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 (U 39 G)	Rulemaking 11-02-019

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON ORDER INSTITUTING RULEMAKING

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Pursuant to Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), and Ordering Paragraph 6 of the Commission's 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 ("OIR"), Pacific Gas and Electric Company ("PG&E") submits the following comments.

I. INTRODUCTION

PG&E fully endorses the objectives of the Commission's rulemaking – raising the bar on the safety of the State's natural gas system. It also welcomes the opportunity to work with the Commission, other California gas utilities, and stakeholders to develop these new rules. Commissioner Florio is correct: this proceeding is not business as usual.

Every comment PG&E offers on the proposed new rules is based first and foremost on its assessment of whether the proposed new rules will enhance public safety (and for the most part we believe that is the case). Our comments next reflect an assessment of whether this safety objective will be achieved in the quickest, most direct way possible. When, based on this assessment, we offer specific comments on technical aspects of the rules, we do so to suggest that the Commission consider an alternative approach, not to object to them. But we do not offer any alternative approach unless it is fully aligned with the over-arching objective of enhancing safety.

As we have stated before, the Commission and those it regulates must share a common goal: public safety. This proceeding offers an important opportunity to develop new approaches to natural gas pipeline safety. These new approaches must challenge our more traditional notions of how public safety should be protected. They must take full advantage of our increasing levels of knowledge, the development of new technologies and the broad public consensus that has emerged in support of the substantial investment needed now to improve our aging infrastructure. California has historically led the United States in the development of new ideas, new businesses and new approaches to old problems. It should do so again.

We first offer comments on the new rules in Attachment A. We next provide some initial observations on the topics for future rules in Attachment B of the OIR. We then propose additional areas for new rules. Last, we request that the Commission promptly act to establish a memorandum account for the limited purpose of recording and tracking gas pipeline expenditures.

We commend the Commission for its intention to act decisively and we support a broad stakeholder process to ensure all interested parties are heard and have an opportunity to help shape the Commission's new gas pipeline safety regulations.

II. SCOPE AND CATEGORIZATION OF PROCEEDING AND PROCEDURAL SCHEDULE

PG&E concurs with the preliminary scope included in the Rulemaking. PG&E also agrees that this Rulemaking should be categorized as a "ratesetting" proceeding as defined in Rule 1.3(e). PG&E believes that workshops and hearings may be needed.

PG&E urges the Commission to adopt the Preliminary Schedule set forth in the Rulemaking, which contemplates receiving the results of the public participation hearings and reports of the Independent Review Panel before a Prehearing conference late in the second quarter of 2011.

III. PROPOSED CHANGES TO THE COMMISSION'S REGULATIONS

A. Attachment A – Proposed Rules for Immediate Implementation

Each of the proposed rules in Attachment A is a specific proposal to enhance natural gas pipeline safety beyond the protections provided by current regulations. PG&E supports the proposed new rules with the revisions discussed below.

1. New Section 145 for General Order 112-E – Strength Test Requirements for Certain Pipelines Operated by PG&E

PG&E has three comments on new Section 145. The first concerns the requirement that PG&E reduce pressure on its pipelines even after it completes an MAOP validation. The second concerns the temporary exemption provisions set forth in the rule. The third addresses the references in proposed Rule 145 to pipelines, rather than to pipeline segments.

We want to emphasize from the outset our strong endorsement of the Commission's approach to pipeline safety, as reflected in the proposed regulations. To assure the safety of all California citizens, all natural gas companies in California should be required to follow them. To the extent we make suggestions below, they are meant to balance the safety needs of the public. These needs extend to both the safe operation of our natural gas system and the reliable delivery of natural gas.

Grandfathering. Currently, the Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations, which the Commission adopted unchanged in General Order (GO) 112-E, allow a pipeline MAOP to be determined in three ways: (1) by use of design pressure

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information on all pipeline components, 49 C.F.R. § 192.619(a)(1); (2) by a pressure test, 49 C.F.R. § 192.619(a)(2); or (3) for pipelines installed prior to July 1, 1970, by means of the so-called "grandfather" provision in 49 C.F.R. § 192.619(c). Section 619(c) provides for the determination of the MAOP based on the highest actual operating pressure between July 1, 1965 and June 30, 1970.

Proposed Rule 145 would require PG&E to reduce pressure on its gas transmission pipelines in Class 3 and 4 locations and HCA pipelines in Class 1 and 2 locations[1] (collectively referred to as "HCA pipelines") installed prior to 1970 for which PG&E does not have records of strength testing. This proposed rule reflects the Commission's desire to eliminate PG&E's reliance on "grandfathered" MAOPs for pre-1970 transmission lines under Section 619(c). PG&E agrees that the existing regulatory scheme allowing grandfathering should now be eliminated and other alternatives used. Just because the regulatory framework has permitted doing something for the past decades does not mean we should continue to do it, particularly as technology advances, our level of knowledge improves and our infrastructure continues to age.

This approach, which will ensure fact based determinations and improve safety, should be applied everywhere, especially in light of this State's aging infrastructure. The proposed rule eliminating grandfathering should be applied to all gas utilities in California and to all pipelines meeting the characteristics of Section 145.2.2 through 145.2.4.

PG&E is already in the process of eliminating grandfathered MAOPs on its HCA pipelines without pressure tests. The MAOP validation process in which PG&E is currently

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1 Class 3 and class 4 locations are highly populated areas as defined in 49 CFR §192.5. "A class location unit is defined as an area that extends 660 feet on either side of the centerline of a continuous 1-mile length of pipeline." Class 3 is a class location unit containing 46 or more buildings intended for human occupancy. Class 4 is any class location unit where buildings of 4 or more stories above ground are prevalent.

engaged will result in MAOPs for these pipelines being validated by engineering analysis, rather than relying on grandfathering.

