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March 30, 2016

PG&E Letter DCL-16-032

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

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Update to the Reactor Vessel Internals Program, Cathodic Protection Licensing Basis, and LR-ISG-2015-01 Evaluation for Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 53

References:

1. PG&E Letter DCL-09-079, "License Renewal Application," dated November 23, 2009
2. PG&E Letter DCL-15-150, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 51," dated December 21, 2015
3. PG&E Letter DCL-15-121, "Response to NRC Letter dated September 24, 2015, Request for Additional Information for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application - Set 38," dated October 21, 2015
4. PG&E Letter DCL-16-023, "Response to NRC Letter dated February 2, 2016, Requests for Additional Information for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application - Set 39 (TAC Nos. ME2896 and ME2897)," dated February 25, 2016

Dear Commissioners and Staff:

By Reference 1, Pacific Gas and Electric Company (PG&E) submitted an application to the U.S. Nuclear Regulatory Commission (NRC) for the renewal of Facility Operating Licenses DPR-80 and DPR-82, for Diablo Canyon Power Plant (DCPP) Units 1 and 2, respectively. The application included the license renewal application (LRA) and LRA Appendix E, "Applicant's Environmental Report – Operating License Renewal Stage."

By Reference 2, PG&E submitted WCAP-17462-NP, Revision 1, "Program Plan for Aging Management of Reactor Vessel Internals at Diablo Canyon Power Plant Unit 1," and WCAP-17463-NP, Revision 1, "Program Plan for Aging Management of Reactor Vessel Internals at Diablo Canyon Power Plant Unit 2." PG&E committed to provide the NRC with an evaluation of the DCPP Units 1 and 2 reactor internals components with regard to fuel designs and fuel management to address plant-specific action items 1 and 2 in NRC Safety Evaluation, Revision 1, on MRP-227 by March 31, 2016. Enclosure 1 provides an evaluation of the DCPP Units 1 and 2 reactor internals components with regard to fuel designs and fuel management.

By References 2 and 3, PG&E committed to update the cathodic protection licensing basis by March 31, 2016. Enclosure 2 provides PG&E's update to the cathodic protection licensing basis.

In February 2016, the NRC issued the final License Renewal Interim Staff Guidance LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations." Enclosure 3 provides PG&E's evaluation of the final LR-ISG-2015-01.

In response to an NRC teleconference conducted on March 17, 2016, PG&E updates the response to request for additional information (RAI) 3.0.3.2.6-3 as submitted in Reference 4. Enclosure 4 contains PG&E's revised RAI 3.0.3.2.6-3 response.

Enclosure 5 contains the affected LRA pages resulting from the cathodic protection licensing basis update with the changes shown as electronic markups (deletions crossed out and insertions italicized).

PG&E makes no new commitments (as defined by NEI 99-04) in this letter. However, PG&E makes changes to existing commitments which are contained in the changes to LRA Table A4-1 in Enclosure 5.

If you have any questions regarding this response, please contact Mr. Terence L. Grebel, License Renewal Project Manager, at (805) 458-0534.

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

Executed on March 30, 2016.

Sincerely,

L. Jearl Strickland, P.E.
Leader, Generation Technical Services

mma0/50812554
Enclosures

cc:	Diablo Distribution
cc/enc:	Marc L. Dapas, NRC Region IV Administrator Balwant K. Singal, NRC Project Manager Richard A. Plasse, NRC Project Manager, License Renewal Binesh Tharakan, Acting NRC Senior Resident Inspector Michael J. Wentzel, NRC Project Manager, License Renewal (Environmental)

MRP-227-A, "Pressurized Water Reactor Internals Inspection and Evaluation Guidelines" Applicability Guideline for Diablo Canyon Power Plant

MRP-227-A, "Pressurized Water Reactor Internals Inspection and Evaluation Guidelines" Applicability Guideline for Diablo Canyon Power Plant

The Nuclear Regulatory Commission staff has determined that additional information, as discussed in References 1 and 2, should be provided by licensees to verify the applicability of Materials Reliability Program (MRP)-227-A (Reference 1). By Pacific Gas and Electric (PG&E) Letter DCL-15-150, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 51," dated December 21, 2015, PG&E addressed the applicability of MRP-227-A for Diablo Canyon Power Plant (DCPP) Units 1 and 2. PG&E committed to provide an evaluation of the DCPP Units 1 and 2 reactor internals components with regard to fuel designs and fuel management based on screening criteria provided in MRP 2013-025 (Reference 2).

For Westinghouse plants, MRP 2013-025 requires that the average core power density, heat generation figure of merit, and the distance from the active fuel to the upper core plate are within the range of the defined limiting threshold values. The limiting threshold values defined for Westinghouse plants are:

- Average core power density is less than 124 Watts/cm^3
- Heat generation figure of merit (F) is less than or equal to 68 Watts/cm^3
- Active fuel to upper core plate distance is greater than 12.2 inches

PG&E evaluated the DCPP Units 1 and 2 reactor internals components with regard to the limiting threshold values defined in MRP 2013-025, and determined that DCPP Units 1 and 2 satisfy each of the three screening criteria, summarized as follows.

