Ameren
MISSOURI

Callaway Plant

November 20, 2012

ULNRC-05929

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

10 CFR 2.101
10 CFR 2.109(b)
10 CFR 50.4
10 CFR 50.30
10 CFR 51.53(c)
10 CFR 54

Ladies and Gentlemen:

DOCKET NUMBER 50-483
CALLAWAY PLANT UNIT 1
UNION ELECTRIC CO.
FACILITY OPERATING LICENSE NPF-30
RESPONSES TO RAI SET #16 AND AMENDMENT 16 TO THE CALLAWAY LRA

References:
1) ULNRC-05830 dated December 15, 2011
2) NRC Letter, "Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 16 (TAC No. ME7708)," dated October 24, 2012
3) ULNRC-05891 dated August 9, 2012
4) ULNRC-05907 dated September 20, 2012
5) ULNRC-05915 dated October 11, 2012

By the Reference 1 letter, Union Electric Company (Ameren Missouri) submitted a license renewal application (LRA) for Callaway Plant Unit 1. Reference 2 dated October 24, 2012 transmitted the sixteenth Request for Additional Information (RAI) related to our application.

Enclosure 1 contains Ameren Missouri's responses to the individual requests contained in the October 24, 2012 RAI. Enclosure 2 contains LRA Amendment 16 to reflect the update to LRA Table 3.6-1, which is described below.

The following updates are provided as part of this transmittal:

- A supplement for Appendix J RAI B2.1.29-1 is being provided to include Type B Tests. (Enclosure 3 and References 3 and 5).

- As requested by the staff, Callaway LRA Table 3.6-1, items 3.6.1.016 and 3.6.1.017 have been revised, as shown in Amendment 16 (provided as Enclosure 2), to state that all fuse holders including fuse holders for electrical penetrations that utilize metallic clamps are within the scope of license renewal at Callaway as part of an active device and do not require aging management. (Enclosure 2 and Reference 4 (RAI 3.6.2.1-1)).

It should be noted that there are no changes to commitments contained within this response.

If you have any questions with regard to these RAI responses, or Amendment 16, please contact me at (573) 823-9286 or Ms. Sarah Kovaleski at (314) 225-1134.

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

Sincerely,

Executed on: November 20, 2012

Les H. Kanuckel

Les H. Kanuckel
Manager, Engineering Design

DS/SGK/nls

Enclosures: 1) Request for Additional Information (RAI) Set #16 Responses
2) Amendment 16, LRA Updates
3) Supplement to RAI B2.1.29-1

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CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION

REQUEST FOR ADDITIONAL INFORMATION (RAI) Set #16 RESPONSES

RAI B2.1.3-1a

Background:

By letter dated August 21, 2012, Union Electric Company d/b/a Ameren Missouri (the applicant) responded to request for additional information (RAI) B2.1.3-1, and stated in part that stud No. 18 became stuck in 1996, 2.625 inches above the base of the stud hole, which indicates 6.505 inches of thread engagement. The applicant also stated that since the minimum required thread engagement is 6.31 inches, stud No. 18 exceeds the requirement for minimum thread engagement. The applicant further stated that since excessive force was not used, no thread damage was caused after the thread became stuck. The applicant also stated that inspection of stud No. 18 prior to reactor vessel head installation found a small burr on the 10th and 11th threads. The burr was removed and there were no other problems noted with the stud threads. The applicant stated that the stud hole threads were also inspected, and no damage was found.

In its response, the applicant also stated that it performs inspections of stud No. 18 as required by the American Society of Mechanical Engineers (ASME) Section XI Code, which include a volumetric examination of the flange threads and the stud, and a VT-1 examination of the surface of the nuts and washers.

Issue:

The staff needs clarification of the applicant's basis for stating that the stuck stud has 6.505 inches of thread engagement remaining and that the required minimum thread engagement is 6.31 inches.

The staff finds that the applicant's response did not address the number of threads which may have been damaged as a result of stud No. 18 getting stuck, uniform wear, or corrosion. In addition, it is not clear from the applicant's response if the noted inspections associated with stud No. 18 were performed right before it became stuck. The applicant's response is also not specific in how ASME Section XI Code inspections can verify the current number of threads which are properly engaged for stud No. 18, particularly if the stud has not been removed since getting stuck in 1996.

Request:

Provide the basis for determining that all of the engaged threads for stud No. 18 are undamaged. In addition, provide justification of the evaluations used to support the basis that stud No. 18 has 6.505 inches of thread engagement, and that the required minimum thread engagement is 6.31 inches.

Callaway Response

The threads of reactor vessel stud 18 and stud hole 18 were inspected immediately prior to installation of the stud. At that time, the threads were intact. When the stud became stuck, excessive force was not used in an attempt to free the stud. Therefore, no threads were damaged by installation of the stud. Although the threads of stud 18 have not been inspected for damage due to wear or corrosion, the other 53 reactor vessel studs and stud holes have been inspected. In the 20 years since 1992, no damage to the threads of the other studs and stud holes has been observed due to corrosion, wear, or any other cause. Since stud 18 is exposed to the same environment as the other studs except during refueling, it is reasonable to conclude that damage to the threads due to corrosion or wear has not occurred. During

refueling, stud 18 is not tensioned and is protected from exposure to the water in the refueling pool, which prevents damage due to corrosion and wear. Based on these considerations, it is unlikely that the threads of reactor vessel stud 18 or the stud hole have suffered any damage.

The UT exam discussed in the response to RAI B2.1.3-1 is capable of identifying cracking and severe corrosion of the threads. This was included in the response to provide confirmation that cracking and severe corrosion of the threads have not occurred.

The length of thread engagement for stud 18 is calculated as follows. A sketch (Figure 1) follows this RAI response. The depth of the stud hole is a minimum of 12.25 inches. The distance from the top of the stud hole to the top of the threads in the stud hole is a maximum of 1.81 inches. The distance from the bottom of the stud hole to the bottom of the stuck stud is 2.625 inches. The distance from the bottom of the stuck stud to the bottom of the threads on the stuck stud is a maximum of 1.31 inches. Thus, the length of thread engagement is

12.25 - 1.81 - 2.625 - 1.31 = 6.505 inches.

