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

July 18, 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, SET 5 (TAC NO. ME7708)

Dear Mr. Heflin:

By letter dated December 15, 2011, Union Electric Company d/b/a Ameren Missouri (the applicant) 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 (Callaway). 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, SET 5

RAI B2.1.1-1

Background:

License renewal application (LRA) Section B2.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," states that, "[t]he ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program manages cracking, loss of fracture toughness, and loss of material." It further states that, "[t]he ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program has been proven within the industry to maintain component structural integrity and ensure that aging effects are discovered and repaired before the loss of component intended function."

NUREG-1801, "Generic Aging Lessons Learned Report," (GALL Report) aging management program (AMP) XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," "detection of aging effects" program element states that "[t]he extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component." In addition, "monitoring and trending" program element states that, "[f]or Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation."

Issue:

The staff reviewed the applicant's Inservice Inspection Summary Reports dated from 1999 to 2012 and noted that degradation including pin hole leaks in the site's essential service water (ESW) system piping have been detected. Leaks have also been detected in the chemical and volume control system letdown piping. During the onsite audit of the Inservice Inspection Program, the staff reviewed documents indicating that, for mitigative measures, the applicant enhanced its water chemistry control and replaced some of the degraded piping with more corrosion resistant stainless steel piping during the current 10-year inservice inspection (ISI) interval, which commenced on December 19, 2004. However, based on recent inspection results, as documented in the Inservice Inspection Summary Reports during the current 10-year ISI interval, the staff noted that there was more piping degradation detected and repaired, indicating the degradation had not been alleviated. In addition, during its onsite audit, the staff reviewed documents indicating that there is still an extensive amount of carbon steel piping in the system that is susceptible to similar degradation. Therefore, the staff lacks sufficient information to conclude that the AMPs "detection of aging effects" program element will be effective in timely detection of aging effects, and the "monitoring and trending" program element will be effective in providing timely corrective or mitigative activities to adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) during the period of extended operation.

Request:

Justify the ISI Program's effectiveness in timely detection of aging effects and identification or prediction of loss of material before through-wall leakage has occurred. Discuss corrective actions to demonstrate the program's effectiveness in addressing ongoing degradation concerns.

RAI B2.1.3-1

Background:

Aging management of the Callaway reactor pressure vessel (RPV) head closure stud bolting (including flange stud hole threads, studs, nuts, and washers) is being managed, in part, using the LRA AMP B2.1.3, "Reactor Head Closure Stud Bolting" program, which is an AMP that is based on conformance with the recommended program elements in GALL Report AMP XI.M3, "Reactor Head Closure Stud Bolting."

During the review of the LRA and the audit of the applicant's operating experience for the AMP, the staff noted that the Callaway plant had several occasions where RPV closure studs had been found to be stuck during stud insertion or removal activities. In some cases the studs had to be either cut or forcibly removed from their RPV flange stud hole locations. In addition, during the audit the staff noted that there are also numerous cases where the RPV lower flange stud holes have had damaged threads, or if the thread regions were repaired, had fewer threads than were originally designed.

Issue:

Section A.1.2.1, Item 7, of NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR) states that "[t]he applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown." The stuck studs or damaged threads were detected during plant refueling or cold shutdown activities and the amount of damaged threads was only determined after the studs were removed from the RPV flange stud hole locations. Therefore, for studs that are stuck in place, the staff is concerned that the examinations performed in accordance with the Reactor Head Closure Stud Bolting program may not be capable of detecting wear or damage in the stud holes or quantifying the amount of wear or damage in the stud holes. In addition, for studs that are stuck in place, the staff is also concerned that there may be some potential for boric acid corrosion to occur in the stud areas with engaged threads or stud hole areas below the stud bottom faces.

Request:

For stuck studs left in place, clarify how the program will detect loss of material due to wear or corrosion (including potential boric acid corrosion) and will quantify the potential amount of damage in areas of the studs and lower flange (including engaged threaded regions and remaining stud hole areas below the stud bottom faces).

RAI B2.1.3-2

Background:

The "operating experience" program element for LRA AMP B2.1.3, "Reactor Head Closure Stud Bolting" program, states that there were multiple instances of stuck studs. The AMP's "operating experience" program element also states that currently there is a stud which has been stuck since 1996, and is only partially engaged. During the audit, the staff also noted that there are additional RPV flange stud holes which may have damaged threads. Specifically, the staff noted that the RPV flange stud hole location Nos. 2, 4, 5, 7, 9, 14, 18, 20, 25, 39, 53, and 54 have or may have missing or damaged threads. This represents more than 20 percent of the applicant's total number of the RPV closure stud bolting.

Issue:

Callaway's RPV flange assembly and its bolting components are categorized as American Society of Mechanical Engineers (ASME) Code Class 1 reactor coolant pressure boundary (RCPB) components. The assembly is designed to appropriate design requirements for reactor vessel mechanical assemblies in Subsection NB of the 1971 Edition of ASME Boiler and Pressure Vessel Code, Section III (ASME Section III), Division 1.

The number of issues with stuck studs or damaged stud hole locations represents more than 20 percent of the total number of the RPV closure stud locations in the RPV flange assembly. Based on the staff's review of the documents associated with the applicant's operating experience, the staff was unable to verify whether the entire RPV flange assembly was reassessed every time a new RPV stud or stud hole issue arose, or whether the evaluation of the entire flange assembly had accounted for the collective impact of all RPV lower flange hole or stud degradation experience to date. Thus, the staff is uncertain as to how "monitoring and trending" is accomplished at the site with respect to this AMP, including how the current condition of the studs, stud holes and flange would be evaluated and reconciled to the design requirements for the flange assembly, as specified in the 1971 Edition of ASME Code Section III.