DCPP Unit 1, Cycle 19 is representative of current and planned future DCPP Unit 1 core designs and is considered low leakage. DCPP Unit 1, Cycle 19 has a maximum heat generation figure of merit of 55.20 Watts/cm^3. DCPP Unit 2, Cycle 19 is representative of current and planned future DCPP Unit 2 core designs and is considered low leakage. DCPP Unit 2, Cycle 19, has a maximum heat generation figure of merit of 54.79 Watts/cm^3. Therefore, the limiting threshold for heat generation figure of merit is satisfied for both DCPP Units 1 and 2.

The current rated power level at DCPP Units 1 and 2 results in an average core power density of 102.94 Watts/cm^3 for all cycles. Therefore, the limiting threshold for average core power density is satisfied for both DCPP Units 1 and 2.

The active fuel to upper core plate distance was greater than 12.2 inches for all operating cycles except for those when Region 4 fuel was installed. Region 4 fuel resulted in a distance of 12.08 inches from the active fuel to the upper core plate, and

was installed during cycles 2 through 4 for both DCPP Units 1 and 2. Region 4 fuel has not been installed since cycle 4, ending in 1991 for both DCPP Units 1 and 2.

Although the configuration of the Region 4 fuel assemblies resulted in a fuel assembly to upper core plate gap of less than 12.2 inches, further evaluation demonstrates that the increase in neutron fluence rate caused by the loss of shielding is offset by the margin afforded by the lower operating power density.

The evaluation demonstrates that the MRP-227-A power density criterion is met with a margin of approximately 17 percent. This margin in power density translates directly into a neutron fluence rate reduction relative to that which would be allowed for plant operation at the 124 W/cm^3 criterion. Conversely, the increase in neutron fluence rate for the Region 4 fuel with a smaller fuel assembly to upper core plate gap would exceed the limit value corresponding to a 12.2-inch gap.

The significantly larger margin associated with the lower power density compensates for the small increase in fluence due to the loss of attenuation in Region 4 fuel. Therefore, it can be concluded that the combined effects of power density and fuel configuration would result in fluence rates less than would be allowed for operation with power densities and fuel to upper core plate configurations based directly on the values specified as the MRP-227-A criteria.

References

1. Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A). EPRI, Palo Alto, CA: 2011. 1022863.

2. EPRI Letter, MRP 2013-025, “MRP-227-A Applicability Template Guideline,” October 14, 2013.

Update to Cathodic Protection Licensing Basis

Update to Cathodic Protection Licensing Basis

Pacific Gas and Electric (PG&E) Company's licensing basis for cathodic protection (CP) of the auxiliary saltwater (ASW) supply and discharge piping is documented in the following letters:

(1) PG&E Letter DCL-10-148, "Response to NRC Letter dated November 03, 2010, Request for Additional Information (Set 29) for the Diablo Canyon License Renewal Application," dated November 24, 2010

(2) PG&E Letter DCL-10-158, "10 CFR 54.21 (b) Annual Update to the DCPP License Renewal Application and License Renewal Application Amendment No. 34," dated December 29, 2010

(3) PG&E Letter DCL-14-103, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 48 and LRA Appendix E, Applicant's Environmental Report – Operating License Renewal Stage, Amendment 1," dated December 22, 2014

(4) PG&E Letter DCL-15-121, "Response to NRC Letter dated September 24, 2015, Request for Additional Information for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application – Set 38," dated October 21, 2015

As discussed in PG&E Letter DCL-15-121, PG&E is currently in the design phase of upgrading its CP system on buried, in-soil ASW system piping and further evaluated the feasibility of protecting all subject piping. For some short sections, PG&E has determined it is technically infeasible or impractical to install CP. In accordance with LR-ISG-2015-01, Appendix B, Section 2.g.iv, PG&E is providing justification for not providing CP for the aforementioned small sections of buried piping. PG&E updates the CP licensing basis as follows.

ASW Supply Piping

The ASW supply piping is approximately 5,800 total linear feet (ft) between four piping trains from the intake structure to the turbine building. The ASW supply piping buried in soil from the intake structure to couplings 27 ft outside of the turbine building wall has CP designed and installed at the whole length. PG&E has recently determined that an approximately 13-ft section of ASW supply piping on each of the four trains before the turbine building has existing galvanic anodes CP that is now depleted. In addition, approximately 14-ft of piping per supply train has never been protected by CP. The remainder of the ASW supply piping has existing impressed current CP (ICCP). To address the 27 ft of unprotected ASW supply piping before the turbine building, PG&E evaluated installation of ICCP.

