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

February 14, 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-2018-01-PGE29-03

SUBJECT: General Order (GO) 112-F Gas Inspection of PG&E's Operations and Maintenance plans, Design and Construction standards, and Part 191 related plans

Dear Mr. Singh:

The Safety and Enforcement Division (SED) of the California Public Utilities Commission conducted a General Order 112-F inspection of Pacific Gas & Electric Company's (PG&E) Operations and Maintenance plans, Design and Construction standards, and Part 191 related plans from January 22 to 26, 2018.

SED's findings are noted in the Summary of Inspection Findings (Summary) which is enclosed with this letter. The Summary reflects only those particular records and procedures that SED reviewed during the inspection.

Within 30 days of your receipt of this letter, please provide a written response indicating the measures taken by PG&E to address the violations and observations noted in the Summary.

If you have any questions, please contact Alula Gebremedhin at (415) 703-1816 or by email at Alula.Gebremedhin@cpuc.ca.gov.

Sincerely,

Kenneth A. Bruno

Kenneth Bruno
Program Manager
Gas Safety and Reliability Branch
Safety and Enforcement Division

Enclosure: Summary of Inspection Findings

cc: Mike Bradley, PG&E Compliance
Susie Richmond, PG&E Gas Regulatory Compliance
Dennis Lee, SED
Kelly Dolcini, SED

SUMMARY OF INSPECTION FINDINGS

I. Probable Violations

1. Title 49 CFR §192.475(c) states in part:

   "(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders."

   SED reviewed PG&E's internal corrosion control procedures and determined that the procedures do not have any measures to ensure that gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m3) at standard conditions (4 parts per million) is not stored in pipe-type or bottle-type holders.

   Although the current procedure requires additional investigation when gas testing reveals hydrogen sulfide levels greater than the limit specified in Title 49 CFR §192.475(c) and PG&E did not find any indication of such gas being stored in its pipe-type or bottle-type holders, the procedure does not clearly prohibit storage of such gases in pipe-type or bottle-type holders which would be a violation of Title 49 CFR §192.475(c). Additionally, the procedure does not state how PG&E ensures that the gas is within the allowable levels of hydrogen sulfide prior to its storage in pipe-type of bottle type holder.

   Therefore, PG&E is in violation of Title 49 CFR §192.475(c) for its failure to have an adequate procedure to address the Title 49 CFR §192.475(c) requirement.

2. Title 49 CFR §192.605(a) states in part:

   "Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year."

   SED found some instances where the PG&E documents provided to SED were not updated with the latest information, and may have caused confusion or complications with compliance.

   a. PG&E Utility Standard A-36, titled "Design and Construction Requirements; Gas Lines and Related Facilities" references CPUC GO 112-D several times. The current standard is CPUC GO 112-F and the PG&E document should reflect that.
   b. PG&E Utility Standard TD-4137S, titled "Pipeline Test Requirements" references CPUC GO 112-E. The current standard is CPUC GO 112-F and the PG&E document should reflect that.
   c. PG&E Utility Standard TD-4800P-02, titled "Gas Transmission Pipeline Abnormal Operating Conditions" contains a table titled "Table 1. Standards and Procedures Addressing Gas Transmission Pipeline AOCs" which outlines the various procedural documents that address how to identify and react to AOCs. During the inspection,

PG&E reported that two of the documents in that table (TD-4001P-08 and TD-4020S) were now superseded by other documents, and were no longer current or relevant. These changes should be reflected in TD-4800P-02, which refers to other procedures.

d. PG&E Utility Standard TD-4125P-03 references CPUC GO 112-E for notifications for increasing MAOP and testing requirements. The current standard is CPUC GO 112-F and the PG&E document should reflect that.
e. PG&E Utility Standard TD-4430P-02 Att2 on page 8 under "Relief Devices" the Governing Document is listed as "WP4430-03". During the inspection, PG&E reported that the document "WP4430-03" is now obsolete.

