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 SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) ON PROPOSED REVISIONS TO G.O. 112-E

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Per the Amended Scoping Memo and Ruling of the Assigned Commissioner issued on May 2, 2013, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) submit the following comments on the Proposed Revision of the Safety and Enforcement Division (SED) to General Order 112-E (GO 112-E) issued on August 15, 2013.

SoCalGas and SDG&E commend SED Staff for their thoughtful proposed revisions to GO 112-E and look forward to continuing to work closely with Commission Staff to refine the Commission's regulations to enhance the safety of California's natural gas transmission system. As indicated in the comments below, SoCalGas and SDG&E largely welcome and support the revisions proposed by SED, and offer a few proposed clarifications and suggested changes, which are described below and reflected in Attachment 1, suggested redlined changes to the clean version of SED's proposed changes. In addition, we offer comments on proposed revisions submitted by The Utility Reform Network (TURN) and the Utility Workers Union of America (UWUA). As discussed further in Section II below, SoCalGas and SDG&E do not object to the proposals submitted by TURN, but some of the changes offered by UWUA may not advance public safety at all, or the cost of implementing such changes may far outweigh the benefits to public safety that may potentially be derived. In such cases, SoCalGas and SDG&E encourage the Commission to refrain from implementing those changes without first providing interested parties with an opportunity to provide evidence of the relative costs and benefits of those UWUA proposals for careful consideration by the Commission.

The revisions proposed by SED and other parties do not address the practical implications of attempting to incorporate regulatory changes into a natural gas utility's operations. Changes in regulatory requirements, even seemingly minor changes, may require significant modifications to SoCalGas and SDG&E's automated scheduling, data collection and work process systems. Periodic maintenance and enhancement of such systems requires that there be scheduled "lock out" periods, during which the systems cannot be modified or changed. Depending on the system, lock out periods can span hours, days and even months, which could inhibit the ability of a natural gas pipeline operator to implement required system changes on an expedited basis. Regulatory changes may also require the development of revised written procedures, the development of new employee and contractor training materials, and formal training of all impacted personnel and contractors. This process also takes time, and must be coordinated so that key personnel are not pulled away from critical safety-related work for training. Therefore, SoCalGas and SDG&E ask that the Commission, in adopting proposed revisions to General Order 112-E, also adopt a period of time of no less than one full calendar year for the new requirements to go into effect, as changes may need to coincide with a January 1 implementation for data collection and analysis.[1] The order could be phrased so as to direct natural gas utilities to begin implementing the new requirements immediately, but allow the utilities sufficient time to operationalize the new regulations.

In addition to an investment of time, implementation of new regulatory requirements will require an investment of funds. The more time that the utilities are provided to implement the changes, the greater their ability to coordinate those changes with ongoing work in a cost efficient

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1 For some changes, implementation mid-year would be problematic for SoCalGas and SDG&E.

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manner. Thus, the less time provided for implementation, the greater the costs of implementation will be. In order for the system changes and training described above to be implemented without diverting funds from other safety-related work, the Commission should adopt a mechanism to allow the natural gas utilities to recover the costs of implementing the new regulatory requirements. SoCalGas and SDG&E propose to incorporate the costs of implementing these regulatory changes into their test year 2016 General Rate Cases.

I. CLARIFICATIONS AND COMMENTS ON SED PROPOSED REVISIONS TO GO-112-E

A. PRC-1: *Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes.*

No Comments.

B. PRC-2: *Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes.*

No Comments.

C. PRC-3: *Provide clarification on existing GO-112-E terms and define new terms related to new metrics or more stringent requirements than otherwise required by 49 CFR, Part 192.*

1. Public Attention Criterion

SED proposes to define Public Attention Criterion as:

> any event that escalates to a level that initiates concerns being submitted to a utility from a large number of people. This can include, for example, large scale reports of the smell of gas by customers in the vicinity of an operator's gas facilities. Public Attention criterion does not necessarily include an individual, or a crowd of persons, watching work being performed on company facilities.

This definition is broadly worded and effectively adds new items to the Commission's reportable incident criteria. SoCalGas and SDG&E do not oppose this addition, so long as essential clarifications are provided to enable natural gas operators to develop systems to comply with this new reporting requirement. First, "a large number of people," as used in this definition, should be clearly defined. SoCalGas and SDG&E propose that "a large number of people" be clarified to mean 15 or more calls/complaints concerning a common safety concern by customers/members of the public. Second, this new reporting requirement should be limited to incidents that are determined to be attributable to a natural gas operator's facilities. Third, the time of discovery should be defined as when the natural gas pipeline operator determined that the concerns identified in the calls/complaints are attributable to the pipeline operator's facilities. The applicable reporting window should commence upon such determination. Finally, concerns raised as a result of planned maintenance operations (*e.g.*, calls from customers to report gas odor attributable to the deliberate release of natural gas as part of scheduled maintenance activities), should be exempted from this new reporting requirement.

2. Rationale for HCA Definition in GO 112

As noted by SED, High Consequence Area (HCA) is defined in 49 CFR 192.903, which allows natural operators to use one of two methods to identify HCAs. Method 1 enables pipeline operators to identify HCAs using Location Class[2] and Method 2 enables pipeline operators to identify HCAs based on Potential Impact Circles.[3] Location Class is based on a set corridor of 1,320 feet (1/4 mile). Potential Impact Circles are calculated using a pipeline's diameter and maximum allowable operating pressure (MAOP). The use of Potential Impact Circles to identify HCA was first incorporated into the regulation in 2003 with the publishing of 49 CFR Part 192 Subpart O – Pipeline Integrity Management. In the development of Subpart O, it was recognized that the use of Location Class on smaller-diameter, lower-stress transmission pipelines would result in the requirement that small diameter pipelines be subject to the assessment and reassessment requirements of Subpart O. These smaller-diameter pipelines typically are shorter in length, are not compatible with in-line inspection tools, and the consequence of a failure is typically lower as compared to larger-diameter pipelines at the same pressures. Thus, the use of Potential Impact Circle calculations was developed to allow pipeline

2 Potential Impact Circles are also used as part of Method 1 HCA identification.

3 Location Class is not used as part of Method 2 HCA Identification.

operators to identify transmission pipelines that would require assessments and reassessments using the pipeline-specific attributes of MAOP and diameter.

"[I]n an effort to be more conservative towards ensuring the safety in areas of more densely populated Class 3 and Class 4 locations," SED proposes to adopt a requirement in California that will restrict pipeline operators to using Method 1. SoCalGas and SDG&E support the Commission's goal of increasing the amount of pipeline subject to subpart O assessment requirements.

To further increase the miles of pipeline subject to subpart O, SoCalGas and SDG&E propose that GO 112-E be revised to restrict the use of Method 2 to pipeline diameters of 12 inches or less, as an alternative to SED's proposal to completely remove the ability of California pipeline operators to use Method 2. Costs for short segments of pipeline, as typically would be the case for 12-inch-and-smaller diameter pipeline in Class 3 and 4 will likely be significant and should be prioritized after the larger-diameter (greater-than-12-inch) pipeline.

The SoCalGas and SDG&E proposal would prioritize resources and further SED's safety enhancement objective by addressing the pipelines in these areas that, in the very remote possibility of a rupture, pose a greater potential consequence. Suggested edits to capture this proposal are provided in Attachment 1.

3. Near-Miss Events

SoCalGas and SDG&E do not currently have automated systems to monitor and track near-miss events.[4] Data regarding excavation damage to our facilities is recorded and available for hits, but not near-misses. As we understand the definition of "near-misses," near-misses are events that are only possible to observe/document when they are encountered during patrols, leak surveys or other surveillance activities, or when our personnel are onsite during an excavation,

4 Note, however, that SoCalGas and SDG&E requested authorization to install fiber optics-based advanced warning systems on larger newly-installed pipelines as part of their pending Pipeline Safety Enhancement Plan.