Request:

a) Identify all RPV flange assembly studs or stud hole locations that have had past experience with stuck studs, damage, or missing stud/stud hole threads. For each location, identify when the issue was first detected, and summarize the corrective actions that were taken to resolve the issue.

b) Clarify how the AMP performs "monitoring and trending" of relevant operating experience. Include in your clarification, an explanation of the type of evaluations that will be performed in individual stud or stud hole problems that are detected at the plant (e.g., stuck studs, or studs or stud holes with damaged or missing threads) and of the entire RPV flange based on the latest configuration of the flange assembly (i.e., studs, stud holes, threads, etc.). Clarify how the evaluations will be used to reconcile the latest, as-known configuration of the RPV flange assembly against applicable ASME Code Section III design requirements.

RAI B2.1.5-1

Background:

The applicant's program evaluation report describes the program elements of the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program (LRA Section B2.1.5).

The "parameters monitored/inspected" program element described in the applicant's evaluation report indicates that RCPB cracking and leakage are monitored by the applicant's ISI program as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in Title 10, Section 50.55a, of the *Code of Federal Regulations* (CFR). In addition, the applicant's third interval ISI plan indicates that the ASME Code Cases N-722-1, N-729-1, and N-770-1 are the code cases used in the applicant's ISI in accordance with 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends that RCPB cracking and leakage are monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

Issue:

ASME Code Case N-770-1 specifies visual examination to detect the reactor coolant leakage and boric acid corrosion associated with Class 1 pressure retaining dissimilar metal piping and vessel nozzle welds. During the audit, the staff noted that the applicant's procedure for boric acid walkdown and the third-interval examination schedule for the applicant's ISI program plan do not clearly indicate the implementation of visual examination specified in ASME Code Case N-770-1.

Request:

Clarify why the applicant's implementing procedure for boric acid walkdown and examination schedule for ISI do not clearly indicate the implementation of visual examination specified in ASME Code Case N-770-1.

As part of the response, confirm whether the implementing procedures or examination schedules of ISI adequately implement visual examination, as specified in Inspection Items A-1 and A-2 of ASME Code Case N-770-1 [i.e., unmitigated butt welds at hot leg operating temperatures to be examined by visual examination each refueling outage (RFO)].

RAI B2.1.5-2

Background:

The applicant's program evaluation report describes the program elements of the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program (LRA Section B2.1.5). The "detection of aging effects" program element described in the evaluation report indicates that the program includes examinations in accordance with the requirements of ASME Code Section XI, as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends that RCPB cracking and leakage are monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

During the audit, the staff noted that the applicant's implementing procedure for boric acid walkdown for the reactor coolant system pressure boundary includes the visual examination to detect reactor coolant leakage and boric acid corrosion.

Issue:

During the audit, the staff also noted that applicant's operating experience indicates that refueling cavity seal leakage caused a potential to interfere with the visual examinations of dissimilar metal welds on the reactor vessel loop nozzles and bottom-mounted instrument penetrations.

The staff needs to confirm whether the applicant's operating experience indicates any other previous or current leakage that may interfere with the visual examination of the reactor vessel nozzles specified in ASME Code Case N-770-1 and the other RCPB components specified in Code Case N-722-1.

In addition, the applicant's implementing procedure for boric acid walkdown for the reactor coolant system does not clearly address how the applicant's procedure would resolve the situation when leakage from other locations obscures the visual examination of the reactor vessel nozzle welds and other RCPB components specified in ASME Code Cases N-770-1 and N-722-1.

Request:

a) Describe the applicant's corrective action that was taken to prevent the refueling cavity seal leakage and to correct the conditions (e.g., corrosion product build-up) that would potentially interfere with the visual examination of dissimilar metal welds on the reactor vessel loop nozzles and bottom-mounted instrument penetrations

b) If existent, describe any other previous or current leakage that may interfere with the visual examination of the dissimilar metal welds on the reactor vessel nozzles, the bottom-mounted instrument penetrations or the other components included in the scope of the program (LRA Section B2.1.5).

c) Describe how the applicant's implementing procedures would resolve the situation when leakage from the other locations interferes with the visual examination of the RCPB components specified in ASME Code Cases N-770-1 and N-722-1.

RAI B2.1.5-3

Background:

The applicant's program evaluation report describes the program elements of Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program (LRA Section B2.1.5). The "parameters monitored/inspected" program element described in the evaluation report indicates that RCPB cracking and leakage are monitored by the applicant's ISI program as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends that RCPB cracking and leakage are monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

ASME Code Case N-770-1 specifies volumetric and visual examinations of Class 1 pressure retaining dissimilar metal piping and vessel nozzle welds. Specifically, Inspection Items of ASME Code Case N-770-1, A-1 and A-2 specify the examinations for unmitigated butt welds at hot leg operating temperatures greater than 625 °F (329 °C) and equal or less than 625 °F (329 °C), respectively.

During the audit, the staff noted that applicant's operating experience indicates that the reactor coolant system has experienced reactor hot leg temperature fluctuations associated with periodic, opposing step changes in adjacent hot leg temperatures. This phenomenon has been referred to by the term "upper plenum anomaly" (UPA) and apparently is caused by a flow switching phenomenon in the reactor vessel upper plenum.

