UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 5, 2012

Mr. Adam C. Heflin
Senior Vice President and Chief Nuclear Officer
Union Electric Company
P.O. Box 620
Fulton, MO 65251

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CALLAWAY PLANT UNIT 1, LICENSE RENEWAL APPLICATION (TAC NO. ME7708)

Dear Mr. Heflin:

By letter dated December 15, 2011, Union Electric Company submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54) for renewal of Operating License NPF-30 for the Callaway Plant Unit 1. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Sarah G. Kovaleski, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2946 or by e-mail at Samuel.CuadradoDeJesus@nrc.gov.

Sincerely,

Samuel Cuadrado de Jesús, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-483

Enclosure:
As stated

cc w/encl: Listserv

CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

RAI B2.1.8-1

Background:

GALL Report AMP XI.M18, "Bolting Integrity," manages aging of closure bolting for pressure retaining components. The program includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc.

Between 1985 and 1987, Callaway installed seal cap enclosures on four swing check valves to mitigate gasket leakage from the bolted body-to-bonnet flange joint. The seal cap enclosures have since been removed, however it is not clear to the staff whether additional seal cap enclosures have been installed or if seal cap enclosures are still used at the site to mitigate leakage.

Issue:

The use of seal cap enclosures as mitigation for leakage may prevent the bolting within the enclosure from being managed for the loss of preload, cracking, and loss of material aging effects since it prevents direct inspection of the bolted joint.

Request:

a) Clarify whether there is any pressure-retaining bolting surrounded by seal cap enclosures at Callaway Plant Unit 1.

b) For all instances where pressure-retaining bolting is surrounded by seal cap enclosures:

   i. Describe the bolting alloy and the leaking water environment (i.e., reactor coolant, secondary water).

   ii. Describe how the bolting will be managed for loss of material, loss of preload, and cracking due to stress corrosion cracking (SCC), as appropriate, in the submerged environment. Provide technical justification for any cases where cracking due to SCC is not included as an applicable aging effect.

   iii. If the aging management approach in item (b) does not include direct inspection of the bolting, provide technical justification for how the aging effects will be effectively managed during the period of extended operation.

c) Describe how the use of seal cap enclosures is controlled such that aging is managed as described in b.ii.

RAI B2.1.9-1

NEI 97-06, Revision 3, "Steam Generator Program Guidelines," was to be implemented by September 1, 2011. The Technical Specification (TS) for Steam Generator Maintenance

Services (S-1032) was used for the Refuel 18 steam generator tube inspections (which commenced after October 15, 2011). This document (S-1032) references NEI 97-06, Revision 2 in Section 4.2.A.4. The staff requests the applicant to discuss whether NEI 97-06 Revision 2 or NEI 97-06 Revision 3 was used during the Refuel 18 inspections. If NEI 97-06 Revision 2 was used, the staff requests the applicant to provide the deviation supporting this exception to the industry guidelines.

RAI B2.1.9-2

The term active degradation is used in EDP-BB-01341, "Steam Generator Surveillance" (e.g., refer to Sections 4.4.1.4, 4.9.7.c, and 7.1). This term, as originally defined, was misleading and is no longer used in the Pressurized Water Reactor Steam Generator Examination Guidelines, which were issued in 2007. The staff requests the applicant to discuss its plans for removing this term from its procedures.

RAI B2.1.9-3

Section 4.1.2.c.3 of EDP-BB-01341, "Steam Generator Surveillance" indicates that if implementation of a guideline change cannot be performed within three months of the due date that a deviation should be processed. This appears to permit implementing the guideline change three months after the due date. Please clarify where this three month "extension" is permitted by the industry guidelines (i.e., if the forwarding letter indicates the guideline change should be implemented by a specific date, it is not clear that a three month automatic extension is justified). If the three month "extension" is not permitted by industry guidance documents, the staff request the applicant to discuss its plans to change its procedures.

RAI B2.1.9-4

Section 4.5.1 of EDP-BB-01341, "Steam Generator Surveillance" deals with secondary side inspections; however, Section 4.5.1.a refers to primary side maintenance activities. This appears to be a typographical error. Please clarify.

RAI B2.1.9-5

Section 4.10.3 of EDP-BB-01341, "Steam Generator Surveillance" requires the condition monitoring report to be completed within 30 days following completion of the outage; however, Section 4.9.6.a.1 requires the condition monitoring report to be completed prior to Mode 4 after a steam generator inspection. The Electrical Power Research Institute (EPRI) Steam Generator Integrity Assessment Guidelines (Section 11.2.2) requires the condition monitoring assessment to be completed prior to Mode 4. The staff requests the applicant to discuss its plans to make its procedures consistent with the industry guidelines.

RAI B2.1.9-6

Section 4.8.5.e of EDP-BB-01341, "Steam Generator Surveillance" refers to "degradation of interest" rather than "existing and potential degradation" as discussed in the EPRI Steam

Generator Integrity Assessment Guidelines (Section 6.2). The staff requests the applicant to discuss whether "degradation of interest" is defined in its procedures. If not, the staff requests the applicant to discuss its plans to modify its procedures to ensure they are consistent with the industry guidelines.

RAI B2.1.9-7

AREVA NP Inc, Document No. 51-9172264-000, "Callaway Unit-1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21" does not appear to justify the length of the operating interval for secondary side degradation. Section 10.3 of the EPRI Steam Generator Integrity Assessment Guidelines indicates that the operational assessment shall include a justification for operating the planned interval between secondary side inspections as well as primary side inspections. Please discuss whether there is a justification for the planned operating interval that addresses degradation of secondary side internals.

