STATE OF CALIFORNIA

EDMUND G. BROWN JR., *Governor*

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

September 6, 2013

Ms. Jane Yura, Vice President
Pacific Gas and Electric Company
Gas Operations – Standards and Policies
6121 Bollinger Canyon Road, Office #4460A
San Ramon, CA 94583

GA2012-19

Subject: General Order 112-E, Pacific Gas and Electric Company's Distribution and Integrity Management Program

Dear Ms. Yura:

The staff of the Safety and Enforcement Division (SED) conducted a General Order 112-E audit of Pacific Gas and Electric Company's (PG&E) Distribution Integrity Management Program (DIMP) from December 10-13, 2012. Also in attendance were representatives from the Pipeline and Hazardous Materials Safety Administration (PHMSA). The audit consisted of a review of PG&E's Distribution Integrity Management Plan (RMP-15), including records and documentation demonstrating compliance. SED did not conduct a field inspection during this audit.

Attached is a "Summary of Inspection Findings" which contains the violations and areas of concern the Audit Team (SED staff and PHMSA) identified during the audit. We also incorporated the Audit Team's review of the revisions made to RMP-15.

Please provide a written response indicating the measures taken by PG&E to address the violations and areas of concern within 30 days from the date of this letter.

Pursuant to Commission Resolution ALJ-274, SED staff has the authority to issue citations for each violation found during the audit. SED will notify PG&E of the enforcement action it plans to take after its review of PG&E's audit response.

If you have any questions, please contact Aimee Cauguiran at (415) 703-2055 or by email at aimee.cauguiran@cpuc.ca.gov.

Sincerely,

Michael Robertson, Program Manager
Gas Safety and Reliability Branch
SED/CPUC

Enclosure: Summary of Inspection Findings

Cc: Larry Deniston, PG&E
Larry Berg, PG&E
Christine Cowsert-Chapman, PG&E
Chris McClaren, PHMSA

Summary of Inspection Findings

Areas of Violations

1. 49 CFR §192.1007 – What are the required elements of an integrity management plan?

   "A written integrity management plan must contain procedures for developing and implementing the following elements:
   (a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.
   (1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.
   (2) Consider the information gained from past design, operations, and maintenance.
   (3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, constructions, operations or maintenance activities)."

   a) PG&E's Risk Management Program (RMP)-15 Attachment C lists various data sources used to identify threats and evaluate risks in its distribution system. However, PG&E mainly uses its Integrated Gas Information System (IGIS) and Riskmaster databases to extract data regarding leaks repaired in its natural gas distribution system to perform threat identification and analysis. PG&E provided a copy of a blank A-form (leak repair) which field personnel complete in the field. PG&E enters the information from the A-Form into its IGIS database.

   During the audit, the Audit Team found that although RMP-15 lists the data fields in IGIS and Riskmaster databases that the PG&E DIMP Team (DIMP Team) utilizes to support its threat and risk analysis, PG&E did not identify which of these data fields are required to perform its analysis. Since the IGIS information is dependent on the accuracy and thoroughness of the field personnel completing the A-forms, PG&E needs to specify in RMP-15 the data fields its uses for its threat and risk analysis. This will also provide PG&E better guidance in identifying "data gaps" which will require further research or review of other records. An example of a data field requiring accurate and complete information is whether there was an injury or fatality resulting from a gas leak.

   Furthermore, PG&E uses conservative values for missing information in RMP-15. To avoid possibly skewing the risk ranking due to a large number of conservative default values in a threat population, the Audit Team informed the DIMP Team that it must provide additional specificity in RMP-15 to include identification of missing data, including a plan to acquire missing, inaccurate, or incomplete data necessary to fill in gaps by knowledge. The Audit Team also informed PG&E that RMP-15 must also include the use of other data sources besides the IGIS and Riskmaster databases (i.e. Tangible Property List) to fill in missing required data for analysis and minimize use of default values.

   PG&E revised RMP-15 Revision 4, Section 4.4, to now identify the required data fields for its threat identification. RMP-15 also mentions that additional data processing is typically required.

However, PG&E did not provide a description of the criteria used to "scrub" the data within RMP-15. Please provide SED a copy of the criteria used for data scrubbing.

Additionally, PG&E does not specify in its revised RMP-15 the planned actions to acquire missing or incomplete required data. Although revised RMP-15 Section 4.5 describes the other methods that PG&E uses to collect information about its gas distribution system, PG&E must develop an action plan that clearly emphasizes the importance of collecting the missing required data.

2. 49 CFR §192.1007 – What are the required elements of an integrity management plan?