We note that proposed Rule 145 would require PG&E to reduce pressure on all pre-1970 HCA pipelines without pressure tests,[2] even after PG&E has validated the MAOP by engineering analysis. We believe that once this validation is completed (both to the satisfaction of PG&E and the Commission) there is no need for continued pressure reductions, especially given other new requirements the Commission is proposing and with which PG&E agrees.

Accordingly, PG&E recommends the proposed Rule 145.2 be revised as follows to make clear that the operating limitation apply to all gas companies and pipelines meeting the specifications now set forth in Rule 145 and to allow PG&E to increase the pressure on its pipelines where pressure reductions have been performed once its MAOP validation is completed.

> **145.2** The operating limitation set forth in Rule 145.1 applies to all natural gas transmission lines exhibiting all of the following characteristics:
>
> **145.2.1** ~~Operated by Pacific Gas and Electric Company~~
> **145.2.2** Installed before January 1, 1970
> **145.2.3** Located in a High Consequence Area of Class 1 or Class 2, or in any area of a Class 3 or 4 pipeline location classification as defined in 49 CFR § 192.5.
> **145.2.4** <u>(a)</u> Reliable, verifiable, and complete records of strength testing ~~in accord with 49 CFR subpart J~~ are not available for inspection by authorized Commission or federal pipeline authorities<u>; and (b) the maximum allowable operating pressure has not been established or validated based on the weakest section of the pipeline or component pursuant to Commission Resolution L-410</u>.

<u>Temporary Exemptions.</u> Completing the records review and MAOP validation takes time, as discussed in PG&E's March 15, 2011 Report on Records and Maximum Operating

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[2] Prior to January 1, 1970, the Commission's GO 112 required pressure testing, not 49 C.F.R. Part 192. Subpart J. Thus, the reference to Subpart J should be deleted. In addition, where a new HCA is identified, the normal PHMSA rules, 49 C.F.R. § 192.905(c) should apply rather than Rule 145.

Pressure Validation and March 21, 2011 Supplement. While PG&E plans to complete this work for its HCA pipelines without pressure tests by August 31 2011, the effective date of the new rule should allow an appropriate transition period for all gas utilities subject to it, and this is the focus of PG&E's second comment on proposed Rule 145.

If new Rule 145 is made effective before PG&E completes its MAOP validation, it could have significant impacts on PG&E's ability to serve its customers fully and safely. As detailed in PG&E's March 15th Report (pp. 19-24, included as Attachment 1), immediate pressure reductions – especially on PG&E's backbone system – in addition to those already implemented would result in immediate adverse public health and safety impacts far exceeding any perceived public safety benefit from reduced pipeline pressure. These safety and operational impacts are further described in Attachment 2 of our comments. Moreover, additional pressure reductions required by Section 145 could compromise PG&E's ability to execute planned pressure testing this year.

To address these issues, PG&E has two proposals. First, PG&E recommends that the Commission provide for an appropriate phase-in of proposed Rule 145. Second, the temporary exemption provisions of Rule 145 should be broadened and clarified to reduce the risk of curtailments, whether caused by weather demands or resulting from operational conditions (including the need to modify operations in light of hydro testing and other exigent activities).

Under proposed Rule 145.3, PG&E could seek a temporary exemption to allow it to operate a pipeline at 90 percent of the maximum operating pressure ("MOP") (instead of 80 percent) for no more than 30 days. To do so, PG&E would be required to submit a letter request to the Commission's Executive Director no less than 45 days before the proposed pressure increase. Any other exemption request would require a formal application to the Commission.

Both of these methods require substantial lead time to operate a pipeline at a higher pressure – at least 45 days for the letter request and probably six months to a year for the application.

In the event of adverse weather (either unusually cold or hot) or equipment malfunction, PG&E may not always be able to predict and therefore control outages. Even when it can predict the likelihood of outages, PG&E may be forced to curtail both core and noncore customers if it has no speedy means of obtaining expedited Commission approval to increase pressure on one or more pipelines: it is impossible to predict accurately equipment malfunction or weather conditions 45 days in advance and weather conditions more than any other factor influences demand for natural gas. In addition, it may be impossible to predict 45 days in advance the need to increase pressure in one pipeline in light of the hydro testing PG&E is now undertaking or other exigent activities, such as equipment malfunctions. Therefore PG&E recommends that the Commission establish a third "emergency" procedure for obtaining Commission approval to increase pressure above the operating limitations set forth in proposed Rule 145, as follows:

> **145.3** ~~Pacific Gas and Electric Company~~ An operator may seek temporary exemptions from the above requirements as follows:
>
> **145.3.1** For exemptions to allow operating up to 90% of recorded maximum operating pressure and limited to no more than 30 days at the higher operating pressure, ~~Pacific Gas and Electric Company~~ an operator may submit a letter request to the Commission's Executive Director, who, in consultation with the Commission's pipeline safety personnel, may grant, deny, or modify the request. Any such letter request must be submitted no less than 45 days before the proposed start date, with a copy sent to all municipalities in which the pipeline is located and parties in R.11-02-019, or a successor proceeding. ~~Pacific Gas and Electric Company~~ The operator will be responsible for serving the Executive Director's responsive letter on all municipalities and parties to R.11-02-019 or a successor proceeding.
>
> **145.3.2** For exemptions to allow operating up to 100% of recorded maximum operating pressure and limited to no more than 90 days at the higher operating pressure, under exigent circumstances necessary to serve load or to manage other system conditions (such as outages, repairs, testing or work on other pipelines or pipeline segments), an operator may submit a letter request to the Commission's Executive Director, who, in

consultation with the Commission's pipeline safety personnel, may grant, deny, or modify the request. Any such letter request must be submitted as far in advance of the proposed start date as practicable, with a copy sent to all cities and counties in which the pipeline is located and parties in R.11-02-019, or a successor proceeding. The operator will be responsible for serving the Executive Director's responsive letter on all such cities and counties and parties to R.11-02-019 or a successor proceeding. At the operator's request showing that the exigent circumstances are continuing, the Executive Director may extend the exemption for successive periods of up to 90 days.