RAI B2.1.9-8

Section 8.6 of the EPRI Steam Generator Integrity Assessment Guidelines indicates, in part, that (1) failure to meet condition monitoring requirements means that the projections of the previous operational assessment were not conservative and that necessary corrective actions shall be identified and (2) even if condition monitoring requirements are met, a comparison of condition monitoring results with the projections of the previous operational assessment shall be performed and that this comparison shall be completed prior to issuance of the final operational assessment since adjustment of input parameters may be required.

In AREVA NP Inc, Document No. 51-9172264-000, "Callaway Unit-1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21" there is a statement that the latter must be performed, but then the report went on to indicate that the assumptions and uncertainties included in the previous operational assessment are validated since none of the detected indications approach the condition monitoring limit and that additional discussions below provide further details. The staff could not locate these additional discussions. In addition, in reviewing the previous operational assessment, the staff could not locate any specific projections such that a comparison of the as-found and previously projected conditions could be compared. It is not clear that the intent of the EPRI requirement has been met. Please clarify. The staff notes that the operational assessment is supposed to be conservative. As a result, even if the actual detected conditions are near (including "slightly" below) the projections from the prior operational assessment, this could indicate a potential non-conservative assessment which may lead to issues in the future if not corrected.

RAI B2.1.11-1

Background:

The LRA states that representative samples of each combination of material and water treatment program are visually inspected every 10 years. LRA Section B2.1.11, "Closed Treated Water Systems," states that the aging management program (AMP) uses four treatment programs for chemistry control, including molybdate control with tolyltriazole (TTA), ethylene glycol, nitrite control with TTA, and Diesel Coolant Additive and ethylene glycol.

During its audit of the applicant's onsite documentation, the staff noted that the applicant's program basis document and inspection procedure for the Closed Treated Water Systems program states that the boron thermal regeneration system (BTRS) chilled water system has a water chemistry environment of molybdate with TTA. In contrast, the applicant's water chemistry monitoring procedure indicates that the BTRS chilled water system is in a

nitrite/molybdate chemistry environment, as defined in EPRI Report TR-1007820, "Closed Cooling Water Chemistry Guideline, Revision 1."

Issue:

It is unclear to the staff which water chemistry control approach is used in the BTRS chilled water system. The staff notes that the improper identification of the water chemistry of the BTRS chill water system may lead to an inadequate inspection sampling of unique combinations of materials and water treatment programs.

Request:

Clarify the water chemistry environment of the BTRS chilled water system and revise the LRA, program basis document, and inspection sampling plan, as necessary.

RAI B2.1.11-2

Background:

The "detection of aging effects" program element of GALL Report AMP XI.M21A, "Closed Treated Water Systems" states that a representative sample of piping and components is selected based on likelihood of corrosion or cracking and inspected at an interval not to exceed once in 10 years.

The enhancement to LRA Section B2.1.11 states that representative samples of each combination of material and water treatment program will be visually inspected at least every 10 years or opportunistically when consistent with sample requirements.
During its audit of the applicant's onsite documentation, the staff noted that the applicant's program basis document states that, for each chemical environment (water treatment), a representative sample of component surfaces is disassembled and inspected every 10 years. The basis document also states that the sample size is 20 percent of the components, up to a maximum of 25 for each chemical environment. The document further states that at least two samples of each material are included in the representative sample for each chemical environment.

The applicant's draft inspection procedure for the Closed Treated Water Systems program states that at least 10 percent of the components for each material-environment combination will be inspected, and that the maximum sample size for each material-environment combination is 10. However, another location in the same procedure states that if the number of inspection opportunities reaches five for any of the material-environment combinations, then the sampling for that material-environment combination is complete.

Issue:

a) The enhancement to the LRA, the LRA basis document, and draft implementing procedure for the inspections in the Closed Treated Water Systems program differ regarding the sampling methodology. Differences include the definition of the sampling population (each material-environment combination or each environment) and the percentage and number of inspections for each population (20 percent with a maximum of 25, 10 percent with a maximum of 10, or a maximum of 5 opportunistic inspections)

   It is unclear to the staff which sampling methodology will be used, and the underlying technical basis for the chosen methodology, for the inspections in the Closed Treated Water Systems program.

b) The LRA and program basis document do not state that inspection locations will be selected based on likelihood of corrosion or cracking. The staff believes that such an inspection methodology is important to ensure that aging can be detected prior to loss of intended function.

Request:

a) State what inspection sampling methodology will be used in the Closed Treated Water Systems program and provide technical justification for the methodology used. Revise the LRA, program basis document, and implementing procedures, as necessary.

b) State whether inspection locations will be selected based on likelihood of corrosion and cracking, or provide technical justification for not doing so.

RAI 3.0.1-1

Background:

GALL Report Section IX.D states that stainless steels are susceptible to SCC when exposed to water environments with temperatures above 60°C (140°F).

LRA Table 3.0-1 states that its water environments encompass the GALL Report defined environments both above and below the SCC threshold. For example, the closed cycle cooling water environment in the LRA encompasses the GALL Report defined environments of closed cycle cooling water and closed cycle cooling water >60°C (>140°F). Also, the secondary water environment in the LRA encompasses the GALL Report defined environments of treated water and treated water >60°C (>140°F).

Issue:

It is unclear to the staff which components in the LRA may be exposed to water temperatures greater than the SCC threshold. Without this information, the staff cannot evaluate whether SCC is being properly managed.

Request:

Identify which in-scope components are exposed to water environments with temperatures greater than the SCC threshold (60°C, 140°F). For any identified items not currently evaluated in the LRA for SCC, add an AMR item to manage this aging effect.

RAI B2.1.13-1

Background:

GALL Report AMP XI.M26, "Fire Protection," is a fire barrier inspection program that includes aging management of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials. The LRA denotes items with an intended function of fire barrier using an "FB." However, there are AMR items in LRA Table 3.5.2-1 for hatch emergency airlock and hatch personnel airlock exposed to plant indoor air which have an intended function of fire barrier but are not being managed for aging using the Fire Protection program.

