STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

July 17, 2018

Mr. Sumeet Singh, Vice President
Pacific Gas and Electric Company
Portfolio Management & Engineering
6111 Bollinger Canyon Road, Room 4590-D
San Ramon, CA 94583

GI-2017-09-PGE29-08

SUBJECT: General Order 112-F Closure Letter for Inspection of PG&E's Transmission Integrity Management Program (TIMP)

Dear Mr. Singh:

The Safety and Enforcement Division (SED) of the California Public Utilities Commission (Commission) reviewed Pacific Gas and Electric Company's (PG&E) response letter dated February 26, 2018 that addressed the findings identified during the General Order (GO) 112-F Transmission Integrity Management Program (TIMP) inspection from September 18-29, 2017.

A summary of the inspection findings documented by SED, PG&E's response to our findings, and SED's evaluation of PG&E's response taken for each finding are outlined for each violation and SED follow up question in this letter and attached spreadsheet.

This letter serves as the official closure of the 2017 Inspection of PG&E's TIMP.

If you have any questions, please contact Paul Penney at (415) 703-1817 or by email at: Paul.Penney@cpuc.ca.gov

Sincerely,

Dennis Lee

Dennis Lee, P.E.
Program and Project Supervisor
Gas Safety and Reliability Branch
Safety and Enforcement Division

Enclosure: Summary of Inspection Findings

cc: Susie Richmond, PG&E Compliance,
Mike Bradley, PG&E Compliance,
Kenneth Bruno (Kenneth.Bruno@cpuc.ca.gov), SED/GSRB,
Alula Gebremedhin (Alula.Gebremedhin@cpuc.ca.gov), SED/GSRB
Sikandar Khatri (Sikandar.Khatri@cpuc.ca.gov), SED/GSRB
Wai-Yin Chan (Wai-Yin.Chan@cpuc.ca.gov), SED/GSRB
Kelly Dolcini (Kelly.Dolcini@cpuc.ca.gov), SED/GSRB

Summary of Inspection Findings

A. <u>PG&E's Internal Audit Findings</u>

During the audit, PG&E provided SED staff with its findings from the internal review it conducted of the TIMP program. **Error! Reference source not found.** below lists all findings from PG&E's internal review. Please note, not all line items from PG&E's internal audit summary are listed; only those items listed as non-compliances were included in Table 1 below. All of PG&E's internal review findings are violations of PG&E's standards, and are therefore violations of Title 49 Code of Federal Regulations (CFR), §192.13(c).

Table 1: PG&E's TIMP Internal Review Summary Findings (IRSF)

Item	Finding Description	# of findings	# of Pending Corrections (as of 9-29-17)	Remediation Date
1	TD-4810P-23 sec 2.3, PG&E is not able to demonstrate that preparation of Feasibility Analysis for Strength Test form has been completed. [T]	44	?	?
2	PG&E not following TD-4810P-18 [T]	3	?	?
3	PG&E not following TD-4810P-17 for PEIR documentation [T]	6		2/2016
4	PG&E not following 4127P-03 regarding HCA requirements (Annual Report or submission to VP) since 2015 [T]	2	2	Pending
5	113248012 PG&E not following In-Line Inspection (ILI) Procedure TD-4810P-11 Rev. 0, Section 6.8.1 [T]	7		10/2016

Please answer the following questions related to the findings noted above.

1. For item 1, please provide a summary of the provisions of TD-4810P-23 standard have been revised, and the rationale for the changes. If PG&E has a change log for TD-4810P-23, this would satisfy this request.
2. For item 1, the corrective actions for the item states in part, "…*Several of the requirements that have not been adhered to for prior assessment projects were discussed…*" Have any of the 44 assessments been invalidated because of not following PG&E's procedure? If so,

please list those projects and the reason for the project being invalidated because of not doing the feasibility analysis per the standard?
3. For item 2, please provide a copy of CAP #113242335.

