-14-143 should have been "9", as shown below.

2. Exelon letter RS-14-003, dated January 13, 2014, inadvertently omitted line items when an additional environment was added to the originally submitted LRA Table 3.4.2-3, Main Condensate and Feedwater System - Summary of Aging Management Evaluation. The missing line items are now restored in Table 3.4.2-3, as shown below.

3. Exelon letter RS-14-003, dated January 13, 2014, established plant specific note 9 in Table 3.3.2-22, Service Water System – Summary of Aging Management Evaluation. Exelon letter RS-14-124, dated May 5, 2014 inadvertently re-numbered plant specific note 9 to note 8, in the revision to Table 3.3.2-22. The plant specific note number is corrected to note 9 in Table 3.3.2-22, as shown below.

This enclosure contains the latest, affected portions of these Summary of Aging Management Evaluation tables with plant specific notes when appropriate.

In order to address the discrepancy described in the first paragraph, page 1 of Enclosure C, LRA Table 3.3.2-21, Sampling System Summary of Aging Management Evaluation, is corrected as follows. The corrected information is shown in ***bolded italics***.

Table 3.3.2-21 Sampling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Pump Casing (Secondary Cooler Pump)	Leakage Boundary	Gray Cast Iron	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	***VII.C2.AP-202***	***3.3.1-45***	A
					Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-72	A

In order to address the discrepancy described in item #1, page 1 of Enclosure C, LRA Table 3.3.2-2, Chemical & Volume Control System Summary of Aging Management Evaluation is corrected as follows. The corrected information is shown in ***bolded italics***.

Table 3.3.2-2 Chemical & Volume Control 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	Pressure Boundary	Stainless Steel	Air with Borated Water Leakage (External)	None	None	VII.J.AP-18	3.3.1-120	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.20)	VII.E1.AP-138	3.3.1-100	A
			Treated Borated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E1.A-88	3.3.1-29	A
			Treated Borated Water > 140 F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E1.AP-82	3.3.1-28	A
				Cumulative Fatigue Damage	TLAA	VII.E1.A-57	3.3.1-2	A, 1
				Loss of Material	Water Chemistry (B.2.1.2)	VII.E1.A-88	3.3.1-29	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.8)			H, ***9***

Plant Specific Notes: (continued)

9. The Flow-Accelerated Corrosion (B.2.1.8) aging management program will be used to manage wall thinning due to mechanisms other than FAC in stainless steel pipe in treated borated water > 140 °F environments.

In order to address the discrepancy described in Item #2, page 1 of Enclosure C, LRA Table 3.4.2-3, Main Condensate and Feedwater System Summary of Aging Management Evaluation, is corrected as follows. The corrected information is shown in ***bolded italics***.

Table 3.4.2-3 Main Condensate and Feedwater 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	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.SP-147	3.4.1-35	A, 8
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-90	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-90	3.4.1-16	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-90	3.4.1-16	A
					Water Chemistry (B.2.1.2)	***VIII.D1.SP-90***	***3.4.1-16***	***A***
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-34	A
			Air - Outdoor (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VIII.H.S-41***	***3.4.1-34***	***A***
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VIII.H.S-30	3.4.1-4	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-34	A
			Concrete (External)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VIII.E.SP-145	3.4.1-47	B
			Soil (External)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VIII.E.SP-145	3.4.1-47	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D1.S-11	3.4.1-1	A, 4
				Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-74	3.4.1-13	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-74	3.4.1-13	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.8)	VIII.D1.S-16	3.4.1-5	A

In order to address the discrepancy described in Item #3, page 1 of Enclosure C, LRA Table 3.3.2-22, Service Water System Summary of Aging Management Evaluation, is corrected as follows. The corrected information is shown in ***bolded italics***.

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - ([CV, 1A and 2B SI, RH, CS, SX] Pump Cubicle Cooler – Byron only) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - ([1B and 2A SI] Pump Cubicle Cooler – Byron only) Tube Sheet	Pressure Boundary	Carbon Steel (with internal coating or lining)	Raw Water (Internal)	Loss of Coating Integrity	Open-Cycle Cooling Water System (B.2.1.11)			H, ***9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - ([CV, 1A and 2B SI, RH, CS, SX] Pump Cubicle Cooler – Byron only) Tube Side Components	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - ([1B and 2A SI] Pump Cubicle Cooler – Byron only) Tube Side Components	Pressure Boundary	Carbon Steel (with internal coating or lining)	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Coating Integrity	Open-Cycle Cooling Water System (B.2.1.11)			H, ***9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A

Plant Specific Notes: (continued)

9. The aging effects for metallic components with an internal coating or lining in a raw water environment include loss of coating integrity. The Open-Cycle Cooling Water System (B.2.1.11) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a raw water environment.