145.3.3 In the event of an operational emergency, an operator may operate up to 100% of recorded maximum operating pressure, as necessary, provided the operator submits a letter request to the Executive Director as soon as practicable after declaring the emergency.

145.3.4 Any other exemption requests will be by formal application to the Commission in accordance with the Commission's Rules of Practice and Procedure.

Pipeline Segments. As currently drafted, Rule 145.1 would impose operating limitations on a "line" that meets all of the characteristics of Rule 145.2. PG&E recommends that the focus of Rule 145, like the integrity management rules, be "pipeline segments." A pipeline may have segments that are not located in Class 3 or 4 or a Class 1 or 2 HCA, and pipelines can be and often are operated at different pressures between different stations. Thus, Rule 145.1 should be modified to read as follows:

145.1 Pacific Gas and Electric Company is prohibited from operating any natural gas transmission ~~line~~ pipeline segment that meets all of the characteristics listed in subsection 145.2 at more than 80% of actual maximum operating pressure reliably and verifiably recorded during the period February 15, 2006 through February 15, 2011. All overpressure protection devices on each such line must be set to control pressure to not exceed the limit established by this subsection.

Similar changes to "segment" should be made to the rest of Rule 145.

2. Proposed New Rule Requiring Inspection of Certain Types of Pipe

The March 24 Assigned Commission's Ruling ("ACR") notes at page 4 that "some natural gas pipeline operators may perceive an advantage to increasing pressure up to the MAOP

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on low-frequency electric resistance welded pipe, lap welded pipe or other pipe meeting certain conditions as described in 49 C.F.R. § 192.917(e)(4)." Section 192.917(e)(4) now provides that if the pressure of a pipe segment with the identified characteristics "has increased over the maximum operating pressure experienced during the preceding five years," an operator must prioritize the covered segment as a high risk segment for a future assessment, and "select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies." The perceived advantage alluded to by the ACR is maintaining the maximum operating pressure ("MOP") by raising the pressure to the MOP during the previous five year period, even if there is no independent operational reason (such as customer demand or pipeline repairs) for doing so. Raising the pressure in this way gives the operator another five years to operate up to that MOP without having to prioritize the segment as high risk for a future assessment.[3]

The proposed rule would require all gas pipeline operators to prioritize as high risk for both baseline assessment and each subsequent assessment all pipeline segments meeting any of the following criteria: (a) contain low-frequency electric resistance welded pipe; (b) contain lap welded pipe; (c) satisfy the conditions specified in ASME/ANSI B31.8S appendices A 4.3 and A 4.4; and (d) has experienced seam failure, whether a covered or noncovered segment, as defined in 49 C.F.R. § 192.903, in the pipeline system. Each segment so identified would have to be assessed by a technology with a proven application capable of assessing seam integrity and seam corrosion anomalies, primarily pigging with a "crack" tool or pressure testing. The proposed

[3] 49 C.F.R. § 192.917(e)(3) has the identical concept and phrasing as 49 C.F.R. § 192.917(e)(4), i.e., whether pressure has increased over "the maximum operating pressure experienced during the preceding five years." PHMSA Integrity Management Program FAQ 231 explains – for section 192.917(e)(3) but not 192.917(e)(4) -- that the phrase the "preceding five years" is the five years preceding identification as an HCA. PG&E understands from recent conversations with PHMSA staff that this same concept is meant to apply to section 917(e)(4) as well. This is significant, since it eliminates any incentive an operator would have to raise pressure up to the MOP or MAOP.

rule would impose this requirement regardless of the level of operating pressure reached during the previous five years.

PG&E supports the Commission's intention to change the rules that allow non-operationally-required pressure increases to maintain the MOP of pipeline segments that contain the identified threats. The proposed rule, however, is broader than the issue it is intended to address. It therefore has implications that could be adverse to safety. The proposed rule requires prioritization of segments with the identified threats, regardless of how they have been operated. Prioritization would be required if as a routine operational matter pressure was increased during the five-year period to the segment's MOP and even if it had been continuously operated well **below** its five-year MOP.

Under Section 917(e)(4), the priority assessment requires use of "proven application capable of assessment seam integrity and seam corrosion anomalies." As a practical matter, there are only two such applications today: in-line inspection (also known as pigging) and hydro testing. A substantial number of the pipeline segments for which this assessment would be required now cannot, because of their configuration and size, accommodate in-line inspection. However, hydro-testing is not entirely risk free. Under the proposed rule, these pipeline segments would be subjected to repeated hydro testing in the absence of any pressure increase that could render the threat unstable. Such repeated hydro testing would be operationally disruptive, requiring lines to be repeatedly taken out of service, and would not accomplish the Commission's safety objective. Moreover, there is some evidence that frequent hydro testing could itself destabilize otherwise stable threats.

We understand and agree with the Commission's concern that pipeline pressures never be increased simply for regulatory (or non-operational) reasons. We suggest that the better approach is to prohibit directly such pressure increases. We therefore recommend revising the proposed rule to prohibit non-operationally-required pressure increases directly, as follows:

> ~~All natural gas pipeline operators must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies for all pipeline segments that meet any of the following criteria:~~
>
> All natural gas pipeline operators are prohibited from making non-operationally-required pressure increases on pipeline segments that meet any of the following criteria:
>
> a. contain low-frequency electric resistance welded pipe;
>
> b. contain lap welded pipe;
>
> c. satisfy the conditions specified in ASME/ANSI B31.8S appendices A 4.3 and A 4.4; and
>
> d. has experienced seam failure, whether a covered or noncovered segment, as defined in 49 C.F.R. § 192.903, in the pipeline system.
>
> For purposes of this rule, a "non-operationally-required pressure increase" is one that is made for any purpose other than to meet load or operational conditions on the operator's pipeline system. "Non-operationally-required pressure increases" include, for example, pressure increases designed to maintain the five-year maximum operating pressure of a pipeline segment.
>
> If a pipeline segment meeting the criteria set forth above experiences a non-operationally-required pressure increase equal to or above the five-year maximum operating pressure, the operator must prioritize the segment in accordance with 49 C.F.R. § 192.917(e)(4).
>
> ~~All natural gas pipeline operators must implement the selected technology as part of its Integrity Assessments in each operator's Integrity Management program pursuant to 49 CFR subpart O. The operator must prioritize the segment as a high risk segment for the baseline assessment or subsequent reassessment.~~