PG&E's Response:
1. Standard TD-4810P-23 will be updated in 2018 and the changes and rationale will be documented in a change log as part of that process. Once updated, PG&E will provide the change log.
2. No, none of the projects were invalidated by not performing the feasibility analysis per TD-4810P-23. The projects were evaluated after the strength tests were performed to ensure the proper test pressure ratios met the assessment requirements for the appropriate resident and time-dependent threats.
3. CAP #113242335 is provided per the request. Attached, please find attachment 1 - "CAP 113242335"

SED's Conclusion:
1. PG&E's response adequately addresses this item. SED staff will follow up on this commitment later in the year.
2. PG&E's response adequately addresses this item.
3. PG&E's response adequately addresses this item.

B. PHMSA's Integrity Management Protocols

I. Violations, Concerns and Recommendations Identified in Protocol Area A: Identify HCAs.

No issues identified.

II. Violations, Concerns and Recommendations Identified in Protocol Area B: Baseline Assessment Plan

This protocol area was skipped since we are past the baseline period.

III. Violations, Concerns and Recommendations Identified in Protocol Area C: Identify Threats, Data Integration and Risk Assessment

C.01.a— If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]

i. external corrosion,
ii. internal corrosion,
iii. stress corrosion cracking…

Issue Identified:
RECOMMENDATION:
For item iii above (stress corrosion cracking), SED staff recommends the following:

PG&E should note in TD-4810P-16, Figure A3 that the screening criteria identified in ASME B31.8S-2004, Appendix A3, for the High pH Stress Corrosion Cracking (SCC) threat is not absolute. These criteria do not account for approximately 25-35% of historical SCC failures. As noted in the National Association of Corrosion Engineers (NACE) RP0204-2004 (Stress Corrosion Cracking Direct Assessment Methodology), Section 1.2.1, "…It is recognized that these screening factors will identify a substantial portion of the susceptible locations, but not all of them." This footnote is also consistent with some of the data points from PG&E's "SCC Tracker" spreadsheet. The footnote will alert PG&E engineers to the fact that the screening criteria are not absolute.

PG&E's Response:

PG&E will update Standard TD-4810P-16, Figure A3 for the High-pH Stress Corrosion Cracking (SCC) threat in 2018 to reflect SED's recommendation. Furthermore, TD-4810P-16 was updated at the end of 2017 with more prescriptive threat identification screening criteria than what is outlined in ASME B31.8S-2004 for the Near Neutral-pH SCC threat. The new identification process aligns more with the locations in PG&E's system where SCC has been discovered and since the Near Neutral-pH SCC locations overlap with the High-pH locations, more pipeline sections in these areas will have the SCC threat identified than what would be identified using the criteria in ASME B31.8S-2004 alone.

SED's Conclusion:

PG&E's response adequately addresses this item.

C.02.f. Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data integration includes:

i. A common spatial reference system that allows association of data elements with accurate locations on the pipeline [ASME B31.8S-2004, Section 4.5];
ii. Integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third party damage [§192.917(e)(1)].

Issue Identified:

Editorial Comment: There are two Table 48's in TD-4810P-01, Attachment 3. Since this is a draft, PG&E may have already caught this error; if not, please correct the numbering.

PG&E's Response:

PG&E corrected this error on 12/12/17 and will revise TD-4810P-01 Attachment 3 as part of the next document update cycle.

SED's Conclusion:

PG&E's response adequately addresses this item.

C.02.i. Verify that the records indicate that all existing data and information on the entire pipeline, that could be relevant to covered segments, has been gathered.

Adequate records that demonstrate all data and information has been gathered should…

Issue Identified:

Recommendation: While reviewing data gathering for the external corrosion threat, PG&E had apparently skipped gathering the Microbiologically Induced Corrosion (MIC) data. However, as explained by PG&E staff, this was an oversight in the latest revision of the procedure. It was verified to be in the prior procedure. Therefore, please revise the latest procedure to reflect data gathering for MIC.

PG&E's Response:

PG&E corrected this error on 12/12/17 and will revise TD-4810P-01 Attachment 3 as part of the next document update cycle. MIC data has been included in the External Corrosion Factor and implemented as part of the risk assessment process in 2017.

SED's Conclusion:
PG&E's response adequately addresses this item.

C.04.a. Verify that the validation process includes a check that the risk results are logical and consistent with the operator's and other industry experience. [§192.917(c) and ASME B31.8S-2004, Section 5.12]

Issue Identified:
Recommendation: SED staff recommends that PG&E elaborate on the different validation steps that are a part of the validation effort in TD-4810S, Section 7.7.