Enclosure D – Aging Management Program Clarifications

Exelon and representatives of the NRC held a telephone conference call on June 30, 2014, to discuss and clarify the responses submitted for RAI B.2.1.23-1 (Exelon letter RS-14-003, dated January 13, 2014) and RAI 3.0.3-3a (Exelon letter RS-14-130, dated May 12, 2014). The NRC was concerned that program basis information located in the response was not adequately addressed in the associated aging management program description in the LRA. The affected aging management programs are One-Time Inspection (B.2.1.20) and External Surfaces Monitoring of Mechanical Components (B.2.1.23). Exelon agreed to review the applicable LRA sections and provide revisions, as appropriate, to include the basis information in the associated LRA sections.

This enclosure contains the updated versions of the applicable LRA sections associated with the One-Time Inspection aging management program (i.e., LRA Section B.2.1.20) and the External Surfaces Monitoring of Mechanical Components aging management program (i.e., LRA Sections A.2.1.23 and B.2.1.23, and LRA Table A.5, Item 23).

LRA Appendix A, Section A.2.1.23 is revised as shown below to provide additional detail regarding the aging management activities provided by the External Surfaces Monitoring of Mechanical Components aging management program. Inserted text is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

A.2.1.23 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspections of metallic and elastomeric components such as piping, piping components, ducting, elastomeric components, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric components through visual inspection of external surfaces for evidence of loss of material and cracking. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation.

Periodic representative inspections to detect corrosion (i.e. loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic ***visual*** inspections under insulation to detect corrosion ***and cracking*** under insulation will continue.

The external surfaces of components that are buried are inspected via the Buried and Underground Piping (A.2.1.28) program. The external surfaces of above ground tanks are inspected via the Aboveground Metallic Tanks (A.2.1.17) program. Internal surfaces are inspected via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (A.2.1.25) program.

This new aging management program will be implemented prior to the period of extended operation.

LRA Appendix A, Table A.5, Item 23 is revised as shown below to provide additional detail regarding the aging management activities provided by the External Surfaces Monitoring of Mechanical Components aging management program and to divide the first paragraph into two paragraphs for clarity. Inserted text is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
23	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components is a new program that manages aging effects of metallic and elastomeric materials through periodic visual inspection of external surfaces for evidence of loss of material and cracking. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation. Periodic representative inspections to detect corrosion (i.e., loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic ***visual*** inspections under insulation to detect corrosion ***and cracking*** under insulation will continue.	Program to be implemented prior to the period of extended operation.	Section A.2.1.23 Exelon letter RS-14-003 01/13/2014 RAI 2.1.23-1 RAI 3.0.3-3 Exelon letter RS-14-051 02/27/2014 RAI 3.5.2-4 ***Exelon letter RS-14-218 07/18/2014***

The Program Description section of LRA Appendix B, Section B.2.1.20 is revised as shown below to provide additional detail regarding the aging management activities provided by the One-Time Inspection aging management program. Inserted text is highlighted by ***bolded italics***. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

B.2.1.20 One-Time Inspection

Program Description

The One-Time Inspection aging management program is a new condition monitoring program that will be used to verify the system-wide effectiveness of the Water Chemistry (B.2.1.2), Fuel Oil Chemistry (B.2.1.18), and Lubricating Oil Analysis (B.2.1.26) aging management programs which are designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation. The program manages loss of material, cracking, and reduction of heat transfer in piping, piping components, piping elements, tanks, pump casings, heat exchangers, and other components within the scope of license renewal for air-outdoor, fuel oil, lubricating oil, reactor coolant, steam, treated water, and treated borated water environments. The program identifies inspections focused 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. A representative sample size of 20 percent of the population (up to a maximum of 25 component inspections) will be established for each of the sample groups and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. The program verifies either no unacceptable age-related degradation is occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the period of extended operation. Technical justification of the methodology and sample size used for selecting components for one-time inspection is documented in the One-Time Inspection Sample Basis Document.

The One-Time Inspection aging management program will also be utilized, in specific cases where existing data is insufficient:

a) to validate that a particular aging effect is not occurring, or
b) to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation.

In these cases, the components will not require additional aging management. ***The One-Time Inspection aging management program will include inspections of insulated and uninsulated air-filled or gas-filled stainless steel or aluminum alloy piping and components located outdoors to verify that stress corrosion cracking is not occurring or is occurring slowly enough to not affect a components intended function during the period of extended operation.***

The elements of the program include (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and plant-specific and industry operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could adversely impact an intended function before the end of the period of extended operation. The monitoring methods will be effective in detecting the applicable aging effects and the frequency of monitoring will be adequate to prevent significant age-related degradation.

