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

September 24, 2015

Mr. Edward D. Halpin
Senior Vice President and Chief
Nuclear Officer
Pacific Gas and Electric Company
P.O. Box 56
Mail Code 104/6
Avila Beach, CA 93424

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DIABLO CANYON POWER PLANT, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – SET 38 (TAC NOS. ME2896 AND ME2897)

Dear Mr. Halpin:

By letter dated November 23, 2009, Pacific Gas & Electric Company (PG&E) submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew the operating licenses DPR-80 and DPR-82 for Diablo Canyon Power Plant, Units 1 and 2, respectively. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review.

These requests for additional information were discussed with Mr. Terry Grebel, 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 at 301-415-1427 or by e-mail at richard.plasse@nrc.gov.

Sincerely,

/RA by Jeff Mitchell for/

Richard Plasse, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-275 and 50-323

Enclosure:
As stated

cc: Listserv

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ADAMS Accession Number: **ML15217A481** *Concurred via e-mail

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DATE	8/ 19 /15	9/ 22 /15	9/ 23 /15	9/ 24 /15

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Letter to E. Halpin from R. Plasse dated September 24, 2015

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DIABLO CANYON POWER PLANT, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – SET 38 (TAC NOS. ME2896 AND ME2897)

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LICENSE RENEWAL APPLICATION
DIABLO CANYON POWER PLANT, UNITS 1 AND 2
REQUESTS FOR ADDITIONAL INFORMATION – SET 38
(TAC NOS. ME2896 AND ME2897)

RAI 3.0.3.2.6-1

Background:

The annual update letter dated December 22, 2014, Enclosure 1, Attachment 7C, Exception 2, states an exception to conducting tests in accordance with NFPA 25 Section 6.3.1 "Flow Tests". The proposed alternative testing includes: (a) testing three fire water hose stations in accordance with NFPA 25 Section 6.3.1 every 5 years; (b) conducting a functional test on all of the in-scope hose stations every 3 years; and (c) opening a flushing connection or drain line at the end of branch lines in sprinkler piping during flow alarm testing in the auxiliary building and intake structure every 18 months. The proposed functional test includes "the absence of any indication of obstruction or other undue restriction of water flow," whereas testing for NFPA Section 6.3.1 verifies that "the water supply still provides the design pressure at the required flow" in the hydraulically most remote hose connection of each zone.

Issue:

It is not clear to the staff that the alternatives consisting of conducting a functional test on all of the in-scope hose stations every 3 years and opening a flushing connection or drain valve at the end of branch lines in sprinkler piping in the auxiliary building and intake structure include recording sufficient quantitative data to identify degraded performance or trends in the fire water system. In addition, there is no mention of opening drain connections for standpipe and sprinkler systems in the turbine building and radwaste storage facility. It is also not clear that testing three fire water hose stations in accordance with NFPA 25 Section 6.3.1 will provide assurance comparable to performing the test for each zone of the entire fire water system.

Request:

State the basis for why: (a) the alternative testing conducted in lieu of NFPA 25 Section 6.3.1 provides sufficient quantifiable data that is capable of being trended to detect degradation in the fire water system; and (b) testing three fire water hose stations in accordance with NFPA 25 Section 6.3.1 is sufficiently representative of the entire fire water system.

RAI 3.0.3.2.6-2

Background:

Annual update letter, dated December 22, 2014, Attachment 7C, Exception 5 for the Fire Water System program states that steel tanks will be inspected in accordance with NFPA-25, Section 9.2.6. However, it takes an exception to Section 9.2.6.4 by stating that any degradation will be entered into the corrective action program and an engineering evaluation will be performed to determine whether further actions are required. The update letter also states that the follow-up actions will be in accordance with either NFPA-25, Section 9.2.7 or Section 4.6.

NFPA-25, Section 9.2.6.4 states that tanks exhibiting signs of pitting, corrosion, or coating failure shall be tested in accordance with Section 9.2.7. NFPA-25, Section 9.2.7 states, "Where a drained interior inspection of a steel tank is required by 9.2.6.4, the following tests shall be conducted," then specifies six specific tests. NFPA-25, Section 4.6, "Performance-Based Programs," states that it provides an alternative means to comply with Section 4.5.2, "Frequency of Tests." It continues by stating that since its inception, NFPA-25 has included a provision allowing an alternative method of performing inspection, testing and maintenance, "but this provision does not detail exactly how such an alternative method should be implemented."

Issue:

It is unclear to the staff what criteria will be used to invoke the six tests specified in NFPA-25, Section 9.2.7 when degradation is exhibited on the interior of steel tanks, in accordance with Section 9.2.6.4. In addition, since Section 4.6 does not provide details on alternative inspection methods, it is unclear to the staff what alternative tests are being proposed to be conducted in lieu of those specified in Section 9.2.7.