The revised proposed rule meets the Commission objective. It prohibits non-operationally-required pressure increases on pipe segments with the identified threats. It still requires the prioritization of such segments as high risk followed by assessment with technologies capable of detecting integrity and seam corrosion anomalies whenever there is a non-operationally-required pressure increase equal to or in excess of the five-year MOP. But, it

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does not require hydro testing in cases where the affected pipeline segment was operated consistently at pressures below MOP.

3. Proposed Revisions to Reporting Requirements in GO 112-E, Section 122.2

The Commission proposes to expand the existing reporting requirements of GO 112-E. Section 122.2 to include pressure-related issues that do not involve a release of gas. The proposed additions would impact the near-immediate reporting of "incidents" meeting the criteria set forth in Rule 122.2(a), as well as the broader quarterly summary reports of the "incidents" outlined in Rule 122.2(d).

PG&E supports the proposed rule. Reporting requirements not only focus attention on the events to be reported, they provide additional incentive for those events not to occur in the first place. We believe that increased reporting requirements – especially when public – will provide additional margins of safety.

To improve the effectiveness of this proposed rule, PG&E requests that the Commission address and clarify certain aspects of the reporting requirements. First, as currently drafted, proposed Rule 122.2(a)(4) would require immediate reporting to the Commission when an "under-pressure condition" occurs, regardless of whether the condition was planned. For example, if an operator reduced pressure on a line in connection with a planned leak repair, the proposed Rule 122.2(a)(4) appears to require immediate reporting as an "incident."

PG&E does not believe this to have been the Commission's intention, and for clarification recommends two possible changes. The first is to delete the following language: "…or any other event other than excavation related damage…." Thus, Section 122.2(a) would state:[4]

[4] The same changes would be made to Section 122(d)(6).

> 4. Incidents in which an under-pressure condition, caused by 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 being shut-down.

An alternate solution would be to add the word "unplanned" before the word "event" :

> 4. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other unplanned event other than excavation related damage, results in any part of the gas pipeline system being shut-down.

Second, Rule 122.2(a)(4) and (d)(6) would require reporting an under-pressure condition that results in "any part" of the gas pipeline system being shut-down. The rule would appear to require notice for a "shut-down" of a single customer service line, since it constitutes a "part" of the gas distribution system. PG&E recommends that the Commission adopt a reporting threshold applicable at the distribution level that captures an appropriate level of significance, for example, a shut-down of the gas distribution system affecting fifty or more customers.

Third, PG&E supports the additional reporting requirements for its gas transmission system. However, PG&E's gas distribution system does not have system-wide Supervisory Control and Data Acquisition ("SCADA") capabilities and, in many parts of the distribution system, PG&E operates pressure monitoring systems located at gas regulator stations which are manually accessed. Consistent with existing practice, PG&E understands the proposed incident reporting requirements to call for reporting on an as-discovered basis.

Fourth, in the March 24 ACR, parties were asked to comment on a revised version of the proposed Rule 122.2(a)(3).[5] Compliance with the March 24 ACR version of Rule 122.2(a)(3) may require PG&E to revise pressure regulation set points downward and to revise its SCADA

[5] The revised version states: "3. Incidents where the failure of pressure relieving and limiting stations, or any other event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP), or any lower established Maximum Operating Pressure (MOP), including a lower MOP established under Rule 145."

alarm policies below current levels.. PG&E needs analyze the operational impact of this further.

Finally, in the March 24 ACR parties were asked to comment on the following question: "Should the Commission require pipeline operators to report any safety-related condition as defined in 49 CFR 191.23(a) in the Quarterly Summary Reports to the CPUC required by Rule 122.2(d)?" PG&E supports the addition of this requirement to Section 122.2(d).

4. Section 125 – Proposed Installation Report

The Proposed Revisions to General Order 112-E, Section 125, would continue to require utilities to file Proposed Installation Reports prior to constructing specified new pipelines, or reconstructing or reconditioning specified existing pipelines. Under the Proposed Revisions, these reports would be required to set forth the proposed route and general specifications of such pipelines, thereby allowing the Commission to verify that the proposed routing, design, maximum allowable operating pressure, strength testing methods, hazard and corrosion protection, and estimated cost, among other factors, are appropriate.[6] The Proposed Revisions would also add definitions for "Construction of a new pipeline," "Reconstruction of an existing pipeline," and "Reconditioning of an existing pipeline," thereby making clear the breadth of the categories of projects to which Section 125 applies.[7]

PG&E supports the OIR's Proposed Revisions to Section 125. In particular, PG&E endorses the emergency provision set forth in proposed Section 125. PG&E requests that the definition of "construction of a new pipeline" be modified as follows to eliminate ambiguity regarding the applicability of a CPCN requirement:

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6 OIR, Attachment A, p. 5 (proposed § 125.4).

7 OIR, Attachment A, p. 4 (proposed § 125.3).

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> An operator ~~commencing service for the first time~~ shall file a Proposed Installation Report with the Commission after receiving any required CPCN approval from the Commission and, subject to the requirements of Section 125.4, prior to the start of construction of the ~~approved~~ project.