Installation of ICCP is feasible for the approximately 27-ft length, which excludes a 2-ft section on each of the four trains between the supply piping flange joint and the turbine building foundation. The ASW supply piping under the turbine building is interconnected with other station piping and the electrical grounding grid. The inability to isolate the in-soil sections of ASW pipe from the interconnecting ASW pipes would result in an excessive CP current draw making for a cost prohibitive and impractically large CP power supply system that would most likely interfere with adjacent buried metallic structures. Therefore, PG&E concludes that it is technically not feasible to install CP on this section of the ASW supply piping. These 2-ft sections of each ASW supply train piping will be adequately managed for aging in accordance with LR-ISG-2015-01, Appendix B, Table XI.M41-2, using Categories where CP is not installed.

ASW Discharge Piping

Each ASW discharge piping train (2 trains per unit) exits the turbine building and remains buried in soil until it is encased in concrete as part of the circulating water discharge conduit. The piping then exits the concrete encasement and returns to soil before it enters encasement in the concrete discharge structure. During the design phase of upgrading the buried ASW CP system, PG&E determined that for Unit 1, the total amount of buried in-soil piping is approximately 56 ft for train 1-1 and 62 ft for train 1-2. The Unit 2 total amount of buried in-soil piping is approximately 32 ft per train.

Unit 1

Installation of ICCP is feasible for the buried in-soil piping, except for three segments. The segments are described below along with the technical justification for not installing CP.

a) 2-ft section between the turbine building interface and the first discharge piping flange joint

   The ASW discharge piping under the turbine building is interconnected with other station piping and the electrical grounding grid. The inability to isolate the in-soil sections of ASW pipe from the interconnecting ASW pipes would result in an excessive CP current draw making for a cost prohibitive and impractically large ICCP system.

   Therefore, because of the technical infeasibility due to required CP current draw, PG&E concludes these 2-ft sections of each ASW discharge piping train will be adequately aging managed in accordance with LR-ISG-2015-01, Appendix B, Table XI.M41-2, using Categories where CP is not installed.

b) Approximately 30 ft (train 1-1) and 36 ft (train 1-2) pipe run between the last coupling and the conduit concrete encasement interface before entering the discharge conduit concrete encasement.

PG&E evaluated 2 options to provide CP to this section of the pipe: bridging couplings and isolating the in-soil section of piping from the concrete encased section of pipe.

Bridging Couplings

Bridging couplings on the pipeline would provide CP for not only the 30-ft and 36-ft ASW discharge piping sections, but also approximately 200 ft of piping that is already encased in concrete for both trains. As discussed in PG&E Letter DCL-15-121, PG&E response to RAI B2.1.18-5, because of the concrete design and elevation of the water table at Diablo Canyon Power Plant (DCPP), there is reasonable assurance that there are no aging effects requiring management for the ASW discharge piping encased in concrete. PG&E does not have the data necessary to determine the required ICCP system capacity to provide CP for the entire discharge length; therefore PG&E cannot determine if bridging the dresser couplings is technically feasible until CP installation is taking place.

Isolating the In-Soil Section of Piping from the Concrete Encased Section of Pipe

Isolating the in-soil section of ASW discharge piping from the concrete encased section of pipe could be completed by various methods. One method would be to install new isolating flanges or couplings just before the buried pipe enters the discharge conduit. However, the addition of either joint type would require full pipe spool removal, which would necessitate an excavation of about 40 ft by 8 ft by 8 ft deep perpendicular to the vehicle access route along the west side of the turbine building. The conduit and other utilities routed over these ASW pipe runs may also pose construction difficulties and risk. In addition, this work would likely extend the normal refueling outage duration, given the intrusive cutting and welding work required to install new insulating joints. Overall, this approach would be a significant cost for the design analysis and construction.

Another method of isolation would be to install isolating flange kits on the existing flanges between the couplings and at the end of the subject runs. This method presents several risk factors since these flanges are encased in concrete integral to the circulating water discharge conduit structures. For instance, breaking away the concrete encasement surrounding the 24-inch flange could initiate new cracks and/or weaken the existing discharge conduit structure. Furthermore, the piping and flanges are at risk of being damaged during concrete removal activities, which could result in significant pipe repairs and possibly warrant cutting/welding and extended train clearance duration. Bolt removal may also be challenged by the residual concrete. Therefore, PG&E concludes that isolating the in-soil section is impractical.

PG&E concludes these 30-ft and 36-ft ASW discharge piping sections will be adequately aging managed in accordance with LR-ISG-2015-01, Appendix B,

Table XI.M41-2, using Categories where CP is not installed due to the potential to damage the ASW piping flanges that are encased in concrete, significant costs during construction, and the lack of technical data to determine CP system capacity.

c) Approximately 1-ft section on coupling shoulders between the concrete discharge conduit and the concrete discharge structure

Installation of CP on these 1-ft sections would require a 15-ft deep excavation at the pipe interface between concrete discharge conduit and the discharge structure. Based on current plant drawings, the piping and coupling configuration leaves less than 4 inches of exposed pipe to make a CP wire bond and perform coating removal and repair work. There is also risk of damaging concrete structures and pipe at interfaces.

