BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms	R.11-02-019 (Filed February 24, 2011)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON PROPOSED RULE CHANGES TO GENERAL ORDER 112

ALEJANDRO T. VALLEJO
JONATHAN D. PENDLETON
Pacific Gas and Electric Company
Law Department
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2916
Facsimile: (415) 973-5520
E-Mail: J1PC@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

Pursuant to the Administrative Law Judge's Ruling Setting Schedule for Filing Comment on Proposed Rule Changes to General Order 112 (Ruling), issued on July 8, 2014, Pacific Gas and Electric Company (PG&E) respectfully submits its comments on the California Public Utilities Commission's (Commission) Safety and Enforcement Division's (SED) Proposed Rule Changes to General Order 112-E, included as Attachment A to the Ruling.

II. BACKGROUND

General Order 112-E establishes the Rules Governing Design, Construction, Testing, Maintenance, and Operation of Utility Gas Gathering, Transmission, and Distribution Piping Systems in California, and became effective on September 11, 1995.[1] Since that time there have been only minor modifications.[2] PG&E appreciates and supports SED's detailed efforts to modify and update General Order 112-E to improve the safety of natural gas systems in California.

[1] Decision (D.) 95-08-053.
[2] See Resolution No. SU-41, May 22, 1996; Resolution No. E-4184, August 21, 2008.

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SED served its initial Proposal for Changes to General Order 112-E on August 15, 2013, following workshops on June 27, 2013 (metrics) and August 1 and 2, 2013 (General Order 112-E). PG&E and other stakeholders provided comments on SED's proposed changes on September 27, 2013. A copy of PG&E's prior comments is included at Attachment 1 for SED's convenience.

The revised Proposed Rule Changes to General Order 112-E, issued on July 8, 2014, propose six new rules: Rules 123.3, 143.1(b), 143.2(d), 143.2(e), 143.5 and 143.6.[3] Each of these six new rules is discussed below in Section III.

The revised Proposed Rule Changes also contain several other previously proposed provisions with significant impact on operators that warrant further consideration before being adopted. PG&E has highlighted these major issues below in Section IV.

Additionally, because of the significant impact of a number of the Proposed Rule Changes, PG&E recommends a phased-in approach to implementing the rules to allow operators sufficient time to modify or establish new programs, develop procedures and train personnel, as well as to account for the cost impact and establish funding, to comply with the rules consistently and effectively. PG&E discusses these important implementation and cost-related issues below in Section V.

PG&E recommends that the Commission schedule a further technical workshop to provide an opportunity for clarification of the newly proposed and modified major changes to General Order 112-E and to enable an exchange of technical information among SED, operators and other stakeholders.

[3] The Ruling at page 1 identifies two of these six new rules: Rules 143.5 and 143.6.

III. COMMENTS ON ADDITIONAL RULES INCLUDED IN THE REVISED PROPOSED RULE CHANGES TO GENERAL ORDER 112-E.

PG&E addresses the six proposed new rules in the order in which they appear in the Proposed Rule Changes to General Order 112-E, issued on July 8, 2014:

(1) Proposed Rule Change 5, Rule 123.3

New Rule 123.3 provides: "All information submitted by an operator pursuant to paragraph 123.2 shall be submitted with verification, under penalty of perjury, from a senior officer of the utility stating that the facts contained in the information are true and correct to the best knowledge of that senior officer."

PG&E Comments

PG&E interprets the term "senior officer" to mean a Vice President and above. As part of a final rule change, PG&E recommends that the Commission clarify this term.

(2) Proposed Rule Change 10, Rule 143.1(b)

New Rule 143.1(b) provides: "A gas leakage survey of transmission pipelines, using leak detecting equipment, must be conducted at least twice each calendar year at intervals exceeding 7 1/2 months."

PG&E Comments

The impact of this new proposed rule is substantial on PG&E's system. PG&E currently conducts annual leak surveys on over 5000 miles of its gas transmission pipelines.

PG&E recommends that the Commission include this newly proposed rule in a further technical workshop to discuss technical details and to fully understand the impact of this proposed change to a risk-based approach to asset management.