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which is only the case where (1) the excavating party has notified SoCalGas and SDG&E in advance and (2) digging is planned near high-pressure/high-priority facilities.

If the intention of SED is to measure the effectiveness of pipeline operators' damage prevention activities, dig-in data reporting would likely be the most effective tool. Further, if SED wants to track near-misses, then we propose that SED adopt a definition consistent with how that term is understood in the industry. In Attachment 1, SoCalGas and SDG&E offer suggested edits to the definition of "near-miss" in GO 112-E that build upon the Common Ground Alliance's definition of "damage" and are more consistent with how that term is used and understood in the industry.

D. PRC-4: *Require the reporting of overpressure and underpressure events on all gas pipeline systems.*

SED proposes to add new reporting requirements for over-pressure and under-pressure events. SoCalGas and SDG&E have the ability to track and report this information and do not oppose the adoption of new reporting requirements for over and under pressure events, provided that natural gas pipeline operators are provided with sufficient time to make such reports. As proposed, pipeline operators would be required to make reports within two or four hours from discovery to be in compliance. SoCalGas and SDG&E propose that pipeline operators be provided with a reporting window of at least 8 hours from the time the operator determines the incident meets the reporting requirement set forth in GO 112-E.

A reporting requirement timeframe of less than 8 hours would be difficult and potentially costly to implement, because such events can occur during off-work hours and there may potentially be a significant time lag between the pressure incident and when personnel are available to trouble shoot/repairing the condition. Currently some of our networks are monitored in a passive mode through the use of paper charts. Compliance with these new reporting requirements may eliminate the ability to passively monitor our system and may require deployment of additional personnel to implement real-time monitoring of all alarms 24 hours a day, seven days per week.

For clarity, an under pressure event should be defined as the loss of gas service to more than a single meter or branch service connection and exclude customer service activities where loss of service is unavoidable.

E. PRC-5: *Incorporate minor updates in federal regulations and implement requirements for the reporting of metrics discussed in the June 27, 2013 Metrics Workshop.*

Although described as "minor updates" in the header, in PRC-5 SED proposes to adopt extensive new reporting requirements spanning numerous areas, including, but not limited to, operator leak response time, excavation damage prevention, Lost and Un-Accounted For Gas (LUAF) and public liaison activities. SoCalGas and SDG&E offer proposed clarifying edits to these provisions in Attachment 1, and explain why such clarifying edits are needed in the subsections below.

1. Leak Response Time

SoCalGas and SDG&E currently collect and track leak response time data and do not oppose reporting of such information to the Commission. SoCalGas and SDG&E note, however, that in the proposed revisions to GO 112-E, SED requires operators to report all response times greater than 45 minutes. SoCalGas and SDG&E seek clarification of whether this is intended to imply that pipeline operators should attempt to achieve a leak response time of less than 45 minutes. Such a requirement would require an investment of time and resources to implement.

Regarding the amount of time it takes a pipeline operator to make repairs, this requirement should be clarified. It is unclear whether this would require operators to report the amount of time it takes to make a leak non-hazardous, or the amount of time it takes to complete all potential repairs, including those performed after the leak has been rendered non-hazardous. Once clarified, SoCalGas and SDG&E will require sufficient time to implement systems for accurately reporting and tracking this information.

2. Excavation Damage Prevention Related Data

SED proposes to add reporting requirements for excavation damage prevention related data involving : (1) number of excavation damages and related costs involving homeowners; (2) number of excavation damages and related costs involving agencies; (3) number of person-days, along with total costs, devoted to excavation field meetings and standby activities for preventing damage to subsurface facilities; and (4) number of person-days, along with total costs, devoted to mark and locate activities and all other subsurface damage prevention activities.

Most of the requested information can be extracted from existing SoCalGas and SDG&E databases, and SoCalGas and SDG&E do not oppose these new reporting requirements. SoCalGas and SDG&E do not, however, currently have the capability of being able to break out standby versus field meetings versus locate and mark costs for each USA ticket. This would require significant effort on behalf of our field employees to attempt to segregate these activities, which often overlap and are performed simultaneously. There is little, if any, benefit to be gained from segregating this data. Indeed, rather than enhance pipeline safety in any way, such a requirement may divert resources away from safety-related work. Therefore SoCalGas and SDG&E recommend that the new proposed reporting requirements be revised to allow the reporting of person-days and costs to perform all USA ticket response activities combined.

3. Lost and Unaccounted For Gas (LAUF Gas)

SED proposes to incorporate new reporting requirements for a "listing of the different causes of LAUF Gas that the Operator tracks as part of its operations" and an "accounting of the effects of each of the different causes of LAUF Gas, actual and/or estimated values. . . ."

LUAF is primarily used for rate making purposes— to determine which customers should pay for the differences between receipts and payments. LUAF is currently reported to the Commission for ratemaking purposes, and this information was recently provided to the Energy Division in response to a data request. As explained in greater detail in that data request response (available upon request), the vast majority of LUAF is attributable to causes unrelated to gas pipeline system integrity. Therefore, tracking of LUAF would not provide information relevant to an assessment of pipeline safety or risk. In fact, most LUAF is attributable to measurement differences. The second and third most significant elements of LUAF are accounting and theft—elements unrelated to system leaks and failures. Leakage for both transmission and distribution only make up about 5-6% of total LUAF for SoCalGas and SDG&E. SoCalGas and SDG&E therefore recommend that GO 112-E be revised to include a reporting requirement for information on known leaks and estimated volumes, rather than estimated LAUF Gas. This would provide data more relevant to an assessment of system integrity.

In addition, the Commission may consider revising its use of acronym "LAUF Gas" in the regulation, since the acronym commonly used in the industry is LUAF (for Lost and Un-Accounted For) gas. Having a different acronym in the regulation than what is used in the industry may create unnecessary confusion.

4. Public Liaison Activities

In Attachment 1, SoCalGas and SDG&E offer minor suggested edits to subsection 3 to account for the fact that there may be additional reasons why an agency may be unable to attend a particular liaison session.

F. PRC-6: *Minor housekeeping issue.*

No Comments.

G. PRC-7: *Clarify the requirements for proposed installation reports and adjust the cost thresholds for reporting, that were determined many decades ago, for inflation.*

The revisions proposed by SED in PRC-7 include a new requirement that "[a]n operator commencing service for the first time shall file a Proposed Installation Report with the Commission after receiving CPCN approval from the Commission and prior to the start of construction of the approved project." This statement should be revised as proposed in Attachment 1, as gas operators are not always required to obtain a CPCN, or Certificate of Public Convenience and Necessity, for new pipe installations.

The legal requirements for obtaining a CPCN are contained in the California Public Utilities Code ("Code"). Code Section 1001 (Chapter 5, Article 1) provides, in relevant part, that "No … gas corporation … shall begin the construction of … a line, plant, or system, or of any extension thereof, without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction." Code Section 1001 goes on, however, to provide that this "shall not be construed to require any such corporation to acquire such certificate for an extension within any city or city and county within which it has theretofore lawfully commenced operations, or for an extension into territory either within or without a city or city and county contiguous to its … line, plant, or system, and not theretofore served by a public utility of like character, or for an extension within or to territory already served by it, necessary in the ordinary course of its business." This statute has been applied by the Commission to hold that CPCNs are not always required prior to construction of a pipeline, but compliance with GO 112-E is.[5]

Read together, the statute and Commission precedent make clear that a utility need not obtain a CPCN for pipeline construction activity that is necessary in the ordinary course of its business and is located in a city or county in which it already is providing service. Adoption of a new requirement in GO 112-E that pipeline operators submit CPCNs for all new pipeline installation projects could undermine the Commission's safety objectives by increasing the costs of and delaying the start of work on new pipeline installation projects.