To address this 1-ft section, PG&E evaluated an alternative to bridge couplings on the pipeline, which would provide CP for not only the 1-ft section of interest, but also approximately 100 ft of piping that is already encased in concrete. As discussed in PG&E Letter DCL-15-121, PG&E response to RAI B2.1.18-5, because of the concrete design and elevation of the water table at DCPP, there is reasonable assurance that there are no aging effects requiring management for the ASW discharge piping encased in concrete. Bridging the couplings would also result in excessive CP current draw making for a cost prohibitive and impractically large ICCP system.

Although no CP would be installed, existing Paraliner (the internal polyvinyl chloride [PVC] pipe liner) and coupling materials provide added corrosion protection to the external pipe surface. The internal Paraliner is lapped over the outer edge of the pipe end and extends 6 inches beyond the distance required to install the coupling over the external surface of the pipe. The coupling shoulder is constructed of a geomembrane fabric and pipe clamps/bands provide additional pipe protection from potential aging effects.

Should a loss of pressure boundary occur in the 1-ft section on the shoulders due to aging affects, there would be a low consequence of failure. The ASW discharge piping fluid is released to the discharge structure for mixing with the circulating water being returned to the ocean. Should the subject section of the ASW discharge piping experience a loss of pressure boundary, the site geologic formations and groundwater flow would direct the water to the ocean (the original discharge destination). In addition to the carbon steel piping, the ASW discharge piping contains a safety-related PVC internal liner which is periodically inspected under a surveillance test and is of adequate strength to prevent leakage. The internal liner will be managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks Program (B2.1.42).

Therefore, because of constructability challenges, the risks during construction, the technical infeasibility due to CP system capacity, additional corrosion protection, and low consequence of failure, PG&E concludes these 1-ft sections of each ASW discharge piping train will be adequately aging managed in accordance with LR-ISG-2015-01, Appendix B, Table XI.M41-2, using Categories where CP is not installed.

Unit 2

Installation of ICCP is feasible for the buried in-soil piping, except for three segments. The segments are described below along with the technical justification for not installing CP.

a) 2-ft section between the turbine building interface and the first discharge piping flange joint

The ASW discharge piping under the turbine building is interconnected with other station piping and the electrical grounding grid. The inability to isolate the in-soil sections of ASW pipe from the interconnecting ASW pipes would result in an excessive CP current draw making for a cost prohibitive and impractically large ICCP system.

Therefore, because of the technical infeasibility due to required current draw, PG&E concludes these 2-ft sections of each ASW discharge piping train will be adequately aging managed in accordance with LR-ISG-2015-01, Appendix B, Table XI.M41-2, using Categories where CP is not installed.

b) Approximately 3-ft section between a piping coupling and the discharge conduit concrete encasement

This short length of pipe is located underneath an existing building structure, which is an extension of the Unit 2 buttress building. There would be less than 4 ft of clearance between the bottom of the building slab and top of the pipe. Bonding new CP wire and coating removal and repair activities would require significant excavation and shoring work with a risk to personnel safety. There is also a risk of damaging adjacent concrete structures.

To address this 3-ft section, PG&E evaluated an alternative to bridge couplings on the pipeline, which would provide CP for not only the 3-ft section of interest, but also approximately 100 ft of piping that is already encased in concrete. As discussed in PG&E Letter DCL-15-121, PG&E response to RAI B2.1.18-5, because of the concrete design and elevation of the water table at DCPP, there is reasonable assurance that there are no aging effects requiring management for the ASW discharge piping encased in concrete. PG&E does not have the data necessary to determine the required ICCP system capacity to provide CP

for the entire discharge length; therefore, PG&E cannot determine if bridging the dresser couplings is technically feasible until CP installation is taking place.

PG&E concludes these 3-ft sections of each ASW discharge train piping will be adequately aging managed in accordance with LR-ISG-2015-01, Appendix B, Table XI.M41-2, using Categories where CP is not installed due to constructability challenges, the risks during construction, and the lack of technical data to determine ICCP system capacity.

c) Approximately 1-ft section on coupling shoulders between the concrete discharge conduit and the concrete discharge structure

As described above for Unit 1, installation of CP on these 1-ft sections would require a 15-ft deep excavation at the pipe interface between concrete discharge conduit and the discharge structure. Piping and coupling configuration leaves less than 4 inches of exposed pipe to make a CP wire bond and perform coating removal and repair work. There is also risk of damaging concrete structures and pipe at interfaces.

To address this 1-ft section, PG&E evaluated an alternative to bridge couplings on the pipeline, which would provide CP for not only the 1-ft section of interest, but also approximately 100 ft of piping that is already encased in concrete. As discussed in PG&E Letter DCL-15-121, PG&E response to RAI B2.1.18-5, because of the concrete design and elevation of the water table at DCPP, there is reasonable assurance that there are no aging effects requiring management for the ASW discharge piping encased in concrete. Bridging the couplings would also result in excessive CP current draw making for a cost prohibitive and impractically large ICCP system.