Issue:

It is not clear to the staff how components with a fire barrier function are being adequately managed for aging using alternative programs.

Request:

Explain how the items with a fire barrier function that are not being managed for aging using the Fire Protection program are being adequately managed for aging using alternative programs. The explanation should include a comparison of the types of inspections, frequency of inspections, and qualifications of personnel performing the inspections.

RAI B2.1.13-2

Background:

The "detection of aging effects" program element of GALL Report AMP XI.M26, "Fire Protection," states that visual inspections of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials are performed by fire protection qualified personnel. LRA Section B2.1.13 states that the Fire Protection program, following enhancement, will be consistent with GALL Report AMP XI.M26. During the audit, the staff noted that procedures QSP-ZZ-65045, "Fire Barrier Seal Visual Inspection," and QSP-ZZ-65046, "Fire Barrier Inspection," state that the personnel performing the inspections are Quality Control Inspectors. The staff also noted that procedure OSP-KC-00015, "Fire Door Inspections," does not state what qualifications are required for personnel who perform the inspections.

The Callaway FSAR-SP, Section 9.5.1.6, and FSAR-SA, Appendix 9.5A, Section A.1 both state that Section 9.5 of the FSAR-SA discusses training for maintaining the competence of the station fire fighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. However, the information regarding training of personnel who maintain and inspect fire protection equipment does not appear to be included in the FSAR-SP or FSAR-SA. RG 1.189, "Fire Protection for Nuclear Power Plants," states that personnel responsible for maintaining and testing fire protection systems should be qualified by training and experience for such work.

Issue:

Neither the FSAR nor the LRA discuss the training and qualifications required for personnel responsible for performing Fire Protection program inspections. It is not clear to the staff whether the personnel who perform inspections as part of the Fire Protection program are properly trained and qualified to perform the inspections, consistent with GALL Report XI.M26.

Request:

Explain the minimum training and qualifications required for personnel who perform Fire Protection program inspections. Explain how only personnel with the required training and experience are assigned to perform Fire Protection program inspections since a fire protection qualification is not used.

RAI B2.1.14-1

Background:

The GALL Report AMP XI.M27, "Fire Water System," recommends that sprinklers that have been in place for 50 years be replaced or a representative sample of sprinklers be field service tested at a recognized testing laboratory in accordance with National Fire Protection Association (NFPA) 25, "Inspection Testing and Maintenance of Water-Based Fire Protection Systems." LRA Section B2.1.14, "Fire Water System," states that sprinklers will be replaced prior to 50 years inservice or a representative sample of sprinklers will be tested, with testing repeated every 10 years.

Issue:

The Fire Water System program does not discuss what type of testing will be performed on the sprinklers if they are not replaced prior to reaching 50 years inservice and whether testing will be performed in accordance with NFPA 25. It is unclear to the staff whether sprinkler field service testing will be performed at a recognized testing laboratory in accordance with NFPA 25.

Request:

Clarify whether sprinkler field service testing will be performed at a recognized testing laboratory in accordance with NFPA 25. If sprinkler field service testing will not be performed at a recognized testing laboratory in accordance with NFPA 25, explain the testing that will be performed, including test methods and acceptance criteria, and how this testing satisfies the guidance in NFPA 25.

RAI B2.1.14-2

Background:

GALL Report AMP XI.M27, "Fire Water System," recommends that sprinklers be tested in accordance with applicable NFPA codes and standards. NFPA 25 states that any sprinklers that show signs of physical damage, corrosion, or loading shall be replaced. LRA Section B2.1.14, "Fire Water System," states in the first operating experience example of the

"operating experience" program element, that during sprinkler head inspections in 2005, 10 sprinkler heads were found with corrosion or damage. The LRA also states that two sprinkler heads were replaced and the rest were cleaned. Review of Callaway Action Request (CAR) 200502420 during the audit identified that there were four sprinklers with damage, three with corrosion, and three with lint, but only two were documented as being replaced.

Issue:

It is unclear to the staff why only two of the sprinklers with identified damage, corrosion, or loading were replaced. This does not appear to be consistent with the guidance in NFPA 25, and therefore does not appear to be consistent with the recommendations in the GALL Report.

Request:

Explain why some of the corroded/damaged sprinklers were not replaced. Explain why this is consistent with the guidance in NFPA 25 and GALL Report AMP XI.M27.

RAI B2.1.14-3

Background:

The "detection of aging effects" program element of GALL Report AMP XI.M27, "Fire Water System," recommends that fire hoses be hydrostatically tested annually in accordance with NFPA codes and standards. LRA Section B2.1.14, "Fire Water System," states an exception to GALL Report AMP XI.M27 to perform hydrostatic hose testing for hose stations that are more than five years old on a three year frequency. During the audit, the staff noted that hydrostatic testing has not been performed since 2007. The staff also noted that CAR 201110777 documents failure of a fire hose when it was charged during fire brigade training in 2011. The hose had last been tested in 2007.

Issue:

It is not clear to the staff why the existing frequency of three years is acceptable to ensure degradation of fire hose is identified prior to loss of intended function.

Request:

Provide justification for why the existing fire hose hydrostatic testing frequency is adequate to identify degradation of fire hose prior to loss of intended function.

RAI B2.1.14-4

Background:

The "detection of aging effects" program element of GALL Report AMP XI.M27, "Fire Water System," recommends that fire hydrants be flow tested annually in accordance with NFPA 25. LRA Section B2.1.14, "Fire Water System," states an exception to GALL Report AMP XI.M27 to perform fire hydrant flow tests every three years. During the audit, the staff reviewed the results of the recent performances of the fire hydrant flow tests. The testing performed in 2011 indicated that approximately 25 percent of the hydrants tested failed to drain in the required time frame. The testing performed in 2007 indicated that approximately 20 percent of the hydrants

tested failed to drain properly, and testing performed in 2005 indicated that approximately 50 percent of the hydrants tested failed to drain as required.