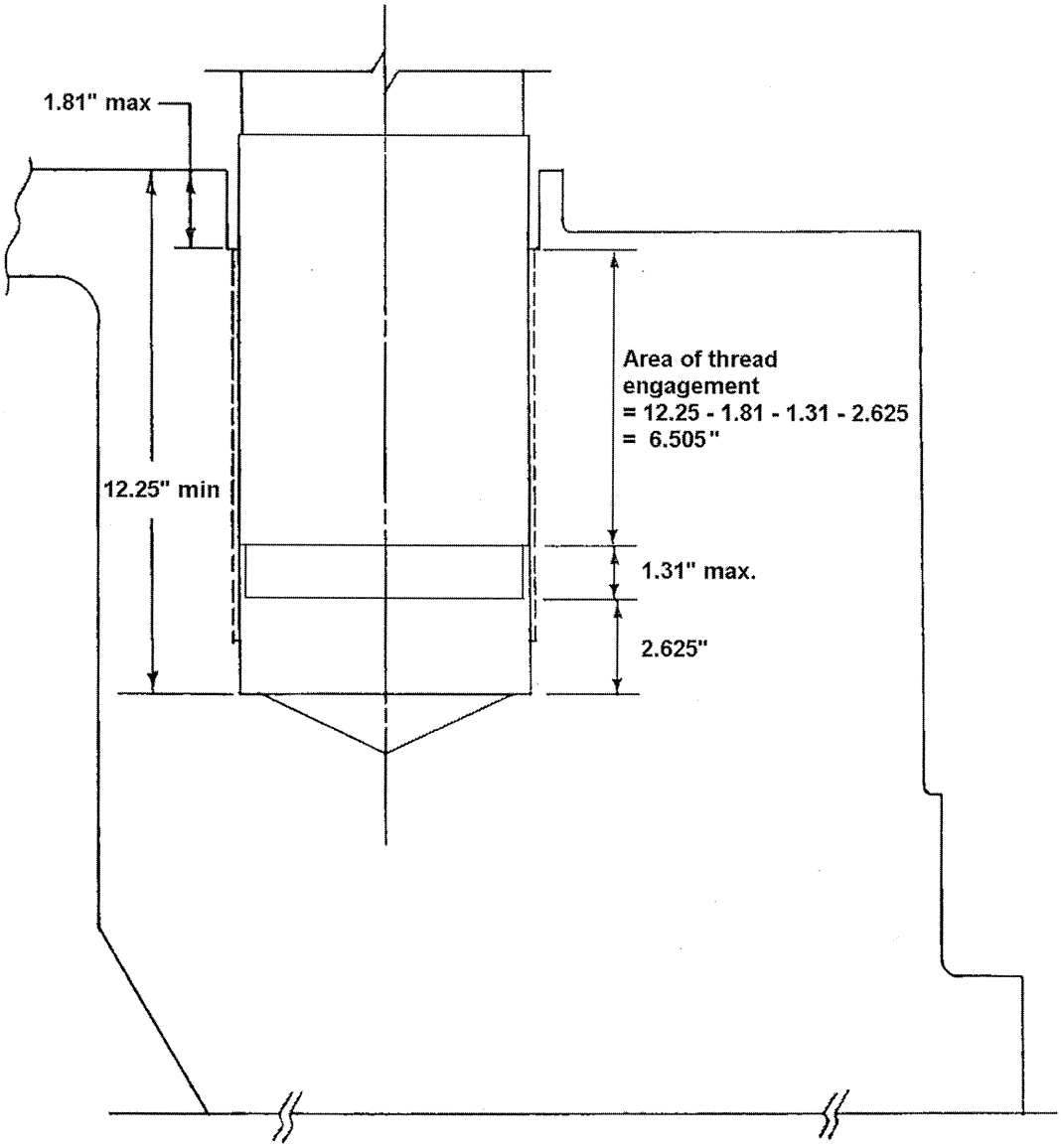
The value of 6.31 inches for minimum length of thread engagement is obtained from information in Combustion Engineering report CENC-1509, *Addendum 2 to Analytical Report for Union Electric Company Callaway Nuclear Power Plant Unit No. 1 Reactor Vessel.* From this report, with full thread engagement length of 9.24 inches, the applied shear stress for the vessel threads is 10.94 ksi. The allowable vessel shear stress is 16.02 ksi. The minimum allowable thread engagement length is then calculated as

9.24 X 10.94/16.02 = 6.31 inches.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

FIGURE 1


1.81" max
12.25" min
Area of thread
engagement
= 12.25 - 1.81 - 1.31 - 2.625
= 6.505"
1.31" max.
2.625"

RAI B2.1.3-2a

Background:

By letter dated August 21, 2012, the applicant responded to RAI B2.1.3-2, and in part identified all stud or stud hole locations which experienced degradation. Specifically, the applicant summarized the actions taken at the following stud or stud hole location numbers: 2, 4, 5, 7, 9, 13, 18, 24, 25, 39, 42, 53, and 54.

The staff also requested an explanation of the type of evaluations performed when closure stud bolting issues are detected on an individual basis and collectively for the entire reactor pressure vessel (RPV) flange assembly. The applicant stated that inputs to the evaluations consider all relevant information, including ASME Code requirements, prior evaluations and documented aging effects.

Issue:

In its review of the applicant's response, the staff noted that the applicant's summary of the problems encountered with its RPV closure stud bolting was not complete in that it did not include information regarding stud Nos. 15 and 35, whose inspection reports were reviewed by the staff during its audit and indicated that the studs for these locations were replacement studs. The staff needs additional information to understand the nature of these replacements (i.e., whether they were replaced due to damage).

In addition, based on the staff's review of the applicant's response, there was no consideration of the cumulative impact of the degraded closure stud bolting over the years on the entire RPV flange assembly. The staff is also uncertain how future RPV closure stud bolting issues will be assessed during the period of extended operation in this respect (e.g., if additional stud locations became damaged over time). The staff's concern is based on the fact that currently at least 10 closure stud bolting locations have some degradation in the form of missing threads. In addition stud No. 18 is stuck in a partially engaged position since fall of 1996.