Issue:

The UPA may increase the local temperatures of the reactor hot-leg nozzles above 625 °F (329 °C) due to non-symmetrical flow mixing such that Inspection Item A-1, rather than A-2, should be applied to the inspections of the applicant's reactor hot leg nozzles. It is not clear to the staff how the applicant's program evaluates the potential effects of the UPA on the reactor hot leg nozzle temperatures and the determination of the inspection items (i.e., Inspection Items A-1 and A-2).

Request:

a) Provide additional information to confirm that the applicant's program uses relevant inspection items in accordance with ASME Code Case N-770-1: (a) Inspection Item assigned to unmitigated hot leg nozzle butt welds (Inspection Item A-1 or A-2), and (b) the maximum and minimum temperatures of the hot leg nozzles based on adequate consideration of the local temperature distributions and fluctuations at the hot leg nozzles.

   As part of the response, describe how the maximum and minimum hot-leg nozzle temperatures are determined (e.g., an engineering evaluation or actual measurements).

b) If the applicant's Inspection Item for the unmitigated hot-leg nozzle welds is A-2 and the maximum temperature of the hot leg nozzles exceeds 625 °F, clarify why the applicant's program does not specify Inspection Item A-1 to the unmitigated hot leg nozzle welds exposed to temperatures exceeding 625 °F.

c) Describe the operating experience in terms of occurrence of primary water stress-corrosion cracking (PWSCC) in the hot leg nozzles to confirm whether the UPA has an adverse effect on PWSCC of the hot leg nozzles.

RAI B2.1.5-4

Background:

LRA Section B2.1.5 addresses the applicant's Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components program. LRA Section B2.1.5 also addresses the operating experience regarding the RPV lower head cladding as follows:

An indication was visually detected in the RPV lower head cladding in 2007, during the remote VT-3 examination of the vessel interior. The indication was evaluated and additional volumetric and surface examinations were performed for better characterization. The indication was determined to be acceptable as is.

Issue:

During the audit, the staff noted that the applicant's RPV bottom head region has at least two indications of cladding degradation (detected in RFOs 13 and 15 respectively), as indicated in LRA Section 4.7.3. Therefore, the staff needs to clarify how many total indications of RPV cladding degradation have been detected. In addition, the staff noted that the LRA does not clearly provide the following information: (a) the root cause analysis and corrective action for the cladding indications, (b) the previous inspection results to identify any change in the size and depth of the cladding indications, and (c) the inspection method and frequency to manage the degradation of the cladding and RPV, and the technical basis for the adequacy of the inspection method and frequency.

Request:

a) Confirm how many total indications of RPV cladding degradation have been detected. In addition, describe the results of the root cause analysis for the cladding degradation (i.e., what caused the cladding degradation) to confirm whether active degradation of the cladding continues to progress.

b) Describe any corrective action taken to prevent additional cladding and vessel degradation. In addition, describe why the corrective action was adequate to manage the degradation of cladding and reactor vessel.

c) Provide the following information regarding the previous inspection results for each of the cladding indications:

   i. Clarify whether any of these cladding indications is associated with cracking, leakage or other degradation of RPV bottom head penetrations.

   ii. Describe the results (size and depth data) of the previous inspections performed after the initial detections of cladding indications. As part of the response, identify any change in the size and depth of the cladding indications in comparison to the initial size and depth that were detected for the first time.

   iii. Compare the most recent depth data with the thickness of the non-degraded cladding and the thickness of the non-degraded reactor vessel steel (excluding the cladding), respectively.

d) Describe the inspection method and frequency of the subsequent inspections of the cladding indications as defined in the applicant's program. In addition, describe the technical basis for why the inspection method and frequency are adequate to manage the degradation of cladding and RPV.

RAI B2.1.6-1

Background:

Table 4-3 of Electric Power Research Institute (EPRI) Report No. 1022863, "Materials Reliability Program: Pressurized Water Reactor [(PWR)] Internals Inspection and Evaluation Guidelines (MRP-227-A)," identifies the flexures in the thermal shield assembly as "Primary Inspection Category" reactor vessel internals (RVI) components for Westinghouse plants that will be implementing the MRP-227-A recommendations. During its audit, the staff noted that the program basis documents state that the design of the RVI does not include thermal shield flexures. Instead, the basis documents state that the RVI design includes neutron shield panels in lieu of thermal shield flexures. The applicant stated the neutron shield panels and bolting have been screened out as Category A, "no additional measures" components.

In contrast, Table 4.3-5 in LRA Section 4.3.3 identifies the applicant performed a fatigue analysis on the thermal shield flexures with a calculated cumulative usage factor (CUF) value of 0.978.

Issue:

The information in the basis documents for the applicant's program is in conflict with the information in LRA Section 4.3.3 with respect to the existence of thermal shield flexures. Thus, it is not clear to the staff if the applicant's RVI design includes thermal shield flexures. The applicant has not indicated which alternative RVI components would serve the same intended function as that for the flexures and whether the alternative components serving the same function would need to be inspected. The applicant has also not explained whether the neutron shield will provide the same intended function as the thermal shield.

Request:

Clarify whether the RVI design includes thermal shield flexures. Specifically:

a) If the design includes thermal shield flexures, justify why the PWR Vessel Internals Program would not implement inspections of the flexures consistent with the MRP-227-A recommendations.

b) If the design does not include thermal shield flexures, identify the RVI components that serve the same intended function as thermal shield flexures do for the generic Westinghouse design in MRP-227-A. Justify why the alternative components would not need to be inspected in accordance with MRP-227-A.

