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February 21, 2020

Mr. Dennis Lee
Program & Project Supervisor
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission
505 Van Ness Ave, 2nd Floor
San Francisco, CA 94102

Dear Mr. Lee:

The Safety and Enforcement Division (SED) of the California Public Utilities Commission conducted a G.O. 112, Operation and Maintenance Inspection of Southern California Gas Company's (SoCalGas) and San Diego Gas and Electric Company's (SDG&E) Transmission Integrity Management Programs (TIMP) from the weeks of October 7-11, 2019, October 14-18, 2019 and November 12-15, 2019. The inspection included a review of procedures and records related to the TIMP In-Line Inspection (ILI) program.

SED staff identified one probable violation and four areas of concern. Attached are Southern California Gas Company's (SoCalGas) and San Diego Gas and Electric Company's (SDG&E) written responses.

Please contact Troy A. Bauer at (909) 376-7208 if you have any questions or need additional information.

Sincerely,

Troy A. Bauer
Pipeline Safety and Compliance Manager

CC:
Terence Eng, SED-GSRB
Kai Cheung, SED-GSRB
James Zhang, SED-GSRB
Khoa Le, SoCalGas and SDG&E
Rodger Schwecke, SoCaGas and SDG&E

2019 SoCalGas and SDG&E Transmission Integrity Management Programs (TIMP) Inspection Report 10/7/2019 to 11/18/2019

Notice of Probable Violations

1. Southern California Gas Company and San Diego Gas and Electric Company meets the requirements for four overall performance metrics and nine threat specific performance metrics required under 192.945(a). However, as identified in the first sentence of 192.945(a), each operator must include measures to evaluate the integrity of each covered pipeline segment. Both the nine threat specific performance metrics and the four overall performance metrics are aggregate performance metrics and do not evaluate the integrity of each covered pipeline segment.

   Southern California Gas Company and San Diego Gas and Electric Company has no performance metrics to evaluate the integrity of each covered pipeline segment in accordance with 192.945(a).

   According to DR #37, Southern California Gas Company and San Diego Gas and Electric Company does not include any other performance metrics, which is required by code.

   Response:
   SoCalGas/SDG&E have implemented a prescriptive Integrity Management (IM) program that meets the requirements of 192.945(a) through the aggregation and analysis of the overall and threat-specific performance metrics specified in ASME/ANSI B31.8S. As reiterated in the PHMSA Advisory ADB–2014–05, "the[se] gas requirements invoke ASME B31.8S–2004, Managing System Integrity of Gas Pipelines. Section 9 of this standard provides guidance on the selection of performance measures." ASME/ANSI B31.8S directs operators to measure performance including all the threat-specific metrics in Nonmandatory Appendix A (Table 9) and the four program measurements specified in 9.4(b). As stated in the 2019 TIMP Audit DR#37, SoCalGas/SDG&E has incorporated PHMSA's approach to performance self-evaluations of covered segments.

   SoCalGas/SDG&E agree that a TIMP performance evaluation process should continually evaluate opportunities to implement relevant performance metrics beyond those required by the Code of Federal Regulations (CFR) and actively practice this. SoCalGas/SDG&E will perform this evaluation during the 2020 calendar year.

Areas of Concern / Recommendation

1. In the ILI standard 167.0210, Rev 2.4, page 7, Southern California Gas Company and San Diego Gas and Electric Company summarizes the training requirements for each job category in Table 1. But in standard 167.0210, Rev 3, Southern California Gas Company and San Diego Gas and Electric Company does not have a table summarizing the training requirements for each job category.

   GSRB staff recommends Southern California Gas Company and San Diego Gas and Electric Company include a table to summarize the training requirements and if the training is periodic including the TIMP101 training.

   Response:
   SoCalGas/SDG&E acknowledges the recommendation from the GSRB staff. The current in-line inspection gas standard for both utilities will be updated to include the minimum training qualifications for each job category.

2. For a level 2 validation (as defined in API 1163, Section 8), 167.0210, Section 9.4.2 says you need at least two digs to get to this level.