This program is not used for systems or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections will be used in these cases.

The One-Time Inspection program will be implemented prior to the period of extended operation. The one-time inspections will be performed within the 10 year period prior to the period of extended operation.

The Program Description section of LRA Appendix B, Section B.2.1.23 is revised as shown below to provide additional detail regarding the aging management activities provided by the External Surfaces Monitoring of Mechanical Components aging management program. Inserted text is highlighted by ***bolded italics***; deletions are shown with ~~strikethroughs~~. Existing text from the LRA, as modified by subsequent submittals, is shown in normal font.

B.2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspection of metallic and elastomeric components such as piping, piping components, ducting, elastomeric components, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric components through visual inspection of external surfaces for evidence of loss of material and cracking in air-indoor, air-outdoor, and air with borated water leakage environments. Visual inspections are augmented by physical manipulation as necessary for evidence of hardening and loss of strength. The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. Insulation and jacketing is inspected, repaired, and installed in accordance with plant-specific procedures and specifications that include configuration features such as minimum overlap, location of seams, etc. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation.

Periodic representative inspections to detect corrosion (i.e. loss of material) under insulation will be conducted on in-scope indoor insulated components and tanks, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation.

For a representative sample of in-scope outdoor components (with the exception of the condensate storage tanks) and for any indoor components operated below the dew point (except indoor insulated tanks, which are discussed below), remove the insulation and inspect a minimum of 20 percent of the in-scope piping length for each material type, or — for components where its configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator) — 20 percent of the surface area. Alternatively, remove the insulation and inspect any combination of a minimum of 25 1-foot axial length sections and components for each material type. Inspections should be conducted in each environment (e.g., air-outdoor, condensation) where condensation or moisture on the surfaces of the component could occur routinely or seasonally.

For a representative sample of in-scope insulated indoor tanks operated below the dew point, the insulation will be removed from either 25 1-square-foot sections or 20 percent of the surface area and inspect the exterior surface of the tank. Sample inspection points will be distributed such that inspections occur on the tank domes, sides, near the bottoms, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (such as on top of stiffening rings).

Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic ***visual*** inspections under insulation to detect corrosion ***and cracking*** under insulation will continue.

Removal of tightly-adhering insulation that is impermeable to moisture will not be required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly-adhering insulation and, therefore, will not be removed. The entire accessible population (i.e., 100%) of in-scope piping that has tightly-adhering insulation will be visually inspected for damage to the moisture barrier during each 10-year period of the period of extended operation. Tightly-adhering insulation will be considered to be a separate population from the remainder of insulation installed on in-scope components. These inspections will not be credited towards the inspection quantities for other types of insulation as described above.

Materials of construction inspected under this program include aluminum alloy, carbon steel, copper alloy, ductile cast iron, galvanized steel, gray cast iron, low alloy steel, and stainless steel. Examples of components this program inspects are piping and piping components, ducting, heat exchangers, tanks, pumps, expansion joints, and hoses. The inspection parameters for metallic components include material condition, which consists of evidence of rust, general, pitting and crevice corrosion, discoloration and coating degradation; evidence of insulation damage or wetting; leakage from piping, ducting, or component bolted joints; and leakage for detection of cracks on the external surfaces of stainless steel and aluminum components exposed to ~~an~~ ***outdoor*** air ~~environment containing halides~~. Coating degradation is used as an indicator of possible underlying degradation of the component. Inspection parameters for elastomeric components include hardening, discoloration, surface cracking, crazing, scuffing, exposure of internal reinforcement for reinforced elastomers, and dimensional changes.

The External Surfaces Monitoring of Mechanical Components program is a visual condition monitoring program that does not include preventive or mitigative actions. The monitoring methods are effective in detecting the loss of material, cracking, and hardening and loss of strength aging effects and the once per refueling cycle frequency of monitoring is adequate to prevent significant age-related degradation.

Inspections, with the exception of inspections performed to detect corrosion under insulation, are performed at a frequency not to exceed once per refueling cycle. This frequency accommodates inspections of components that may be in locations that are normally only accessible during refueling outages. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components intended functions are maintained. Inspections performed to detect corrosion under insulation will be conducted during each 10-year period of the period of extended operation.

Any visible evidence of degradation will be evaluated for acceptability of continued service. Acceptance criteria will be based upon component, material, and environment combinations. Deficiencies will be documented and evaluated under the corrective action program.

The external surfaces of components that are buried are inspected via the Buried and Underground Piping (B.2.1.28) program. The external surfaces of above ground tanks are inspected via the Aboveground Metallic Tanks (B.2.1.17) program. This program does not provide for managing aging of internal surfaces. The External Surfaces Monitoring of Mechanical Components program is a new program that will be implemented prior to the period of extended operation.