RAI B2.1.6-2

Background:

Table 4-9 in EPRI Report No. 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)" identifies the upper support ring or skirt in the upper internal assembly of Westinghouse reactor designs as "Existing Program Category" RVI components for Westinghouse plants implementing the MRP-227-A recommendations.

Issue:

During the audit, the staff noted that the applicant's program basis documents do not identify that scope of the AMP includes inspections of an upper support ring or skirt in upper internals assembly of the facility. It is not clear to the staff if the RVI design includes an upper support ring or skirt. The applicant has not indicated which alternative RVI components would serve the same intended function as that for the upper support ring or skirt and whether the alternative components serving the same function would need to be inspected.

Request:

Clarify whether the RVI design includes an upper support ring or skirt.

a) If the design includes an upper support ring or skirt, justify why the PWR Vessel Internals Program would not implement inspections of the component consistent with the MRP-227-A recommendations.

b) If the design does not include an upper support ring or skirt, identify the RVI components that serve the same intended function as the upper support ring or skirt do for the generic Westinghouse design in MRP-227-A. Justify why the alternative components would not need to be inspected in accordance with MRP-227-A.

RAI B2.1.6-3

Background:

Section 4.4.3 and Table 4-9 in MRP-227-A list those existing program components that are identified as ASME Code Section XI core support structure components. MRP-227-A states that these components are examined per ASME Code Section XI Table IWB-2510, "Examination Category B-N-3 requirements."

Issue:

During the audit, the staff noted that the applicant's program basis documents do not identify which RVI components are ASME Code Section XI, Examination Category B-N-3 components. The applicant also has not explained whether the method of performing the VT-3 visual examination in accordance with this examination category would actually achieve coverage of those RVI components that were designated as ASME Code Section XI Examination Category B-N-3 components in the MRP-227-A report. The applicant has not explained if there are any additional RVI components that are ASME Code Section XI, Examination Category B-N-3 components, but not assumed in Table 4.9 of the generic MRP-227-A methodology.

Request:

a) Identify all RVI component locations that are designated as ASME Code Section XI, Examination Category B-N-3 components.

b) Identify any B-N-3 component locations and associated aging effects that are not assumed in Table 4.9 of the generic MRP-227-A methodology.

c) Based on previous ASME Section XI examinations of B-N-3 component surfaces, clarify and justify whether the implementation of VT-3 examinations of these surfaces will actually achieve coverage of those B-N-3 components locations that are identified in the MRP-227-A report and included in the RVI design.

RAI B2.1.7-1

Background:

SRP-LR, Section A.1.2.3.1, states that the scope of program should include the specific components that are being age managed by the program. LRA Section B2.1.7, "Flow-Accelerated Corrosion," states that analyses to determine critical locations in piping and other components susceptible to flow-accelerated corrosion (FAC) are performed using CHECWORKS™. The CSI Technologies, "Callaway FAC System Susceptibility Evaluation Report," states that the purpose of this evaluation is to define the scope of the Flow-Accelerated Corrosion program. Appendix A of Callaway FAC System Susceptibility Evaluation Report states that the chemical and volume control system (designated as BG) is excluded from the Flow-Accelerated Corrosion program based on non-susceptible materials. However, LRA Table 3.3.2-10, "Auxiliary Systems – Summary of Aging Management Evaluation – Chemical and Volume Control System," includes an item for carbon steel piping that is being managed for wall thinning by the Flow-Accelerated Corrosion program.

Issue:

It is not clear to the staff whether the LRA is crediting the Flow-Accelerated Corrosion program for managing portions of a system that has been excluded from the Flow-Accelerated Corrosion program based on non-susceptible material, or whether the system has susceptible material that was not evaluated in the Callaway FAC System Susceptibility Evaluation Report.

Request:

For the component(s) addressed by the AMR item in LRA Table 3.3.2-10, which are being managed for wall thinning by the Flow-Accelerated Corrosion program, clarify whether the LRA is crediting the Flow-Accelerated Corrosion program for managing portions of systems that have been excluded from the program through the "Callaway FAC System Susceptibility Evaluation Report," or whether the system has components with susceptible material that were not evaluated in the above report. Depending on the determination, include additional information to ensure that other components in other tables do not have similar issues.

RAI B2.1.7-2

Background:

GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," "detection of aging effects," program element states that ultrasonic or radiographic testing is used to detect wall thinning. LRA Section B2.1.7, Program Description, states that the program uses baseline and follow-up inspections, and the inspections are performed "using ultrasonic, visual or other approved testing techniques capable of detecting wall thinning."

Issue:

The GALL Report AMP does not discuss visual inspections as a method to detect wall thinning. Neither the Callaway AMP Evaluation Report nor the implementing procedures for the Flow-Accelerated Corrosion program describe the use of visual inspections. It is not clear to the staff whether visual inspections will be used in lieu of ultrasonic testing, or other approved testing technique, to detect wall thinning or in what specific circumstances visual inspections will be used in the Flow-Accelerated Corrosion program.

Request:

Provide information to clarify how visual inspections are used to detect wall thinning due to FAC. If visual inspections are used in lieu of volumetric non-destructive examination techniques, provide the bases for verifying that minimum wall thickness criteria will be met and calculating the remaining service life of a component. Depending on resolution, clarify the summary description of the program in LRA Appendix A, Final Safety Analysis Report supplement.