Request:

a) Supplement the response to RAI B2.1.3-2 to include information on all RPV closure stud bolting corrective action, repair, and replacement activities performed to date, which were not included in the letter dated August 21, 2012.

b) Provide a condition assessment and evaluations which justify the adequacy of the entire RPV flange assembly, which accounts for all the locations with known closure stud bolting degradation.

Callaway Response

a) A review of plant records confirmed that the two reactor vessel studs mentioned in this RAI have been replaced. Stud 15 was replaced in June, 1984, shortly after Callaway's initial fuel load. Stud 35 was replaced in the spring of 1989. Both studs were replaced because of thread damage. No other repair or replacement activities were discovered in the review of the plant records.

b) Callaway manages cracking and loss of material in the reactor vessel studs and stud holes consistent with the Reactor Head Closure Stud Bolting program. Callaway performs

volumetric examinations of all studs and visual inspections of those studs which are accessible. Callaway follows the recommendations of Regulatory Guide 1.65, *Materials and Inspections for Reactor Vessel Closure Studs*, to prevent degradation of the studs. In addition, the studs and stud holes are protected from exposure to the borated water of the refueling pool to prevent loss of material due to corrosion.

In the 20 years since 1992, examinations of the reactor vessel studs and stud holes have found no evidence of cracking or loss of material. All studs have been tensioned to design criteria during this period and have performed their intended function.

No reactor vessel stud or stud hole has experienced thread damage since 1992. In the early years of Callaway's operation, industry knowledge of stud handling procedures and use of lubricants was still developing, which led to the thread damage and stuck studs experienced at Callaway. Stud 18, which became stuck in 1996 due to ingress of foreign material into the stud hole, is the only stud to have become stuck in this time period. Based on the progress Callaway and the industry have made in these areas, and on the length of time since these problems have been experienced at Callaway, it is unlikely that they will recur in the future. However, if these types of problems do occur, Callaway's corrective action program will ensure that all repairs, replacements, and evaluations meet applicable NRC commitments in the Callaway CLB.

Two evaluations, performed in 1987 and 1989, were related to the problems Callaway has experienced with the reactor vessel studs. Both of the evaluations addressed minimum thread engagement. Based on ASME Code stress limits, the minimum thread engagement was calculated to be 5.54 inches. A minimum thread engagement of 6.31 inches can be inferred from the Combustion Engineering vessel design report, which is conservative compared to the 5.54 calculated value. The 6.31 value has been used at Callaway to determine acceptability of the reactor vessel stud thread engagement.

The 1989 evaluation provided criteria for taking partial credit for damaged threads. However, all damaged threads were removed from the stud holes in 1989 and 1992, so that there are presently no damaged threads. All studs with damaged threads were replaced, so that no stud currently has damaged or missing threads.

The 1989 evaluation noted that if thread degradation occurs along one side of the vessel flange hole, the resulting load redistribution increases stresses and fatigue usage in the stud. However, the evaluation showed that there is enough design margin to compensate for any possible degradation distribution.

The first evaluation was performed in 1987. In Refuel 2, five reactor vessel studs became stuck during removal, and resources were not available to remove the studs during the outage. The 1987 evaluation provided justification for operation in the subsequent cycle with all five of the stuck studs partially withdrawn, and one left untensioned.

The 1987 evaluation provided three recommendations in addition to the conclusion that the plant could be operated with one stud not tensioned and four studs partially withdrawn but tensioned. These recommendations are paraphrased as follows.

Recommendation 1. Tension the head with stud 2 left untensioned.

This recommendation was met - stud 2 was left untensioned in the cycle following Refuel 2.

Recommendation 2. Operate the plant until the next refueling outage with stud 2 untensioned. In order to minimize loading conditions on the closure to minimize the

potential for o-ring seal leakage, the vessel should not be hydrotested and the heat-up rate should be held to 50 °F/hr or less until stud 2 is removed and replaced.

The plant was operated for one cycle with stud 2 untensioned. A hydrotest of the reactor vessel was not performed with stud 2 untensioned. A review of plant logs indicated that the heat-up rate following this outage met the 50 °F/hr limit. The purpose of limiting the heat-up rate was to reduce the potential for o-ring seal leakage. No o-ring leakage occurred while operating with stud 2 untensioned, indicating that the heat-up rate was acceptable.

Recommendation 3. Remove studs, inspect the vessel threads, and replace the stuck studs at the earliest opportunity. Plans should be made to remove stud 2, inspect the threads in hole 2 and clean up the threads in hole 2 during the next refueling outage. If the threads are found to be too severely damaged to be cleaned up, the vessel can be operated until the following refueling outage with a missing stud, at which time an insert should be installed in the flange.

As recommended, stud 2 and the other four stuck studs were destructively removed during the next refueling outage. Threads in each of the five stud holes were damaged by the stud removal process and resulted in the loss of threads in those stud holes. However, a sufficient number of threads remained to allow all the studs to be fully tensioned in subsequent cycles.

If operation with an untensioned stud is necessary in a future cycle, the Callaway corrective action program will ensure that appropriate specific evaluations are performed.

The second evaluation was written in 1989, prior to Refuel 3, in anticipation of stud hole thread damage occurring when the five stuck studs from Refuel 2 were destructively removed. The purpose of this report was to develop criteria to accept or reject reactor vessel thread degradation on a generic basis. There were five recommendations from this report.

Recommendation 1. While it is possible to accept some damage to threads in the reactor vessel flange, primary emphasis should be placed on avoiding thread damage in the first place. Precautions which should be taken include:

- *minimize corrosion,*
- *keep threads clean and well lubricated,*
- *clean up threads with a tap or die if there is any sign of sticking,*
- *avoid impacts to the threads during stud installation and removal, and*
- *avoid excessive use of impact, or slugging, wrenches for sticking studs.*

This recommendation has been met. The threads are cleaned and lubricated each outage, and steps are taken to prevent exposure to the borated water in the refueling pool to minimize corrosion. The procedure for stud removal allows stud removal using only approved stud removal tools. Slugging wrenches are not in the list of approved stud removal tools. If difficulty is encountered while inserting a stud, it is removed and the problem is addressed through the corrective action program, which may include using a tap or die to clean up the threads. All stud handling procedures require care to protect the threads when handling studs.