In sections 125.3 and 124(b) SED proposes to include new reporting requirements, but as defined, some of the elements proposed to be tracked would not provide any insight into safety related issues. Thus, in Attachment 1, we propose deleting "alignment" and "interference" from the definition of "Reconstruction of an existing pipeline" to avoid the creation of new reporting requirements that would not provide any additional insight into safety-related issues.

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5 *See*, *e.g.*, Decision 07-01-014.

H. PRC-8: *Minor housekeeping issues.*

No Comments.

I. PRC-9: *Place limitations on how long plastic pipe can be stored unprotected outdoors.*

SED propose to add a new limitation on the amount of time that plastic pipe may be subjected to unprotected outdoor exposure. Currently, GO 112-E allows plastic pipe to be stored outdoors no longer than the amount of time recommended by the manufacturer. The proposed revisions would limit this timeframe to a maximum of two years. SoCalGas and SDG&E currently have a three year maximum outdoor storage policy that is based on the capabilities of the purchased pipe, as documented in literature provided by the pipe manufacturers. Documentation of this policy has been verified back to 1998. This material property is also specified as a requirement in our material specification for plastic pipe and required by our purchasing contracts. Reducing this limitation from three years to two years would not enhance public safety and would therefore, result in the needless waste of otherwise sound pipe.

49 CFR 192 makes reference to outdoor UV exposure of polyethylene (PE) pipe in section 192.59(a)(1), which states that PE pipe is qualified for use "if it is manufactured in accordance with a listed specification." The current "listed specification" recognized in section 192.59(a)(I) is the 1999 version of American Society for Testing and Materials (ASTM) Design Standard (D) 2513. The requirements specified by that standard state the following:

> **ASTM D 2513-99 § A1.5 Requirements for Pipe and Fittings**
> § A1.5.7 *Outdoor Storage Stability*—PE pipe stored outdoors and unprotected for at least two years from date of manufacture shall meet all the requirements of this specification. PE pipe stored outdoors for over two years from date of manufacture is suitable for use if it meets the requirements of this specification.

While the intent of this language was to ensure that the PE resin and pipe manufacturers effectively formulated their products with effective stabilizer and antioxidant additives to withstand up to two years of unprotected outdoor exposure, the practical effect has created

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ambiguity about whether the standard effectively sets an 'age limit,' as opposed to a material specification to which the product must conform.

In 2009, ASTM D 2513 was revised to require yellow PE materials to be UV stabilized for not less than three years and to require black PE materials to be UV stabilized for not less than ten years. ASTM D 2513-09a requirements are stated as follows:

> **ASTM D 2513-09a § 4. Materials**
> § 4.10 *Outdoor Storage Stability*—PE materials shall be Code C or E as defined in Specification D3350. Code C material shall contain 2 to 3 percent well dispersed carbon black, and due to the absorptive properties of the carbon black, is considered to be stabilized against deterioration from unprotected exposure to UV for not less than 10 years. Code E material shall be stabilized and protected against deterioration from unprotected UV exposure for not less than 3 years.

On Aug 16, 2013 PHMSA published a Notice of Proposed Rulemaking to address the adoption of ASTM D 2513-09a. Recognition of this revision will eliminate the ambiguity of the language of the 1999 ASTM standard. Industry technical studies have also been performed on PE pipe which has been stored outdoors for longer than three years that confirm the 2009 ASTM standards are conservative and within the performance limits required for gas distribution applications with respect to safety and overall system integrity. To our knowledge there have not been any industry reports of failures resulting from material degradation due to over-exposure to UV radiation for pipe managed within the UV exposure limitations specified by the manufacturers.

J. PRC-10: *Provide clarification, specify requirements related to the prioritization and repair of leaks, and to confirm that employees performing covered tasks are qualified using equipment similar to that used in operations.*

No Comments.

K. PRC-11*: Provide clarification for test requirements pertaining to all pipelines, provide clearance requirements not specified in federal regulations, and to align clearance requirement in GO-112-E with the clearance requirement contained the Commission's GO-128.*

In Attachment 1, we offer suggested edits to section 144.2 to clarify that subparagraph (b) is an exemption to, rather than an additional testing requirement of, section 192.511 and 192.513.

L. PRC-12: *Establish a section within GO 112-E to specify recordkeeping requirements related to transmission lines.*

No Comments.

M. PRC-13: *Minor housekeeping issues.*

No Comments.

N. PRC-14: *Incorporate new requirements related to Operator's mobile LNG operations.*

In Attachment 1, SoCalGas and SDG&E propose edits to clarify that the applicability of the new regulation, incorporated as 162.4, is limited to "<u>utility-owned</u>" mobile LNG equipment.

O. PRC-15: *Minor housekeeping issues.*

No Comments.

P. PRC-16: *Minor housekeeping issues.*

No Comments.

Q. PRC-17: *Minor housekeeping issues.*

No Comments.

R. PRC-18: *Minor housekeeping issues.*

No Comments.

S. PRC-19: *Implement a new subpart within GO 112-E to include whistleblower protections already established as a regulation by D.12-12-009.*

No Comment.

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II. COMMENTS ON PARTIES INITIAL WORKSHOP COMMENTS AND PRE-WORKSHOP COMMENTS

A. TURN

TURN proposed wording changes to Section 101.4, 123.2 and 145, which are acceptable to SoCalGas and SDG&E.

B. UWUA

In its Workshop Statement, dated June 27, 2013, UWUA proposes to add several additional requirements to GO 112-E. UWUA's proposals are largely either in conflict with existing law, redundant and therefore, unnecessary, raise significant ratemaking implications that should be considered by the Commission prior to their adoption, would be more appropriately handled through the collective bargaining process or may actually undermine public safety. SoCalGas and SDG&E recommend that suggested changes that conflict with existing law or are redundant not be incorporated into the revised GO 112-E to avoid confusion or potentially conflicting requirements. SoCalGas and SDG&E further recommend that those UWUA proposals that implicate ratemaking policy should be carefully considered by the Commission in the context of this Rulemaking or other appropriate proceeding and should not be adopted unless a record is established to demonstrate that the benefits outweigh the foreseeable cost. Similarly, proposals that would not have a discernible safety benefit should not be adopted.

In particular, UWUA's proposal to add the following underlined language to revised GO 112-E is inconsistent with the law and should not be adopted:

> These rules do not supersede the federal pipeline safety regulations but are supplements to the federal regulations, <u>except that specific standards or requirements in these rules in conflict with a federal standard will control</u>.

If the Commission believes further clarification of this provision of GO 112-E is required, the revision should acknowledge that to the extent state and federal regulations are in conflict, the federal law controls. To the extent a state regulation exceeds, but does not conflict with, federal regulations, then state law may control.

Specific proposals that are redundant of existing rules and regulations include, but are not limited to, UWUA's proposed revisions to the definitions of Commission-regulated pipeline facility and HCA, and proposed valve maintenance requirements. GO 112-E includes the incorporation of Title 49 Part 192 which defines the term pipeline facility and the sub-categorization of the facilities in section 192.3. It is not necessary, and may cause confusion and even conflict with the Federal Code to define the term in GO-112-E. The UWUA proposal to define HCA as in section 192.903 is redundant, as GO 112-E already incorporates all of part 192, including the definition of HCA. Moreover, as discussed above, SED proposes to adopt a more stringent method of identifying HCA that would result in the identification of more HCA mileage than required by the Federal Code. SoCalGas and SDG&E propose an alternative to SED's proposal, which also would result in more transmission pipeline being designated as HCA than the Federal Code allows. The SoCalGas and SDG&E proposal also preserves the intent of the federal regulations to apply the incremental assessment requirements of Part 192 Subpart O to transmission pipeline that have a potential for relatively greater consequence in the unlikely event of a failure. Valve Maintenance is already addressed in CFR 192 as well.