This clarification is needed because not all pipeline projects require CPCN approval. *See* Pub. Util. Code § 1001; D.07-01-014 (no CPCN required for PG&E's Line 57C gas transmission pipeline project). This revision will make clear that, whenever a CPCN is required, a Proposed Installation Report shall be filed after the CPCN is issued, while avoiding any issue as to General Order 112-E's consistency with existing authorities.

B. Attachment B – Topics On Which New Rules Will Likely Be Proposed

PG&E supports development of new rules on the topics listed in Attachment B of the OIR. Our preliminary thoughts on these topics are described below. PG&E encourages the Commission to prioritize the evaluation of topics listed in Attachment B based upon their safety impact. Our comments below rank order the topics based on our recommended prioritization. Again, our underlying approach is to ask whether there are opportunities to improve the level of public safety. We believe that across the board, those opportunities exist and that the Commission and the industry should take advantage of them.

1. Threat Identification and Mitigation and Retrofitting Transmission Lines to Allow Inline Inspections

PG&E believes that the most important overall activity is to require pipeline operators to identify threats along their pipelines and come up with a plan to mitigate the threats, including research and development and the retrofitting of transmission lines to allow inline inspections.[8] To be effective, this must be a multi-faceted approach that combines on-going integrity management activities with accelerated analytic and field activities to address more quickly

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[8] OIR, Attachment B, pp. 1 and 5.

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safety risks than would otherwise be the case. These accelerated activities must be in addition to on-going integrity management activities; they may not and should not supplant them. Equally important, both the identification and mitigation of threats must be based on the new regulatory regime the Commission proposes. Grandfathering should be eliminated, and the focus should be on how to best address our aging infrastructure.

PG&E's Pipeline 2020 is composed of these types of accelerated activities. Through this program, PG&E will focus on pre-1970 pipeline segments. It will review the physical attributes and documentation of each pipeline segment in the system in order to assess susceptibility to the following key pipeline integrity threats: 1) pipe manufacturing defects; 2) pipeline fabrication and construction defects; 3) ground movement; 4) hard spot cracking; 5) stress corrosion cracking; and 6) corrosion and latent mechanical damage. It will then identify mitigating actions, such as hydrostatic tests, in-line inspection, replacement of pipe, or installation of equipment, to reduce or eliminate the specific risk. In addition, it will retrofit existing pipeline segments and help with the development and implementation of new "pigging" technology so that all transmission pipelines operating at or above 30 percent Specified Minimum Yield Strength ("SMYS") are "piggable."

If the Pipeline 2020 Program is approved by the Commission, PG&E expects that by the end of 2014 it will: 1) replace about 235 miles of gas transmission pipeline; 2) strength test a minimum of approximately 545 miles of pipeline; and 3) modify about 200 miles of pipeline to accommodate In-Line Inspections ("pigging").

2. Valve Automation

PG&E endorses the Commission's proposal that operators evaluate the installation of automatic or remote controlled values. Perhaps more than anything else, immediately following the San Bruno accident it became very clear that the public demands that regulators and industry take a hard look at the use of valve automation.

As with improved threat identification and mitigation as well as pipeline modification to accommodate inline inspections, PG&E is beginning to install new automated valves as part of Pipeline 2020. It expects that by the end of 2014 it will replace, automate and upgrade about 230 gas shut-off valves. The objective of this program is to enable PG&E to either remotely or with local control rapidly shut off the flow of gas in response to a gas pipeline rupture. Under the design criteria for the program, automated valves are to be spaced so that in the event of a full pipeline rupture, pressure in the pipe will dissipate in minutes following valve closure. The valve program will also replace valves where needed to assure "piggability" in the pipeline system.

PG&E will identify line segment candidates for valve automation in response to: 1) population density in Class 3 and Class 4 locations and 2) earthquake fault crossings. We will also enhance our SCADA system as part of Phase 1 to allow operators in our Gas Control Center to identify and respond quickly to isolate sections of pipeline if a line rupture occurs. PG&E expects to have installed approximately 19 new installations by the end of this year, all of which will be located on the San Francisco Peninsula.

We believe the Commission should require every natural gas system in California to fully utilize valve automation and to show by way of example to the rest of the country how to improve safety through the use of automated valves.

3. Require Operators To Strengthen Emergency Response Procedures

PG&E endorses the development of new requirements to strengthen emergency response procedures and it specifically asks the Commission to schedule workshops on the topic. It is important to open an early dialogue with all affected stakeholders, including first responders, local and state agencies, other utilities, Commission staff and concerned citizens to discuss this aspect of the Rulemaking. These discussions should be open and collaborative. Their goal should be the development of emergency response procedures that are national models for the industry.

We have begun to expand our collaborations with first responders and we are working with them to design a proposed new program that would improve the first response in the event of any type of incident – both gas and electric. Directionally, we think that any effective program should link three activities: (1) prevention; (2) preparedness; and (3) response. Prevention consists of programs to educate public safety first responders, including fire and peace officers, contractors, infrastructure departments, community members, school children, and other stakeholders. Such programs include damage prevention (for example, "call before you dig" or "look up and live"), recognizing safety hazards (for example, the sound and smell of leaking gas), and preventing injury and securing a site once an incident has occurred. Preparedness activities include developing plans, training to the plan, and exercising the plan. Response activities are those required to recover from routine to significant incidents involving gas and electricity, including assembling into Unified Command with public safety first responders. We also believe the Commission should solicit views on whether a prescriptive approach is needed for all emergency plans throughout the state or whether performance standards should be developed with each utility and first responder to implement plans that would meet these standards.

4. Clearance Between Gas Pipelines And Other Subsurface Structures

PG&E supports the adoption of new clearance rules and has two areas it specifically believes should be addressed. First, the Commission should evaluate appropriate measures to ensure that the clearance standards are safely and fully implemented by the parties engaging in construction activities. Under current rules, utilities lack sufficient authority to enforce existing clearance standards when a third party seeks to install new pipelines that deviate from the 12 inch clearance requirement in 49 C.F.R. § 192.325.