Recommendation 2. Studs with more than a few degraded threads should be replaced. Studs used in vessel flange holes with degraded threads should be free of damage.

This recommendation has been met. All studs with degraded threads have been replaced, and all studs currently in use are free of damage.

Recommendation 3. Use of impact wrenches and slugging wrenches should be limited to a maximum kinetic energy input of about 20,000 lb-ft. In the event that a stud cannot be removed with this level of energy input, it would be best to leave the stud in place and cover it with a sealed sleeve during refueling. If there is adequate engagement length left after providing for complete removal of five threads by the impact wrench plus any previously existing degradation, the stud can be retensioned after refueling. If there is not adequate engagement length left, then it will be necessary to cut the stud out. If there is no time to cut the stud out, it is technically acceptable to leave the stud untensioned until the next outage provided appropriate precautions are taken.

This recommendation has been met. Slugging wrenches are not used to remove studs. Stud 18, which became stuck in 1996, has been left in place and is covered during refueling to protect it from the borated water in the refueling pool. A slugging wrench was not used to attempt to remove it, so no threads were damaged. It has adequate thread engagement to allow it to be tensioned during operation.

Recommendation 4. Degraded threads should be assessed using the acceptance criteria in the report. If damage only slightly exceeds the acceptance criteria, it may be possible to continue operating the plant by limiting hydrotesting or heat-up rates.

The criteria in the 1989 evaluation were used in Refuel 3 to evaluate the stud hole threads. The condition of the threads has not required limiting hydrotesting or heat-up rates.

Recommendation 5. An inspection report describing the damage, and mapping the damage if appropriate, should accompany each evaluation report. The evaluation report should include the video tape inspection records.

The damage to the stud hole threads were described in Nonconforming Material Reports (NMRs), as required by Callaway procedures, and included diagrams mapping the damage. Video tapes were not included as part of the NMRs because video tapes were not allowed as QA records.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI B2.1.10-2a

NUREG 1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," aging management program (AMP) XI.M20, "Detection of Aging Effects," states that the inspection scope and testing frequencies are in accordance with the applicant's docketed response to Generic Letter (GL) 89-13. Callaway Plant, Unit 1's (Callaway's), response to GL 89-13, dated January 29, 1990, states that selected sections of essential service water (ESW) system piping are inspected each refueling outage (RFO) for corrosion, erosion, and biofouling, and that any piping with localized damage will be retested and trended each RFO. NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (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 sample size. In RAI B2.1.10-2, the staff requested the criteria used to select locations in the ESW system inspected by the Open-Cycle Cooling Water System Program and the number of these locations.

The response to RAI B2.1.10-2, dated August 21, 2012, provided a description of the criteria used to select the sections of piping that are inspected each outage. However, in addressing the sample size, the response only stated that the number of selected locations varies from outage to outage and did not provide any specific information. The staff noted that the response to RAI B2.1.10-6 states Callaway inspected 2000 feet of above-ground, carbon-steel ESW piping using low frequency electromagnetic testing (LFET) in spring 2008, inspected 300 feet of ESP piping during each RFO in fall 2008, spring 2010 and fall 2011, and planned to inspect 200 feet of ESW piping in the spring 2013 RFO.

Issue:

Although the RAI responses provided the length of piping inspected with LFET, they do not provide the context relative to the overall amount of ESW piping. It is unclear to the staff whether the reduced inspection scope is a consequence of a lesser amount of susceptible piping due to ongoing replacement activities or some other cause. In addition, the RAI response did not address the number of locations that are monitored each RFO due to previously identified localized damage, as stated in the response to GL 89-13. It is unclear to the staff whether there are any locations currently being monitored, whether the number is increasing or decreasing, and if the number is changing, whether the changes are due to specific causes.

Request:

Regarding the amount of ESW piping being inspected each RFO using LFET, provide a justification for the apparent reduction in the amount of piping inspected form 2000 feet in 2008, 300 feet in 2010 and 2011, and 200 feet in 2013, including an approximate percentage of the system that is inspected. In addition, provide the current number of locations where localized damage is being monitored each outage, and if applicable discuss the trend in this number.

Callaway Response

In 2007/2008, Callaway conducted a three phase project to inspect above-ground carbon steel ESW piping. There is approximately 3800 feet of 6" diameter or greater above-ground carbon steel piping in the ESW system. The first phase of inspections began in the Fall of 2007 in which

approximately 220 feet of high risk lines were inspected using LFET. This represents approximately 6% of the total amount of above-ground carbon steel ESW piping. The second phase of the inspections occurred in the Spring of 2008 and covered approximately 2000 feet of ESW piping. This represents approximately 53% of the total amount of above-ground ESW piping. This phase of the program took over a month to complete and should not be seen as a normal inspection size. Due to the satisfactory results of the phase 1 and 2 inspections, the scope for phase 3 (Fall 2008) was reduced to roughly 300 feet. Since the completion of this project, ESW piping continues to be inspected each refueling outage. Approximately 310 feet of above-ground carbon steel piping was inspected during the Spring 2010 refueling outage, and 170 feet was inspected during the Fall 2011 refueling outage. Consistent with these inspection sizes, approximately 200 feet (approximately 5% of the total) is planned for the next refueling outage in the Spring of 2013.

The number of areas that are currently planned for localized pitting monitoring during the Spring 2013 refueling outage is 11. This sample size is consistent with the inspection results and the extent of replacements being performed in the ESW system. As pipe sections have been replaced, monitoring of localized pits in that location was cancelled.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI B2.1.10-3a

Background:

The GALL Report AMP XI.M20 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. Since coatings may not have been applied at the time, and Callaway's response to GL 89-13 did not address protective coatings, RAI B2.1.10-3 requested confirmation that the program includes periodic inspections to detect coating degradation and verification of the coating inspection frequencies. The RAI response stated that the 5- and 6-year inspections frequencies provide reasonable assurance that the program will effectively identify coating failure and aging so that corrective actions can be initiated, because "the total amount of internal coating is small and there has been no recent documented operating experience of internal coating failures."