Issue:

It is not clear to the staff why the existing fire hydrant flow testing frequency of three years is acceptable to identify degradation prior to loss of intended function given that hydrant flow testing performed in 2005, 2007, and 2011 resulted in 20-50 percent of the hydrants failing to drain in the required time.

Request:

Provide justification for why the existing hydrant flow testing frequency is adequate to identify degradation of the fire hydrants prior to loss of intended function.

RAI B2.1.14-5

Background:

GALL Report AMP XI.M27, "Fire Water System," manages aging for components exposed to fire water to ensure degradation is detected prior to loss of intended function. GALL Report AMP XI.M27 includes system flow testing and pipe wall thickness evaluations to manage aging. LRA Section B2.1.14, "Fire Water System," states that flow testing is performed every three years and pipe wall thickness examinations or internal inspections will be performed prior to the period of extended operation and every 10 years.

In the "operating experience" program element, the LRA includes an operating experience example which states that there was a leak in the fire water system in 2005 identified by excessive jockey pump run times. CAR 200510105 clarifies that the leak was on buried piping on an isolable branch. The LRA includes another operating experience example in which a low cleanliness factor was identified during system flow testing in 2006. Chemical cleaning was performed on the fire water system to improve the cleanliness factor. However, after chemical cleaning, five leaks developed which were subsequently repaired. During the audit, the staff noted that microbiologically influenced corrosion (MIC) contributed to the low cleanliness factor and leakage; and that subsequent to the chemical cleaning, additional leaks have occurred. The staff also noted that system flow testing performed in 2011 identified a low cleanliness factor again and that compensatory measures were required to maintain system intended function.

Issue:

The fire water system degraded from a clean system in 2006 to a degraded system in 2011 in which compensatory measures were required to maintain system intended function. System flow testing performed on a three year frequency and pipe wall thickness evaluations performed on a 10 year frequency do not appear to be adequate to ensure aging is identified prior to loss of intended function throughout the period of extended operation. It is not clear to the staff how aging of the fire water system will be adequately managed during the period of extended operation such that loss of intended function of the fire water piping does not occur.

Request:

a) For the past 10 years, list each instance of internal or external degradation of the fire protection piping which resulted in either thru-wall or significant penetration of the pipe wall (e.g., approaching pipe minimum wall thickness). Include out-of-scope piping instances where the environment is similar to that of in-scope piping. Include the following:

   i. date discovered,
   ii. description of location of the degradation (e.g., internal, external, aboveground, buried),
   iii. probable cause, if known (e.g., MIC, coating degradation leading to general or pitting corrosion),
   iv. configuration of the degradation (e.g., plug type, planar), and
   v. extent of degradation, or results of extent of condition review, if conducted

b) Describe the results of general internal and external observations of the condition of the piping and coatings that have been conducted for the past 10 years.

c) Given the above, project the condition of the internal and external surfaces of the fire protection system in-scope piping through the end of the period of extended operation. For example, extent of MIC sites, condition of external coatings, general pipe wall thickness.

d) State the basis for why the configuration of the in-scope fire protection system will have sufficient structural integrity to meet all design loads throughout the period of extended operation. Include consideration of multiple flaws located in a configuration such that they cannot be considered as independent flaws.

e) State how the inspections of the fire water system will be augmented to ensure that the assumptions used in the response to "d" above, will be met throughout the period of extended operation.

RAI B2.1.15-1

Background:

The "preventive actions" program element of the Aboveground Metallic Tanks program states that there are no sealants or caulking applied at the external interface between the bottoms of the condensate storage tank (CST) and refueling water storage tank (RWST) and their concrete foundations. The GALL Report AMP recommends that sealant or caulking be applied at the external surface of the interface joint to minimize the amount of water penetrating the interface, which could lead to corrosion of the tank bottom.

Issue:

The above statements are not consistent, and the applicant did not identify this as an exception and provide a justification for not meeting the recommendation. Given that this preventive measure is not met, it is not clear to the staff why the number of tank bottom volumetric inspections to be conducted (i.e., one within five years of entering the period of extended

operation and whenever tank is drained) is adequate to ensure that the tank's intended function(s) will be met during the period of extended operation.

Request:

State the basis for why the proposed inspection schedule of CST and RWST tank bottom is sufficient to ensure that the tanks will meet their intended function(s) during the period of extended operation.

RAI B.2.1.15-2

Background:

The "preventive actions" program element of the Aboveground Metallic Tanks program states:

- the stainless steel CST does not have a protective coating; the insulation materials have a documented evaluation demonstrating that there are not any harmful substances which could leach onto the tank surface; and, the insulation has a protective aluminum jacket with overlapping seams. In contrast to this statement, LRA Table 3.4.2-6, Insulation, plant-specific note 3, in pertinent part, states, "[t]he dome of the stainless steel tank is prepped with a low halogen (<200 ppm) primer prior to the application of the foam urethane."

- the stainless steel RWST does not have a protective coating, and the insulation has a protective aluminum jacket with overlapping seams,

During the staff's walkdown of the structure that partially encloses the CST, water stains were observed on the side of the tank where insulation is not installed.

The GALL Report AMP recommends that, "[i]n accordance with industry practice, tanks may be coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure."

Issue:

The staff has the following concerns/questions:

- The staff lacks sufficient information related to the potential for chemical compounds in the cooling tower water or soil (which could become airborne), if present, to migrate to the tank's external surface and cause cracking, pitting, or crevice corrosion of the stainless steel surface.