RAI B2.1.7-3

Background:

GALL Report AMP XI.M17, "acceptance criteria" program element states that inspection results are input for a predictive code to calculate the number of operating cycles remaining before the component reaches the minimum allowable wall thickness. Industry guidance, Nuclear Safety Analysis Center (NSAC) 202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," states that a minimum safety factor should never be less than 1.1, to account for wear rate inaccuracies when calculating the remaining service life of a component. The Flow-Accelerated Corrosion program implementing procedure, EDZ-01115, specifies a safety factor of 1.1 in calculating an "Inspection Index" for some situations. LRA Section B2.1.7, Program Description, states that "FAC Manager Web Edition," is utilized to calculate component wear, wear rate and the next scheduled inspection.

Issue:

It is not clear to the staff whether the Flow-Accelerated Corrosion program implementing procedure requires a safety factor of 1.1 when calculating the remaining service life of a component. Although specified in calculating an "Inspection Index" it does not appear that this value is currently being used to determine a component's next scheduled inspection. In addition, it is not clear whether "FAC Manager Web Edition," uses a safety factor of 1.1 in calculating wears rates and next scheduled inspections.

Request:

Confirm that calculations to determine the remaining service life or the next scheduled inspection of a component use a safety factor of 1.1 and provide information showing how this aspect is controlled through the implementing procedure(s). Alternatively, provide the bases for why the safety factor recommended by industry guidance is not being used, and how calculations for remaining service life and next scheduled inspections account for potential wear rate inaccuracies.

RAI B2.1.7-4

Background:

SRP-LR Section A.1.2.3.10, "Operating Experience," states that the operating experience of existing programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. GALL Report AMP XI.M17, "program description," states that the program relies on implementation of the guidelines in the NSAC-202L. That guidance document states that it addresses wall thinning caused by FAC, and that it does not cover other thinning mechanisms, such as cavitation, and erosive wear.

The Callaway Plant Aging Management Callaway Action Request (CAR) Operating Experience Report for this program cites "loss of material due to erosion" as an aging effect addressed by this program in its discussion for CAR 200608992. The Operating Experience Report also discussed CAR 200102270, which listed the corrective actions to prevent recurrence for wall thinning in main feedwater components, and stated, "...expanded the scope of wall thinning inspections to include other potential damage mechanisms (impingement, cavitation, etc.)." In addition, the Operating Experience Report included CAR 201004190, which addressed a valve with internal erosion and "adjacent pipe wall erosion," and stated that the CAR is addressed by the Flow-Accelerated Corrosion program.

Issue:

Based on the Operating Experience Report provided for this program, it was not clear to the staff whether mechanisms other than FAC are being managed by this program. In addition, based on past corrective actions, the scope of wall thinning inspections may include impingement and cavitation aging mechanism.

Request:

Discuss whether aging mechanisms other than FAC are being managed through the Flow-Accelerated Corrosion program. If applicable, provide information regarding this enhancement to the program. Since aging mechanisms such as erosion due to cavitation, droplet impingement, or flashing have been identified in operating experience documents at Callaway, if the resulting loss of material is not being managed by the Flow-Accelerated Corrosion program, provide the AMP(s) where this aging effect is being managed and provide details on how the aging effect due to these mechanisms is being managed.

RAI B2.1.7-5

Background:

GALL Report AMP XI.M17, "acceptance criteria," program element states that if calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, corrective action should be considered.

The Callaway Operating Experience Report included CAR 20043322, which addresses the findings from FAC inspections during RFO 13. For component AE05-AB590, the CAR states that "this calculation decreased the design minimum thickness required by utilizing the measured ultimate tensile strength listed in the Certified Materials Test Report [(CMTR)]." In

justifying the use of CMTR data, Callaway personnel provided Engineering Design Guide, ME 013, "Pipewall Thickness," which stated that "the use of CMTR data [in] lieu of using the published allowable stress for the material is permissible to further refine the minimum wall thickness analyses." The Design Guide also stated that, as it is defined, the minimum wall thickness is the thickness that will meet the applicable code requirements for a given application and that the process described can also be applied to piping designed to American National Standards Institute (ANSI) B31.1.

Issue:

It is the staff's understanding that the minimum wall thickness calculated for ASME Class 2 and Class 3 and ANSI B31.1 applications requires the use of published allowable stress values and does not include consideration of CMTR data. It is not clear to the staff whether Callaway's minimum wall thickness calculations allow the use of CMTR data to reduce the minimum wall thickness in determining continued operation, or scheduling the next inspection of a component.

Request:

Provide information regarding the use of CMTR data to reduce the minimum wall thickness calculated for ASME Class 2 and Class 3 and ANSI B31.1 applications, as documented in Design Guide ME 013, "Pipewall Thickness." If this approach will be used during the period of extended operation, demonstrate through NRC-approved code cases, or other documentation, that this approach meets the applicable code(s) of construction and the CLB for Callaway.

RAI B2.1.7-6

Background:

The GALL Report, "Introduction," states that if an applicant takes credit for a program in the GALL Report, it is incumbent on the applicant to ensure that the operating experience at the plant is bounded by the operating experience for which the GALL Report was evaluated.

The Callaway Operating Experience Report included CAR 200500411, which describes the failure of a flow meter component due to FAC. Based on the discussion, a flow tube separated from its venturi throat, migrated down the pipe, and blocked the minimum recirculation flow line. The spool piece containing the flow venturi had been inspected in 2004 and was projected to last more than 50 years; however, the configuration of the flow element does not allow it to be inspected from the outside of the pipe using ultrasonic testing methods. The staff notes that while the wall thinning due to FAC is not unique, this operating experience is unique because normal wall thinning inspections cannot be used to monitor ongoing wall thinning of a passive component.