Although no CP would be installed, existing Paraliner (the internal PVC pipe liner) and coupling materials provide added corrosion protection to the external pipe surface. The internal Paraliner is lapped over the edge of the pipe end and extends 6 inches beyond the distance required to install the coupling over the external surface of the pipe. The coupling shoulder is constructed of a geomembrane fabric and pipe clamps/bands provide additional pipe protection from potential aging effects.

Should a loss of pressure boundary occur in the 1-ft section due to aging affects, there would be a low consequence of failure. The ASW discharge piping fluid is released to the discharge structure for mixing with the circulating water being returned to the ocean. Should the subject section of the ASW discharge piping experience a loss of pressure boundary, the site geologic formations and groundwater flow would direct the water to the ocean (the original discharge destination). In addition to the carbon steel piping, the ASW discharge piping contains a safety-related PVC internal liner which is

periodically inspected under a surveillance test and is of adequate strength to prevent leakage. The internal liner is managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks Program (B2.1.42).

Therefore, because of the risks during construction, the technical infeasibility due to rectifier capacity, and low consequence of failure, PG&E concludes these 1-ft sections of each ASW discharge piping train will be adequately aging managed in accordance with LR-ISG-2015-01, Appendix B, Table XI.M41-2, using Categories where CP is not installed.

For the entire length of buried ASW supply and discharge piping, 5,892 ft would be cathodically protected and a total of 92 ft would not be cathodically protected. As described in PG&E Letter DCL-15-121, inspections required by the DCPP Buried Piping and Tanks Inspection Program (B2.1.18) will be conducted consistent with the specific changes provided to GALL, Revision 2 in LR-ISG-2015-01.

Operating Experience Review

A review of the most recent 10 years of DCPP operating experience was conducted for buried, in-soil, carbon steel components. The results indicated that no externally degraded conditions occurred that would not have met the acceptance criteria of the DCPP Buried Piping and Tanks Inspection Program (B2.1.18).

Prior to the most recent 10 years, PG&E excavated and inspected the exterior of the ASW supply piping near the turbine building in 1992. These pipelines were in the ground for over 20 years. The top quadrants of each pipe were the areas most affected by pitting corrosion. The corrosion was removed, pitting was filled, and coatings were reapplied to cease further corrosion.

As indicated in PG&E Letter DCL-97-010, "Auxiliary Saltwater System Piping Bypass Project," dated January 27, 1997, a portion of the ASW supply piping was bypassed due to a concern that localized corrosion was occurring in the section of the piping buried in the tidal zone outside the intake structure. As discussed above, except for the 2-ft sections on each train near the turbine building interface, the piping buried in soil from the intake structure to the turbine building wall has or will have CP installed the whole length prior to the period of extended operation. This operating experience is not applicable because all of the ASW supply and discharge sections without CP are not buried below sea level and are not exposed to the same soil environment that previously led to localized external corrosion.

In December 1997, during an external piping inspection, pitting corrosion was identified on the Unit 2 ASW supply piping near the bypass piping discussed above. The pitting was determined to have occurred prior to the installation of CP earlier that same year.

The pitting corrosion was removed, pitting was filled, and coatings were reapplied to cease further external corrosion.

Since installation of CP on the ASW supply piping, the CP has been available more than 90 percent of the time, as evidenced by meeting the acceptance criteria in LR-ISG-2015-01, Table XI.M41-3.

Soil Sampling

The most significant soil property regarding soil corrosivity is electrical resistivity. Soil resistivity testing was performed in the vicinity of the ASW supply and discharge piping in 1992 and 1998.

In 1992, the soil testing was performed at the ASW supply lines near the turbine building. The soil resistivity ranged from 322 to 380 ohm-cm, which is characterized as corrosive since it is less than 1000 ohm-cm. In each 10-year period, PG&E will perform inspections of the non-CP sections of buried, in-soil ASW supply and discharge piping consistent with the requirements in the preventive action categories described in LR-ISG-2015-01, Table XI.M41-2.

In 1998, soil testing was performed in the route of the ASW supply and discharge piping west of the turbine building. The soil resistivity ranged from 785 to 875 ohm-cm for those anodes closest to the turbine building. This range is characterized as corrosive since it is less than 1000 ohm-cm. The ASW supply and discharge piping is coated with a fiber wrapped petroleum-based epoxy coating providing substantial external corrosion protection. In each 10-year period, PG&E will perform inspections of the non-CP sections of buried, in-soil ASW supply and discharge piping consistent with the requirements in the preventive action categories described in LR-ISG-2015-01, Table XI.M41-2.

PG&E amends LRA Table A4-1, item 53 to include installation of ICCP on the buried, in-soil ASW supply and discharge piping as discussed above and will submit a final report to the NRC to confirm the completed scope.

License Renewal Interim Staff Guidance LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations"

License Renewal Interim Staff Guidance LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations"

LR-ISG-2015-01 contains recommended technical and editorial changes to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 2, Aging Management Program (AMP) XI.M41, "Buried and Underground Piping and Tanks."