(3) Proposed Rule Change 10, Rule 143.2(d)

New Rule 143.2(d) provides: "Grade 1 and 2 leaks can only be downgraded once to a Grade 3 leak without a physical repair. After a leak has been downgraded to Grade 3, the leak must be reevaluated within 15 months and repaired within 21 months."

PG&E Comments

As currently written, the proposed rule appears to contain a conflict: in the first sentence the rule provides that a Grade 1 or 2 leak can only be downgraded once to a Grade 3 without being repaired, but then provides that after a leak has been downgraded to a Grade 3 it must be repaired within 21 months. PG&E believes SED's intention is to create a rule that prohibits an operator from downgrading and upgrading a leak multiple times, without the leak being repaired, but not to require an operator to repair all leaks that have been downgraded to a Grade 3 leak, even if downgraded once.

To effectuate what PG&E believes is SED's intent in proposing this new Rule 143.2(d), PG&E recommends that the proposed rule be revised as follows:

"Grade 1, 2+ and 2 leaks can only be downgraded once to a Grade 3 leak without a physical repair. After a leak has been downgraded to Grade 3, the leak must be reevaluated ~~within~~ every calendar year not to exceed 15 months ~~and repaired within 21 months~~. Once downgraded to a Grade 3 leak, if the leak is upgraded at any time to a higher grade, the operator must repair the leak within the period of time specified in its leak repair procedures for the higher grade, and cannot be downgraded again."

(4) Proposed Rule Change 10, Rule 143.2(e)

New Rule 143.2(e) provides: "All underground leaks on transmission lines classified as Grade 2 or 3, or any subcategories between Grade 2 or 3 an Operator may establish, must be repaired by the Operator either upon discovery or within one year after discovery."

PG&E Comments

PG&E agrees with the proposed rule with the following recommended clarification: that the referenced "underground leaks" are on the transmission pipe itself (body of pipe and seam or girth welds) and would not include leaks on transmission fittings or components (valves, threaded caps, etc.).

(5) Proposed Rule Change 10, Rule 143.5

New Rule 143.5 (Encroachments) provides: "With the exception of gas pipeline facilities related to installations in gas meter rooms or other specially designed indoor locations where an outdoor meter installation is not possible or practical, a utility transporting LNG, natural gas or other gas shall not construct any part of a LNG, natural gas or other gas pipeline system under a building. In addition, the utility shall not allow constructed encroachments on to its pipeline right-of-way that would hinder maintenance activities on the pipeline or cause a lengthy delay in accessing its pipeline facilities during an emergency. If the utility finds a building or other encroachments built over a pipeline system after the effective date of this section, then the utility may require the party causing the encroachment to remove the building or other encroachments from over the pipeline or to reimburse the utility for its costs associated with relocating the pipeline system. The utility shall determine, within 90 days after discovering the encroachment, whether the encroachment can be resolved within 180 days. If the utility determines that the encroachment cannot be resolved within 180 days, the utility shall, within 90 days of discovery of the encroachment, submit to the CPUC a written plan to resolve the encroachment within a period longer than 180 days. The CPUC may then extend the 180-day requirement in order to allow the party causing the encroachment and the utility to implement the written plan to resolve the encroachment. If the utility does not submit a written plan, and the encroachment is not resolved within 180 days of discovery, the utility shall discontinue service to the pipeline system. The utility must provide written notice of any imminent service discontinuance per this section to the Commission 30 days prior to discontinuing service."

PG&E Comments

PG&E supports the spirit of this proposal. However, as written, the term "pipeline system" is overly broad and potentially would require an operator to discontinue service to an entire community that is part of the same gas distribution pipeline system, and potentially would have an even wider impact on service if the term "pipeline system" is meant to apply to transmission pipelines. PG&E does not believe this to be SED's intent, and recommends for clarity that this proposed rule be revised to remove the sentence: "If the utility does not submit a written plan, and the encroachment is not resolved within 180 days of discovery, the utility shall discontinue service to the pipeline system."

Additionally, PG&E recommends that the final rule clarify the term "constructed encroachments," and that the 180 day time period in the proposed rule be extended to 365 days to allow for sufficient time for an operator to resolve any outstanding issues raised by its customers.