Request:

State the basis and justify why entering degradation of the interior surface of steel tanks into the corrective action program will be sufficient to manage the effects of aging during the PEO when NFPA-25 states that testing shall be completed when degradation is noted.

RAI 3.0.3.2.6-3

Background:

Annual update letter dated December 22, 2014, Attachment 7C, Exception 6 for the Fire Water System program, states that inspection frequencies may be adjusted based on testing and inspection results, in accordance with NFPA-25, Section 4.6.

Issue:

Although NFPA-25, Section 4.6, "Performance-Based Programs," allows adjustments to inspection frequencies, as noted in Section A.4.6, a performance-based program requires that a maximum allowable failure rate be established and approved by the authority having jurisdiction in advance of implementation. In addition, a formal process for reviewing failure rates and making adjustments to test frequencies must be documented and have concurrence from the authority having jurisdiction prior to any changes to the test program. Furthermore, adjusted frequencies must be technically defensible and supported by evidence of reliability, and data collection and retention must be established so that data used to alter frequencies are representative, statistically valid, and evaluated against firm criteria. Without the details relating to the proposed maximum allowable failure rate and the formal process for reviewing and making adjustments, the staff has insufficient information to evaluate this exception.

Request:

Provide details, as discussed in NFPA-25, Section 4.6, “Performance-Based Programs,” for all aspects related to adjusting inspection or test frequencies based on past data. Alternatively, propose exceptions to specific inspection frequencies and provide the bases to justify the change to these frequencies.

RAI 3.0.3.2.6-4

Background:

The annual update letter dated December 22, 2014, revises LRA Section A1.13. The revised LRA Section A1.13 does not address whether the fire water system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

SRP-LR Table 3.0-1, as modified by LR-ISG-2012-02 states that the water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

Issue:

LRA Section A1.13 is not consistent with SRP-LR Table 3.0-1, as modified by LR-ISG-2012-02 and a basis was not provided.

Request:

State the basis for not including a statement that the fire water system will be normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated in the licensing basis for the period of extended operation.

RAI 3.1.2.2.3.1-1

Background:

By letter dated December 23, 2013 (PG&E Letter DCL-13-119), the applicant submitted its 10 CFR 54.21(b) annual update to its LRA. In this annual update, the applicant deleted a paragraph of LRA further evaluation Section 3.1.2.2.3.1, “Loss of Fracture Toughness due to Neutron Irradiation Embrittlement TLAA.” This paragraph discussed the applicant’s pressurized thermal shock implementation for the Unit 1 reactor vessel. The applicant has also submitted annual updates to its LRA by letters dated December 20, 2011 (PG&E Letter DCL-12-124), and December 21, 2011 (PG&E Letter DCL-11-136).

Issue:

The staff is unclear why the applicant deleted this paragraph of the further evaluation Section 3.1.2.2.3.1. In its annual updates to the LRA, the applicant has provided updated time limited

aging analyses (TLAAs) associated with its neutron fluence pressurized thermal shock and upper shelf energy analyses for Units 1 and 2.

Request:

Justify why this paragraph in LRA Section 3.1.2.2.3.1 was deleted from the LRA. Otherwise, clarify how further evaluation of loss of fracture toughness due to neutron embrittlement, is addressed regarding the updated Pressurized Thermal Shock and Upper Shelf Energy TLAAs for Diablo Canyon Units 1 and 2.

RAI 3.4.2.3.1-1

Background:

As amended by letter dated February 25, 2015, LRA Table 3.4.2-1 states that internally coated/lined carbon steel piping, valves, and tanks exposed to sulfuric acid will be managed for loss of coating integrity by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR line items cite generic note H. LRA Table 3.4.2-1 does not describe the sulfuric acid environment or state the material of the coating/lining.

GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," defines the scope of the program as "[p]iping, piping components, heat exchangers, and tanks exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil."

Issue:

GALL Report AMP XI.M42 does not identify sulfuric acid or any other acidic/caustic chemical environments as within the scope of the program. The periodicity of inspections stated in Table 4a of AMP XI.M42 is based on the environments stated in the "scope of program" program element (e.g., treated water, raw water). The staff lacks sufficient information to evaluate the applicant's claim that internally coated/lined carbon steel exposed to sulfuric acid can be managed through its Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program given that information on the coating material and environment was not provided.

Request:

1. Describe the operational environment of internally coated/lined carbon steel piping, valves, and tanks exposed to sulfuric acid in the Turbine Steam Supply System, identifying at a minimum: temperature, sulfuric acid concentration, and flow rate.