The staff acknowledges that Callaway's recent operating experience has not identified internal coating failure; however, historically, Callaway Action Requests (CARs) 200102332, 200207034, 200407638, 200508460 and 200711241, address varying levels of coating degradation in the ESW system. In addition, the staff notes recent industry operating experience at Seabrook, which identified the use of internal linings beyond their established service life as a contributing cause of lining failure. In addition, the staff notes that lining or coating service life can be 20 years, as stated in NRC Inspection Manual Part 9900, "Maintenance - Filled Organic Coatings Used in Maintenance of Safety Related Equipment."

Issue:

For coatings installed in the ESW system, for which failure could adversely affect the safety function of downstream components, it is unclear to the staff what the service life, established as part of the initial installation, is for each coating and whether this aspect is being tracked. The staff notes that industry guidance documents, such as Electric Power Research Institute (EPRI) 1008282, "Life Cycle Management for Service Water Systems," state that all coatings degrade over time, and that when a coating degrades, ideally, it will fail in small pieces rather than in large sheets. It is unclear if periodic inspections include activities other than visual inspections to ensure that loss of adhesion is not occurring to limit the size of the failed coating pieces. In addition, with respect to the coating inspections being performed, industry guidance documents such as EPRI 1019157, "Guideline on Safety-Related Coatings" recommend that personnel performing inspections of the coatings meet certain qualifications. In its review of program basis documents, the staff did not identify information concerning qualifications of personnel that perform coating inspections.

Request:

a) For each location where coating failure may adversely affect the safety function of downstream components, provide the service life of the coating as established by the coating vendor or by other means. For locations where the coating may be approaching the end of its service life, describe program activities, other than visual inspections, that ensure downstream components are not adversely affected due to adhesion degradation of coating.

b) Describe the qualifications requirements of personnel performing the coating inspections for this AMP and if they are inconsistent with industry guidance, provide the bases for any inconsistencies.

Callaway Response

a) Callaway uses Chesterton 810 and 855 coatings on the internals of safety-related essential service water heat exchangers and strainers. Because "service life" is dependent on variables associated with the type of service a coating experiences, Callaway does not rely on estimated service life to manage internal coatings. Rather, intervals for monitoring the condition of the internal coatings begin immediately after coatings are applied. Coating inspections of the heat exchangers occur with a minimum frequency of every five years. Coating inspections of the essential service water strainers occur with a minimum frequency of every six years, coinciding with major essential service water system outages.

   Callaway performs visual inspections as the primary method of monitoring the condition of internal coatings of the essential service water strainers and heat exchangers. EPRI Technical Report (TR) 1019157 "Guideline on Nuclear Safety-Related Coatings, Revision 2" Section 8.4 states, "Coatings degrade in ways that are easily detected visually and prior to detachment." Section 8.5 states, "The most effective way to conduct a thorough coating condition assessment and detect coating degradation is through visual inspection." Visual inspections focus on indications of blistering, cracking, flaking, peeling, delamination or rusting. According to EPRI TR 1019157 Section 8.6, "In response to the NRC questions (regarding the validity of using only visual inspections), EPRI commissioned a task in 2006 titled Evaluation of Coating Failures and the Potential Influence of Aging/Adhesion Data Collection Procedure. In this task, industry experts traveled to four U.S. nuclear power plants and performed visual inspection of containment safety-related coatings and performed pull-off adhesion testing at coated areas that exhibited acceptable visual conditions. In all cases, the areas that exhibited acceptable visual conditions also had measured pull-off adhesion strengths of 200 psig (13.79 Mpa gauge) or greater (the original design requirement required by ANSI N5.12). These data are referenced by the NRC in NRC Staff Review Guidance Regarding Generic Letter 2004-02, Closure in the Area of Coatings Evaluation (March 2008)." While this testing was performed on Service Level I coatings, the results clearly showed that acceptable visual inspections corresponded with good coatings.

   Any indications of degradation of coatings are documented using the Callaway corrective action program, and evaluated for repair, replacement, or continued service through the next inspection interval. Corrective actions, extent of condition reviews, and evaluations for continued service are performed consistent with ASTM D7167 "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant." ASTM D7167 states that physical tests, such as dry-film thickness and pull-off adhesion testing, may be performed as part of an evaluation when indications of a degraded condition are discovered during routine visual inspections. These physical tests may be performed when directed by the evaluator.

   Therefore, consistent with EPRI recommendations, Callaway will continue to perform visual inspections as the primary method to monitor the condition of internal coatings in the essential service water system. This will provide reasonable assurance that downstream components in the essential service water system are not adversely affected due to adhesion degradation of coatings.

b) Coating inspections will be performed by a qualified Nuclear Coating Specialist (NCS) as defined by ASTM D7108 or by Coatings Surveillance Personnel (CSP) under the technical direction of the NCS.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI B2.1.10-5a

Background:

GALL Report AMP XI.M20, "acceptance criteria" program element states that inspected components should exhibit adequate design margin regarding design dimensions. In RAI B2.1.10-5, the staff noted that an engineering evaluation apparently justified the structural integrity of the degraded flange by citing an incorrect manufacturing tolerance and requested Callaway to provide the acceptance criteria to be used where flange thicknesses have been adversely affected. The response to RAI B2.1.10-5 stated that the 12.5 percent manufacturing tolerance cited in CAR 200703680 did not apply to flange thickness and provided the quality control acceptance criteria for seating surface degradation with instructions that any flange face defect exceeding the criteria would require a CAR which would be evaluated by the engineering department.

Issue:

The staff noted that the flange degradation acceptance criteria pertained to the flange surface area, which would affect leakage, but it did not address loss of flange thickness, which would affect structural integrity. In addition, the staff noted the CAR 200703680 addressed a condition requiring an engineering evaluation and the engineering evaluation apparently justified the structural integrity of the flange based on tolerances that did not apply to flanges. It was not clear to the staff whether the use of the incorrect tolerance was captured in the corrective action program to determine if application of the 12.5 percent manufacturing tolerance for pipe wall thickness occurred in other circumstances.