PG&E's licensing basis for the Diablo Canyon Power Plant (DCPP) Buried Piping and Tanks Inspection Program (B2.1.18) is documented in the following letters:

(1) PG&E Letter DCL-09-079, "License Renewal Application," dated November 23, 2009

(2) PG&E Letter DCL-10-097, "Response to NRC Letter dated July 19, 2010, Request for Additional Information (Set 9) to the Diablo Canyon License Renewal Application," dated August 2, 2010

(3) PG&E Letter DCL-10-113, "Response to NRC Letter dated August 3, 2010, Request for Additional Information (Set 16) for the Diablo Canyon License Renewal Application," dated August 30, 2010

(4) PG&E Letter DCL-10-148, "Response to NRC Letter dated November 03, 2010, Request for Additional Information (Set 29) for the Diablo Canyon License Renewal Application," dated November 24, 2010

(5) PG&E Letter DCL-11-002, "Response to Telephone Conference Call Held on December 9, 2010, Between the U.S. Nuclear Regulatory Commission and Pacific Gas and Electric Company Concerning Responses to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated January 21, 2011

(6) PG&E Letter DCL-11-022, "Pacific Gas and Electric Company Supplements a Response to Requests for Additional Information Related to the Diablo Canyon Nuclear Power Plant, Units 1 and 2, License Renewal Application," dated March 14, 2011

(7) PG&E Letter DCL-14-103, "10 CFR 54.21(b) Annual Update to the Diablo Canyon Power Plant License Renewal Application (LRA), Amendment 48 and LRA Appendix E, Applicant's Environmental Report – Operating License Renewal Stage, Amendment 1," dated December 22, 2014

(8) PG&E Letter DCL-15-121, "Response to NRC Letter dated September 24, 2015, Request for Additional Information for the Review of the Diablo

Canyon Power Plant, Units 1 and 2, License Renewal Application – Set 38," dated October 21, 2015

(9) PG&E Letter DCL-16-023, "Response to NRC Letter dated February 2, 2016, Request for Additional Information for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application – Set 39," dated February 25, 2016

PG&E prepared its license renewal application (LRA) based on the guidance in GALL Report, Revision 1, September 2005. The NRC staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1801, Revision 1. The NRC staff issued Draft NUREG-1801, Revision 2 in September 2010. The NRC staff considered the operating experience summarized in the Draft NUREG-1801, Revision 2 and requested PG&E to address selected items. This review is summarized in the License Renewal Safety Evaluation Report (SER), dated June 2, 2011. Subsequent to issuance of the SER, PG&E revised its LRA licensing basis in accordance with 10 CFR 54.21(b) and also addressed License Renewal Interim Staff Guidance LR-ISG-2011-03 and Draft LR-ISG-2015-01, which provided revisions to the GALL Report, Revision 2, XI.M41, "Buried and Underground Piping and Tanks," AMP by including specific additional guidance, which was not previously reviewed in the SER.

LR-ISG-2015-01 was issued in February 2016 and provided further specific guidance in the form of changes to technical and editorial guidance. In order to address the recommendations in LR-ISG-2015-01, PG&E updates its licensing basis for the DCPP Buried Piping and Tanks Inspection Program (B2.1.18) to be in compliance with the specific changes provided to GALL Report, Revision 2 in LR-ISG-2015-01 as discussed in this enclosure. The specific changes between the two LR-ISG-2015-01 versions that required updates to the DCPP Buried Piping and Tanks Inspection Program (B2.1.18) licensing basis involve changes to the following Elements:

- Element 3 – Parameters Monitored or Inspected
- Element 4 – Detection of Aging Effects
- Element 6 – Acceptance Criteria
- Element 7 – Corrective Actions

<u>Parameters Monitored or Inspected:</u>

The DCPP Buried Piping and Tanks Inspection Program (B2.1.18) will be consistent with the specific changes in LR-ISG-2015-01, Appendix B, Section 3 for the parameters monitored or inspected.

<u>Detection of Aging Effects:</u>

Systems in the scope of the DCPP Buried Piping and Tanks Inspection Program (B2.1.18) are the ASW system, makeup water system, diesel fuel oil system, and fire

water system. Inspections that will be conducted by DCPP Buried Piping and Tanks Inspection Program (B2.1.18) for the buried and underground ASW piping, buried makeup water system piping and valves, and underground diesel fuel oil piping will be consistent with the specific changes in LR-ISG-2015-01, Appendix B, Table XI.M41-2, as modified for a two-unit site.

Consistent with the specific changes in LR-ISG-2015-01, Appendix B, Sections 2.g.iii and 4.e.i, PG&E will perform either a periodic flow test of the fire water system in accordance with National Fire Protection Association 25, Section 7.3, at a frequency of at least one test in each one-year period, or conduct an annual system leakage rate test.