Second, the Commission should consider the adoption of a horizontal clearance requirement for gas pipelines. A 12 inch clearance is not adequate for parallel installations. When designing a new transmission pipeline, PG&E strives to achieve two to three feet of separation between parallel installations. Larger diameter pipelines should have larger horizontal clearance requirements (given the need for larger excavations and more room required to perform work on the pipeline). PG&E is not aware of any existing code requirement related to horizontal clearance. Adoption of horizontal clearance requirements applicable to third parties and utility operators would provide a stronger basis for compliance, uniformity and safety. At present, PG&E attempts to implement and enforce its design standards but lacks the ability to enforce a horizontal clearance requirement.

PG&E recognizes that there may be jurisdictional issues associated with the CPUC's authority over non-investor-owned utilities that operate pipelines. Therefore, it may be necessary to consider legislative solutions or recommend changes to federal regulations as part of the OIR to address these clearance issues.

5. Requirement For Gas Quality Monitoring

PG&E endorses a requirement that each operator have a program to monitor, analyze and prevent liquid intrusion and sulfur buildup in its pipeline system.

6. Incorporating One-Call Law Requirements For Marking Underground Facilities

49 C.F.R. § 192.614(a) requires operators of buried pipelines to participate in a "written program to prevent damage to that pipeline from excavation activities." The operator can meet that requirement by participating in a qualified one-call system. The new rule would incorporate

the one call law by reference and would require jurisdictional utilities to accurately mark their facilities, as well as meet all other requirements contained therein.

As part of our participation in the One-Call system, PG&E responds to locate requests and mark facilities to the best of our ability. Occasionally, we run across facilities that we are not able to locate through conductive or inductive means (e.g., a plastic service where a locating wire may have been damaged by excavation activity or other means). In these situations, we are forced to use the footages from maps to assess the location of the underground facilities.[9] Other issues we run across which can cause potential mismarks include interference and contacts by other utilities. PG&E suggests that the proposed rule require the utility to accurately mark their facilities or "take other reasonable steps to prevent pipeline damage from excavation activities for pipeline facilities that are difficult to mark and locate."

7. Test Requirements For Pipelines Operating Below 100 Psig And Service Lines

Current rules do not specify durations for pressure tests for distribution mains operating below 100 psig or service lines. The proposed rule would require new service lines to be operated below 1 psi to be pressure tested at a minimum pressure of 10 psig. The proposed rule will also require short sections of pipeline used for repairs to be pressure tested at the operating pressure, at a minimum.

PG&E agrees it is appropriate to adopt a new rule which would specify pressure testing requirements for distribution mains and service lines. We agree that service lines to be operated below 1 psi be should be tested at a minimum of 10 psig. This minimum testing requirement

9 We have been exploring new technology for the more challenging locates. In addition to testing new locating equipment, we have also rolled out an "inline locating tape" which allows us break down a meter-set and insert a locatable device through the service in situations where there is no locating wire.

would be in line with 49 C.F.R. § 192.509(b), which specifies test requirements for pipelines other than service lines. In addition, consistent with Section 509(b), the new rule should require pressure testing on new service and distribution main segments to be operated at 60 psig or less at a minimum of 90 psig.

PG&E does not believe it is necessary to adopt a new rule requiring pressure testing on short segments used for repair since existing regulations already require short sections of pipeline used for repairs to be pressure tested at the operating pressure, at a minimum. (*See*, 49 C.F.R. §§ 192.509, 192.511, and 192.513)

8. Report Cathodic Protection Deficiencies And Provide A Timetable For Remedial Actions

Cathodic Protection (CP) prevents buried metallic pipe from corroding. The new rule would require operators to report to the Utilities Reliability and Safety Branch (USRB) any CP systems that remain down for a period longer than six months. It would also require operators to provide a timetable for restoring the CP, and the reasons for the delay.

PG&E supports the concept of a CP monitoring and reporting requirement. One suggestion we have is that the scope of the rule should not be limited to a CP system being "down," which is an ambiguous term in this context. PG&E uses temporary measures that allow us to maintain adequate cathodic protection levels even when the CP system is "down."[10] This ambiguity could be addressed if the rule were to require reporting where there are "inadequate levels of cathodic protection" for six months.

9. Cover Requirements For Transmission Lines

49 C.F.R. § 192.327(c) currently allows installation of transmission lines or mains with

[10] For example, if a CP system goes down, PG&E can bond a wire to another nearby CP area to maintain adequate cathodic protection while we work to address the situation. Or, if more than one rectifier is operating in a given area, and one goes down, adequate cathodic protection may be maintained by the other rectifiers for that area.

less than the required minimum cover, provided that it has additional protection to withstand anticipated external loads. The new rule would require operators to establish a program to monitor transmission pipelines to identify segments with reduced underground cover. The program would provide additional damage prevention measures for such segments. In addition, the new rule would require operators to continuously monitor these transmission pipelines for any damages caused, directly or indirectly, by the reduced cover and take corrective actions.

PG&E agrees that existing regulations adequately address minimum cover requirements for new pipeline installations. There are no existing rules applicable to maintaining or monitoring cover requirements over time. PG&E has existing procedures for monitoring and addressing segments with reduced coverage when identified as part of its on-going assessments. However, PG&E currently does not have a systematic program in place to verify and test coverage levels for existing gas transmission pipelines across the system. Ongoing monitoring of coverage levels for existing transmission lines would require a substantial change in current operations, at a significant cost. In addition, if a transmission line with insufficient coverage is discovered, questions about how to address the situation arise.[11]

We believe it would be worthwhile to evaluate new requirements for monitoring clearance requirements and mitigating instances of insufficient cover for existing transmission lines provided that there is an appropriate phase-in over time so that the multiple new demands on utility resources resulting from this OIR can be prudently managed. PG&E believes that this would be an appropriate topic for workshops with interested stakeholders to discuss potential innovative and cost-effective means to monitor cover for existing pipelines, and how to address

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11 For example, if inadequate cover is discovered for a transmission line that runs through agricultural land, the insufficient cover could be addressed by lowering the transmission line (at a significant cost), or by adding soil to increase the cover.