Request:

For structural integrity evaluations that will be performed during the period of extended operation, where flange thickness has been adversely affected due to corrosion or other aging mechanisms, provide the acceptance criteria to ensure that the component intended function(s) will be maintained consistent with all current licensing basis (CLB) design conditions. Provide assurance that the use of the 12.5 percent pipe wall manufacturing tolerance will not be applied to engineering evaluations of flange structural integrity during the period of extended operation.

Callaway Response

It is not Callaway practice to evaluate acceptance of degraded flanges based on manufacturer's tolerances. The 12.5% manufacturer's tolerance applies to pipe wall thickness as well as flange hub thickness at the welding end. Flange thickness and tolerances provided in the manufacturer's standards are applicable to manufacturing practices.

CAR 200703680 was written because flange surface corrosion was observed that impacted approximately 50% of an essential service water flange face. The allowable level of surface degradation on the flange face is 50% measured transversely (i.e., between the inside and outside radius of the flange at the most severely affected location), per the Callaway Operational Quality Control Manual (OQCM). Should the surface degradation on the flange face exceed this 50% limit, then corrective action such as coating, weld build-up, or flange replacement, is taken. For the condition described in CAR 200703680, corrective action was taken to apply a coating. The affected piping has since been replaced with stainless steel.

In the evaluation of CAR 200703680, the engineer recommended coating as the corrective action. The engineer also made a statement that the structural integrity of the flange is not adversely impacted by the observed corrosion. To validate the statement, the engineer compared the observed corrosion to the original information from the manufacturer, which stated that the pipe can tolerate a 12.5% wall thickness reduction. As the observed flange degradation was less than that, it was a reasonable qualitative conclusion that structural integrity was not challenged. If there was reason to believe that structural integrity was challenged, then the application of a coating would not have been an appropriate corrective action and flange repair or replacement would have been pursued. A search of Callaway operating experience revealed no instances where degraded flange condition challenged structural integrity.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI B2.1.10-6a

Background:

RAI B2.1.10-6 addressed several operating experience issues including a discussion in CAR 200703627 relating to the correlation between ESW system leaks and system testing for engineered safety feature actuation system (ESFAS) initiation. The CAR stated that during test procedures ESW components above elevation 2037 will naturally drain while the pump is secured, and that actions have not been effective in preventing ESW system hydraulic transients resulting from the testing. The RAI asked Callaway to confirm that transient loads, which occur during ESFAS testing and a loss of offsite power event, have been included in the structural integrity calculations for the system.

The response to this portion of the RAI stated that numerous plant modifications and plant procedures have been made over the years to address the water hammer which will occur when the ESW pump starts, following a loss of offsite power. Although not specifically stated, these changes apparently have not prevented this hydraulic transient from occurring. The response also stated:

> Calculations of minimum wall thickness are not required to consider the transient pressure caused by a water hammer event. The Callaway pipe design standard establishes how design pressures are defined and allows pressure/temperature excursions in excess of design for short periods of times.

Issue:

The ASME Boiler and Pressure Vessel Code, provides the requirements for establishing design, service and test loads and limits. Section NCA-2142.1, "Design Loadings," states that the design pressure shall include allowances for pressure surges. In addition, although Callaway's pipe design standard may allow pressure excursions in excess of design for short periods of time, the ASME Code limits the stresses that result from these pressure excursions depending on how these loads are considered with respect to service level. It is unclear to the staff why hydraulic transient loads due to design basis events do not need to be included in the structural integrity evaluations of the ESW system for ongoing age-related degradation during the period of extended operation.

Request:

Provide documentation demonstrating that activities will continue to be conducted in accordance with the CLB for structural integrity evaluations of the ESW system due to age-related degradation. Specifically, address why the exclusion of pressure surges, caused by hydraulic transient loads during ESFAS testing and loss of offsite power events, in structural integrity evaluations meets the CLB.

Callaway Response

When determining minimum wall thickness for piping, ASME code equations are used. The pressure equation uses the design pressure of the system as defined by the ASME code. Callaway adheres to the requirement that ASME Section III, Class 2 and 3 "Design Pressure"

shall be based on the most severe condition of coincident pressure and temperature and shall include a suitable margin above the pressure at which the system will normally be operated to allow for probable pressure surges (due to system upset conditions) up to the setting of pressure relieving devices (if required). Upset Conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power. Upset Conditions include any abnormal incidents not resulting in a forced outage and also forced outages for which the corrective action does not include any repair of mechanical damage. The estimated duration of an Upset Condition shall be considered to be 30 minutes unless otherwise stated. The stress limits set by the Design Pressure and Temperature shall not be exceeded by more than 1.5 times during emergency system conditions and 2.0 times during faulted system conditions. (Reference MS-01, Piping Class Summary, Rev. 96) In the early 1990s, when it was recognized that procedural guidelines alone would not prevent water hammer from occurring during a LOOP event, pipe stress evaluations were performed to include water hammer as an Upset Condition. The pipe stress evaluations that were performed to include water hammer as an Upset Condition include structural effects of the water hammer on the system. The structural interactions of the event are accounted for by factoring the pipe stress results in the code equations to determine the minimum wall thickness.

As noted in the response to RAI B2.1.10-6, to address susceptibility of the ESW system to water hammer during LOOP and ESFAS testing, Callaway installed multiple modifications and implemented procedure changes. Most recently, 30" check valves were installed on the ESW system between the service water cross connect valves and the 2000-ft elevation to prevent the supply headers from draining during ESFAS testing or an actual LOOP event, and valves EFHV0037 and EFHV0038 (ESW isolation valves to the UHS Cooling Tower) were re-sequenced to open upon ESW pump start instead of at time zero. These modifications were installed during Refueling Outage RF18 in the fall of 2011 as discretionary enhancements to bolster the system's defense in depth against potential water hammer occurrences.