Issue:

The failure of the flow element resulted in macrofouling, which is not an aging mechanism that is associated with the Flow-Accelerated Corrosion program. The Flow-Accelerated Corrosion program manages loss of material, which is associated with the "pressure boundary." As defined in Nuclear Energy Institute (NEI) 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," the intended function of "pressure boundary" is to "provide pressure retaining boundary so that sufficient flow at adequate pressure is delivered." In this case, the pressure retaining boundary was not affected,

but the result was insufficient flow, which is a purpose of the pressure boundary intended function. In that regard, the plant-specific operating experience is not bounded by the industry operating experience for which the GALL Report program was evaluated.

Request:

If macrofouling due to flow element failure caused by FAC is no longer applicable to Callaway, provide the bases for why it is not applicable. Otherwise, if this aging mechanism will be managed by the Flow-Accelerated Corrosion program or by another AMP, then provide information to demonstrate how macrofouling due to flow element failure caused by FAC will be managed.

RAI B2.1.10-1

Background:

GALL Report AMP XI.M20 states that the program relies on implementation of the recommendations in Generic Letter (GL) 89-13, and the "detection of aging effects" program element states that inspection methods (e.g., visual or nondestructive examination) are in accordance with the applicant's docketed response to GL 89-13. LRA Section B2.1.10, "Open-Cycle Cooling Water System," states that the activities for this program are consistent with the Callaway commitments to GL 89-13. The applicant's response to GL 89-13, dated January 29, 1990, states that selected sections of ESW system piping are inspected each RFO for corrosion, erosion, and biofouling. The applicant's response to GL 89-3 also states that "each pipe is radiographed to determine any localized pitting. This is followed by ultrasonic testing using accurately placed grid locations to determine the extent of any damage."

Callaway's AMP Evaluation Report for Open-Cycle Cooling Water System, Section 3.4.2, states that selected sections of ESW piping are ultrasonically tested every 18 months for trending of wall thickness measurements. Callaway's implementing procedure, EDP-ZZ-01121, "Raw Water Systems Predictive Performance Program," does not discuss radiography as one of the nondestructive examination techniques used to inspect ESW piping.

Issue:

The activities for this program do not appear to be consistent with the Callaway commitments to GL 89-13 regarding nondestructive examination techniques conducted each RFO.

Request:

Provide information demonstrating that the open-cycle cooling water system program is consistent with the Callaway commitments to GL 89-13, regarding nondestructive examination techniques conducted during each RFO. If radiographic examinations are no longer being performed, then provide documentation related to this apparent change to an NRC commitment, and if other inspection methods are being credited in lieu of radiographic examinations, describe how they provide a similar ability to detect degradation.

B2.1.10-2

Background:

SRP-LR, Section A.1.2.3.4, "Detection of Aging Effects," states that when sampling is used in condition monitoring programs, applicants should provide the basis for the inspection population and the sample size. Callaway's response to GL 89-13, dated January 29, 1990, states that selected sections of ESW system piping are inspected each RFO for corrosion, erosion, and biofouling.

Callaway's AMP Evaluation Report for Open-Cycle Cooling Water System, Section 3.4.2, states that wall thickness of selected sections of ESW piping are trended and that locations are determined by the raw water systems engineer. During its review of Callaway's implementing procedure, EDP-ZZ-01121, "Raw Water Systems Predictive Performance Program," the staff could not confirm the information describing the number of trended locations, nor the criteria used to identify these locations. In addition, the implementing procedure included Appendix 2, "Non-Trended Monitored Locations for Raw Water Program," and stated that raw water corrosion engineer updates this list as required, but did not discuss what those requirements were and did not provide the purpose of these non-trended monitored locations

Issue:

Information was not available regarding the number or selection criteria for the locations being trended by the "Raw Water Systems Predictive Performance Program." Also, the identification criteria and purpose of the non-trended monitored locations listed in Appendix 2 was not provided.

Request:

a) For the selected sections of ESW piping that are inspected each outage for corrosion, erosion and biofouling, provide details regarding the number of locations inspected, the criteria used to select the locations and the inspection method(s) used.

b) For the non-trended monitored locations, provide information regarding the criteria used to select the locations and the purpose for monitoring these non-trended locations.

B2.1.10-3

Background:

GALL Report AMP XI.M20, states that the program relies on implementation of the recommendations in GL 89-13, which includes surveillance and control techniques to manage aging effects caused by protective coating failures and other mechanism in the open-cycle cooling water system. The "parameters monitored/inspected" program element states, in part, that components with internal linings or coatings are periodically inspected, and that the program ensures that defective protective coatings that could adversely affect component performance are detected. LRA Section B2.1.10, Program Description, states that Callaway uses internal coatings on the component cooling water heat exchanger end bells, channels, and tubesheets, the control room air conditioner tubesheets, the class 1E electrical equipment air conditioner tubesheets, and the ESW system strainers.

Callaway's AMP Evaluation Report for Open-Cycle Cooling Water System, Section 3.3.2, states that heat exchanger inspections are performed for fouling, sediment, corrosion, erosion, and pitting; however, coating failure is not included. This section also states that heat exchangers and ESW strainers are coated, "but this amount of surface area is relatively small and has not been a concern for [ESW] system performance." Implementing procedure ETP-ZZ-3001, "GL 89-13 Heat Exchanger Inspections" Section 7.1.11 states to check heat exchanger coatings when they are accessible for inspections, but Callaway's revised GL 89-13 commitments in letter dated July 16, 2007, states that thermal performance testing will be the primary monitoring method of component cooling water heat exchanger with cleaning and inspections planned as necessary.