2. Identify the coating/lining being used on internally coated/lined carbon steel piping, valves, and tanks exposed to sulfuric acid in the Turbine Steam Supply System.

3. Justify why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program inspection intervals are adequate such that the intended function will be maintained.

RAI 3.4.2.3.1-2

Background:

As amended by letter dated February 25, 2015, LRA Table 3.4.2-1 states that loss of coating integrity for internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide will be managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR line items cite generic note H. LRA Table 3.4.2-1 does not describe the sodium hydroxide environment or state the material of the coating/lining.

GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," defines the scope of the program as "[p]iping, piping components, heat exchangers, and tanks exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil."

Issue:

GALL Report AMP XI.M42 does not identify sodium hydroxide or any other acidic/caustic chemical environments as within the scope of the program. The periodicity of inspections stated in Table 4a, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers," of AMP XI.M42 is based on the environments stated in the "scope of program" program element (e.g., treated water, raw water). The staff lacks sufficient information to evaluate the claim that loss of coating integrity for internally coated/lined carbon steel exposed to sodium hydroxide can be managed through the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program given that information on the coating material and environment was not provided.

Request:

1. Describe the operational environment of internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide in the turbine steam supply system, identifying at a minimum: temperature and sodium hydroxide concentration.

2. Identify the coating/lining being used on internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide in the turbine steam supply system.

3. Justify why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program inspection intervals are adequate such that the intended function of the internally coated/lined carbon steel piping, valves, and tanks exposed to sodium hydroxide will be maintained.

RAI 3.4.2.3.1-3

Background:

As amended by letter dated February 25, 2015, LRA Tables 3.4.2-1 and 3.4.2-4 state that loss of coating integrity for internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water will be managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR line items cite generic note H. LRA Table 3.0-1, "Mechanical Environments," defines secondary water as the following GALL Report environments: steam, treated water, treated water >60 °C, secondary feedwater/steam, and secondary feedwater.

GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," defines the scope of the program as "[p]iping, piping components, heat exchangers, and tanks exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil."

Issue:

GALL Report AMP XI.M42 does not identify steam, treated water >60 °C, secondary feedwater/steam, secondary feedwater, or any other high temperature environments as within the scope of the program. The periodicity of inspections stated in Table 4a of AMP XI.M42 is based on the environments stated in the "scope of program" program element (e.g., treated water). The staff lacks sufficient information to evaluate the claim that loss of coating integrity for internally coated/lined carbon steel exposed to steam, treated water >60 °C, secondary feedwater/steam, secondary feedwater or any other high temperature environments can be managed through the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program given that information on the coating material and GALL Report environment was not provided.

Request:

1. Identify the GALL Report environments for internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply and condensate systems. Complete the additional requests below for each GALL Report environment not listed in the AMP XI.M42 "scope of program" program element (e.g., steam, treated water >60 °C, secondary feedwater/steam, secondary feedwater).

2. Identify the temperature of internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply and condensate systems for each GALL Report environment not listed in AMP XI.M42.

3. Identify the coating/lining being used on internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water in the turbine steam supply and condensate systems for each GALL Report environment not listed in AMP XI.M42.

4. Justify why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program inspection intervals are adequate such that the intended function of the internally coated/lined carbon steel piping, valves, and demineralizers exposed to secondary water will be maintained for each GALL Report environment not listed in AMP XI.M42.

RAI 4.2.1-1

Background:

Attachment 2 of the applicant's 2011 annual update (December 21, 2011) indicates that a neutron fluence assessment of the beltline and extended beltline regions through the period of extended operation was performed by Westinghouse in WCAP-17299-NP, "Fast Neutron Fluence Update for Diablo Canyon Unit 1 and Unit 2 Pressure Vessels," Revision 0, February 2011.

In the following reference, the applicant indicated that its methods used to develop the calculated reactor vessel fluence are consistent with the NRC-approved methodology described in WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," Revision 2, January 1996.

- WCAP-15985, Revision 0, "Analysis of Capsule V from Pacific Gas and Electric Company Diablo Canyon Unit 1 Reactor Vessel Radiation Surveillance Program," January 2003 (ADAMS Accession No. ML031400342)

Issue:

The applicant did not clearly address whether the neutron fluence methodology used in WCAP-17299-NP, Revision 0 and the 2011 annual update is consistent with the methodology described in WCAP-14040-NP-A, Revision 2.

Request:

Clarify whether the neutron fluence calculational methodology used in WCAP-17299-NP, Revision 0 and the applicant's 2011 annual update is consistent with the methodology described in WCAP-14040-NP-A, Revision 2. If not, provide additional information to demonstrate that the applicant's fluence methodology adheres to Regulatory Guide 1.190.