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potentially unsafe coverage situations.

10. Reporting Problems Associated With Mechanical/Compression Fittings

Gas pipeline operators use mechanical fittings for joining and pressure sealing two pipes together. 49 C.F.R. Part 192 does not have specific requirements applicable to mechanical/compression fitting installations and failure analysis. The new rule would require the operator to review procedures for using mechanical couplings, including coupling design and installation, and ensure that they meet manufacturer recommendations and take action to prevent future failures and minimize risks associated with mechanical/compression fittings. PG&E supports this proposed rule.

11. Assessment Of Existing Meter Set Assemblies And Other Pipeline Components To Protect Them From Excessive Snow And Ice Loading

Excessive snow and ice accumulation on pipeline facilities can cause failures due to additional stress imposed on Meter Set Assemblies ("MSAs") or other pipeline components. Current federal regulations do not require operators to monitor the potential impact of excessive snow and ice on these facilities or to inform the public about possible hazards from snow and ice accumulation on regulators and other pipeline facilities. The new rule would require all California gas pipeline operators to initiate an assessment program to evaluate the condition of MSAs which are susceptible to snow and ice accumulation, replace or recondition all existing MSAs that are not adequately supported or protected from excessive snow and ice load and install protective barriers and support for all new MSA installations.

The climate in PG&E's service territory is such that PG&E MSAs are not subject to high snow and ice loads. Because of this, PG&E has not found it necessary to develop standards to protect MSAs from snow and ice loading. PG&E does not believe that initiating an assessment program to evaluate the susceptibility of MSAs to snow and ice accumulation is needed in our service territory.

C. Additional Topics

We believe there are several other topics that should be added to the OIR. We believe these topics provide important additional opportunities for the Commission and industry to develop new standards that will result in genuine improvements in both operations and regulation and that these improvements will make a direct contribution to public safety. They are:

- Standardized Leak Grading and Reporting Requirements: The Commission should adopt uniform leak grading standards and leak reporting requirements so that it is possible to conduct an "apples to apples" comparison of pipeline operator leak rates.
- Uniform Recordkeeping and Retrieval Standards: The Commission has recently ordered PG&E to produce pipeline records in accordance with an NTSB directive. PG&E believes it would be appropriate to adopt uniform record retention requirements and retrieval standards for all utilities so that compliance requirements are clear and consistent on a going forward basis.
- Penalties For Dig-Ins: Although this may ultimately be an issue for legislation, PG&E suggests that the Commission evaluate the existing penalties for dig-ins and evaluate whether they are a sufficient deterrent to incent excavating parties to use the 811 one call process. For example, perhaps it would be appropriate to apply higher penalties to repeat offenders or for willful disregard of the one call requirements.
- Setbacks From Existing Pipelines: Although this will likely require legislative

action, the Commission should consider adopting a policy statement calling for state and local land use regulations to require new development to maintain a specified minimum distance from existing gas transmission lines.

IV. RATEMAKING AND OTHER INCENTIVES FOR PRUDENT UTILITY OPERATIONS

The OIR states that the Commission will evaluate how to align ratemaking policies, practices and incentives to better reflect safety concerns and ensure ongoing commitments to public safety. PG&E supports this principle; indeed, that is what ratemaking is all about. The OIR recognizes that California is "facing a situation of aging infrastructure and the need for investment in upgrading and replacement of that infrastructure," and that the costs associated with pressure testing and pipeline upgrades and replacements are "likely to be non-trivial."[12] Since the Commission's new rules will apply to all gas utilities, under ordinary ratemaking principles, PG&E expects the Commission will appropriately provide for rate recovery of the costs associated with the new mandates.

Because we are concerned about safety, PG&E has not been waiting for an established ratemaking mechanism before making safety-related expenditures. As the OIR notes, PG&E sought a memorandum account in Advice Letter 3171-G on December 1, 2010, for the limited purpose of tracking and recording the costs of implementing the Pipeline 2020 Program and complying with Commission and other governmental agency mandates.[13] The Commission should in this proceeding authorize each of the gas utilities to establish a memorandum account

[12] OIR, pp. 12 –13.

[13] On April 5, a draft resolution was issued for comment that proposes to deny without prejudice PG&E's request for a memorandum account on the grounds that this request should be taken up in the OIR. Although it is not clear what the draft means when it states that the request was denied "without prejudice," PG&E assumes it means that a memorandum account filing in this docket will receive the benefit of the original December 1, 2010 filing date.

to track such costs, in PG&E's case with an effective date of December 1, 2010 as for AL 3171-G.[14]

The Commission should focus on putting the new rules in place and then, as the OIR states, consider rate recovery for each utility of the significant expenditures that are likely to be required in the OIR.

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[14] Approving the memorandum account would not authorize rate recovery – that issue must be addressed by the Commission in connection with an application for recovery of any such costs in rates. See, Resolution G-3432, pp. 3-4. The burden of proof will be on PG&E to demonstrate in its application the reasonableness of cost recovery and parties will have a full and fair opportunity to evaluate and contest PG&E's request. Absent a memorandum account, some of the expenditures that are currently being made by PG&E at the Commission's direction may not be eligible for recovery in rates under the rule against retroactive ratemaking.

V. CONCLUSION

The safe operation of our natural gas pipelines must be the top priority of both the pipeline operators and those charged with their regulation. PG&E commends the Commission for its efforts reflected in this OIR and it pledges to work closely with all affected stakeholders to achieve and maintain this top priority. Our collective goal should be to set an example for the country on how effective regulation can enhance the safety of our national gas pipeline system.