Acceptance Criteria:

The DCPP Buried Piping and Tanks Inspection Program (B2.1.18) will be consistent with the specific changes in LR-ISG-2015-01, Appendix B, Section 6, "Acceptance Criteria," except for qualifications of coatings specialists. As discussed in PG&E Letter DCL-16-023, response to RAI B2.1.18-4, individuals responsible for conducting coating inspections for the Buried Piping and Tanks Inspection Program (B2.1.18) will be qualified in accordance with ASTM D4537, which is endorsed by NRC Regulatory Guide (RG) 1.54. The individuals responsible for assessing the type and extent of coating degradation will be qualified in accordance with ASTM D7108-05, which is also endorsed by NRC RG 1.54.

Corrective Actions:

The DCPP Buried Piping and Tanks Inspection Program (B2.1.18) will be consistent with the specific changes in LR-ISG-2015-01, Appendix B, Section 7, "Corrective Actions," for inspection findings that do not meet acceptance criteria.

LRA Section A1.18 and Table A4-1, Item 52 are revised to address LR-ISG-2015-01 as shown in Enclosure 5.

In addition, LRA Table A4-1, Item 7 is being deleted, because it is a duplication of LRA Table A4-1, Item 52 for implementing the DCPP Buried Piping and Tanks program (B2.1.18).

Revised Response to Request for Additional Information (RAI) 3.0.3.2.6-3

<u>*RAI 3.0.3.2.6-3*</u>

<u>*Background*</u>*:*

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.

<u>*Issue*</u>*:*

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.

<u>*Request*</u>*:*

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.

<u>PG&E Revised Response to RAI 3.0.3.2.6-3</u>

In response to an NRC teleconference question, PG&E updates the response to RAI 3.0.3.2.6-3 as submitted in PG&E Letter DCL-16-023 as shown below:

PG&E will enhance the Fire Water System Program (B2.1.13) to revise plant procedures to document the process for using performance-based monitoring (testing, maintenance, inspection, consequence of system maloperation). Prior to making any changes to inspection/test frequencies, PG&E will establish a maximum allowable failure rate, and proceduralize a process for reviewing failure rates and making adjustments to inspection/test intervals. Test/inspection results data utilized for establishing reliability metrics will be statistically valid, evaluated against firm criteria, and retained for reference. Concurrence of Nuclear Electric Insurance Limited (NEIL) will be obtained on the process used to determine test/inspection frequencies, and the maximum allowable failure rate, in advance of any alternations to the test/inspection

program. The procedure will contain a formalized method of increasing or decreasing the frequency of testing/inspection when systems exhibit either a higher than expected failure rate or an increase in reliability as a result of a decrease in failures, or both. The justification for changing the interval will be documented using the CAP, and referenced in the revision history for the implementing inspection/testing procedure.

The inspections/testing intervals of the Fire Water System program will be determined by a performance based approach as allowed in NFPA-25, Section 4.6, "Performance-Based Programs". The minimum inspection/testing interval (the interval approved in the DCPP Fire Water System program) may be extended when acceptable performance is established, as defined by EPRI Report 1006756, "Fire Protection Equipment Surveillance Optimization and Maintenance Guide," Section 11.2. Acceptable performance is defined as "as found" inspections/testing where the number of instances the acceptance criteria is not met does not exceed the maximum allowable failure rate, *termed "reliability goals"* ~~approved in advance by NEIL~~ *in EPRI Report 1006756*. ~~NEIL~~ *EPRI Report 1006756* ~~has provided~~*provides* the period of time over which the previous results should be reviewed to establish the failure rate. The period of time (and minimum sample size) is dependent on the revised interval of testing/inspection. Data to be used in analyzing the potential for modifying test and inspection frequencies would not be obtained any earlier than five years prior to the period of extended operation. ~~The NEIL recommendations are documented in Section 11.2.1.1 of EPRI 1006756~~. ~~Those intervals are shown in the table below.~~

~~Minimum Recent Data Collection Period for Expanding Test/Inspection Intervals~~	
~~Test/Inspection Frequency~~	**~~Required Data~~**
~~Up to quarterly~~	~~2 years of most recent data~~
~~Quarterly up to annual~~	~~3 years of most recent data~~
~~Annual up to fuel cycle~~	~~5 years of most recent data~~
~~Fuel cycle or longer~~	~~Extension currently not permitted~~

Because there is not sufficient industry operating experience, EPRI Report 1006756, Section 11.2 will not be used to modify the frequency associated with fire water storage tank tests/inspections, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to its configuration. PG&E will not make performance-based frequency modifications of these inspections until NRC approves use of a methodology for modification of these inspection frequencies.

When an equipment failure occurs, it is entered into the CAP, trended, and an engineering evaluation is performed. Resulting corrective actions are taken based on

the cause of the problem. Test results would be evaluated upon completion of each test scoped in the program to ensure compliance with the established performance based criteria. If the maximum allowable failure rate is exceeded during the required data interval, the inspection/test interval will be adjusted in accordance with NEIL approved method for increasing inspection/test frequency. Once cause determination and corrective actions have been completed, acceptable performance may be re-established.