RAI 4.2.3-1

Background:

In Pacific Gas and Electric Company (PG&E) Letter DCL-11-136 dated December 21, 2011, the applicant provided an update of the upper shelf energy (USE) analysis for ferritic components in the reactor pressure vessels (RPVs) of Diablo Canyon, Units 1 and 2. The applicant stated that, in accordance with Regulatory Guide (RG) 1.99, Revision 2, the USE data from Unit 1 surveillance Capsule V were determined not to be credible and were, therefore, not included in the USE projections for Unit 1 RPV components represented in the Diablo Canyon RPV

surveillance program for Unit 1. Instead, the applicant stated that the USE values were projected to 54 effective full power years (EFPY) of operation using USE analysis methods and criteria that are given in Position 1.2 of RG 1.99, Revision 2.

Issue:

Page No. 1.99-2 in RG 1.99, Revision 2, establishes the following regulatory discussion regarding the application of Charpy-impact data for neutron fluence-dependent RPV adjusted reference temperature calculations and USE analyses:

> When there are two or more sets of surveillance data from one reactor, the scatter of ΔRT_{NDT} values about a best-fit line drawn as described in Regulatory Position 2.1 normally should be less than 28 ºF for welds and 17 ºF for base metal. Even if the fluence range is large (two or more orders of magnitude), the scatter should not exceed twice those values. Even if the data fail this criterion for use in . . . [ΔRT_{NDT}] . . . shift calculations, they may be credible for determining decrease in upper-shelf energy if the upper shelf can be clearly determined, following the definition given in ASTM E185-82.

The staff seeks further justification why all capsule data (i.e., those from the Capsule S, Y, and V Charpy-impact tests of materials representing Weld Heat 27204 in the Unit 1 RPV material surveillance program) have not been applied to the 54 EFPY USE analyses for RPV weld components in Unit 1 fabricated from the same weld heat.

Request:

Justify why all capsule data (i.e., those from the Capsule S, Y, and V Charpy-impact test specimens for Weld Heat 27204 in the Unit 1 reactor vessel material surveillance program as reported and analyzed in WCAP-15958, Rev. 0) have not been used as the basis for calculating the 54 EFPY USE values for Unit 1 RPV weld components fabricated from the same weld heat (i.e., for the USE calculations of intermediate shell axial welds 2-442 A, B and C, and lower shell axial welds 3-442, A, B, and C).

RAI 4.2.2-4

Background:

In PG&E Letter DCL-11-136 (Dec. 21, 2011), the applicant provided an update of the pressurized thermal shock (PTS) analysis for ferritic components in the RPVs of Diablo Canyon, Units 1 and 2.

Issue 1:

The staff performed independent PTS calculations for the Unit 1 RPV beltline and extended beltline components (54 EFPY) and has verified that all ferritic components in the beltline and extended beltline regions of the Unit 1 RPV will satisfy the PTS screening criteria for the components through 60 years of licensed operations (i.e., through 54 EFPY). However, some of the analysis parameter values independently calculated by the staff differ from those reported

for RT_{PTS} assessment parameters in license renewal application (LRA) Table 4.2-4 for Unit 1 or in LRA Table 4.2-5 for Unit 2.

Request 1:

a) Margin term values for Unit 1 RPV upper shell plates B4105-1 (Heat No. C2824-1) and B4105-2 (Heat No. C2824-2): Provide the σ_U and σ_Δ values used to calculate the margin term value for the RT_{PTS} calculation and the basis for reporting a margin term value of 39.2 ºF for these components.

b) Margin term values for Unit 1 RPV upper shell plate B4105-3 (Heat No. C2608-2B): Provide the σ_U and σ_Δ values used to calculate the margin term value for the RT_{PTS} calculation and the basis for reporting a margin term value of 41.2 ºF for these components.

c) Margin term values for Unit 1 RPV intermediate shell axial welds 2-442 A, B, and C, and lower shell axial welds 3-442 A, B, and C (all made from Heat No. 27204): Provide the σ_U and σ_Δ values used to calculate the margin term value for the RT_{PTS} calculation and the basis for reporting the margin term value of 44.0 ºF for these components.

d) Chemistry factor values for Unit 1 RPV intermediate shell axial welds 2-442 A, B, and C, and lower shell axial welds 3-442 A, B, and C (all made from Heat No. 27204): Provide the basis for reporting a chemistry factor of 214.1 ºF for these components.

e) Chemistry factor values for Unit 2 RPV upper shell axial welds 1-201 A, B, and C, and intermediate shell axial welds 2-201 A, B, and C (all made from Tandem Heat 21935/12008): Provide the basis for reporting a chemistry factor of 204.6 ºF for these components.

f) Provide the methodology basis (i.e., plant-specific, generic, NRC-generic, MTEB 5-2, etc.) of the $RT_{NDT(U)}$ value that was reported for each RPV beltline or extended beltline component referenced in LRA Table 4.2-4 and in LRA Table 4.2-5.