"(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion, natural forces, excavation damage, other outside force damage, material, or welds, equipment failures, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience."

a) RMP-15 Revision 3 described PG&E's process for identifying Potential threats discovered through field experience, non-leaking incident investigations, internal SMEs (field interviews and field questionnaire), National Transportation Safety Board (NTSB), PHMSA Advisory Bulletins, or other industry reports. The DIMP Team presented its review list of PHMSA Advisory Bulletins to identify threats that may exist in PG&E's system. Additionally, RMP-15 Attachment C lists additional data sources beyond IGIS and Riskmaster which PG&E generally uses during Root Cause Analysis (RCA). However, PG&E only applies its RCA process on Known Threats.

   The Audit Team reviewed RMP-15 and determined that it did not describe how the DIMP Team uses additional data sources, such as excavation damage not resulting in a release of natural gas, near-miss events, and Operations and Maintenance records, to identify Potential threats in its system. Also, PG&E did not include a review of Potential Threats during its Threat Steering Committee (TSC) meetings to ensure that it validates and addresses the Potential Threats. Although these threats may not have caused damage in PG&E's facilities, this will allow an opportunity for the company to be proactive and address the threats before they cause significant damage or injury.

   Revised RMP-15 Attachment E contains a TSC meeting agenda template, which includes a discussion of new Potential Threats. However, the Audit Team determined that it still is not clear how the DIMP Team or the TSC uses other available information such as operations and maintenance records to identify Potential Threats. Although PG&E discusses the Division-specific issues or concerns during its DIMP Field review, the Audit Team believes that PG&E must consider reasonably available resources including a separate review of the operations and maintenance records to validate if the records reflect any concerns brought up during the DIMP Field review, and if there are any other areas that could potentially have been missed during the discussion with Division personnel.

b) The original RMP-15 lacked detail on how the DIMP Team gains more knowledge of Potential Threats, including those concerns raised during its DIMP Field Reviews and Field Questionnaires. During the audit the Audit Team and PG&E discussed a concern raised by a local distribution engineer regarding the anode replacement cycle. Although the DIMP Team appeared to have taken additional steps to validate the concern, the procedure did not describe this validation process for Potential Threats.

The revised RMP-15 states that PG&E collects Potential threats from various sources that the DIMP Team reviews for applicability to PG&E's distribution assets. The appropriate TSCs review and approve the final list of Potential Threats. Attachment E of the revised RMP-15 states the TSC is responsible for developing a process to review the applicability of threats to PG&E's system. However, RMP-15 does not describe in detail how the DIMP Team considers the pipeline's designs, operations, maintenance, and environmental factors that can affect the integrity of the pipeline in assessing applicability and validity of potential threats.

3. 49 CFR §192.1007 – What are the required elements of an integrity management plan?

"(c) Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk."

a) During the audit, PG&E identified its pipeline threats as Known Threats, Emerging Threats, and Potential Threats. PG&E groups the threats into eight general categories as required in 49 CFR §192.1007(b). RMP-15 Section 5 defined these threats as follows:

- Known Threats: Threats contributing to 0.5% or greater of the total leak count.
- Emerging Threats: Threats that contribute to less than 0.5% of the total leak count.
- Potential Threats: Non-leaking and are discovered through field experience, internal Subject-Matter Experts (SME), etc.

RMP-15 Section 6.2 described PG&E's relative risk model used to rank risks of threats that resulted to leaks. PG&E said that it evaluated Emerging Threats and Potential Threats qualitatively to determine if action is required to mitigate the threats.

The Audit Team found that the RMP-15 lacked detail on how PG&E evaluated and addressed Emerging and Potential threats. Emerging Threats in particular, although contributing to less than 0.5% of the total leaks, are existing threats that PG&E must address beyond the manner of Potential Threats. Although such a threat can occur at a low frequency, it may result in a high consequence event.

Since the audit, PG&E revised RMP-15 and currently identifies pipelines threats as Known Threats (resulted to leaks) and Potential Threats (non-leaking events). The DIMP Team uses a relative risk model to rank risks of Known Threats. PG&E continues to use a qualitative method in evaluating Potential Threats to determine if it needs to take action to mitigate the threats. PG&E needs to describe in RMP-15 how it conducts qualitative ranking of Potential Threats.

b) PG&E's risk algorithm calculates a threat's total risk value as the summation of the product of Likelihood of Failure and Consequence of Failure for each individual leak caused by the threat. Since PG&E currently uses leak data to identify threats in its system, Likelihood of Failure is equal to 1. The Consequence of Failure includes individual component attributes with assigned weight values.

During its review of the Consequence components, the Audit Team found the assigned default weight values for the following attributes to be zero if the data is unknown.