- The applicant has not provided information related to whether the insulation on the RWST contains harmful substances that could leach onto the tank surface and cause corrosion.

- Given the inconsistency between the program and LRA Table 3.4.2-6 in regard to protective coatings on the CST, the staff questions if coatings are applied on the entire

or portions of the CST and RWST external surfaces. In addition, if the coatings are credited for purposes of license renewal, whether holiday testing was conducted during initial application of the coating and whether the coatings will be inspected during the period of extended operation.

- It is not clear that insulation jacketing will prevent water intrusion into the tank insulation and then onto the tank surface.

Request:

a) State whether there is or could be the potential for chemical compounds in the cooling tower water, soil, or other sources to migrate to the CST or RWST insulation jacketing or tank external surfaces.

b) State whether the RWST insulation contains any harmful substances which could leach onto the tank surface. If so, state the basis for why the currently proposed inspections are capable of detecting cracking, pitting, or crevice corrosion on the external surfaces of the tank.

c) State whether and what portions of the CST is coated and, if applied and not the same as documented in LRA Table 3.4.2-6, Insulation, plant-specific note 3, state the coating composition.

d) If the tank external surface coating has been credited for purposes of license renewal (e.g., limit the potential for corrosion of external surfaces, allow less inspections of external surfaces of the tank), state whether holiday testing was conducted during initial application of the coating and state the basis for why no coating inspections are proposed as part of the program unless opportunistically inspected during insulation removal. If the tank external surface coating has not been credited for purposes of license renewal, state why the proposed inspections are adequate in light of coatings not being available as a preventive measure.

e) Given the evidence of water stains on the side of the CST where insulation is not installed, state the basis for why it can be concluded that the CST and RWST insulation jacketing will prevent water intrusion into the tank insulation and then onto the tank surface.

f) If the cooling tower water is not currently treated, or is currently treated with biocides or other chemicals which do not contain harmful chemical compounds, and the basis for any of the above questions is that harmful compounds cannot reach the external surfaces of the CST and RWST:

   i. revise LRA Section A1.15 to state that chemical treatments of cooling tower water will not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tank, and

   ii. propose a schedule for periodic site soil samples that will demonstrate that harmful compounds are not accumulating on the soil surface.

RAI B2.1.15-3

Background:

The "detection of aging effects" program element of the Aboveground Metallic Tanks program states that visual inspections of the exterior surfaces of the CST and RWST are conducted when the surface is accessible. It also states that for inaccessible exterior tank surfaces, the program will sample wall thickness to ensure that the tank bottom and tank wall sections with insulated outer surfaces are not losing material or cracking. It further states that thickness measurements will be conducted once within five years of entering the period of extended operation and whenever the tank is drained, and at least one measurement per square yard of tank surface will be performed. GALL Report AMP XI.M29, Aboveground Metallic Tanks, recommends that external surfaces of the tank be inspected on a refueling outage interval.

Issue:

The staff questions whether obtaining one thickness data point per square yard of tank surface is sufficient to detect pitting, crevice corrosion, and cracking. Alternatively, if the quantity of inspection points is not changed, the staff questions whether the inspection frequency is sufficient. The staff also questions how a tank wall thickness measurement will also be capable of detecting cracking. The staff further questions what percent of opportunistically removed insulation would be deemed sufficient to not conduct the internal volumetric exams.

Request:

a) State how obtaining one thickness data point per square yard of tank surface is sufficient to detect pitting, crevice corrosion, and cracking once within five years of entering the period of extended operation and whenever the tank is drained, given that the GALL Report AMP XI.M29 is based on inspections of 100 percent of the external surface of a tank on a refueling outage interval.

b) State what wall thickness measurement technique will be used that is capable of detecting wall thickness and cracks.

c) State what percentage of opportunistically removed insulation would be deemed sufficient to not conduct the internal volumetric exams, including whether removal of insulation in one quadrant of the tank would be considered adequate for the entire tank's circumference.

RAI B2.1.15-4

Background:

The "operating experience" program element of the Aboveground Metallic Tanks program, LRA Section B2.1.15, and the staff's independent review of CARs and work orders demonstrate that multiple inspections of the internal surfaces of the Fire Water Storage Tanks (FWST), spanning 2007 through 2011, have revealed blistering and delamination of coatings. Work orders documented that these defects were not all repaired prior to returning the tanks to service. The work orders document that the acceptance of the as-found defects that were not repaired was based on internal cathodic protection of the tank preventing corrosion of exposed metal surfaces.

Issue:

Neither the LRA AMP nor FSAR Supplement state that the cathodic protection system is credited as a preventive measure to account for the plant-specific operating experience. In addition, the staff lacks sufficient information to conclude that the delaminating coatings would not block downstream components either based on current levels of delamination or those that could occur in the period of extended operation.

Request:

a) State the basis for why blistering and delamination of coatings will not occur during the period of extended operation despite the current trend of plant-specific operating experience. Alternatively, revise the program and LRA Section A1.15, FSAR Supplement to credit the FWST internal cathodic protection system as a preventive measure to prevent corrosion on exposed bare metal as-left surfaces of the tanks.

b) State the basis for why delamination of coatings will not prevent downstream in-scope components from being able to perform their intended function(s) during the period of extended operation, including consideration of the size of delaminations that could occur during the period of extended operation.

RAI B2.1.16-1

Background:

Element 2, "preventive actions," of the GALL Report AMP XI.M30, "Fuel Oil Chemistry," states that periodic cleaning of a tank allows the removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Although periodic draining of water is incorporated into the applicant's Fuel Oil Chemistry Program, it appears that the applicant takes an exception to the GALL Report as the program does not state that the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank will be cleaned periodically as recommended by the GALL Report.