Issue 2:

In the revision of LRA Table 4.2-5 for Unit 2 PTS analysis, the applicant provided additional RT_{PTS} calculations for the Unit 2 RPV lower shell axial welds 3-201 A, B, and C (Weld Heat No. 33A277) using surveillance data from Pressurized Water Reactor (PWR) RPV surveillance programs other than the programs for the Diablo Canyon units. Although this weld heat is not represented in any of the capsules in the Unit 2 RPV material surveillance program, the staff has determined the Charpy-impact weld test specimens for welds made from Weld Heat No. 33A277 were included in the RPV surveillance program for Farley Unit 1 (a Westinghouse unit), as well as those for Calvert Cliffs Unit 1 and Unit 2 (both are CE units). This weld heat is also included in the RPV surveillance programs for some U.S. boiling water reactors.

Request 2:

Identify and justify which of the sister plant RPV surveillance programs have been used as the sources of the surveillance data for the RT_{PTS} values for Unit 2 RPV lower shell axial welds 3-201 A, B, and C (as made from Weld Heat No. 33A277) and which of the capsule reports from these are being used as the source of the surveillance data for these welds. Clarify whether there are any plant-specific operational condition differences of note (e.g., differences in operating temperatures for the sister plant units from Diablo Canyon Unit 2) that would need to be identified and factored into the RT_{PTS} calculations for Unit 2 RPV lower shell axial welds 3-201 A, B, and C. If so, clarify how the differences in the operational characteristics have been factored into the RT_{PTS} calculations for Unit 2 RPV lower shell axial welds 3-201 A, B, and C.

RAI B2.1.9-2

Background:

Annual update letter, dated December 22, 2014, states that microbiologically-induced RIC was identified in the auxiliary saltwater (ASW) system, and that the Open-Cycle Cooling Water System program manages the aging effects associated with the system. The letter states that the program inspects the ASW piping every fourth refueling outage to verify the integrity of the plastic pipe-liner and to detect indications of corrosion of the base material.

As amended by LR-ISG-2012-02, SRP-LR added further evaluation Section 3.3.2.2.8, “Loss of Material Due to Recurring Internal Corrosion.” The further evaluation states that RIC can result in the need to augment AMPs beyond the recommendations in the GALL Report and recommends that if recurring aging effects are identified, the applicant addresses the following five aspects:

> (a) why the program’s examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Issue:

Although the need to augment AMPs beyond the recommendations in the GALL Report may not always be warranted if RIC is identified, the identification of RIC causes the staff to question the effectiveness of the aging management activities to ensure that the effects of aging are being adequately managed. While the staff’s safety evaluation report (SER) previously concluded that the effects of aging will be adequately managed by this program, it is unclear to the staff whether the identification of RIC in the ASW system warrants augmented inspections by the Open-Cycle Cooling Water System program. It is also unclear to the staff whether prior internal corrosion occurrences resulted in any changes to the Open-Cycle Cooling Water System

program, and whether the trend for internal corrosion occurrences in the ASW system is indicative of a program that adequately manages the effects of aging.

In addition, by letter dated February 25, 2015, the AMR items associated with loss of coating integrity for the carbon steel piping and valves with coating or lining in the ASW system were changed from the Open-Cycle Cooling Water System program to the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. Consequently, it is unclear to the staff whether any aspects of the inspections for the ASW piping will be changed as allowed under the new program.

Request:

For the past occurrences, which led to the identification of RIC in the ASW system, discuss what changes were made to Open Cycle Cooling Water System program and provide the bases to demonstrate that current program will adequately manage any recurring aging effects. Provide specific information relating to the adequacy of the “every fourth refueling outage” inspection frequency to verify the integrity of the plastic pipe-liner and to detect indications of corrosion of the base material. Include a discussion about the trend for internal corrosion occurrences in the ASW system to show that the program adequately manages the recurring aging effects. Also include information relating to the five specific further evaluation aspects for managing RIC as stated in SRP-LR further evaluation Section 3.3.2.2.8 if not covered in the preceding items.

For the current inspections of the plastic pipe-liner, provide details about the extent (i.e., 100 percent or sample (with the bases for the sampling process)), and criteria for increasing frequency or sample size (if appropriate). Discuss whether the change for managing the loss of coating integrity from the Open-Cycle Cooling Water System program to the new Coatings/Linings program will result in any changes to the types, extent, and frequency of inspections that pertain to RIC.