- Other Injury: Number of non-employee injuries
- Employee Injury: Number of employee injuries
- Other Fatality: Number of non-employee fatalities
- Employee Fatality: Number of employee fatalities

PG&E stated that the company is likely to have this information due to civil liabilities. However, defaulting of these unknowns to zero can potentially rank a higher threat lower than it should be (a less conservative approach). Although PG&E lists in its revised RMP-15 these consequence factors as either required data or a mandatory field, PG&E needs to emphasize to its field crews that they need to provide accurate information and shall not leave fields blank on the A-Form. In which case, if these are truly required data fields, there should be no default values for these consequence factors.

c) RMP-15 Section 6.7 describes PG&E's process for determining high risk areas with poor Program and Activities Addressing Risk (PAAR) performance. PG&E further analyzes these fields through its Root Cause Analysis (RCA) process. During the audit, PG&E corrected its definition of high risk as areas with a calculated risk greater than one standard deviation instead of two standard deviations. This correction is reflected in RMP-15 Revision 4 Attachment B.

PG&E cross references the level of risk for each threat (low, medium, high) with its PAAR performance (good, fair, poor) using a five-year linear trend of leak repairs for a geographic area for each threat. PG&E currently subdivides its areas for non-excavation related threats by Division, and excavation damage by City.

PG&E has a wide geographical territory with varying environmental and operational conditions. For this reason, the subdivision used for risk analysis of non-excavation related threats should not be constrained at the PG&E Division level. PG&E must modify its process to provide for additional subdivision of its assets into areas with similar characteristics to effectively identify threats and rank risks across its varying areas. PG&E must establish subdivisions in its DIMP that adequately demonstrate where a threat is occurring based on its highest density, and appropriately address the threat in that specific area, not to be masked across a wider geographical area.

d) RMP-15 Table 7.1 shows the Risk levels and Performance ratings cross matrix. During the audit, PG&E only performed RCA in areas identified with high risk threat with poor PAAR performance. The earlier revision of RMP-15 stated that PG&E developed this threshold to maintain a manageable number for the RCA process.

The RCA process is an integral part of DIMP as it aims to identify root causes, resulting to a better understanding of the pipeline distribution system's threats. The RCA process also provides opportunities to measure the effectiveness of its PAAR, and identify additional Preventive and Mitigative measures needed to reduce risk. The Audit Team expressed its concern that the current procedure constrains the RCA process only to areas of high risk/poor performance, when PG&E should also conduct sufficient analysis in areas of high risk/fair performance and medium risk/poor performance. PG&E must not base its RCA process on its limitations in personnel resources. It instead, must assess system risks and dictate the amount of resources needed to implement its DIMP effectively.

After the audit, PG&E expanded the RCA process in RMP-15 Revision 4, Table 7.1 to also include areas of high risk/fair performance and medium risk/poor performance as shown below:

		Performance		
		Good	Fair	Poor
Risk	Low	Review next DIMP cycle	Review next DIMP cycle	Review next DIMP cycle
	Medium	Review next DIMP cycle	Review next DIMP cycle	Perform RCA
	High	Review next DIMP cycle	Perform RCA	Perform RCA

The revision made to the RCA process to expand quadrants requiring RCA satisfies this audit finding.

4. 49 CFR §192.1007 – What are the required elements of an integrity management plan?

"(f) Periodic Evaluation and Improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations."

RMP-15 Section 9 describes the evaluations and reviews PG&E conducts within the various portions of the DIMP program, including a review of the RMP-15 (written plan) annually and the re-evaluation of the program every five years.

Specifically, PG&E describes in Section 9.2 the annual review of its threats conducted by the TSCs, DIMP Risk Management, and DIMP Engineering teams. The Audit Team found that RMP-15 lacked detail on how PG&E conducts the annual review of threats, including a development of formal evaluation process defining certain milestones needed to complete the evaluation. For instance, the evaluation should identify certain tasks (i.e. Field Reviews, RCA, etc.) to be completed prior to the annual evaluation by the TSC. A structured agenda or guidance document for the TSC annual review could provide PG&E more understanding of the data sources, context of the review, and expected outcome of the review.

The revised RMP-15 Attachment E which contains the TSC charter currently states that TSC can conduct it meetings to support the various DIMP phases. Additionally, RMP-15 Section 9.2 states that it is after the threat identification and risk ranking of known and potential threats phases that the TSC conducts its review for accuracy. RMP-15 must also require the TSC to review the PAAR performance measures, and the analysis used to determine which areas require RCAs, including the appropriateness of the distribution band used to make the determination for RCA.