Since these changes were implemented, there have been no recurrences of water hammer in conjunction with ESFAS testing nor has Callaway experienced a LOOP event. An evaluation performed prior to these changes noted that a water hammer event predicted to occur from a true ESFAS actuation would not prevent ESW or components served by ESW from performing their functions. Since these changes were implemented, one water hammer event that was not related to ESFAS testing or a LOOP event has occurred during dynamic fill activities. This event took place during Refueling Outage 18 in the fall of 2011, and was attributed to valve EFHV0038 stopping mid position due to high torque. During the time it took for Operations personnel to investigate the unexpected valve response, this portion of the ESW system self-drained and was no longer water solid. This condition was not identified prior to the dynamic fill activities. The high torque condition experienced by valve EFHV0038 was an isolated occurrence.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

Amendment 16, LRA Updates

Enclosure 2 Summary Table

Affected LRA Section	LRA Page
Table 3.6-1	3.6-19

Callaway Plant
License Renewal Application
Amendment 16

Changed the wording for fuse holders to conform with Table 3.6-1 of NUREG-1800.

Table 3.6-1, Summary of Aging Management Programs in Chapter VI of NUREG-1801 for Electrical Components (Page 3.6-19), is revised as follows (new text show underlined and deleted next shown in strikethrough):

Table 3.6-1 Summary of Aging Management Programs in Chapter VI of NUREG-1801 for Electrical Components

Item Number	Component Type	Aging Effect / Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1.016	Fuse holders (not part of active equipment): metallic clamps composed of Various metals used for electrical connections exposed to Air – indoor, uncontrolled	Increased resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply); fatigue due to ohmic heating, thermal cycling, electrical transients	Fuse Holders	No	Not applicable. All fuse holders including fuse holders for electrical penetrations that ~~utilizing~~ utilize metallic clamps are within the scope of license renewal ~~are~~ as part of an active device and do not require aging management.
3.6.1.017	Fuse holders (not part of active equipment): metallic clamps composed of Various metals used for electrical connections exposed to Air – indoor, controlled or uncontrolled	Increased resistance of connection due to fatigue caused by frequent manipulation or vibration	Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms or fatigue caused by frequent manipulation or vibration	No	Not applicable. All fuse holders including fuse holders for electrical penetrations that ~~utilizing~~ utilize metallic clamps are within the scope of license renewal ~~are~~ as part of an active device and do not require aging management.

CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION

Supplement to RAI B2.1.29-1

RAI B2.1.29-1

Background:

LRA Section B2.1.29 states that the 10 CFR Part 50 Appendix J AMP has implemented Option B for the 10 CFR Part 50 Appendix J leak rate tests (LRTs) and is consistent with the GALL Report, Revision 2, AMP XI.S4. The LRA further states that the 10 CFR Part 50 Appendix J program ensures that the structural integrity of the containment will be maintained to withstand the maximum calculated pressure in the event of a loss of coolant accident (LOCA). Measure of leakage rates across pressure containing or leakage limiting boundaries and inspections as implemented through the program provide for the detection of age-related pressure boundary degradation for the period of extended operation. Per the "scope of program," program element of the GALL Report AMP XI.S4, all containment boundary pressure-retaining components are subject to leak rate testing and inspections.

Issue:

Callaway Plant Unit 1 FSAR-SP, and "ESP-SM-01001, Containment Leakage Rate Testing Program," procedure indicate that a number of penetrations are excluded from local leak rate tests (LLRTs). In addition, the audited plant's operating experience database indicated that the applicant has substituted LLRTs in lieu of VT-2 inspections. It is not clear how the applicant will manage the aging effects for any components that are not included in its "scope of program," program element.

Request:

For those components (valves, penetrations, and other components) that have been excluded from the 10 CFR Part 50 Appendix J program, identify how aging effects will be managed during the period of extended operation. Indicate which AMPs will be used to manage the aging effects for each of the exempted/excluded components, or justify why an AMP is not necessary for the period of extended operation.

Callaway Response

Pressure-retaining components whose failure (loss of leak-tightness) could contribute to an increase in the overall integrated leakage rate of the containment system are subjected to Type A Integrated Leak Rate Testing (ILRT).

Containment penetrations that are provided with double seal closures and connections to allow for pressurization between the seals are subjected to Type B Local Leak Rate Testing (LLRT). FSAR-SP, Section 6.2.6.2, Containment Penetration Leakage Rate Tests (Type B Tests), specifies that Type B tests are performed on the following containment penetrations:

a. Personnel access hatches
b. Equipment hatch
c. Fuel transfer tube
d. Electrical penetrations
e. Penetration 34, containment pressurization line
f. Penetration 51, ILRT pressurization pressure sensing line
g. Penetrations 36, 50 and 68, maintenance spare air and electrical access penetrations

Containment isolation valves that meet the following criteria are subjected to Type C LLRT:

a. The penetrating system provides a direct connection between the inside and outside atmospheres of the containment under normal operation.

b. The system is isolated by containment isolation valves that close automatically to effect containment isolation in response to a CIS signal.

c. The system is not an engineered safety feature system consisting of a closed piping system outside of the containment.

As stated in FSAR-SP, Section 6.2.6.1.2, ILRT Test Method, "For penetrations that are exempt from Type B or C tests, the leakage testing requirement of Appendix J is accomplished by the Type A test." Therefore, the scope of the 10 CFR Part 50 Appendix J program includes all pressure-retaining components of the containment structure, and all of these components will be age-managed under this program during the period of extended operation.

In addition to the leak rate testing, aging management for all containment pressure-retaining components is provided within the containment inservice inspection program. Prior to each Type A test, and at least once every three years, the ASME Section XI, Subsection IWE program performs a general visual examination of 100% of the accessible surfaces of the steel liner plate, penetrations, integral attachments, connection welds, and bolting. Any aging effects identified during these examinations will be managed in accordance with the program described in LRA Appendix B2.1.26, ASME Section XI, Subsection IWE.