RAI B2.1.13-5

Background:

Annual update letter dated December 22, 2014, states that RIC was identified in carbon steel components exposed to raw water in the fire protection system. The Fire Water System program was revised to address the changes to GALL Report AMP XI.M27 “Fire Water System.” The update letter states that Fire Water System program will be enhanced as described in SER Section 3.0.3.2.6 to perform additional volumetric examinations and visual inspections of above ground fire water system piping. In addition, the program will be revised to address the changes to GALL Report AMP XI.M27 made by LR-ISG-2012-02, Section C, and the following revisions are sufficient to manage RIC in the fire protection system:

1. Internal and external visual inspections are performed on accessible exposed portions of fire water piping during plant maintenance activities, or at least once every 18 months for external visual inspections, and every 5 years for internal visual inspections. Consistent with LR-ISG-2012-02, Section C.iii.b, volumetric examination will not be used in lieu of prescribed visual examinations of the internal surface of piping. The inspections detect loss of material due to corrosion, ensure that aging effects are managed, and detect

surface irregularities that could indicate wall loss below nominal pipe wall thickness. When surface irregularities are detected, follow-up volumetric wall thickness examinations are performed.

2. Augmented volumetric wall thickness inspections are performed on 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect in each five-year interval prior to the PEO. The 20 percent of piping inspected in each 5-year interval shall be in different locations than previously inspected piping.

As amended by LR-ISG-2012-02, SRP-LR added further evaluation Section 3.3.2.2.8. The further evaluation recommends that if recurring aging effects are identified the applicant address the following five aspects:

> (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Issue:

Although the need to augment AMPs beyond the recommendations in the GALL Report may not always be warranted if RIC is identified, the identification of RIC causes the staff to question the effectiveness of the aging management activities to ensure that the effects of aging are being adequately managed. It is unclear to the staff whether prior internal corrosion occurrences resulted in any changes to the Fire Water System program, and whether the trend for internal corrosion occurrences within the system is indicative of a program that adequately manages the effects of aging. It is also unclear to the staff how the update letter addresses the further evaluation criteria in SRP-LR Section 3.3.2.2.8. For example, the applicant states that augmented volumetric wall thickness measurements will be performed on 20 percent of the piping segments that cannot be drained or piping segments that allow water manage RIC. The staff notes that corrosion in the fire protection system will likely occur in areas that cannot be drained, but it is not possible for the staff to conclude that only performing augmented inspections on piping segments that cannot be drained will adequately address RIC. In addition, the applicant does not describe decision points where an increase in the frequency or severity of RIC would result in increased inspections. Furthermore, the staff noted in SER - Section 3.0.3.2.6 that the applicant will perform opportunistic inspections of buried piping when excavated; however, it is unclear to the staff how this inspection procedure will adequately manage RIC of buried components before loss of intended function (e.g., leaks) occurs.

Request:

For the past occurrences which led to the identification of RIC in the fire protection system, discuss what changes were made to Fire Water System program and provide the bases to

demonstrate that current program will adequately manage any recurring aging effects. Include a discussion about the trend for internal corrosion occurrences in the fire protection system to show that the program adequately manages the recurring aging effects. Also include the five further evaluation aspects for managing RIC as stated in SRP-LR further evaluation Section 3.3.2.2.8.

RAI B2.1.15-2

Background:

Attachment 17 of the applicant's 2014 annual update (December 22, 2014) states that participation in the Electric Power Research Institute (EPRI) (PWR) Supplemental Surveillance Program includes donation of up to seven Charpy V-Notch specimens (material Plate B5454-1) from the already tested Unit 2 Capsule V. The applicant indicated that, because the donated specimens will no longer be stored, the specimen donation is an exception to the Generic Aging Lessons Learned (GALL) Report (Rev. 1) aging management program (AMP) XI.M31 guidance that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage for future reconstitution use, in case the surveillance program is reestablished.

10 CFR 50.61(c)(2) requires that licensees shall consider plant-specific information that could affect the level of embrittlement to verify that RT_{NDT} (adjusted reference temperature) for each vessel beltline material is a bounding value for the specific reactor vessel. 10 CFR 50.61(c)(2) also states that this information includes but is not limited to the reactor vessel operating temperature and any related surveillance program results.

Issue:

The staff noted that LRA Table 4.2-3 indicates that the B5454-1 plate material is a reactor vessel beltline material of Unit 2. It is unclear to the staff whether the applicant will consider test data on B5454-1 plate material, which will be obtained from the EPRI PWR Supplemental

Surveillance Program, in its reactor vessel embrittlement evaluations such as evaluations to determine adjusted reference temperature and upper-shelf energy.