UWUA seeks to preclude SoCalGas from communicating with and obtaining input directly from its employees. This amounts to an attempt to change the National Labor Relations Act (NLRA) and is an attempt to circumvent Region 21 of the National Labor Relations Board's recent refusal to preclude SoCalGas from surveying and communicating with employees on matters of pipeline safety. It is critical to public safety that we retain the right to communicate directly with our employees, as afforded under the NLRA and mandated by the Commission.

UWUA attempts to vastly expand the definition of Gas Pipeline System/expand service offerings. It is not clear how this proposal would enhance public safety; these proposals appear designed to create more work and more jobs that would be subject to the exclusive jurisdiction of the UWUA, which consequently would be the direct beneficiary of any additional dues.

UWUA attempts to preclude the use of contractors. Collective bargaining is the proper venue for this topic, not the regulatory arena. Contractors have and continue to be an integral part of SoCalGas and SDG&E's reliable service to the public and pipeline safety.

Adequate workforce is already defined in Commission Approved Safety Plan. Public Utilities Code section 961 requires that each gas corporation develop a plan for the safe and reliable operation of its Commission-regulated gas pipeline facilities and ensure an adequately sized, qualified and properly trained workforce to carry out the plan. This requirement is already in Public Utilities Code and would be redundant.

III. CONCLUSION

SoCalGas and SDG&E would like to once again reiterate their appreciation for SED's efforts. SoCalGas and SDG&E share the Commission's commitment to enhancing the safety and reliability of California's natural gas transmission infrastructure and look forward to continuing to work closely with Commission Staff to achieve this goal.

Respectfully submitted,

By: *_/s/ Deana Michelle Ng_*
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Attachment 1

PRC-1

Rationale for PRC-1: *Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes.*

Final Version

101 PREAMBLE

101.1 This General Order shall be known as the "State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems." It will be referred to herein as "these rules."

101.2 These rules are incorporated in addition to the Federal Pipeline Safety Regulations, specifically, Title 49 of the Code of Federal Regulations (49 CFR), Parts 191, 192, 193, and 199, which also govern the Design, Construction, Testing, Operation, and Maintenance of Gas Piping Systems in the State of California. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to the Federal Regulations.

PRC-2

Rationale for PRC-2: *Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes.*

Final Version

104 PROCEDURES FOR KEEPING GENERAL ORDER UP-TO-DATE

104.1 It is the intent of the California Public Utilities Commission to automatically incorporate all revisions to the Federal Pipeline Safety Regulations, 49 CFR Parts 191, 192, 193, and 199 with the effective date being the date of the final order as published in the Federal Register.

PRC-3

Rationale for PRC-3: *Provide clarification on existing GO-112-E terms and define new terms related to new metrics or more stringent requirements than otherwise required by 49 CFR, Part 192.*

Final Version

105 DEFINITIONS

Commission means the Public Utilities Commission of the State of California.

Holders means any structure used to store gas, which either has a displacement of 500 or more cubic feet, or will contain 10,000 or more standard cubic feet of gas at its maximum design pressure, except that a pipeline which is used primarily for transmission or distribution of gas, but which also serves a storage function, is not a holder for purposes of this General Order.

Inert gas means a gas which will not burn or support combustion, such as nitrogen, carbon dioxide or mixtures of such gases.

Utility means any person, firm, or corporation engaged as a public utility in transporting natural gas, liquefied natural gas (LNG), hydrocarbon gas, or any mixture of such gases for domestic, commercial, industrial, or other purposes.

Operator means any utility, person or entity operating a natural gas transmission or distribution system, including master-meter distribution system subject to PU Code Section 4351-4361, or a propane gas (LPG) distribution system subject to PU Code Section 4451-4465.

Vicinity means an area surrounding an incident in which an operator's gas pipeline facilities could have been a contributing factor to the event

Public Attention criterion means any event that escalates to a level that initiates concerns being submitted to a utility from a large number of people. This can include, for example, large scale reports (15 or more) of the smell of gas by customers in the vicinity of an operator's gas facilities. Public Attention criterion does not necessarily include an individual, or a crowd of persons, watching work being performed on company facilities. This also excludes planned operations where the customers have been notified.

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.

High Consequence Area (HCA) is defined by 49 C.F.R §192.903.~~, which allows two different methods to be used towards determining locations where HCAs exist. However, i~~In an effort to be more conservative towards ensuring public~~the~~ safety in ~~areas of~~ more densely populated ~~Class 3 and Class 4 locations,~~ areas, the Commission restricts the use of Method 2 in §192.903 to pipeline with a diameter of 12 inches or less.~~Operators to using Method 1, as defined in 49 C.F.R §192.903, in determining HCAs.~~ Accordingly, the Commission modifies ~~defines a high consequence area as~~paragraph (2) of the High Consequence Area Definition in §192.903 to read as follows:

> (2) The area within a potential impact circle *of a pipeline 12 inches or less in diameter* containing –

Newly identified HCA shall be scheduled for baseline assessment in accordance with §192.905(c).

> ~~(a) A Class 3 location under § 192.5; or~~
>
> ~~(b) A Class 4 location under § 192.5; or~~
>
> ~~(c) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or~~
>
> ~~(d) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.~~

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Near-miss events mean unplanned events that are not categorized as damages and do not result in injury, illness, ~~damage~~, release of gas, loss of gas service, or over-pressurization of gas pipeline facilities, or otherwise a reportable incident, but had the potential to do so if not addressed through work site mitigation measures. Such events can include, but are not limited to:

(a) A subsurface pipeline facility mismarked for excavation purposes;

(b) Excavation activity near a pipeline facility conducted without a USA ticket;

~~(a)~~(c) The operation of an incorrect valve or pressure regulator;

~~(b)~~(d) An incorrectly mapped pipeline facility;

(e) Deficiencies ~~identified~~ in an approved standard, procedure or process found due to a near miss event that occurred during an active construction project. ~~as defined above.~~

Number of excavation tickets or Number of excavation damages reported per the data requirements of Section 123, **Annual Reports**, means to include all original and renewal one-call notices received by the Operator.

Under-pressure condition means loss of service to more than a single customer/meter and specifically excludes single events that can occur at single premise/meter location or branch connection.

Damage: Any impact or exposure that results in the need to repair an underground facility due to a weakening or the partial or complete destruction of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility. [1]

[1] Common Ground Alliance User Guide, June 2013, page 22.

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PRC-4

Rationale for PRC-4: *Require the reporting of overpressure and underpressure events on all gas pipeline systems.*

Final Version

122 GAS INCIDENT REPORTS

122.1 Each operator shall comply with the requirements of 49 CFR Part 191, for the reporting of incidents to the United States Department of Transportation (DOT). The operator shall submit such reports directly to the DOT, with a copy to the California Public Utilities Commission (CPUC).

122.2 Requirements for reporting to the CPUC.

(a) Each operator shall report incidents to the CPUC that meet the following criteria:

1. Incidents which require DOT notification.
   i. An event that involves a release of gas from a pipeline or of liquefied natural gas (LNG) or gas from an LNG facility and
      - A death, or personal injury necessitating in-patient hospitalization; or
      - Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.

   ii. An event that results in an emergency shutdown of an LNG facility.
2. Incidents which have either attracted public attention or have been given significant news media coverage, that are suspected to involve natural gas and/or propane (LPG) gas, which occur in the vicinity of the operator's facilities; regardless of whether or not the operator's facilities are involved.
3. Incidents where the failure of a pressure relieving and limiting stations, or any other event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable limitations set forth in 49 CFR § 192.201.

