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Mr. Ken Bruno
Program Manager
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission
320 W. Fourth Street, Suite 500
Los Angeles, CA 90013

Dear Mr. Bruno:

The Safety and Enforcement Division (SED) of the California Public Utilities Commission conducted a G.O. 112 Inspection of SoCalGas and SDG&E's TIMP Program from August 8-19, 2016.

SED made eight recommendations. Attached are SoCalGas and SDG&E's written responses and corrective actions.

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

Sincerely,

Troy A. Bauer

CC: Michelle Wei, SED/GSRB
Kan Wai Tong, SED/GSRB

ATTACHMENT

Recommendations and Concerns

1. **Protocol Area A. Identify HCAs:**

A03 Identified Sites

Protocol A.03.b states:

> *"Identified sites must be identified using the following sources of information: [§192.905(b)]*
>
> 1. *Visible markings such as signs, or*
> 2. *Facility licensing or registration data on file with Federal, State, or local government agencies, or*
> 3. *Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public."*

Supplemental guideline states in part:

> *"Operators may be able to improve on this source of information by providing the officials with copies of their system maps and/or by meeting face to face with the officials in an effort to improve communications and the understanding of what information is desired." (See FAQ-170, FAQ-120, and FAQ-195)*

The SEU's Gas Standard TIMP.3, Section 3 of Southern California Gas Company (SoCalGas) states in part:

> *"Prior to the published Baseline Assessment Plan Schedule in 2004, the Public Affairs department at the Utilities sent out letters to public officials requesting information on identified site locations. A limited response was received; therefore the Utilities also use other methods of gathering identified site information"*

Although, SEU uses other methods in gathering identified site information, the public agencies typically have more comprehensive information than those found in the public domains. As a result, SED recommends that SEU proactively communicate with the public agencies and officials in order to improve the source of information for locating the identified sites.

RESPONSE:

Currently, SoCalGas/SDG&E use a combination of data sources to update their datasets in support of their annual updates of their identified site for HCA analysis. Feedback from public officials is one of many datasets used in SoCalGas' and SDG&E's HCA analyses. As noted in Gas Standard 192.02 Procedure for HCA Segment Identification and TIMP Chapter 3, SoCalGas/SDG&E have attempted to reach out to public officials to obtain possible identified site locations. However, in previous efforts, minimal responses were received. As noted, SoCalGas/SDG&E annually update their identified site data sets using tax parcel information , and update their data sets every three years using information from various other public agencies (such as California Department of Education and California

Department of Social Services). This information is used to augment field reports from the companies' pipeline patrol and HCA pre-assessment field activities. However, based upon SED's recommendation, SoCalGas/SDG&E are working to implement new technology that will allow public agencies and officials, who chose to participate, a platform through which to continually communicate information regarding identified sites.

2. Protocol Area C. Identify Threats, Data Integration, and Risk Assessment:

C.01 Threat Identification

Protocol C.01.e states in part:

> *"Verify that the approach appropriately considers industry data and experience."*

The Gas Standard TIMP.5, Section 2.5 of SoCalGas states in part:

> *"Develops and modifies the overall risk and threat strategy by providing on company experiences and improvement."*

The industry data and experience often provides valuable information in the improvement of the overall risk and threat strategy. As a result, it is recommended that SEU incorporate both industry and company data and experience in the improvement of the overall risk and threat strategy.

RESPONSE:

SoCalGas/SDG&E agree with this recommendation. As a result, TIMP.5, section 2.5 was revised to include industry experiences in its development and modification of the overall (TIMP) risk and threat strategies. Below is a screenshot of the revised TIMP.5:

2.5 The **Risk & Threat Steering Committee** is composed of the Pipeline Integrity Director, Assessment Planning & Records Manager, Transmission Integrity & Analysis Manager, GIS Management Manager, Integrity Assessment & Remediation Manager and Risk & Threat Team Lead. The Committee is responsible for annually providing guidance to the development and modification of the overall risk and threat strategy by providing guidance on company and industry experiences and improvements. This includes, but is not limited to, the following items:

- Risk Algorithm **GAS STANDARD 167.0207/G8177**, *TIMP Risk Algorithm*
  - Threat thresholds and rationale
  - Weight factors for Likelihood of Failure
  - Weight factors for Consequence of Failure
  - Attribute weight factors for threats
- Modifications to risk assessment software.

Figure 1: Screenshot of revised TIMP.5, Threat and Risk Assessment

3. **<u>C.04 Validation of the Risk Assessment</u>**

<u>Protocol C.04.c states in part:</u>

> *"Verify that records demonstrate that the risk assessment was revised as necessary as new information was obtained or conditions changed on the pipeline segments"*

SED reviewed the pipeline segment 1018, 0+00 to 167+00 (HCA ID: 4000026) with SEU during the audit. The review revealed that the pipeline segment records were not updated. For example, the pipeline 1018, 0+00 to 167+00 was replaced in 12/7/2012; however, the 2014 risk and threat report still showed that the construction/replacement date of that pipeline was 5/26/1966. Another example, all transmission pipelines are required to be catholically protected, SEU's record indicated the cathodic protection of the transmission pipeline as unknown during the audit.