Request:

Clarify whether the applicant will consider test data regarding the B5454-1 plate material, which will be obtained from the EPRI PWR Supplemental Surveillance Program, in its reactor vessel embrittlement evaluations such as evaluations to determine adjusted reference temperature and upper-shelf energy. If not, provide justification for why the applicant will not consider the test data in its reactor vessel embrittlement evaluations.

RAI B2.1.18-3

Background:

As amended by letter dated December 22, 2014, LRA Section B2.1.18, "Buried Piping and Tanks Inspection Program," states that for steel piping, where cathodic protection is not available or does not meet the acceptance criteria in LR-ISG-2011-03, "Changes to the Generic

Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'," Table 4a, "Inspection of Buried Pipe," footnote 2.C., the number of inspections will be based upon soil sampling results.

LR-ISG-2011-03, Table 4a footnote 2.C, recommends that inspections should be escalated to preventive action Category F if leaks have occurred in buried piping due to external corrosion, or significant coating degradation or metal loss has been detected in more than 10 percent of inspections conducted.

Issue:

Although soil sampling is one of the inputs to determine whether increased inspections should be conducted (i.e., preventive action Category F), LR-ISG-2011-03 AMP XI.M41, Table 4a, footnote E.ii, recommends that plant-specific operating experience should also be considered.

Request:

State and justify the basis for why plant-specific operating experience should not be considered in addition to soil sampling results when considering the need to implement preventive action Category F inspections.

RAI B2.1.18-4

Background:

As amended by letter dated December 22, 2014, the Buried Piping and Tanks Inspection Program does not state what buried component inspection findings would be considered as adverse indications. In addition, with the exception of cathodic protection acceptance criterion, the program does not state that it will be consistent with the "acceptance criteria" program element of LR-ISG-2011-03 AMP XI.M41.

LR-ISG-2011-03 AMP XI.M41 recommends that examples of adverse indications resulting from inspections include leaks, material thickness less than minimum, coarse backfill within 6 inches of a coated pipe or tank with accompanying coating degradation, and general or local degradation of coatings so as to expose the base material.

LR-ISG-2011-03 AMP XI.M41 recommends acceptance criteria such as: (a) if components show evidence of corrosion, the remaining wall thickness in the affected area should be determined and

(b) for hydrostatic tests, the test acceptance criteria is no visible indications of leakage and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or quantified leakage across test boundary valves.

Issue:

It is unclear to the staff whether the “detection of aging effects” and “acceptance criteria” program elements will be consistent with the GALL Report AMP XI.M41 because adverse

indications were not defined and acceptance criteria were not stated for activities such as wall thickness verification and hydrostatic tests in lieu of visual inspections.

Request:

State what indications would be considered as adverse indications and the acceptance criteria for the program.

RAI B2.1.18-5

Background:

Amendment 48, dated December 22, 2014, states that there are no aging effects requiring management (AERM) for steel and stainless steel piping, piping components, and tanks encased in concrete. The amendment states that this is supported by SRP-LR Table 3.3-1 line item 3.3.1-112, which states that for steel piping embedded in concrete there are no AERM and no recommended AMP as long as the concrete meets certain attributes (i.e., low water-to-cement ratio, low permeability, and adequate air entrainment) and there is no plant-specific operating experience related to degradation of the concrete. For the stainless steel components embedded in concrete, the amendment cites line item 3.3.1-120, which states that there are no AERM and no recommended AMP. The amendment also states that a majority of the piping and piping components are within buildings where the potential for water intrusion into the concrete is very low. The amendment further states that there has been no plant-specific operating experience revealing aging effects for metallic components embedded in concrete. Amendment 48 further states that letter dated November 24, 2010, further justifies the lack of aging effects for piping embedded in concrete. This letter states, “[t]he ASW system piping that is not cathodically protected is encased in concrete. The concrete provides a noncorrosive environment for the steel piping such that CP is not necessary and there are no aging effects.”

GALL Report Items E-42, EP-31, S-01, and SP-37 state that loss of material is managed for steel and stainless steel piping and piping components exposed to soil or concrete by AMP XI.M41.

Issue:

The staff has concluded that there is reasonable assurance that there are no AERM for components that are: (a) embedded in concrete that are within buildings and (b) not potentially externally exposed to water. However, for components where the concrete is exposed to soil, due to the potential for exposure to water, loss of material should be managed by LR-ISG-2011-03, AMP XI.M41.

Request:

For components that are embedded in concrete that are exposed to soil, state and justify the basis for why water will not penetrate the concrete and potentially cause loss of material.