   For a level 3, Southern California Gas Company and San Diego Gas and Electric Company does not have a hard and fast rule that defines the difference between the two levels of validation. GSRB staff advocates for a hard and fast rule to define the difference.

   Response:
   API 1163, In-line Inspection Systems Qualification, will be incorporated by reference into 49 CFR Part 192.493 as part of the new rulemaking changes initiated by PHMSA, which go into effect on July 1, 2020. SoCalGas/SDG&E will develop guidelines to differentiate between the 3 levels of validation identified in the standard. These requirements will be incorporated into the in-line inspections standards, for both utilities, by the time the new regulation goes into effect.

3. Add language to define "should" statements, which are consistent with this IA question and address FAQ 244. The language can be put in TIMP.1 or any other standard Southern California Gas Company and San Diego Gas and Electric Company deems appropriate.

   Response:
   SoCalGas/SDG&E currently address the requirements of PHMSA FAQ 244 and CFR section. PHMSA FAQ 244 begins by stating that “OPS expects operators to implement “should” statements in industry standards that are invoked by the rule.” NACE SP0502, Pipeline External Corrosion Direct Assessment Methodology, is incorporated by reference in 49 CFR 192.7. SoCalGas/SDG&E have defined and incorporated all “should”

statements in the recommended practice into the Definitions section of Gas Standards 167.0209/G8179, External Corrosion Direct Assessment Procedure.

4. SEMPRA has two pipelines where the screening criteria in B31.8S-2004 are almost met. These pipelines are Line 225 and Line 2001 East. GSRB staff advocates two things:

   1. Include a footnote in your threat identification procedure (167.0203) to alert engineers of the fact that the screening criteria do not account for approximately 25-35% of SCC failures.

   2. Do an integrity assessment for SCC on the two pipelines identified above.

   Response:
   SoCalGas/SDG&E conducts identification of threats of each covered segment in accordance with 192.911(c), 192.917(a)(1) and ASME/ANSI B31.8S-2004 (incorporated by reference). Specific to the Stress Corrosion Cracking (SCC) threat, ASME/ANSI B31.8S-2004 Appendix A3.3 lists the criteria to consider:

   (a) operating stress > 60% SMYS
   (b) operating temperature > 100°F
   (c) distance from compressor station ≤ 20 miles
   (d) age ≥ 10 years
   (e) all corrosion coating systems other than fusion-bonded epoxy (FBE)

   SoCalGas/SDG&E considers these criteria in accordance with ASME/ANSI B31.8S-2004 Appendix A3.3. The NACE RP0204-2004 Stress Corrosion Cracking Direct Assessment Methodology document acknowledges ASME B318S as the primary guidance document for SCC threat evaluation, and further the NACE document clarifies that its function is to serve as guidance for SCC assessment in situations where 1) the threat has been both identified as a risk for significant SCC, and 2) where SCCDA is identified an appropriate approach. As such, the NACE document is not incorporated by reference in 49 CFR Part 192 or included as amplifying threat identification criteria.

   The preceding discussion aside, neither ASME or NACE preclude the use of additional actions to enhance the threat management process, and as a proactive measure, SoCalGas/SDG&E have also implemented additional NDE actions (magnetic particle inspections) at every TIMP related direct examination site (regardless of the SCC threat identification criteria) to enhance the data collection utilized as part of the threat identification process. This supplemental inspection of the pipe condition is valid for all forms of surface cracking including those not explicitly identified in any threat criteria. Thus far, SCC has not been detected at any direct examination site. This measure (which is above and beyond code requirements and includes pipeline segments that do not meet above SCC criteria) serves to provide an additional measure of detection for risk factors related to significant SCC.

The threat identification process is applied across all covered pipe segments (in accordance with the regulations) in order to ultimately assign the appropriate assessment methods to each covered segment in a consistent manner. Neither L225 nor L2001 East have a history of failure due to SCC. They do not have any indications of SCC detected through direct examination and do not satisfy the programmatically consistent threat identification criteria for an active SCC threat identified by the process described above. Therefore, a SCC assessment for those pipelines is not required or necessarily appropriate at this time.