SED recommends SEU to revise its data transferring and the quality assurance processes in order to validate that the information used in the risk assessment is up-to-date and accurate.

<u>RESPONSE:</u>

SoCalGas/SDG&E are continuously working towards incorporating additional operational/maintenance data in their High Pressure Pipeline Database (HPPD. In order to determine where to best allocate resources (i.e., personnel to conduct QA/QC reviews, etc.), SoCalGas/SDG&E revised their High Pressure Project Reconciliation policy to require a target upload timeline of 180 days, for new information updating the HPPD from the date of the Notice of Operation (NOP). The new upload requirement is applicable to Completion Drawings, As-Built Survey Data, Pipeline Feature Data Collection Forms, and Form 2112-Pipeline Database Update. For CP specifically, SoCalGas/SDG&E is reviewing all CP voltages received through their SAP and MAXIMO work management systems in order to update any missing/erroneous HPPD values. SoCalGas/SDG&E have a plan to incorporate CP criteria data for all transmission pipelines into the HPPD by the end of 2017.

4. **Protocol Area D. DA Plan:**

D.12 SCCDA Assessment, Examination, & Threat Remediation

Protocol D.12.b states in part:

> *"Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with* *ASME B31.8S-2004, Appendix A3.4* *(b)) within 12 months of the failure, using a documented hydrostatic retest program* developed specifically for the affected segment(s), as required by ASME B31.8S-2004, Appendix A3.4."

Supplemental guideline states in part:

> *"Upon returning the pipeline to gas service, conduct a flame ionization survey of the pipeline segment."*

SoCalGas 's Gas Standard 182.0170, Section 4.8.3 specified that each weld is visually inspected and nondestructively tested after being placed into service. The supplemental guideline requires a flame ionization survey upon returning the pipeline to gas service. As a result, SED recommends that SEU review and revise the Gas Standard 182.01.70 accordingly.

RESPONSE:

SoCalGas/SDG&E agree with the recommendation that a leak survey be conducted, for pipelines which have experienced an in-service leak or rupture attributable to SCC, upon returning the pipeline to service following a hydrostatic pressure test. However, SoCalGas/SDG&E reserve the right to utilize an alternative, equivalent leak survey method. Gas Standard 167.0216, Stress Corrosion Cracking Direct Assessment Procedure, was republished to incorporate this recommendation:

4.4.2. Response and Remediation

The procedures for response and remediation following the discovery of SCC must be in accordance with Part 192.933 and ASME B31.8S A3, taking into account NACE 0204-2004.

If cracks are found, they will be removed by grinding. The pipeline maximum operating pressure will be reduced to 80% of the highest recent operating pressure while grinding and assessment takes place. The remaining strength of the ground pipe should be evaluated in accordance with **Gas Standard 182.0050** and repaired in accordance with **Gas Standard 223.0180**. The pipeline should then be recoated, reinstated and returned to full service.

If the cracks are severe, >30% wall thickness, the cracked section should be cut out, or alternatively cracks must be removed by grinding, evaluated in accordance with **Gas Standard 182.0050** and repaired in accordance with **Gas Standard 223.0180**. The segment can be returned to service at a reduced operating pressure of 80% of the highest recent operating pressure until a pressure test can be completed to ensure integrity. A leak survey or equivalent method will be performed after the pipeline has been pressure tested and prior to returning to service.

Figure 2: Screenshot of revised Gas Standard 167.0216, SCC-DA Procedure

5. **<u>Protocol Area E. Remediation:</u>**

<u>E.01 Program Requirements for Discovery, Evaluation and Remediation Scheduling</u>

<u>Protocol E.01.c states:</u>

> *"Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. [§192.933(c)]"*

Although the Section 7.2.1, paragraph 4 of ASME specifies the requirement for monitored indications, SoCalGas 's Gas Standard TIMP.10, Section 4 did not define the inspection frequency of the monitored conditions. SED recommends that SEU review the ASME standards and revise the Gas Standard TIMP.10 to address the requirements of the monitored conditions.