(6) Proposed Rule Change 10, Rule 143.6

New proposed rule 143.6 (Compatible Emergency Response Standard) provides: "In establishing emergency response procedures, all gas utilities shall use, at a minimum, the Incident Command Systems (ICS) as a framework for responding to and managing emergencies and disasters involving multiple jurisdictions or multiple agency responses. The ICS used by utilities must be compatible with the ICS used by the first responder community within the State of California, and as detailed in California Government Code Section 8607(a), All gas utilities must have the ICS in place to be activated when necessary to the types of emergency events listed and detailed within the written emergency plans gas utilities are required to maintain per 49 CFR Part 192, §192.615."

PG&E Comments

PG&E supports this proposed rule change.

IV. COMMENTS ON OTHER MAJOR RULE CHANGES INCLUDED IN THE REVISED PROPOSED RULE CHANGES TO GENERAL ORDER 112-E.

In addition to the newly proposed rules discussed above, PG&E provides the following comments on several major rule changes included in the revised Proposed Rule Changes.

(1) Proposed Rule Change 3, Section 105, Definitions: High Consequence Area

The Proposed Rule Changes include the following modification to Section 105, Definitions:

"High Consequence Area (HCA) is defined by 49 CFR §192.903, which allows two different methods to be used towards determining locations where HCAs exist. However, in an effort to be more conservative towards ensuring the safety **in more densely populated areas**, the Commission **restricts the use of Method 2 in 49 CFR §192.903, in determining HCAs, to pipeline segments of 12-inches or less. Accordingly, the Commission modifies paragraph (2) of the High Consequence Area defined by 49 CFR §192.903 to read as follows:**

(2) The area within a potential impact circle of a pipeline 12-inches or less in diameter containing -TR

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HCAs newly identified through the Commission's restriction on Method 2 shall be scheduled for baseline assessment in accordance with 49 C.F.R §192.905(c)."[4]

PG&E Comments

This proposed change would cause a significant impact to PG&E's Transmission Integrity Management Program (TIMP). PG&E currently utilizes Method 2, which is consistent with common industry practices and the proposed change would cause a significant impact to PG&E's Transmission Integrity Management Program (TIMP).[5] While the proposed application of Method 1 to only those lines greater than 12-inches in diameter[6] reduces this impact (as opposed to application to the entire transmission system), the result would potentially impede progress on prioritizing the highest risk pipe sections for assessment, regardless of class location or HCA status. Further, pipe diameter is only one variable to consider, as smaller diameter pipe operating at high pressures can have a Potential Impact Radius (PIR) that is greater than larger diameter pipe.

Method 2 is a technical basis for HCA determination because it considers the actual area where a potential failure of a pipeline could have significant impact on people or property. Method 1 is based upon class location, which is determined by an evaluation of structure counts within 660 feet of the pipeline regardless of PIR. Many locations have PIRs that are much smaller than 660 feet and even though pipe may be designated as class 3 or 4, the pipe may pose no risk to structures or property outside of the PIR. The increased HCA mileage therefore may not necessarily translate to an increase in enhancing public safety.

PG&E is committed to expanding integrity management principles outside of HCAs, as demonstrated by expanding and improving its In Line Inspection (ILI) program (which due to the

[4] The bold text identifies the new language in the revised Proposed Rule Changes, issued on July 8, 2014, compared to the initial Proposal for Changes to General Order 112-E, served on August 15, 2013.
[5] In 2009, PG&E reported the second highest number of HCA miles for any operator in the United States.
[6] PG&E assumes SED's reference to "12-inches" in the proposed definition is to diameter, and recommends that this be clarified before a rule change is finalized.

nature of ILI assessments, incorporates significant amount of non-HCA mileage), and by considering habitable structures within PIRs regardless of class location or HCA designation as part of our risk prioritization process. However, additional requirements for TIMP integrity assessments using Method 1 may shift the prioritization of additional assessments toward lower risk class 3 or 4 areas where habitable structures may not exist within the PIR, instead of toward higher risk non-HCA areas.