Therefore, PG&E is in violation of Title 49 CFR §192.605(a) for its failure to capture and update the incorrect information during the annual review of the documents as it required by Title 49 CFR §192.605(a).

3. Title 49 CFR §192.609 states:

"Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40 percent of SMYS, or ***indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine****;*

> *(a) The present class location for the segment involved.*
> *(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.*
> *(c) The physical condition of the segment to the extent it can be ascertained from available records;*
> *(d) The operating and maintenance history of the segment;*
> *(e) The maximum actual operating pressure [the maximum pressure that occurs during normal operations over a period of 1 year] and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and,*
> *(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area."*

SED reviewed PG&E's gas pipeline class location procedures and determined that procedure TD-4127S does not adequately address Title 49 CFR §192.609 as the requirements in Title 49 CFR §192.609 are only included under the section for "Pipeline Operating Over 40% SMYS" in the procedure. All pipelines should be subject for the required Title 49 CFR §192.609 study when the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location. However, PG&E indicates that its practice follows Title 49 CFR §192.609 and all pipelines are screened for the required §192.609 study. SED recommends PG&E to revise its procedure TD-4127S.

In addition, the current gas pipeline class location procedures lack detail on how PG&E conducts its study to determine the items listed in Title 49 CFR §192.609(a)-(f). PG&E indicated that a PG&E internal form is used by its personnel when conducting the required Title 49 CFR §192.609 study and it addresses the items listed in listed in Title 49 CFR §192.609(a)-(f). (Please note that page 2 of the PG&E internal form states that, "In accordance with 49 CFR §192.609, a study must be performed on pipeline sections that have changed up in class and operating at greater than 40% SMYS.")

SED recommends PG&E to revise this form to ensure that it does not only limit the study to be done with pipeline operating at greater than 40% SMYS and include or reference it in its gas pipeline class location procedures.

Therefore, PG&E is in violation of Title 49 CFR §192.609 for its failure to adequately address the requirements of Title 49 CFR §192.609 to include transmission pipelines which operates below 40% SMYS.

4. Title 49 CFR §192.611 states:

"(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS [specified minimum yield strength] of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per § 192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per § 192.620, the alternative maximum allowable

operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date."

SED reviewed PG&E's gas pipeline class location procedures and determined that TD-4127S does not adequately address the requirement in Title 49 CFR §192.611(d) as the requirement in Title 49 CFR §192.611(d) is only included under the section for "Pipeline Operating Over 40%SMYS" in the procedure. All pipeline should be subject for the requirement in Title 49 CFR §192.611(d) regardless of the %SMYS.

SED recommends PG&E to revise its procedure TD-4127S. In addition, the current procedure is not clear on how PG&E addresses the requirements in Title 49 CFR §192.611(a). PG&E indicated that the three options under Title 49 CFR §192.611(a) are being considered by its personnel when they perform corrective action to make pipeline commensurate with the present class location as required in its procedure TD-4127P-03.

Therefore, PG&E is in violation of Title 49 CFR §192.611(a) for its failure to adequately address the requirements of Title 49 CFR §192.611(a) to include in its procedure the essential items that the personnel need to consider when performing such corrective action and reference Title 49 CFR §192.611(a) if it is being considered during the process.

PG&E also needs to revise its procedure TD-4127S to adequately address the Title 49 CFR §192.611(d) requirement, which relate to the Title 49 CFR §192.609 requirement noted under NOPV 3 above.