PG&E's Response:
PG&E will update TD-4810S in 2018 and elaborate on the validation steps that are performed. As part of the 2017 Risk Assessment process, PG&E performed validation of the source data, data integration and the risk results. Additionally the validation process includes Steering Committees Review of the results to assure the results are usable and consistent with PG&E and industry experience.

SED's Conclusion:
PG&E's response adequately addresses this item.

F.04.b. For pipelines operating at or above 30% SMYS, verify that the operator meets the following requirements:

i. If the operator establishes a reassessment interval greater than seven (7) years, a confirmatory direct assessment (refer to Protocol G) must be performed at intervals not to exceed seven (7) years followed by a reassessment at the interval established by the operator (refer below). [§192.939(a)]…

Issue Identified
Concern: PG&E personnel stated that when a new threat is identified, PG&E gives itself 10 years to assess the segment for that new threat from the date the threat is identified. Further, PG&E decouples the assessment due date from the established assessment due date for other threats. This could extend the reassessment interval beyond 7 years, and depending on the new threat identified for a segment, PG&E could extend the reassessment cycle through an impermissible method.

While Part 192, Subpart O is silent on the addition of newly identified threats to an already existing HCA segment that has been baseline assessed, SED staff does not believe PG&E's method of incorporating new threats is allowable unless Part 192.939(a) is followed in incorporating a new baseline assessment for the new threat. This code section states:

> *(a) Pipelines operating at or above 30% SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. <u>The maximum reassessment interval by an allowable reassessment method is seven years</u>.*

If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals… [Underline Added]

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941.

This means that PG&E must do an assessment once every seven years by an allowable method.

There are multiple ways that PG&E can extend the reassessment cycle beyond seven actual years. The first way is for PG&E to use 192.939(a) to extend the reassessment cycle beyond seven years by using Confirmatory Direct Assessment (CDA) in the seventh year. Therefore, PG&E could assess for newly identified threats, on a period of 10 years with the caveat that PG&E would need to do a CDA at year 7. An extended reassessment cycle (i.e., greater than 7 years) for a new threat should be consistent with risk identified in doing the evaluation required by 192.937(b).

This is also consistent with PHMSA's FAQ-40 (Frequency of Assessments). The question and answer are as follows:

How often must periodic integrity assessments be performed on HCA pipeline segments after the baseline assessment is completed?

Assessments of some kind must be performed at intervals no longer than seven years. Assessments for all threats must be performed using in-line inspection, pressure testing, direct assessment, or "other technology" within the maximum intervals specified in 192.939, which vary based on operating stress levels. (Operators whose integrity management programs satisfy the criteria for "exceptional performance" in 192.913 can establish longer intervals for these assessments, based on their risk assessments). Seven-year assessments conducted within those maximum intervals (if the maximum interval exceeds 7 years) can be performed using confirmatory direct assessment or, for low-pressure pipelines, the methods specified in 192.941.

The second way to extend the reassessment cycle is a result of the "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011." This is covered in FAQ-41. The question and answer are as follows:

FAQ-41. Does the requirement that gas pipeline operator establish assessment intervals not to exceed a specified number of years mean calendar years (i.e., *pipe assessed in 2004 must be re-assessed during 2011) or actual years? [06/09/2004] [Revised 02/22/2016]*

Re-assessments must be conducted in accordance with an operator's procedures for determining the appropriate reassessment interval. Prior to the enactment of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, the maximum interval was set using actual years from the date of the previous assessment. Effective January 3, 2012, this was modified such that the maximum interval may be set using the specified number of calendar years. For example, a pipe segment assessed on March 23, 2004 with a seven year interval must be re-assessed before December 31, 2011, using at least confirmatory direct assessment. This segment would need to be re-assessed using one of the methods specified in the rule before December 31, 2014, December 31, 2019 or December 31, 2024, depending on its operating stress (see § 192.939). Note that this change from actual years to calendar years is specific to gas pipeline reassessment interval years and does not alter the actual year interval requirements which appear elsewhere in the code for various inspection and maintenance requirements.