As discussed above, PG&E recommends that the Commission schedule a further technical workshop and include discussion of the details of this modified proposed rule to better understand the technical basis for the 12-inch diameter threshold and whether there are other variables that also should be considered, as well as to explore how this proposed rule change impacts a risk-based approach to integrity management.

(2) Proposed Rule Change 3, Section 105, Definitions: Covered Task

The Proposed Rule Changes include the following modification to Section 105, Definitions:

"Covered Task means those tasks defined by 49 C.F.R §192.801, but also includes "new construction" in the federal definition of "covered task." Accordingly, the Commission defines a covered task that will be subject to the requirements of 49 CFR §§ 192.803 through 192.809 as an activity, identified by the Operator, that:

(a) Is performed on a gas pipeline;

(b) Is an operations, maintenance, or new construction task;

(c) Is performed as a requirement of 49 CFR, Part 192; and

(d) Affects the operation or integrity of the gas pipeline.

PG&E Comments[7]

PG&E is generally supportive of this change. However, it does represent a significant impact to our Operator Qualification (OQ) program, construction program and the applicant installation process. PG&E has identified several new OQ tasks that would require procedures to be developed and communicated to all PG&E field personnel and contractors. PG&E anticipates 3 to 5 years to develop and communicate the new processes and to train impacted employees, as well as significant associated costs.

(3) Proposed Rule Change 5, Section 123.2(i): Lost and Unaccounted For Gas (LUAF)

The Proposed Rule Changes include the following additions to Section 123, Annual Reports:

"i) Lost and Unaccounted For Gas (LUAF Gas)

1. A listing of the different causes of LUAF Gas that the Operator tracks as part of its operations; and

2. An accounting of **the contribution by** each of the different causes of LUAF Gas, actual and/or estimated values, which factor into the aggregated LUAF Gas value provided by the Operator on all reports submitted pursuant to subsection 123.1. **An Operator must provide details on how each estimated value is derived."**[8]

[7] See also PG&E's September 27, 2013 comments at Attachment A.

[8] The bold text identifies the new language in the revised Proposed Rule Changes, issued on July 8, 2014, compared to the initial Proposal for Changes to General Order 112-E, served on August 15, 2013.

PG&E Comments

1. This information is not currently available. PG&E does not track various LUAF causes. Instead, our LUAF calculation comes from a mass balance of the system; i.e., LUAF = Measured inputs – Measured outputs, adjusted for changes in pipeline inventory.

Also, without a consistent definition of the causes of LUAF, operators may have varying definitions and ways of calculating LUAF and may attribute LUAF to different causes. PG&E recommends that SED provide further details and definitions on LUAF and cause categories in order to ensure that operators calculate and report this information consistently.

2. This information also is not currently available. One contributing factor to LUAF is natural gas released to atmosphere, which is available from the Green House Gas reporting provided to the California Air Resources Board and the annual Natural Gas STAR report.

V. TIMING OF IMPLEMENTATION OF THE PROPOSED RULE CHANGES AND COST RECOVERY ISSUES.

When the Proposed Rule Changes to GO 112-E are finalized and adopted by the Commission, careful consideration should be given to the timing of implementation. Certain of the rule changes will require new procedures to be developed and training to be completed. Also, certain of the changes will have significant cost impacts, and if implemented between utility rate case proceedings may result in unintended cost recovery challenges.

For these reasons, PG&E recommends that each utility implement the changes to GO 112-E in conjunction with its applicable rate case cycle, in which the utility will provide its plan to implement the changes and provide its funding estimate.

VI. CONCLUSION

PG&E appreciates the opportunity to provide comments on the proposed changes to General Order 112-E. As noted in these comments, PG&E recommends that the Commission schedule a further technical workshop to provide an opportunity for clarification of the newly proposed and modified major changes to General Order 112-E, and to enable an exchange of technical information among SED, operators and other stakeholders.

Respectfully Submitted,

ALEJANDRO T. VALLEJO
JONATHAN D. PENDLETON

By: /s/
JONATHAN D. PENDLETON

PACIFIC GAS AND ELECTRIC COMPANY
Law Department
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2916
Facsimile: (415) 973-5520
E-Mail: J1PC@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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