<u>RESPONSE:</u>

SoCalGas/SDG&E agree with this recommendation. As a result, TIMP.10, section 4.4 was revised to address the inspection requirements for monitored conditions. Below is a screenshot of the revised TIMP.10:

> 4.4. Schedule for Evaluation and Remediation
>
> All anomalies discovered through an approved integrity assessment method (refer to **Manual TIMP.9)** shall be examined within the following timeframes[1] according to their anomaly classification:
>
> - Immediate repair conditions – examination or temporary pressure reduction within a period not to exceed 5 days.
> - One-year conditions – within 365 days.
> - Scheduled conditions – as defined by Figure 4 in ASME B31.8S.
> - Monitored conditions - do not require examination and evaluation until the next scheduled integrity assessment interval provided that they are not expected to grow to critical dimensions prior to the next scheduled assessment.
>
> After examination and evaluation, any defect found to require remediation shall be promptly scheduled in accordance with **Standard 167.0236** or **Standard G8166** or the operating pressure shall be lowered to a safe margin until remediation is completed.

Figure 3: Screenshot of revised TIMP.10, Remediation

6. Protocol Area H. Preventive and Mitigative Measures

H.01 General Requirements (Identification of Additional Measures)

Protocol H.01.a states:

> *"Verify that the process for identifying additional measures is based on identified threats to each pipeline segment and the risk analysis required by §192.917. [Note: Protocol H.08 addresses the implementation decision process for additional preventive and mitigative measures.] [§192.935(a)]"*

SoCalGas 's Gas Standard TIMP .12, Section 3 did not address outside force as weather related condition. SED recommends that SoCalGas incorporate the outside force as weather related condition in the Gas Standard.

RESPONSE:

SoCalGas/SDG&E agree with this recommendation. Since "Outside Force" is addressed as part of the "Weather Related and Outside Force" threat category, it is appropriate to clearly state its inclusion within the table. As a result, TIMP.12, section 3 was revised from "Weather Related" to "Weather Related & Outside Force":

PREVENTIVE AND MITIGATIVE MEASURES	SOCALGAS: TIMP.12 SDG&E: TIMP.12

in 49CFR 192.935(a):

From ASME B31.8S-2004	3rd Party Damage	External Corrosion	Internal Corrosion	Equipment	Incorrect Operation	Weather Related & Outside Force	Manufacturing	Construction	Stress Corrosion Crckg
Pipeline Patrol Increase	X	X				X	X		

Figure 4: Screenshot of revised TIMP.12, Preventive and Mitigative Measures

7. **<u>Protocol Area N. Submittal of Program Documents</u>**

<u>N.01 Integrity Management Program Document Submittal</u>

<u>Protocol N.01.a states in part:</u>

> *"PHMSA and State or local pipeline safety authorities, as applicable. [§192.911(n)]……."*

The title of the Gas Standard TIMP.20, Section 10 states that:

"How to Notify PHMSA"

The contents of that section actually describe the process to notify PHMSA and CPUC. As a result, SED recommends SEU to modify the title in order to avoid the unnecessary confusion for the readers.

<u>RESPONSE:</u>

SoCalGas/SDG&E agree with this recommendation. As a result, TIMP.20, section 10 was revised to clarify the section addresses both PHMSA and CPUC notifications:

> 10. HOW TO NOTIFY PHMSA and CPUC– Reference: §192.949
>
> The Pipeline Safety and Compliance Manager is responsible for contacting PHMSA and the CPUC regarding requirements in this document. The Pipeline Safety and Compliance Manager shall notify the PHMSA and the CPUC in accordance with 49 CFR Subpart O 192.949 and **Gas Standard 183.08**, *Pipeline Safety Reports and Notifications to CPUC and PHMSA*.

Figure 5: Screenshot of revised TIMP.10, Remediation

8. Protocol Area B. Baseline Assessment Plan

B06 Changes

Protocol B06.b states in part:

"Verify that required BAP changes have been made and that for all changes, the following are documented: [ASME B31.8S-2004, Section 11(a)]"

Supplemental guideline states in part:

"FAQ-111 states that changes requiring PHMSA notification would include significant revisions to the BAP such as significant delays in segment assessments or changes that affect the overall manner in which an operator is conducting its IM program."

SoCalGas 's Gas Standard TIMP 14, Section 3.4 did not address FAQ-111. SED recommends that SEU review and address the FAQ-111 in the Gas Standard accordingly.

RESPONSE:

SoCalGas/SDG&E agree with this recommendation. As a result, TIMP.14, section 3.4 was revised to include FAQ-111 as an example of a significant change:

3.4. Significant Change

A change that is significant is any modification to the Program or transmission system that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the Program Elements. All significant changes require PHMSA notification within 30 days of adoption (See **TIMP.20,** *Regulatory Interaction*). Examples of significant changes include (but are not limited to):

- Merger or major acquisition (per FAQ 10)
- Significant change in total HCA mileage (25% change per FAQ 183)
- Application of new assessment technologies (per FAQ 97)
- Significant revisions to the assessment (BAP) schedule; such as significant delays in segment assessments, or changes that affect the overall manner in which an operator is conducting its IM program (per FAQ 111)
- Change in integrity management method (i.e., prescriptive vs. performance based)

Figure 6: Screenshot of revised TIMP.20, Management of Change