**License Renewal Application (LRA) Amendment 53
Affected LRA Tables**

License Renewal Application (LRA) Amendment 53
Affected LRA Sections and Tables

LRA Sections and Tables	Reason for Change
Section A1.18	To address the LR-ISG-2015-01 evaluation (see Enclosure 3)
Table A4-1, Items 7, 52, and 53	To address the update to the cathodic protection licensing basis (see Enclosure 2) and LR-ISG-2015-01 evaluation (see Enclosure 3)

A1.18 BURIED PIPING AND TANKS INSPECTION

The Buried Piping and Tanks Inspection program manages cracking, loss of material, and change in surface conditions of buried and underground piping, piping components and tanks in the auxiliary saltwater system, diesel generator fuel transfer system, fire protection system, and the makeup water system. The program manages aging through preventive, mitigative, (i.e., coatings, backfill quality, and cathodic protection) and inspection activities. Visual inspections monitor the condition of protective coatings and wrappings found on steel and copper alloy components and directly assess the surface condition of cast iron, polyvinyl chloride, and asbestos cement components with no protective coatings or wraps. *Evidence of wall loss beyond minor scale observed during visual inspections of buried piping will require a supplemental surface and/or volumetric non-destructive testing.* ~~Evidence of damaged wrapping or coating defects is an indicator of possible age-related degradation to the external surface of the components. The presence of discolorations, discontinuities in surface texture, cracking, crazing, changes in material properties or loss of material of unwrapped cast iron, polyvinyl chloride, and asbestos cement components is an indicator of possible aging of the external surface of the components.~~ The program includes opportunistic inspection of buried piping and tanks as they are excavated or on a planned basis if opportunistic inspections have not occurred.

The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

Inspections are conducted by qualified individuals. Individuals responsible for conducting coating inspections will be qualified in accordance with ASTM D4537and individuals responsible for assessing the type and extent of coating degradation will be qualified in accordance with ASTM D7108-05, which are endorsed by NRC RG 1.54. When the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of operation, an increase in the sample size is conducted. If a reduction in the number of inspections recommended in LR-ISG-2015-01, Table XI.M41-2 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing is conducted once in each 10-year period starting 10 years prior to the period of extended operation. ~~Soil samples will be conducted in the vicinity of in-scope buried, non-cathodically protected steel piping and piping components. Soil samples will be conducted in the vicinity of in-scope buried auxiliary saltwater system steel piping in which the cathodic protection system does not meet the availability or effectiveness requirements. Soil samples will be conducted during the ten-year period prior to the period of extended operation and in each subsequent ten-year period during the period of extended operation.~~

~~Alternative to visual inspection of the external surface of steel piping, hydrostatic testing or an inspection of the internal surface of the piping that is capable of precisely determining pipe wall thickness may be used.~~

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended operation. Inspections will be conducted during each 10-year period beginning 10 years prior to entering the period of extended operation. ~~Examinations of buried piping will consist of visual inspections. Significant indications of degradation observed during visual inspections of buried piping will require a supplemental surface and/or volumetric non-destructive testing.~~

The Buried Piping and Tanks Inspection program implements the specific additional guidance provided in LR-ISG-2011-03 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3~~,~~; ~~and~~ the specific changes provided in draft LR-ISG-2015-01 as discussed in PG&E Letter DCL-15-121, Enclosures 1 and 2, and DCL-16-023~~,~~; *and the specific changes provided in LR-ISG-2015-01 as discussed in PG&E Letter DCL-16-032, Enclosure 3*.

Table A4-1 License Renewal Commitments

Item #	Commitment	LRA Section	Implementation Schedule
~~7~~	~~Implement the Buried Piping and Tanks Inspection program as described in LRA Section B2.1.18.~~	~~B2.1.18~~	~~During the 10 years prior to the period of extended operation.~~
52	The Buried Piping and Tanks Inspection Program will be *implemented as described in LRA Section B2.1.18 and will*~~revised to~~ conform to the specific additional guidance provided in LR-ISG-2011-03 as discussed in PG&E Letter DCL-14-103, Enclosure 1, Attachment 3~~,~~;~~ and~~ the specific changes provided in draft LR-ISG-2015-01 *as discussed*~~, and~~ in PG&E Letter*s* DCL-15-121, Enclosures 1 and 2, and DCL-16-023~~,~~*; and the specific changes provided in LR-ISG-2015-01 as discussed in PG&E Letter DCL-16-032, Enclosure 3*. Fire mains will be subject to a periodic flow test in accordance with NFPA 25 section 7.3 at a frequency of at least one test in each one year period. These flow tests will be performed in lieu of excavating buried portions of Fire Water pipe for visual inspections.	B2.1.18	Within 10 years prior to the period of extended operation
53	PG&E will install *impressed current* cathodic protection for the *buried* ASW discharge *and supply* piping in contact with soil *as described in PG&E Letter DCL-16-032 and will submit a final report to the NRC to confirm the completed scope*.	B2.1.18	*During the 10 years p*~~P~~rior to the period of extended operation