AMP XI.M30, element 4, "detection of aging effects," recommends that at least once during the 10-year period prior to the period of extended operation, each diesel fuel tank is drained and cleaned, the internal surfaces are visually inspected (if physically possible) and volumetrically inspected if evidence of degradation is observed during visual inspection, or if visual inspection is not available. The LRA states an enhancement to perform volumetric examinations on the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank within the 10-year period prior to the period of extended operation and at least once every 10 years after entering the period of extended operation.

Issue:

Periodic cleaning of a tank is an effective measure to mitigate corrosion. The staff recognizes that performing a periodic volumetric examination could identify if corrosion is occurring in the fuel oil tank.

Request:

State how the volumetric examination, which will be conducted every 10 years, will be sufficient to ensure that the intended function of the tanks will be maintained in lieu of not performing periodic tank cleanings that will mitigate any corrosion that may occur. Alternatively describe the actions that the plant will perform to prevent or mitigate corrosion of the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank and the basis for how these actions will be effective.

RAI B2.1.16-2

Background:

The applicant provided the following operational experience:

> During Refuel 17 (Spring 2010), as part of the 10-year cleaning and inspection of the emergency fuel oil system storage tank TJE01A, the condition of the internal coating was inspected and determined to be in acceptable condition. No debris, sludge, or bare metal areas were identified during the inspection. The coal tar epoxy coating was in good condition; however, coating blisters were identified in various places. An engineering evaluation determined the identified blistering was acceptable since all instances were less than nickel size. No issue with the coatings has been documented in any of the previous inspections. The procedure requiring the condition of each tank coating to be documented was enhanced to require inclusion of pictures of the internal coating condition and additional details regarding tank internal coating cleanliness, coating color, coating uniformity, and general tank condition.

Issue:

Given that the engineering evaluation described in the operating experience did not state the potential corrosion rate if the blisters were to open up, it is not clear to the staff that the tank would be capable of performing its intended function(s) should further degradation of the coatings occur between inspections.

Request:

State the corrosion rate and minimum design wall thickness of the fuel oil system storage tank should one of the blisters open up, exposing the fuel oil in the tank to the bare metal material of the tank. Additionally, provide an evaluation of the adequacy of the 10 year inspection interval based on the evaluation of the corrosion rate.

RAI B2.1.19-1

Background:

In Section B2.1.19 of Appendix B to the LRA, the applicant took an exception to GALL Report AMP XI.M33 for buried gray cast iron components, stating that these components do not need to be inspected for selective leaching if the components are within the scope of the fire protection system, have been installed in accordance with NFPA 24, and the activity of the jockey pump is monitored on an interval not to exceed one month. Additionally, the applicant

stated that the exception is consistent with the fire protection aging management requirements of GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks."

Issue:

GALL Report AMP XI.M41 specifically states that the program does not address selective leaching, and that GALL Report AMP XI.M33 is applied in addition to this (AMP XI.M41) program. The internal and external environments both can lead to selective leaching in gray cast iron components, and potentially challenge the structural integrity of the component (e.g., piping). Selective leaching cannot be detected by flow monitoring or operation of a jockey pump. A hardness test or alternative mechanical examination is needed in order to confirm the absence or presence of selective leaching unless preventive measures such as cathodic protection are in place (for external surfaces).

Request:

Explain how buried gray cast iron components in the fire protection systems will be managed for loss of material due to selective leaching.

RAI B2.1.25-1

Background:

The "scope of program" program element of the Buried and Underground Piping and Tanks program states that the emergency diesel engine fuel oil storage and transfer system consists of buried piping and tanks with a safety-related function and contains hazardous materials. Based on a review of drawing LR-CW-JE-M-22-JE01, the emergency diesel engine fuel oil storage and transfer system also appears to include in-scope underground piping. However, LRA Table 3.3.2-21, "Auxiliary Systems – Summary of Aging Management Evaluation – Emergency Diesel Engine Fuel Oil Storage and Transfer System," does not include any aging management review (AMR) items associated with underground piping.

Issue:

There appears to be an inconsistency between the license renewal drawing and the program description in regard to the existence of in-scope underground emergency diesel engine fuel oil storage and transfer system piping.

Request:

Clarify whether there is underground piping in the emergency diesel engine fuel oil storage and transfer system that is within the scope of license renewal. If there is underground piping within the scope of license renewal, describe how the piping will be managed for aging. Also, provide any necessary corrections to the LRA to reflect the change.

RAI B2.1.25-2

Background:

The "preventive actions" program element of the Buried and Underground Piping and Tanks program states that coatings for buried stainless steel piping are only required to protect from a chloride environment to prevent SCC. In addition, it states that the design temperature of the ultimate heat sink is 95°F and the maximum temperature of the refueling water storage tank is 120°F. The basis document further states that these temperatures are below the threshold temperature for SCC as stated in GALL Report Section IX.D.

GALL Report AMP XI.M41, Table 2a, Preventive Actions for Buried Piping and Tanks, footnote 3 states, "[c]oatings are provided based on environmental conditions (e.g., stainless steel in chloride containing environments). If coatings are not provided, a justification is provided in the LRA."

GALL Report Section IX.D states:

> Temperature threshold of 140°F (60°C) for SCC in stainless steel: Stress corrosion cracking (SCC) occurs very rarely in austenitic stainless steels below 140°F (60°C). Although SCC has been observed in stagnant, oxygenated borated water systems at lower temperatures than this 140°F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. With a harsh enough environment (i.e., significant contamination), SCC can occur in austenitic stainless steel at ambient temperature. However, these conditions are considered event-driven, resulting from a breakdown of chemistry controls.