Containment isolation valves that do not meet the above criteria for Type C testing are listed in RAI B2.1.29-1 Table 1. In addition to Type A leakage testing, these valves are subject to the aging management programs that are applicable to their respective systems, based on their materials and environments. All of these valves are constructed of stainless steel and are exposed to an external environment of either plant indoor air or borated water leakage, neither of which produces any aging effect for stainless steel. Therefore, no aging management is required for the external surfaces. The internal environments for these valves do have aging effects associated with stainless steel and do require aging management. The applicable aging management programs are identified in RAI B2.1.29-1 Table 1.

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-79	EJ 8708A	RHR Pump A Suction Relief	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-52	EJ 8708B	RHR Pump B Suction Relief	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-21	EJ 8841A	RHR Pump Disch to RCS hot Leg 2	A	Table 3.2.2-6	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-21	EJ 8841B	RHR Pump Disch to RCS Hot Leg 3	A	Table 3.2.2-6	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-21	EJ HCV-8825	RHR to SI Test Line Iso Valve	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-82	EJ HCV-8890A	RHR A to SI Pumps Test Line Iso Valve	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-27	EJ HCV-8890B	RHR B to SI Pumps Test Line Iso Valve	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-79	EJ HV-8701A	RCS Hot Leg 1 to RHR Pump A Suction	A	Table 3.2.2-6	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-52	EJ HV-8701B	RCS Hot Leg 4 to RHR Pump B Suction	A	Table 3.2.2-6	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-82	EJ HV-8809A	RHR Pump A Cold Leg Injection Iso Valve	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-27	EJ HV-8809B	RHR Pump B Cold Leg Injection Iso Valve	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-15	EJ HV-8811A	CTMT Recirc Sump to RHR Pump A Suction	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-14	EJ HV-8811B	CTMT Recirc Sump to RHR Pump B Suction	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-21	EJ HV-8840	RCS Hot Leg Recirc Iso Valve	A	Table 3.2.2-6	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-88	EM 8815	Boron Injection Header to RCS Cold Leg Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-88	EM HV-8801A	Boron Injection Header to RCS Cold Legs	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-88	EM HV-8801B	Boron Injection Header to RCS Cold Legs	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-87	EM HV-8802A	SI Pump A Disch Hot Leg Iso Valve	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-48	EM HV-8802B	SI Pump B Disch Hot Leg Iso Valve	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-49	EM HV-8823	SI/Accumulator Injection Test Line Iso Valve	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-48	EM HV-8824	Safety Injection Pump B Test Line Iso Valve	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-49	EM HV-8835	SI Pumps Disch to Cold Legs Iso Valve	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-88	EM HV-8843	Boron injection Header Test Line Iso	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-87	EM HV-8881	Safety Injection Pump Test Line Iso Valve	A	Table 3.2.2-5	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-87	EM V-001	SI Pump Hot Leg 2 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-87	EM V-002	SI Pump Hot Leg 3 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-48	EM V-003	SI Pump Hot Leg 1 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-48	EM V-004	SI Pump Hot Leg 4 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-16	EN HV-01	CTMT Recirc Sump to CTMT Spray Pump A Iso	A	Table 3.2.2-1	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-13	EN HV-07	CTMT Recirc Sump to CTMT Spray Pump B Iso	A	Table 3.2.2-1	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-66	EN HV-12	CTMT Spray Pump B Discharge Iso Valve	A	Table 3.2.2-1	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-89	EN HV-6	CTMT Spray Pump A Discharge Iso Valve	A	Table 3.2.2-1	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-89	EN V-013	CTMT Spray Pump A to CTMT Spray Nozzles	A	Table 3.2.2-1	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-66	EN V-017	CTMT Spray Pump B to CTMT Spray Nozzles	A	Table 3.2.2-1	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-82	EP 8818A	RHR Pump to Cold Leg 1 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-82	EP 8818B	RHR Pump to Cold Leg 2 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-27	EP 8818C	RHR Pump to Cold Leg 3 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-27	EP 8818D	RHR Pump to Cold Leg 4 Injection	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-49	EP V-0010	SI Pumps Disch to Cold Leg 1	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-49	EP V-0020	SI Pump Disch to Cold Leg 2	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-49	EP V-0030	SI Pump Disch to Cold Leg 3	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-49	EP V-0040	SI Pump Disch to Cold Leg 4	A	Table 3.2.2-5	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components and Water Chemistry (B2.1.2)
P-101	GS HV-12	Hydrogen Analyzer A Inlet Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-101	GS HV-13	Hydrogen Analyzer A Inlet Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-101	GS HV-14	Hydrogen Analyzer A Inlet Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-97	GS HV-17	Hydrogen Analyzer A Disch Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-97	GS HV-18	Hydrogen Analyzer A Disch Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-99	GS HV-3*	Hydrogen Analyzer B Inlet Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-101	GS HV-31	Sample Line to CTMT Atmos Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-101	GS HV-32	Sample Line to CTMT Atmos Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-97	GS HV-33	Sample Return From CTMT Atmos. Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-97	GS HV-34	Sample Return From CTMT Atmos. Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-99	GS HV-36	Sample Line to CTMT Atmos Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-99	GS HV-37	Sample Line to CTMT Atmos Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)

RAI B2.1.29-1 Table 1

PENETRATION	VALVE NUMBER	FUNCTION	TYPE TEST	LRA Table	AMP
P-56	GS HV-38	Sample Return from CTMT Atmos Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-56	GS HV-39	Sample Return from CTMT Atmos Monitor	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-99	GS HV-4	Hydrogen Analyzer B Inlet Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-99	GS HV-5	Hydrogen Analyzer B Inlet Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-56	GS HV-8	Hydrogen Analyzer B Disch Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-56	GS HV-9	Hydrogen Analyzer B Disch Iso	A,C	Table 3.2.2-3	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.23)
P-64	SJ HV-128	PZR/RCS Liquid Sample Inner CTMT Iso	A,C	Table 3.3.2-9	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-64	SJ HV-129	PZR/RCS Liquid Sample Outer CTMT Iso	A,C	Table 3.3.2-9	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)
P-64	SJ HV-130	PZR/RCS Liquid Sample Outer CTMT Iso Valve	A,C	Table 3.3.2-9	Water Chemistry (B2.1.2) and One-Time Inspection (B2.1.18)