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4. Incidents in which an under-pressure condition, caused by the failure of a pressure controlling device, unplanned operation or other unscheduled event, excluding excavation- related damage, results in service loss to multiple customers or the removal of DOT jurisdictional pipeline from service. ~~Incidents in which an under-pressure condition, caused bywhere the failure of any pressure controlling device, or any other event other than excavation related damage, results in any part of the gas pipeline system losing service or being shut-down~~.

(b) In the event of an incident listed in 122.2(a) above, an operator shall go to the Commission's website, select the link to the page for reporting emergencies and follow the instructions thereon. If internet access is unavailable, the Operator may report using the backup telephone system.

1. If the utility is notified of the incident during its normal working hours, the report should be made as soon as practicable but no longer than ~~2~~ 8 hours after the utility ~~i~~ determines it meets the reporting criteria set forth in 122.2(a).1-4.~~s aware of the incident and its personnel are on the scene~~.
2. If the utility is notified of the incident outside of its normal working hours, the report should be made as soon as practicable but no longer than ~~4~~ 8 hours after the utility determines it meets the reporting criteria set forth in 122.2(a).1-4.~~is aware of the incident and its personnel are on the scene.~~
3. All reports required by this section shall be followed by the end of the next working day ~~by~~ with an email or telefacsimile (fax) of the standard reporting form, "Report of Gas Leak or Interruption," CPUC File No. 420 (see attachment).

(c) Written Incident Reports .

1. The operator shall submit to the CPUC on DOT Form PHMSA F7100.1 (http://ops.dot.gov/library/forms/forms.htm#7100.1)for distribution systems and on DOT Form PHMSA F7100.2 (http://ops.dot.gov/library/forms/forms.htm#7100.2) for transmission and gathering systems a report describing any incident that required notice under Item 122.2(a)(1).

2. Together with the form required by (c)(1) above, the operator shall furnish a letter of explanation giving a more detailed account of the incident unless such letter is deemed not necessary by the CPUC staff. The operator may confirm the necessity of a letter of explanation by email. If, subsequent to the initial report or letter, the operator discovers additional material, information related to the incident, the operator shall furnish a supplemental report to the CPUC as soon as practicable, with a clear reference by date and subject to the original report. These letters, forms, and reports shall be held confidential under the provisions of Paragraph 2, Exclusions, of General Order 66-C and Public Utilities Code Section 315.

3. The operator of a distribution system serving less than 100,000 customers need not submit the DOT forms required by paragraph (1) above; however, such operator must submit the letter of explanation required by (2) above, subsequent to any initial report to the CPUC, unless such letter is deemed unnecessary by the CPUC staff.

(d) Quarterly Summary Reports. Each operator shall submit to the CPUC quarterly, not later than the end of the month following the quarter, a summary of all CPUC reportable and non-reportable gas leak related incidents which occurred in the preceding quarter as follows:

1. Incidents that were reported through the Commission's Emergency Reporting website.

2. Incidents for which either a DOT Form PHMSA F7100.1 or F7100.2 was submitted.

3. Incidents which involved escaping gas from the operator's facilities and property damage including loss of gas in excess of $1,000.

4. Incidents which included property damage between $0 and $1,000, and involved fire, explosion, or excavation related damage.

5. Incidents where the failure of a pressure relieving and limiting stations, or any other event, results in pipeline system pressure exceeding its established Maximum Allowable Operating

Pressure (MAOP) plus the allowable limitations set forth in 49 CFR § 192.201.

~~6.~~ Incidents in which an under-pressure condition, caused by the failure of a pressure controlling device, unplanned operation or other unscheduled event, excluding excavation-related damage, results in service loss to multiple customers or the removal of DOT jurisdictional pipeline from service. ~~Incidents in which an under-pressure condition, caused by~~where ~~the failure of any pressure controlling device, or any other event other excavation related damage, results in any part of the gas pipeline system losing service or being shut-down.~~

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PRC-5

Rationale for PRC-5: *Incorporate minor updates in federal regulations and implement requirements for the reporting of metrics discussed in the June 27, 2013 Metrics Workshop.*

Final Version

123 ANNUAL REPORTS AND MECHANICAL FITTING FAILURE REPORTS

123.1 Each operator shall submit to the DOT, with a copy to the CPUC, annual reports and mechanical fitting failure reports required by 49 CFR, Part 191, §§191.11, 191.12 and 191.17. Such reports shall be submitted in the manner prescribed in 49 CFR Part 191.

123.2 At the same time copies of the reports required by paragraph 123.1, each operator shall submit, in a format and guidance provided by the Commission's Safety and Enforcement Division or its successor, the following information to demonstrate to the Commission and the public an Operator's efforts towards minimizing the risk from system leaks and failures:

a) Number of gas leaks associated with causes, pipeline materials, sizes, and decades of installation.

b) For leaks replaced in the calendar year, show time between finding the leak and its repair in intervals of 0-3 months; 6-9 months; 9-12 months; 12-15 months; and greater than 15 months. For the aggregated value of leaks repaired greater than 15 months, segregate the value into leaks that are never regraded; regraded once; regarded twice; regraded three times; and regraded more than three times.

c) Response times, segregated in five-minute intervals and by Division, District, and/or Region, to reports of leaks or damages reported to the Operator by its own employees or by the public. The intervals start with 0-5 minutes, all the way to 40-45 minutes, and with all response times greater than 45 minutes. The timing for the response starts when the utility first receives the report and ends when an Operator's qualified representative determines the reported leak is not hazardous or the Operator's representative(s) complete actions to mitigate a hazardous

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leak and render it non-hazardous. In addition, the Operator must report, using the same intervals, the times for the first company responder to arrive on scene.

d) The number of events in which pressure in any pipeline facility exceeded the maximum allowable operating pressure (MAOP) by 50% or more of the allowances provided for by 49 CFR § 192.201. For any transmission pipeline facility where the operator applies the provisions of 49 CFR § 192.917 (e)(3) or (e)(4), any increases above the maximum operating pressure must be reported. Also, for low-pressure systems (i.e., inches of water column pressure), all pressure increases above MAOP must be reported. Increases in pressure above MAOP resulting from planned, designed, testing, or other intentional operations performed per procedures or process established by the operator are exempted from this requirement. For purposes of reporting, "events" includes each occurrence of overpressurization that develops between overpressurization being noted and maintenance being performed.

e) The percentage of maps that have been updated within the timeframe set forth in an operator's procedures to reflect changes, repairs, or new additions of pipeline facilities, including valves, regulator stations, fittings and other pressure carrying components.~~The amount of time it takes for changes, repairs, or new facilities to be finalized and updated, per the Operator's procedures, to the Operator's facilities maps. The provided information shall show the number of facilities mapped segregated into the following time intervals~~

~~1. Less than 14 days~~;

~~2. More than 14 days, but less than 30 days;~~

~~3. More than 30 days, but less than 90 days;~~

~~4. More than 90 days, but less than 180 days;~~

~~5. More than 180 days, but less than 360 days;~~

~~6. More than 360 days~~.

f) The number of employees, by operating Division, District, Region, or Other (i.e., an employee of a mobile workforce not assigned to Division, District, or Region) evaluated, and those disqualified after evaluations, performed by the Operator per 49 CFR§ 192.805 (d) or (e).

g) The 32 metrics required to be tracked per 49 CFR § 192.945(a) and ASME B31.8S, Chapter 9, Table 9.

h) Excavation Damage Prevention Related Data

1. Number of excavation damages and related costs involving homeowners;

2. Number of damages and related costs involving agencies (i.e., Caltrans, non-pressurized sewer, etc.) excluded per California Government Code 4216 (GC4216);

3. Number of person-days, along with total costs, devoted to: i) excavation field meetings (per GC4216); and ii) stand-by activities for preventing damage to subsurface facilities during an excavation;

4. Number of person-days, along with total costs, devoted to: i) mark and locate activities (per GC 4216); and ii) all other subsurface damage prevention activities excluding those from paragraph 3 above.

i) Leaks and Related Gas Volumes used to Calculate Lost and Unaccounted For Gas

1. The total number of leaks and volumes broken down by Transmission and Distribution, used to calculate the leakage component of the LUAF reported under subsection 123.1

~~i) Lost and Unaccounted For Gas (LAUF Gas)~~

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

~~2. An accounting of the effects of each of the different causes of LAUF Gas, actual and/or estimated values, which factor into the aggregated LAUF Gas value provided by the Operator on all reports submitted pursuant to subsection 123.1.~~

j) Public liaison activities

1. The number of public liaison baseline activities scheduled by the Operator and the number of public liaison activities actually performed.