RAI B2.1.22-5

Background:

GALL Report AMP XI.M29, "Aboveground Metallic Tanks," as revised by Interim Staff Guidance for License Renewal (LR-ISG)-2012-02, states that verification of the effectiveness of the AMP is performed to ensure that degradation is not occurring in inaccessible locations, such as exterior portions of the tanks in contact with concrete. Table 4a, "Tank Inspection Recommendations," in LR-ISG-2012-02 recommends that volumetric inspections be conducted on the external surfaces of tank bottoms and shells exposed to concrete to manage the aging effect of loss of material.

By letter dated December 22, 2014, multiple sections of the LRA were amended in response to LR-ISG-2012-02. Enclosure 1, Attachment 7D, of the letter states that the stainless steel refueling water storage tanks, carbon steel condensate storage tanks, and carbon steel transfer storage tank are outdoor and sit on concrete foundations. LRA Tables 3.2.2-1 and 3.2.2-5 were revised to include aging management review (AMR) items for these tanks that reference the Inspection of Internal Surfaces of Miscellaneous Ducting and Piping Components Program. The AMR items cite plant specific notes indicating that the tank bottoms are to be volumetrically inspected for loss of material. Attachment 7D also states that these tanks are encased in concrete and that there are no aging effects to be managed for the external surfaces.

Issue:

The tank bottoms and side walls are both exposed to concrete; however, the aging effect of loss of material is only being managed for the tank bottoms. It is unclear to the staff what actions will be taken to ensure that degradation is not occurring at inaccessible locations of tank shells, specifically the external surfaces of the tank shells exposed to concrete.

Request:

State the basis for ensuring that degradation is not occurring at the external surfaces of tank shells for the stainless steel refueling water storage tanks, carbon steel condensate storage tanks, and carbon steel transfer storage tank given that volumetric inspections are not being performed in accordance with Table 4a of AMP XI.M29 in LR-ISG-2012-02.

RAI B2.1.22-6

Background:

Annual update letter, dated December 22, 2014, provides changes to the LRA that address issues from LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." Attachment 7A of the letter states that, as discussed in LR-ISG-2012-02, Section A, recurring internal corrosion (RIC) was identified in copper alloy components exposed to potable water in the makeup water system, and the internal surfaces of these components are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The letter also states:

> following a failure of the copper components exposed to potable water due to RIC, this program will be used to either: (a) replace the component with a material that is more corrosion-resistant; (b) take corrective actions to prevent recurrence of the RIC; (c) perform augmented inspections to detect aging before a loss of function occurs, or; (d) credit mitigating actions in accordance with NEI 95-10, Appendix F.

As modified by LR-ISG-2012-02, SRP-LR includes further evaluation Section 3.3.2.2.8, "Loss of Material due to Recurring Internal Corrosion." The further evaluation section recommends that if recurring aging effects are identified the applicant addresses the following five aspects:

> (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

With regard to potential augmented requirements, SRP-LR Section 3.3.2.2.8 states that these include:

> alternate examination methods, (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

In addition, as modified by LR-ISG-2012-02, GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that if RIC has occurred, a plant specific program will be necessary unless this program includes augmented requirements

to ensure that any recurring aging effects are adequately managed. The modified AMP XI.M38 also states that this program may be used if the failed material is replaced by one that is more corrosion-resistant. The staff's intent was for all of the susceptible material to be replaced with more corrosion-resistant material, not just the components that fail.

Issue:

Although the need to augment AMPs beyond the recommendations in the GALL Report may not always be warranted if RIC is identified, the identification of RIC causes the staff to question the effectiveness of the aging management activities to ensure that the effects of aging are being adequately managed. The annual update letter states that one of the four approaches that could be taken following a failure is to "perform augmented inspections to detect aging before a loss of function occurs." However, GALL AMP XI.M38 includes the detection of aging effects and the need for corrective actions before loss of intended function (i.e., failure). Since RIC has been identified in copper alloy components in the makeup water system, it is unclear to the staff which of the four approaches was used to resolve this issue in the past. Unless one of the other four approaches was taken for these past occurrences (which should have provided a long term solution and precluded the need for managing this issue), the staff is unclear what augmented inspections were performed and if these condition monitoring activities are continuing and will continue during the period of extended operation (PEO).

Request:

For the prior occurrences which led to the identification of RIC in copper alloy components of the makeup water system, provide information relating to how these issues were previously addressed. If past activities did not provide a long term solution and preclude the need for managing this issue, provide details related to augmented inspections that will be included in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and discuss how RIC will be identified before loss of intended function occurs throughout the PEO. Include information relating to the five specific further evaluation aspects for managing RIC as stated in SRP-LR further evaluation Section 3.3.2.2.8.