Issue:

The staff recognizes that GALL Report Section IX.D states a 140°F threshold for SCC in stainless steel components; however, in contrast to the treated water environments, the soil environment is not controlled to preclude the potential for significant levels of contaminants. Given that contaminants can accumulate in the soil due to normal environmental interactions, the 140°F threshold may not apply to buried piping. In addition, the GALL Report, item AP-137, states that stainless steel components exposed to soil are susceptible to loss of material due to pitting and crevice corrosion.

During the AMP audit, the applicant did not provide any documentation demonstrating that the soil in the vicinity of the buried stainless steel piping had sufficiently low levels of contaminants to preclude pitting and crevice corrosion, and SCC. If soil sample results are not available or they reveal contaminant levels that could result in pitting and crevice corrosion, and SCC, the staff believes that augmented inspections of buried piping beyond those recommended in Table 4a of GALL Report AMP XI.M41 could be utilized to demonstrate that the aging effects are not occurring.

Request:

Provide the results of soil sampling in the vicinity of in-scope buried uncoated stainless steel piping that demonstrate that loss of material due to pitting and crevice corrosion, and SCC will

not occur due to exposure to contaminants in the soil. If this is not the case, state how these aging effects will be managed.

RAI B2.1.25-3

Background:

The "preventive actions" program element of the Buried and Underground Piping and Tanks program states that the preventive actions of the program will be consistent with the GALL Report; however, during its audit the staff identified five CARs spanning 2006 through 2010 citing weakness in cathodic protection system performance. In addition, a Close-Interval Survey (CIS) and Direct Current Voltage Gradient (DCVG) Survey - Buried Fire Water Protection Piping, dated May 2008, stated that 23 percent of the fire protection system, representing 2,658 feet of piping, was inadequately protected. GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," recommends that a cathodic protection be installed, monitored, annually tested, and potential differences and current measurements be trended to identify changes in the effectiveness of the system.

Issue:

Paragraph 54.21 (d) of 10 CFR states, "[t]he FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging..." The staff believes that cathodic protection system performance is a key preventive measure for managing the aging effects of buried piping. Given that plant-specific operating experience demonstrates a long period of degraded performance of the cathodic protection system, further details on cathodic protection system availability and effectiveness should be included in the FSAR supplement summary description.

Request:

Revise the LRA Section A1.25 discussion of cathodic protection to include a discussion that the cathodic protection system meets NACE SP0169 or NACE RP0285, is monitored for effectiveness at least once a year, and potential difference and current measurements are trended to identify changes in the effectiveness of the systems and/or coatings.

RAI B2.1.25-4

Background:

The "detection of aging effects" program element of the Buried and Underground Piping and Tanks program states that the fire water jockey pump performance will be monitored in lieu of conducting excavated direct visual examinations of in-scope buried fire water system piping. The GALL Report AMP recommends a similar provision.

Issue:

The staff reviewed several CARs and noted that there have been numerous leaks in the fire water system piping. Thus, it is not clear to the staff that there is adequate sensitivity for monitoring buried fire water piping with the fire water jockey pump (i.e., cumulative time when the fire jockey pump is not running is sufficiently long to show a change in performance should a leak occur).

Request:

For the past five years, provide a summary of trend results for the fire water jockey pump that demonstrate that there is sufficient sensitivity to detect leaks in in-scope buried piping. If the trend results are not capable of demonstrating this, state the basis for why monitoring fire water jockey pump performance is sufficient to ensure that the fire water system will meet its intended function during the period of extended operation.

RAI B2.1.25-5

Background:

A CIS and DCVG Survey Buried Fire Water Protection Piping, dated May 7, 2008, recommended that for locations not meeting -850 mV criterion, the station should determine whether the alternative 100 mV potential shift criterion would demonstrate acceptable cathodic protection. In addition, it recommended that locations more negative than -1200 mV be addressed to ensure that coating disbondment is not occurring.

The "acceptance criteria" program element of AMP XI.M41 states that, "[c]riteria for soil-to-pipe potential are listed in NACE RP0285-2002 and SP0169-2007." NACE SP0169-2007 Section 6.2.2.2.2 states, "[i]n some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria in Paragraph 6.2.2.1 may not be sufficient." NACE SP0169-2007 Section 6.2.2.3.3 states, "[t]he use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbondment of the coating."

Issue:

When dissimilar metals are present in the environment (e.g., steel in relation to the copper grounding grid) the 100 mV criterion is only acceptable if it can be demonstrated that the most noble metal will be adequately protected. If the applicant will utilize the 100 mV criterion on in-scope components during the PEO, it must provide the basis for protecting the most noble metal. In addition, in order to verify consistency with the GALL Report AMP XI.M41, the staff must understand the applicant's approach to locations more negative than -1200mV.

Request:

Starting 10 years prior to and extending through the period of extended operation:

a) State whether the 100 mV polarization will be used as acceptance criterion. If the 100 mV polarization will be used in this time period, state the basis for how the most noble buried in-scope material will be adequately protected.
b) State whether as-left survey findings will be allowed to be more negative than -1200 mV, and if they will, state the basis for why protective coating disbondment will not occur.

RAI B2.1.25-6

Background:

The "operating experience" program element of the Buried and Underground Piping and Tanks program, LRA Section B2.1.25, states that from 2008 to 2009, portions of the emergency

service water (ESW) system were replaced with high density polyethylene (HDPE) piping due to material conditions of the system including pinhole leaks, pitting, and other localized degradation of the pressure boundary. LRA Table 3.3.2-4 states that there are steel piping, strainer and valve components in the ESW system exposed to raw water (internal) and a buried environment that have not been replaced. The Buried and Underground Piping and Tanks Inspection Program, Appendix A, Attachment 1, states that four inspections will be performed on steel ESW piping in each 10-year period starting 10 years prior to the period of extended operation.