2. A summary of public agencies (by county and agency name) to which the Operator provided notice of, and made available for participation, its annual liaison sessions during each of the five calendar years preceding the reporting year. The summary must also denote which agencies were able to have representation at the session.

3. In an effort to provide a convenient resource for the public to use towards confirming that Operators and first responders continue to work together in better coordinating responses to emergencies, each Operator shall make the same information provided per paragraph 2 above available on its website with a link to the information provided on the CPUC website. Attendance of agencies at liaison sessions is voluntary and agencies may be unable to attend a particular session for a variety of reasons, including responding~~dependent on agencies having to allocate resources~~ to emergencies that occur when sessions are scheduled.

k) Gas Safety Plan

1. Each Operator must submit a Gas Safety Plan, as codified by Pub. Util. Code §§ 961 and 963, and as ordered by the Commission in D.12-04-010.

2. Each operator must make any modifications to its Gas Safety Plan identified by the Commission's Safety and Enforcement Division, or its successor.

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PRC-6

Rationale for PRC-6: *Minor housekeeping issue.*

Final Version

124 REPORTING SAFETY RELATED CONDITIONS

124.1 The requirements of 49 CFR, Part 191, §§191.1, 191.7, 191.23, and 191.25, to report specified safety-related conditions, are incorporated by references as part of these rules. Copies of all reports submitted to the Secretary of Transportation pursuant to the foregoing requirements shall be submitted to the Commission concurrently.

PRC-7

Rationale for PRC-7: *Clarify the requirements for proposed installation reports and adjust the cost thresholds for reporting, that were determined many decades ago, for inflation.*

Final Version

125 PROPOSED INSTALLATION REPORT

125.1 This section applies to the construction of a new pipeline, or the reconstruction or reconditioning of an existing pipeline, to be operated at a hoop stress of 20 percent or more of the specified minimum yield strength.

125.2 The proposed installation reports required by this section shall be filed based on the following:

(a) For utilities with less than 50,000 services in the state of California according to the Annual DOT Report, Form PHMSA F 7100.1-1 that is required by 49 CFR §191.11, the Proposed Installation Report shall be submitted to the Commission for any installation that is estimated to cost $1,400,000 or more. The Annual DOT Report referenced above shall be the report filed by the utility for the year previous to that of the proposed installation; or

(b) For utilities with 50,000 services or more in the state of California according to the Annual DOT Report, Form PHMSA F 7100.1-1 required by 49 CFR §191.11, the Proposed Installation Report shall be submitted to the Commission for any installation that is estimated to cost $3,500,000 or more. The Annual DOT Report referenced above shall be the report filed by the utility for the year previous to that of the proposed installation.

125.3 Definitions:

(a) "Construction of a new pipeline" means the installation of pipeline that will serve as a loop or extension to an existing pipeline or as an independent or stand-alone pipeline, any of which will be placed in service for the first time by an operator who filed a Form PHMSA F-7100.1-1 for the calendar year preceding the year in which construction takes place. An operator commencing service for the first time shall file a Proposed Installation Report with the Commission ~~after receiving CPCN approval from the Commission and~~ prior to the start of construction of the approved project.

(b) "Reconstruction of an existing pipeline" means the installation of pipeline that will replace an existing pipeline or pipeline segment due to ~~alignment interference,~~ deteriorating or aging conditions, pressure/capacity enhancement, or other safety related reason.

(c) "Reconditioning of an existing pipeline" is defined as the work associated with repairing, structurally reinforcing, the replacement of fittings or short segments of pipe, or for the removal and reapplication of pipe coating. The term does not include altering or retrofitting a pipeline or its appurtenances to allow for the passage of internal inspection devices.

125.4 At least 30 days prior to the construction of a new pipeline or~~,~~ reconstruction, ~~or reconditioning of an existing pipeline~~, a report shall be filed with the Commission setting forth the proposed route and general specifications for such pipeline. The specifications shall include but not be limited to the following items:

(a) Description and purpose of the proposed pipeline.
(b) Specifications covering the pipe selected for installation, route map segregating incorporated areas, class locations and design factors, terrain profile sketches indicating maximum and minimum elevations for each test section of pipeline, and, when applicable, reasons for use of casing or bridging where the minimum cover will be less than specified in §192.327.
(c) Maximum allowable operating pressure for which the line is being constructed.
(d) Test medium and pressure to be used during strength testing.
(e) Protection of pipeline from hazards as indicated in §192.317 and §192.319.
(f) Protection of pipeline from external corrosion.
(g) Estimated cost with supporting detail.

125.5 ~~In cases of reconditioning projects that do not result in relocating pipeline from the general location it occupies prior to the project, then the information stated in Section 125.4 (b) does not need to be provided within the report filed per Section 125.4.~~

~~**126.6**~~ In cases of projects necessary on an emergency basis, the report required by Section 125.4 shall be filed with the Commission as far in advance of the project as practicable, but no later than 5 business days after the project has been initiated. Reports filed for emergency projects, in addition to other information required per Section 125.4, must also detail reasons that necessitated the project being performed on an emergency basis.

125.6~~7~~ During strength testing of a pipeline to be operated at hoop stresses of 20 percent or more of the specified minimum yield strength of the pipe used, any failure shall be reported on appropriate forms established by the Commission.

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PRC-8

Rationale for PRC-8: *Minor housekeeping issues.*

Final Version

141 GENERAL

141.1 Each operator shall comply with the requirements of 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section of the General Order addresses specific construction, testing, and safety standards in addition to those included in 49 CFR Part 192. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

PRC-9

Rationale for PRC-9: *Place limitations on how long plastic pipe can be stored unprotected outdoors.*

Final Version

142 PLASTIC PIPE

142.1 Plastic Pipe Storage   At the time of installation, plastic pipe to be used for gas transportation, shall not have been subjected to unprotected outdoor exposure longer than the time recommended by the manufacturer, or the time period specified in the operator's operations and maintenance plan, or 3years, whichever ever is least.

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PRC-10

Rationale for PRC-10: *Provide clarification, specify requirements related to the prioritization and repair of leaks, and to confirm that employees performing covered tasks are qualified using equipment similar to that used in operations.*

Final Version

143 DISTRIBUTION AND TRANSMISSION SYSTEMS

143.1 Leakage Surveys and Procedures - A gas leak survey, using leak detecting equipment, must be conducted in business districts and in the vicinity of schools, hospitals and churches, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement, and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

143.2 Leak classification and action criteria—Grade—Definition—Priority of leak repair.

(1) A "Grade 1 leak" is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.