Similarly, RMP-15 Section 9.8 must also provide detail on the DIMP program re-evaluation every five years. PG&E must describe, at a minimum, what documents and records it reviews to measure the overall program effectiveness, and how PG&E uses the results of performance monitoring in RMP-15 Section 8 in its evaluation.

5. 49 CFR §192.1011 – What records must an operator keep?

> *"An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of all superseded integrity management plans developed under this subpart."*

RMP-15 Section 13 describes PG&E policy for retaining records and supporting documentation demonstrating compliance with the requirements of the code that PG&E will keep for a minimum of 10 years. During the audit, PG&E representatives mentioned that there is currently no intention to adopt a company-wide record retention policy affecting its distribution system operations and maintenance records. Instead, the DIMP Team will take snapshots of records reviewed as a part of the DIMP cycle.

The Audit Team found that PG&E needed to include in RMP-15 guidance and to identify specific documents and records that demonstrate compliance to this part of the code, requiring a 10-year retention period. PG&E revised RMP-15 Section 13.2 to include the list of documents and records that it uses through the various phases of its DIMP and is required to maintain for at least 10 years. The revision made to the RMP-15 satisfies this Audit Team's finding.

Areas of Concern/Recommendations

1. Covered facilities under DIMP

   RMP-15 Section 2 defines PG&E's systems that covered under DIMP. The current revision of RMP-15 identified some numbered pipelines that are operating over 60 psig but are not considered transmission under 49 CFR §192.3. The Audit Team recommended that PG&E perform a comprehensive review of its system annually, including a review of PG&E Drawing Number 086868 which lists pipelines operating over 60 psig, to ensure that PG&E covers all its distribution pipelines in its DIMP.

   PG&E extended the list of Covered Facilities in RMP-15 Revision 4. SED reviewed the extended list and is satisfied with revisions PG&E made addressing this area of concern.

2. Evaluating and Prioritizing Risks

   a) The Audit Team reviewed PG&E's risk algorithm and identified the following assigned values that its believes needed to be changed or reviewed:

      - Damage – PG&E assigns a default value of zero if the damage is unknown. Loss of gas is almost always a given in a gas leak event which costs some monetary consequence. The Audit Team advised PG&E that the default value for this attribute should at least be five. PG&E revised RMP-15 to incorporate this recommendation, which satisfies this area of concern.

      - Pressure and Proximity – PG&E assumes that distribution pipelines operating above 60 psig are located farther away from structures and are assigned a Proximity value equivalent to a main operating at 60 psig or less. Although this may be true for most of these distribution pipelines, PG&E has high pressure regulating stations (HPR) or farm taps that are located closer to a building structure than a distribution main. PG&E should review these locations and assign an appropriate weight score commensurate to the amount of a gas leak and proximity of the leak from a structure.

      - Grade – This attribute is a component of the consequence cause by the magnitude of leak. PG&E currently uses the final leak designation when assigning a value to this attribute. PG&E Standard currently allows downgrading of hazardous leaks or Grade 1 leaks to Grade 2+ by safely allowing the gas to vent, until repairs are completed. Downgrading via venting can provide a false sense of the magnitude of the leak. PG&E should use the more conservative assigned value for leaks that it downgrades via venting.

   b) The Audit Team also recommends clarifying and defining some of the consequence factors and attributes that PG&E uses. For instance, there should be a clear definition of what PG&E considers an injury, above ground, and in a substructure. During the audit, the Audit Team and PG&E discussed examples where PG&E needed to provide better clarification. These examples included instances of an individual who went to a hospital as the result of a gas leak, whether or not they required an overnight stay, and a leak on an above ground meter located in a garage.

c) PG&E currently defines Known Threats as those leaks contributing to 0.5% or greater of the total leaks, and Emerging Threats as leaks contributing to less than 0.5% of the total leaks. According to the DIMP Team, the risk algorithm currently accounts for all leaks regardless of the 0.5% threshold. Thus, PG&E masks Emerging Threats within its risk algorithm. PG&E should evaluate whether the 0.5% threshold is necessary and adequate to account for these lower frequency threats.

PG&E eliminated Emerging Threats in its revised RMP-15, which satisfies this area of concern.

3. Identify and implement measures to address risks

As stated in the RMP, PG&E had several programs in place prior to the implementation of DIMP. The revised RMP-15 currently includes some of these programs, and Attachment A lists programs that PG&E developed as a result of its DIMP analysis.

PG&E should continue to include in its RMP a requirement to evaluate the various existing programs, including those not listed in the RMP, to ensure that correct PAAR are in place to address the identified threats in its system, and that it monitors the appropriate performance measures.