Issue:

Given that these steel components are in the same environment as the replaced piping, it is possible that the degradation of the steel piping will occur at the same rate (on a unit length basis) as experienced in the past for the entire system. Also, given inconsistent site-wide performance of the cathodic protection system, the staff lacks sufficient information to determine that four inspections in each 10-year period will ensure that the intended function(s) of the portions of the ESW that have not been replaced with HDPE piping will be met during the period of extended operation.

Request:

State the basis for why four inspections in each 10-year period, starting 10 years prior to the period of extended operation, of buried steel piping in the ESW system is sufficient to ensure that the intended function(s) of the portions of the ESW will be met throughout the period of extended operation.

RAI 3.3.1-1

Background:

The LRA cites SRP-LR items 3.3.1-112 and 3.3.1-120 for steel and stainless steel piping, piping components, and other component types embedded in concrete.

SRP-LR item 3.3.1-112 addresses steel piping, piping components, and piping elements exposed to concrete for which there is no recommended aging effect requiring management (AERM) or AMP, "provided 1) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete." SRP-LR item 3.3.1-120 addresses stainless steel piping, piping components, and piping elements exposed to concrete as well as other environments (e.g., air –indoor, uncontrolled, gas, dry air) for which there is no recommended AERM or AMP.

The "program description" of GALL Report AMP XI.M41 states, "[t]he terms 'buried' and 'underground' are fully defined in Chapter IX of the GALL Report." Briefly, buried piping and tanks are in direct contact with soil or concrete (e.g., a wall penetration). The "scope of program" program element of GALL Report AMP XI.M41 states, "[t]his program is used to

manage the effects of aging for buried and underground piping and tanks constructed of any material including metallic, polymeric, cementitious, and concrete materials."

Issue:

There is an internal misalignment in the GALL Report in that the definition of buried piping and scope of AMP XI.M41 conflicts with items 3.3.1-112 and 3.3.1-120, which state that there is no AERM or recommended AMP for the concrete environment. Regardless of the misalignment, the staff lacks sufficient information to conclude that the in-scope steel and stainless steel piping and piping components embedded in concrete do not need to be age managed. For example, if

steel piping is embedded in concrete, is within a building or under a building but above the water table, the potential for water intrusion into the concrete is very low, and therefore, the conditional statements associated with SRP-LR item 3.3.1-112 represent a sufficient basis for why there are no aging effects for these items.

Request:

For in-scope steel and stainless steel piping and piping components embedded in concrete, state the basis for why there are no aging effects for these items, or provide any necessary corrections to the LRA to reflect the change.

RAI 4.7.8-1

Background:

LRA Section 4.7.8 dispositions the TLAA for the replacement of Class 3 piping with HDPE piping as in conformance with 10 CFR 54.21(c)(1)(i), meaning that, "[t]he analyses remain valid for the period of extended operation." Calculations 2007-13241 (Revision 1), Minimum Wall Thickness for ESW Buried HDPE Piping (ML082630799), and 2007-1670 (Revision 0), Buried HDPE Piping Stress Analysis (ML082630800), utilize a 40 year normal service life and include 30-day duration of peak post-accident conditions. LRA Section 4.7.8 states that the replacement of the buried ESW piping with HDPE material began in 2008. The staff further noted that the design analysis for 40 years surpasses the end of the period of extended operation for the applicant's site, October 2044.

Issue:

Based on a review of the UFSAR, the staff noted that other transient scenarios less severe than the postulated 30-day transient (e.g., inadvertent opening of a pressurizer safety or relief valve, minor steam system piping failure) could result in operating parameters which are higher than those for the 40-year life parameters and for which multiple frequencies could occur in the plant's expected life (i.e., 60 years). These other potential transients are not reflected in the calculations.

Request:

State why other transient scenarios less severe than the postulated 30-day transient are not included in the HDPE calculations and provide the basis for why they do not impact the 40-year life of the piping.

RAI 2.4.7-1

Callaway LRA Section 2.4.7, "In-Scope Tank Foundations and Structures" lists only the Category I safety-related RWST and valvehouse, the safety-related CST and the FWST as the tanks in scope of license renewal for that specific section. In regards to the structural foundations and supports of other safety-related tanks that are not specifically called out in the LRA, such as the component cooling water surge tank and the chemical and volume control system tank, it is not clear if the tank supports are analyzed under the specific LRA section that describes the structure that houses the tank, or as a separate commodity, such as LRA Section 2.4.7.

Please provide a brief description of the general methodology used to categorize the tanks within the LRA.

July 5, 2012

Mr. Adam C. Heflin
Senior Vice President and Chief Nuclear Officer
Union Electric Company
P.O. Box 620
Fulton, MO 65251

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CALLAWAY PLANT UNIT 1, LICENSE RENEWAL APPLICATION (TAC NO. ME7708)

Dear Mr. Heflin:

By letter dated December 15, 2011, Union Electric Company submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54 (10C FR Part 54) for renewal of Operating License NPF-30 for the Callaway Plant Unit 1. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Sarah G. Kovaleski, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2946 or by e-mail at Samuel.CuadradoDeJesus@nrc.gov.

Sincerely,
/RA/
Samuel Cuadrado de Jesús, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-483

Enclosure:
As stated
cc w/encl: Listserv
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ADAMS Accession No.: ML12164A905 *concurrence via e-mail

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NAME	YEdmonds	SCuadrado	DMorey	SCuadrado
DATE	6/22/12	6/25/12	6/27/12	7/05/12

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Letter to A. Heflin from S. Cuadrado DeJesus dated, July 5, 2012

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CALLAWAY PLANT UNIT 1, LICENSE RENEWAL APPLICATION (TAC NO. ME7708)

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