(a) Prompt action in response to a Grade 1 leak may require one or more of the following:

(i) Implementation of the gas pipeline company's emergency plan pursuant 49 CFR § 192.615;

(ii) Evacuating the premises;

(iii) Blocking off an area;

(iv) Rerouting traffic;

(v) Eliminating sources of ignition;

(vi) Venting the area;

(vii) Stopping the flow of gas by closing valves or other means; or

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(viii) Notifying police and fire departments.

(b) Examples of Grade 1 leaks requiring prompt action include, but are not limited to:

(i) Any leak, which in the judgment of gas pipeline company personnel at the scene, is regarded as an immediate hazard;

(ii) Escaping gas that has ignited unintentionally;

(iii) Any indication of gas that has migrated into or under a building or tunnel;

(iv) Any reading at the outside wall of a building or where the gas could potentially migrate to the outside wall of a building;

(v) Any reading of eighty percent LEL or greater in an enclosed space;

(vi) Any reading of eighty percent LEL, or greater in small substructures not associated with gas facilities where the gas could potentially migrate to the outside wall of a building; or

(vii) Any leak that can be seen, heard, or felt and which is in a location that may endanger the general public or property.

(2) A "Grade 2 leak" is a leak that is recognized as being not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.

(a) Each gas pipeline company must repair or clear Grade 2 leaks within fifteen months from the date the leak is reported. If a Grade 2 leak occurs in a segment of pipeline that is under consideration for replacement, an additional six months may be added to the fifteen months maximum time for repair provided above. In determining the repair priority, each gas pipeline company should consider the following criteria:

(i) Amount and migration of gas;

(ii) Proximity of gas to buildings and subsurface structures;

(iii) Extent of pavement; and

(iv) Soil type and conditions, such as frost cap, moisture and natural venting.

(b) Each gas pipeline company must reevaluate Grade 2 leaks at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.

(c) Grade 2 leaks vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the criteria, will require prompt scheduled repair within the next five working days. Other Grade 2 leaks may require repair within thirty days. The gas pipeline company must bring these situations to the attention of the individual responsible for scheduling leakage repair at the end of the working day. Many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic reevaluation as necessary.

(d) When evaluating Grade 2 leaks, each gas pipeline company should consider leaks requiring action ahead of ground freezing or other adverse changes in venting conditions, and any leak that could potentially migrate to the outside wall of a building, under frozen or other adverse soil conditions.

(e) Examples of Grade 2 leaks requiring action within six months include, but are not limited to:

(i) Any reading of forty percent LEL or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak and where gas could potentially migrate to the outside wall of a building;

(ii) Any reading of one hundred percent LEL or greater under a street in a wall-to-wall paved area that does not qualify as a Grade 1 leak and where gas could potentially migrate to the outside wall of a building;

(iii) Any reading less than eighty percent LEL in small substructures not associated with gas facilities and where gas could potentially migrate creating a probable future hazard;

(iv) Any reading between twenty percent LEL and eighty percent LEL in an enclosed space;

(v) Any reading on a pipeline operating at thirty percent of the specified minimum yield strength or greater in Class 3 or 4 locations that does not qualify as a Grade 1 leak; or

(vi) Any leak that in the judgment of gas pipeline company personnel at the scene is of sufficient magnitude to justify scheduled repair.

(3) A "Grade 3 leak" is a leak that is not hazardous at the time of detection and can reasonably be expected to remain not hazardous.

(a) Each gas pipeline company should reevaluate Grade 3 leaks during the next scheduled survey, or within fifteen months of the reporting date, whichever occurs first, until the leak is regraded or no longer results in a reading.

(b) Examples of Grade 3 leaks requiring reevaluation at periodic intervals include, but are not limited to:

(i) Any reading of less than eighty percent LEL in small gas associated substructures, such as small meter boxes or gas valve boxes; or

(ii) Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building.

143.3 Valve Maintenance - Each valve, the use of which may be necessary for the safe operation of a distribution system, must be inspected, serviced, lubricated (where required) and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

143.4 Operator Qualification - The equipment and facilities used by a gas pipeline company for training and qualification of employees must be similar to the equipment and facilities on which the employee will perform the covered task.

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PRC-11

Rationale for PRC-11: *Provide clarification for test requirements pertaining to all pipelines, provide clearance requirements not specified in federal regulations, and to align clearance requirement in GO-112-E with the clearance requirement contained the Commission's GO-128.*

Final Version

144 TEST REQUIREMENTS FOR PIPELINES TO OPERATE BELOW 100 p.s.i.g.

144.1 Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i.g. must be leak tested in accordance with 49 CFR §192.509 and the following:

(a) Each main that is to be operated at less than 1 p.s.i.g. must be tested to at least 10 p.s.i.g.

(b) Each main to be operated at or above 1 p.s.i.g. but less than 60 p.s.i.g. must be tested to at least 90 p.s.i.g.

(c) Each main to be operated at or above 60 p.s.i.g. but less than 100 p.s.i.g. must be tested to a minimum of 1.5 times the proposed MAOP.

144.2 Service lines and plastic pipelines must be leak tested in accordance with 49 CFR §192.511 or §192.513, respectively, except for the exemption defined in (b) below~~. In addition to these requirements~~:

(a) In addition to these requirements, e~~E~~ach new service line to be operated at a pressure less than 1 p.s.i.g, must be tested to a minimum pressure of 10 p.s.i.g, for a minimum duration of 5 minutes.

(b) Short sections of pipes~~line~~ used to repair existing service ~~lines~~ lines only require a~~must be~~ pressure test~~ed~~ at the operating pressure.

144.3 Clearance between gas pipelines and other subsurface structures

(a) All natural gas transmission pipelines must be installed in conformance with the requirements of 49 CFR, Part 192, §192.325:

(b) All natural gas distribution pipelines (main and service) must be installed in conformance with the requirements of 49 CFR, Part 192, §192.325 and the following:

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(1) Independently Installed: Gas pipelines, when independently installed, shall be separated, where practicable from electrical supply systems, water, oil, communication, or other pipe systems or other foreign substructures, by a clearance of at least 12 inches when paralleling and by at least 6 inches when crossing.

(2) Concurrently Installed: Gas pipeline, when concurrently installed with electrical supply systems, water, oil, communication, other pipe systems, or other foreign substructures, shall be installed with the separation required by Commission General Order 128, Rule 31.4-A2, except that by mutual agreement between all of the parties involved there may be less separation for duct systems for supply cables of 0 - 750 volts.

(c) In all instances where the required separations cannot be maintained, it is the responsibility of the party installing facilities to assure that the reduced separations assure the integrity of the gas pipeline facilities, which includes any cathodic protection that may be applied to the gas pipeline facilities.

PRC-12

Rationale for PRC-12: *Establish a section within GO 112-E to specify recordkeeping requirements related to transmission lines.*

New Rule Section 145 TRANSMISSION LINES: RECORDKEEPING

145 TRANSMISSION LINES: RECORDKEEPING

145.1 Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and/or vintage as the pipeline on which repairs are made, whichever, is longer.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. However, repairs, or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

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PRC-13

Rationale for PRC-13: *Minor housekeeping issues.*

Final Version

161 GENERAL

161.1 Each operator shall comply with the requirements of 49 CFR Part 193 - Liquefied Natural Gas Facilities: Federal Safety Standards. This section of the General Order addresses specific standards for the design, construction, testing, operation, and maintenance of liquefied natural gas facilities in addition to those included in 49 CFR Part 193. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

SB_GT&S_0158323

PRC-14

Rationale for PRC-14: *Incorporate new requirements related to Operator's mobile LNG operations.*

Final Version

162 LIQUEFIED NATURAL GAS FACILITIES

162.1 Except for a pipeline facility in operation or under construction before January 1, 1973, no operator may store, treat, or transfer liquefied natural gas in a pipeline facility unless that pipeline facility meets the applicable requirements of this part and of NFPA Standard No. 59A.