Issue:

Callaway has coatings applied to various heat exchanger and the ESW strainers, but it is not clear how the aging effects caused by failure of these coatings are being managed by the Open-Cycle Cooling Water System program. While most heat exchangers will be periodically inspected in lieu of thermal performance testing, which provides an opportunity to inspect for coating degradation, the primary monitoring method for the component cooling water heat exchanger is thermal performance testing, which may not afford an opportunity to detect coating degradation prior to failure.

Request:

a) For heat exchangers with applied coatings, where coating failure could adversely affect the heat exchanger or downstream components, clarify whether periodic inspections procedures will include the detection of coating degradation. Alternatively, provide justification to demonstrate that periodic inspections for coating degradation are not needed.

b) Except for the component cooling water heat exchanger, confirm that the frequency of these inspections will not exceed 5 years (as documented in Callaway's revised GL 89-13 commitments), or provide justification for an inspection frequency greater than 5 years. For the component cooling water heat exchanger, address the inspection frequency for occasions where periodic thermal performance testing, flow verification or routine monitoring of the heat exchanger differential pressure does not indicate the need for inspection or cleaning for extended periods.

B2.1.10-4

Background:

GALL Report AMP XI.M20 "detection of aging effects" program element states that inspection methods (e.g., visual or nondestructive examination) are in accordance with the applicant's docketed response to GL 89-13. LRA Section B2.1.10, "Open-Cycle Cooling Water System," states that the activities for this program are consistent with the Callaway commitments to GL 89-13. Callaway's response to GL 89-13, dated January 29, 1990, Enclosure 2, Item III.B, states, in part, that air flow rates of all air-to-water heat exchangers are taken and trended and that visual inspections of the air side of the heat exchangers will be performed. Callaway's letter dated July 16, 2007, which modified its GL 89-13 commitments, appears to address cleaning and inspection of the water side of the tubes for all of the room coolers, but does not discuss air side inspections. For the containment air coolers, the 2007 letter states the primary monitoring

method will be cleaning and inspection of the inner tube walls and outer coil fins per EDP-ZZ-01112.

Implementing procedures EDP-ZZ-01112, "Heat Exchanger Predictive Performance Manual," and ETP-ZZ-03001, "GL89-13 Heat Exchanger Inspection," do not discuss inspections of the air side of heat exchangers, and do not address the tracking and trending of air flow rates on air to water heat exchangers. The note in EDP-ZZ-01112, Step 4.1.1.g states that EPRI 1007248 was used as additional guidance on non-condensing room coolers to determine the inspection and cleaning methods. EPRI 1007248, "Summary," states "...an analysis in conjunction with periodic flow and pressure-drop testing and regular air-side inspections and cleanings satisfies the intent of Generic Letter 89-13..."

Issue:

The activities for this program do not appear to be consistent with the Callaway commitments to GL 89-13 regarding inspections for the air-side of heat exchangers. In addition, although heat transfer is the intended function listed for heat exchangers exposed to ventilation atmosphere in various LRA Tables, (e.g., 3.3.2-11, 3.3.2-13, 3.3.2-14, 3.3.2-15, and 3.3.2-19), reduction of heat transfer is not listed as an aging effect requiring management for these GL 89-13 components.

Request:

Provide information demonstrating that the open-cycle cooling water system program is consistent with the Callaway commitments to GL 89-13, with respect to air-side inspections and air flow rate trending of heat exchangers. If inspection and trending activities for fouling of the air side of heat exchangers are being performed, then update the appropriate tables in the LRA to reflect these aging management activities for aging effects requiring management of the associated components. However, if visual inspections of the air side of the heat exchangers are no longer being performed, and air flow rates are not being taken and trended, then provide documentation related to this apparent change to an NRC commitment and either describe how reduction of heat transfer due to air-side fouling is being managed or provide the bases for not treating air-side reduction of heat transfer as an aging effect requiring management.

B2.1.10-5

Background:

GALL Report AMP XI.M20, "acceptance criteria," program element states that inspected components should exhibit adequate design margin regarding design dimensions (e.g., minimum required wall thickness). SRP-LR Section A.1.2.3.6, "Acceptance Criteria," states that acceptance criteria should ensure that the component intended function(s) are maintained consistent with all CLB design conditions during the period of extended operation. Callaway's AMP Evaluation Report for this program, Section 3.6.2 states that minimum wall thickness acceptance criteria are listed in the procedure EDP-ZZ-1121, Attachments 3 and 4.

In its review of operating experience reports, the staff noted in CAR 200703680 that a flange for an ESW valve had corrosion damage. The Corrective Actions section states:

The extent of the corrosion damage identified does not adversely impact the structural integrity of the flange. The standard Class 3 manufacturing tolerance of 12.5% thickness provides assurance that this condition is not a structural or pressure boundary issue.

The CAR states that more than 50 percent of the gasket seating area was damaged by corrosion, but it does not provide any information regarding the depth of the corrosion.

Issue:

The acceptance criteria listed in procedure EDP-ZZ-1121, Attachments 3 and 4 only apply to pipe minimum wall thickness and do not address flange thicknesses. The 12.5 percent manufacturing tolerance, stated in the CAR, typically only applies to pipe wall thickness, and the tolerance for flange thickness is typically specified in ANSI B16.5, "Pipe Flanges and Flanged Fittings" with a 0.0 "minus" value. ANSI B16.5 does not appear to give a "plus or minus" 12.5 percent tolerance for flange thickness, and without knowing the depth of the corrosion and the thickness of the flange, the structural integrity of the flange during the period of extended operation has not been demonstrated.