II. Areas of Concern/ Observations/ Recommendations

1. Title 49 CFR §191.5(b) states:

   "Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800-424-8802 (in Washington, DC, 202 267-2675) or electronically at http://www.nrc.uscg.mil and must include the following information:

   > *(1) Names of operator and person making report and their telephone numbers.*
   > *(2) The location of the incident.*
   > *(3) The time of the incident.*
   > *(4) The number of fatalities and personal injuries, if any.*
   > *(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages."*

   PG&E's procedure TD-4413P-01 ("Reporting of Gas Events") Step 3.1.2(b) states:

   "*Be prepared to provide information on the name of the operator, the name and telephone number of the person making the report, the location of the incident, the number of fatalities and injuries, and all other significant facts that are relevant to the cause of the incident or extent of the damages. Report the DOT report number and the time the NRC was called*".

   SED noted that PG&E's procedures do not specify to provide the time of the incident to the NRC, as required by Title 49 CFR §191.5(b) (3).

2. Title 49 CFR §191.15(c) states:

   "Where additional related information is obtained after a report is submitted under paragraph (a), (b) of this section, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report."

   PG&E's procedure "Reporting of Gas Events" TD-4413P-01 Step 6.1.4 states:

   *"When the **information is complete**, then prepare and submit a supplemental report."*

   By not specifying when reports will be provided, PG&E's procedures do not guarantee providing reports with the timeliness of "as soon as practicable".

3. Title 49 CFR §191.22(c) (2) states:

   "An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

   > *(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.*

(ii) A change in the name of the operator;
(iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, or LNG facility;
(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter; or
(v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter"

PG&E's procedure "Gas Legal Requirements, Government Commitments and Planned Activity Reporting" TD-4012S Section 5 covers operator registry notifications, but has no language addressing the requirements of Title 49 CFR §191.22(c)(2).

While the events covered by Title 49 CFR §191.22(c)(2) are infrequent, and are of such magnitude that PHMSA would most likely learn of the event without PG&E notification, a formal notification procedure must still be in place to address such events.

4. Title 49 CFR §192.727(b) states:

"Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard."

PG&E's Utility Standard A-38 "Procedures for Purging Gas Facilities" states:

"1. Purging is required when:

A. New or existing facilities are brought into service.

B. Existing facilities are temporarily taken out of service and the removal of natural gas is necessary.

C. Lines are abandoned. Section §192.727 of General Order 112 states that abandoned facilities ***do not have to be purged when the volume of gas is so small that there is no potential for hazard****. Company policy requires that all sections of abandoned main be purged. (For abandonment procedures, refer to Standard Practice 463-2)."*

During the inspection, SED asked PG&E if there was a written standard specifying what PG&E considered a *"**volume of gas is so small that there is no potential for hazard."*** PG&E responded in an email on 01/24/2018:

"*While PG&E does not define the volume of gas considered so small there is no potential for hazard, personnel use a CGI to monitor the presence of natural gas to determine whether there is potential for hazards*."

PG&E does not have a specific cutoff value or criteria for when a volume of gas is so small that there is no potential hazard. SED recommends setting a specific cutoff value or other clear criteria for when purging is not required, for consistent application throughout its system.

5. <u>Title 49 CFR §192.741(b) states:</u>

"*On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.*"

PG&E Utility Standard TD-4125P-05, "Recording Pressures in Distribution Gas Systems" states that a permanent pressure recorder is required on

"each high-pressure or semi-high-pressure distribution system" that is *"supplied by a single district regulator station where a complete system outage would constitute 500 or more customer-outage hours. (Determine customer-outage hours based on estimated average outage time for incidents such as regulator freeze-up, third-party damage, etc., from the time of the outage until restoration of service, including response time plus repair time plus relighting time.)"*

SED found that the current procedure does not provide prescriptive guidance on calculating customer-outage hours. SED is concerned that the use of an estimated average outage time for incidents is not a representative value of a complete system outage due to the varying parameters surrounding the incidents (i.e. location of dig-in, proximity of incident to PG&E responders, the number of customers supplied by the single district regulator station, the types of customers served in the distribution system, etc.).
SED recommends that PG&E provide additional guidance in determining the necessity of installing recording gauges, including the parameters and considerations taken into account when calculating customer-outage hours.