162.2 No operator may store, treat, or transfer liquefied natural gas in a pipeline facility in operation or under construction before January 1, 1973, unless

(a) The facility is operated in accordance with the applicable operating requirements of this part and of NFPA Standard 59A; and

(b) Each modification or repair made to the facility after December 31, 1972, conforms to the applicable requirements of this part and NFPA Standard 59A, insofar as is practicable.

162.3 The operator, who is planning to build a LNG facility in the state of California, shall notify the Utilities Safety and Reliability Branch 90 days prior to commencing construction on that LNG facility.

162.4 All operators must include utility-owned mobile LNG equipment within the written operations and maintenance plans required by 49 CFR, Part 192, §192.605. Operators must provide written, detailed, procedures for the operation and maintenance of their mobile LNG units. These procedures must include a requirement to perform operational tests of utility-owned mobile LNG equipment, after any modifications are performed to the equipment (including computer equipment and software) that could affect equipment operation, before using modified equipment for actual field use.

PRC-15

Rationale for PRC-15: *Minor housekeeping issues.*

Final Version

181 GENERAL

181.1 Each operator shall comply with the requirements of 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section of the General Order addresses specific standards for the design, construction, testing, operation, and maintenance of gas holders in addition to those included in 49 CFR Part 192. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

PRC-16

Rationale for PRC-16: *Minor housekeeping issues.*

Final Version

182 PIPE-TYPE AND BOTTLE-TYPE HOLDERS: DESIGN AND CONSTRUCTION

182.1 All holders shall comply with the requirements of 49 CFR §§192.175 and 192.177.

182.2 Electrical equipment and wiring installed at holders must conform to the National Electrical Code, NFPA-70, so far as that Code is applicable.

182.3 Any holder designed and constructed in accordance with the requirements for location class 1 or 2, but not 3, shall be installed at least 75 feet from a flammable building or adjoining property that may have a flammable building constructed thereon in the future, or from the nearest rail or a track on a railroad private right-of-way. Also, no utility shall construct or install a flammable building within fifty feet of a holder. (A flammable building shall be understood to be a building, roof or siding of which consist of wood or other readily combustible material.)

182.4 Each vent line that exhausts gas from a pressure relief valve or blowdown valve must extend to a location where the gas may be discharged without hazard.

182.5 A device which will maintain a continuous pressure record shall be installed at the inlet or outlet of each holder, except that where a group of holders are jointly connected and are all filled from the same gas source and all empty into a common line or system, only one device will be required. A pressure indicating device shall be installed on each container in the holder.

182.6 Each holder facility must have adequate fire-protection facilities.

182.7 Holders shall be provided with overpressure protection systems complying with the requirements of 49 CFR, §192.195.

182.8 When a holder is constructed adjacent to any existing electric transmission line normally carrying voltages in excess of 50,000 volts, the holder shall be located no nearer to the lines than the height of the poles carrying them.

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PRC-17

Rationale for PRC-17: *Minor housekeeping issues.*

Final Version

183 PIPE-TYPE AND BOTTLE-TYPE HOLDERS: PLAN FOR INSPECTION AND TESTING

183.1 All leaks of any consequence in gas pipeline, valves and equipment in the vicinity of a holder must be promptly repaired upon discovery, or as soon as practicable. All hazardous leaks must be remedied at once.

183.2 In addition to other inspections required by this Part, after a high pressure holder has been in service for a period of ten years, and at intervals not exceeding ten years thereafter, a complete and thorough internal and external inspection shall be made and reported upon by competent inspectors who are selected by the utility and are agreeable to the Commission. A copy of the report shall be provided to the Commission.

183.3 In lieu of an internal inspection, when it is not practical to enter the holder, a sufficient number of plugs shall be cut from, or holes bored in, the shell at points believed most subject to internal corrosion, to enable examination for corrosion. The interior of at least one container of a holder constructed entirely of pipe and fittings shall be inspected by removing the end closures and entering the container.

183.4 As an alternative to the above requirements to enter the container, or to cut plugs or bore holes in the holder, a nondestructive test procedure such as ultrasonic testing may be used. The test instrument must be calibrated to measure the wall thickness of the steel plates so that the error of indication shall not vary more than plus or minus two thousandths (±0.002) of an inch.

183.5 When such inspections determine that the holders are in a defective and hazardous condition, they shall be taken out of service until repaired and placed in a safe workable condition. All others in the same group shall immediately be inspected and repaired if found defective. If any portion of the shell of a high pressure holder is located underground and exposed to the soil, inspection of its exterior for corrosion and leaks shall be made by suitable representative excavations at the time of the inspection.

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PRC-18

Rationale for PRC-18: *Minor housekeeping issues.*

Final Version

201 GENERAL

Each operator shall comply with the requirements of 49 CFR Part 192 -Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section of the General Order addresses specific standards for the design, construction, testing, operation, and maintenance of petroleum gas vessel stations in addition to those included in 49 CFR Part 192. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

SB_GT&S_0158329

PRC – 19

Rationale for PRC-19: *Implement a new subpart within GO 112-E to include whistleblower protections already established as a regulation by D.12-12-009.*

New Rule – Subpart G –Whistleblower Protections

SUBPART G – WHISTLEBLOWER PROTECTIONS

301 General

301.1 Each operator shall post in a prominent physical location, as well as an electronic notice on its website where its employees are likely to see it, a notice containing the following information:

Report unsafe conditions to the Public Utilities Commission by calling the whistleblower hotline at 1(800) 649-7570 or by e-mail to safetyhotline@cpuc.ca.gov.

Under sections 451 of the California Public Utilities Code, every public utility shall furnish and maintain such service, instrumentalities, equipment, and facilities, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees and the public. Further, under section 963(b)(3) of the California Public Utilities Code, it is the policy of this State that California natural gas utilities and the Commission's regulation of natural gas utilities place safety of the public and the natural gas utilities' employees as the top priority consistent with the principle of just and reasonable cost-based rates. In addition, under section 961(e) of the California Public Utilities Code, the Commission and natural gas utilities must provide meaningful and ongoing opportunities for the utilities' workforce to participate in the utilities' development of a plan for the safe and reliable operations of their pipeline facilities and to contribute to developing an industry wide culture of safety. In view of the above, any employee of the natural gas utility or of an independent contractor working under contract with a natural gas utility, who in good faith, believes that unsafe conditions, services or facilities of the utility threaten the health or safety of its patrons, the employees or the public, has a right to report the conditions to the California Public Utilities Commission. The employee can report the conditions by calling the Commission's Whistleblower Hotline at 1(800) 649-7570, either anonymously or by giving the employee's name, or by sending an e-mail with the pertinent facts and/or documentation to safetyhotline@cpuc.ca.gov. This requirement shall be in addition to any right the employee has to contact any other State of Federal agency, if the employee has reasonable cause to believe that the information discloses a violation of a state or federal statute, or a violation or noncompliance with a state or federal rule or regulation.

302 The Utility Has No Right to Retaliate Against an Employee For Notifying the California Public Utilities Commission

302.1 In addition to other statutes, which provide remedies for retaliation against Whistleblowers (e.g., the California Whistleblower Act, California Labor Code § 1102.5), or any other remedy an employee may have in a court, the Commission prohibits California natural gas utilities from retaliating against any employee, who reports, in good faith, unsafe conditions to the Commission. For purposes of this regulation, the Commission retains the option to impose penalties and any other remedies provided under the California Public Utilities Code for any natural gas utility, which the Commission finds violates this regulation.

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