Request:

For structural integrity evaluations that will be performed during the period of extended operation, where flange thicknesses have been adversely affected due to corrosion or other aging mechanisms, provide the acceptance criteria that will be used to ensure that the component intended function(s) will be maintained consistent with all CLB design conditions, or provide the bases for applying the "standard Class 3 manufacturing tolerance of 12.5 percent" to flange thicknesses.

B2.1.10-6

Background:

SRP-LR, Section A.1.2.3.10, "Operating Experience," states that past corrective actions for existing AMPs should be considered, and that feedback from past failures should have resulted in appropriate program enhancements or new programs.

LRA Section B2.1.10, "Operating Experience" states that buried portions of the ESW supply piping were replaced with high-density polyethylene (HDPE) piping and that sections of aboveground or underground carbon steel piping that interface with the buried piping were replaced with stainless steel. It also stated that these modifications were performed as a result of corrective actions concerning pinhole leaks, pitting, and other localized degradation of the ESW piping system. Callaway's AMP Evaluation Report, "Scope of Program," program element states that the carbon steel ESW system buried piping that was not replaced with HDPE, will either be replaced or will continue to be inspected to monitor internal degradation. In addition, the staff noted in the License Renewal Component List for this AMP that a number of carbon steel components are still in service, and plans for future replacements with corrosion resistant materials were not provided.

During its review of operating experience, the staff noted the discussion in CAR 200703627 that correlated the discovery of ESW system leaks with engineered safety feature actuation system (ESFAS) testing. Based on the CAR, ESW components above elevation 2037 will naturally drain with the pump secured in the ESFAS procedures, and actions taken to date have not been effective in preventing ESW system hydraulic transients during ESFAS testing. In addition, the staff noted the discussion in CAR 200608086 which stated, "other than the one incident in 2005, the impact of through-wall leaks on the ultimate heat sink inventory, piping structural integrity and room flooding, have not been significant enough to adversely affect the ability of the system to perform its intended design safety function."

Issue:

Based on the extent of degradation in the ESW, the staff lacks sufficient information to conclude that the open-cycle cooling water System program will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. Due to the pervasive nature of degradation in the system, it is unclear to the staff what enhancements were made to this AMP or whether new programs were created to address the consequences of past program weaknesses. Since additional leaks continue to be identified, it is unclear to the staff what specific corrective actions were taken to prevent recurrence of the identified problems. In addition, based on ESFAS testing, hydraulic transient loads may be an expected load during certain CLB events and therefore, should be included in the structural evaluations for component degradation.

Request:

a) For the event in 2005 where the ability of the system to perform its intended safety function was adversely affected, provide the corrective actions that were taken and the enhancements that were made to the program which give reasonable assurance that the ESW system's intended functions will be maintained consistent with the CLB during the period of extended operation.

b) Provide a summary of the augmented inspections that are currently being performed, to identify loss of material before through-wall leakage occurs, including inspection method(s) and frequency, number and selection of locations, and acceptance criteria. If corrective actions include plans for replacing piping, provide those aspects that can be credited in license renewal to alleviate ongoing degradation concerns. If specific inspections have not been incorporated into current site procedures, or if planned piping replacements are being credited for license renewal, provide an enhancement and an associated commitment for this program.

c) Provide a summary of analyses conducted in the past 5 years for the ESW system that evaluated the structural integrity of areas where degradation has caused pipe wall thicknesses to be less than nominal values. Include data to demonstrate that the degradation is limited to independent, localized corrosion sites or state how structural integrity has been evaluated for the potential of multiple adjacent corrosion sites that could have a cumulative adverse impact. If only independent localized corrosion sites have been discovered to date, state the basis for why multiple adjacent corrosion sites will not occur during the period of extended operation. In addition, provide a summary of any associated evaluations that considered system interactions such as flooding, spraying water on equipment, and loss of flow. Also, confirm that hydraulic transient loads, which are evident

during ESFAS testing, have been included in the structural integrity calculations, or provide justification why these CLB loads do not need to be included.

RAI B2.1.20-1

Background:

LRA Section B2.1.20 states that there are 19 socket welds in the small-bore piping population. During the audit, the applicant indicated that a recent recount by the applicant showed that there are in fact 23 Class 1 small-bore socket welds.

Issue:

Based on the applicant's previous miscount as well as the staff's experience with reviews of other LRAs for similar PWR facilities, where the typical number of in-scope socket welds are roughly twice the number indicated by the applicant, the staff is concerned that an accurate population of in-scope socket welds may not be fully represented in the applicant's LRA.

Request:

Verify and confirm the number of in-scope Class 1 small-bore socket welds in the population of ASME Code Class 1 piping. Based on this review, amend LRA Sections A1.20 and B2.1.20, to indicate the correct population of in-scope socket welds.

July 18, 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 PLAN UNIT 1 LICENSE RENEWAL APPLICATION, SET 5 (TAC NO. ME7708)

Dear Mr. Heflin:

By letter dated December 15, 2011, Union Electric Company d/b/a Ameren Missouri (the applicant) 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 (Callaway). 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.: ML12179A400 *concurrence via e-mail

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NAME	IKing	SCuadrado	DMorey	SCuadrado
DATE	7/11/12	7/17/12	7/17/12	7/18/12

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Letter to A. Heflin from S. Cuadrado DeJesus dated, July 18, 2012

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CALLAWAY PLAN UNIT 1 LICENSE RENEWAL APPLICATION, SET 5 (TAC NO. ME7708)

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