This could result in an extension of the assessment cycle up to almost eight actual years depending on PG&E's needs. The foregoing analysis is for pipeline segments operating at or above 30% of SMYS.

Request: Please provide a report to SED staff on this topic during the next integrity assessment scheduled for March of 2018.

PG&E's Response:
PG&E continues to follow the requirements of 192.939, sections of ASME B31.8S-2004 (incorporated by reference) and PHMSA FAQs, including the performance of integrity assessments on covered segments at the required intervals. PG&E will provide a more detailed update on the approach to performance of baseline assessments for newly identified threats on existing HCAs during the next audit, scheduled for March 19th, 2018.

SED's Conclusion:
Per SED's request, PG&E provided an update on this issue during the 2018 TIMP audit. It is SED's understanding that PG&E agrees with SED's conclusion regarding performance of baseline assessments for newly identified threats on existing HCAs, and that they must be done with the framework of 192.939.

F.04.c. For pipelines operating < 30% SMYS, verify that the operator selects one of the following reassessment approaches:

i. *Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in §192.939(a)(1) except that the stress level referenced in §192.939(a)(1)(ii) would be adjusted to reflect the lower operating stress level. <u>However, if an established interval is more than seven (7) years, the operator must conduct at seven (7) year intervals either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.</u> An operator must use the test pressures specified in*

ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939.[§192.939(b)(1)]

Issue Identified

Concern:

The foregoing analysis in protocol F.04.b is also applicable to this protocol question where PG&E has pipeline segments operating at <30% SMYS.
§192.939(b)(1) states:

> *(b) Pipelines Operating Below 30% SMYS. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—*
>
> *(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941…*

Therefore, in this case (i.e., pipeline segments operating at less than 30% SMYS), PG&E could baseline assess for newly identified threats on already existing HCA segments that have been baseline assessed, on a period of 10 years with the caveat that PG&E would need to do a CDA or low stress reassessment at year 7 as identified in the table from 192.939 above. An extended reassessment cycle (i.e., greater than 7 years) for a new threat should be consistent with risk identified in doing the evaluation required by 192.937(b).

Request: Please provide a report to SED staff on this topic during the next integrity assessment scheduled for March of 2018.

PG&E's Response:

PG&E continues to follow the requirements of 192.939, sections of ASME B31.8S-2004 (incorporated by reference) and PHMSA FAQs, including the performance of integrity assessments on covered segments at the required intervals. PG&E will provide a more detailed update on the approach to performance of baseline assessments for newly identified threats on existing HCAs during the next audit, scheduled for March 19th, 2018.

SED's Conclusion:

Per SED's request, PG&E provided an update on this issue during the 2018 TIMP audit. It is SED's understanding that PG&E agrees with SED's conclusion regarding performance of baseline assessments for newly identified threats on existing HCAs, and that they must be done with the framework of 192.939.

Violations, Concerns and Recommendations Identified in Protocol Area D: DA Plan

This protocol area was skipped since it was audited in 2016 and will be audited again in 2018.

IV. Violations, Concerns and Recommendations Identified in Protocol Area E: Remediation

No issues identified.

V. Violations, Concerns and Recommendations in Identified in Protocol Area F: Continual Evaluation and Assessment

No issues identified

VI. Violations, Concerns and Recommendations Identified in Protocol Area G: Confirmatory DA

This protocol area was skipped since it will be audited during the 2018 TIMP audit.

VII. Violations, Concerns and Recommendations Identified in Protocol Area H: Preventative and Mitigative Measures

No issues identified.

VIII. Violations, Concerns and Recommendations Identified in Protocol Area I: Performance Measures

No issues identified.

IX. Violations, Concerns and Recommendations Identified in Protocol Area J: Record Keeping

No issues identified.

X. Violations, Concerns and Recommendations Identified in Protocol Area K: Management of Change (MOC)

No issues identified.

XI. Violations, Concerns and Recommendations Identified in Protocol Area L: Quality Assurance

No issues identified

XII. Violations, Concerns and Recommendations Identified in Protocol Area M: Communications Plan

No issues identified.

XIII. Violations, Concerns and Recommendations Identified in Protocol Area N: Submittal of Program Documentation

No issues identified.