Respectfully submitted,

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B. Additional Pressure Reductions Could Adversely Impact Customers

As noted above, PG&E has documented pressure test records or historical operating pressures for over 90% of the 1,805 miles of HCA pipelines on its transmission system. PG&E has already reduced pressure to 80 percent of MAOP on over 190 miles of 10 pipelines and distribution feeder mains. Additional reductions could compromise PG&E's ability to execute substantial planned pressure testing this year. Even more significant, further pressure reductions could jeopardize PG&E's ability to meet customers' natural gas needs and may create serious public safety risks.

The mileages for which PG&E is still reviewing records and for which it plans hydro testing in 2011 may seem relatively modest, but they represent only the HCA portions of PG&E's pipelines. Pressure reductions affect not just the HCA segments, but the entire pipeline and, depending on the location of the pipeline in the system, may affect other interconnected pipelines as well. For example, 80 miles of the HCA pipe PG&E is going to hydro test or replace this year is on its backbone system. A pressure reduction on these 80 miles of HCA pipe would affect more than 1,300 miles of total backbone pipeline or nearly 25% of PG&E's transmission system.

The backbone system not only serves to bring natural gas into California, the large quantity of gas in the backbone pipelines also provides a form of storage for the entire system, helping to meet the daily and hourly changes in system demand and providing the capacity to inject gas into storage. PG&E estimates that a 20 percent pressure reduction on the backbone system would reduce system inventory capacity by as much as 67 percent and storage injection by 10 percent. In addition, a pressure reduction on the backbone would result in substantially more frequent Operational Flow Orders (OFO), significant risk of Emergency Flow Orders (EFO), and a risk of uncontrolled customer outages.

In periods of high natural gas usage, reduced backbone pressure and the associated diminished capacity can cause uncontrolled customer outages when pipeline pressure is insufficient to meet demand, creating significant public safety risks. This can happen both in winter, when heating demand for natural gas is high, as well as on hot summer days when electric generation units draw heavily on natural gas supplies to meet peak electric generation demand. In an uncontrolled outage, the public safety risk is heightened because pipeline pressure decreases to the point that customer pilot lights go out, while residual gas remains in the system that could migrate back into homes and businesses, and ignite.

To avoid the safety risks associated with uncontrolled outages, PG&E would need to implement controlled curtailments in such situations. In a controlled curtailment PG&E must shut off service proactively to both residential and business natural gas customers in the affected region. A controlled curtailment can last for many days, and can happen at any time of year. As noted above, the natural gas transmission system experiences peaks not only in the cold winter months due to customer heating demand but also in the summer when natural gas-fired electric generation helps to meet high cooling demand. In a controlled curtailment PG&E must close multiple valves controlling supply to an area or neighborhood in order to deplete the pressure on the line, and then individually turn off every residential or business meter and service valve in that area. The pipeline system must then be purged of natural gas to eliminate any air that may have entered the de-pressurized system. Natural gas service can only be safely restored on a customer-by-customer basis, because at each residence or business PG&E must open the service valve, check for leaks, re-light pilot lights and check appliances. Depending on the number of customers impacted, this process can take weeks, or even months.[11]

The impact of further pressure reductions is not limited to the extreme energy demands associated with very cold winter or very hot summer days; additional reductions are also likely to affect normal operations, maintenance and important system improvements. For example, PG&E uses the milder springtime months to buy natural gas at lower prices and inject it into storage for later use during those more extreme temperature days of winter and summer. Wholesale shippers, who supply gas to many noncore customers on PG&E's system, do the same. With lowered system capacity, it is likely storage injection will be insufficient to meet peak demands of all customers this coming winter. Further, as part of its Pipeline 2020 Program, PG&E has committed to install more than a dozen automated or remote shut-off valves as part of

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[11] PG&E can only estimate the amount of time it would take to complete service restoration to potentially tens of thousands of business and residential natural gas customers. PG&E has had little experience with natural gas controlled curtailments for residential customers on a large scale; however, because it is necessary to visit, inspect and test each service connection individually, the process is likely to take much longer than electric customer restoration.

a pilot program this summer. To execute this pilot program effectively, it will be necessary to have a pipeline system that offers the greatest flexibility, or redundancy, to reroute supplies while those valves and their related infrastructure are installed on other sections. In other cases, the ambitious pipeline testing program PG&E will begin this spring may entail taking significant sections of natural gas transmission lines out of service for days or weeks at a time, which will reduce system flexibility and system redundancy. Virtually every action PG&E takes – whether testing, repair, replacement or upgrade – requires taking part of a pipeline out of service. Pressure reductions on other pipelines diminish PG&E's ability to use alternate means to serve customers during such planned outages.

The impact of a 20 percent pressure reduction on local transmission can also be severe even without backbone pressure reductions. Depending on the location and scope of additional reductions, residential and business customers could experience interruptions in service. The following table sets forth two examples of the effect on a moderate winter day of a 20 percent pressure reduction on local transmission alone:

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Description	Local Transmission HCA Miles	Local Transmission Miles Affected	Consequences (moderate winter day)
Pipe segments without complete pressure test records and with pre-1962 24 to 36 inch double submerged arc welded (DSAW) pipe or what is recorded as pre-1974 seamless pipe greater than 24 inches in diameter	72	570	• Core residential and small business customers curtailed 20 - 30 days/yr • 20,000 – 50,000 people affected (7,000 – 15,000 accounts) • Noncore curtailed 35 – 40 days/yr
Pipe segments described above plus segments containing low frequency electric resistance weld (ERW), single-submerged arc weld (SSAW), lap weld or flash pipe installed prior to 1970	362	2,700	• Core residential and small business customers curtailed 10 – 35 days/yr • 85,000 - 170,000 people affected (28,000 - 57,000 accounts) • Noncore (including refineries and electric generation) curtailed significantly 20 – 70 days/yr

The curtailments illustrated above are based on a moderate winter day. On a cold winter day or during a stage 1 or stage 2 abnormal peak day, the curtailments – including core residential and small business customers – would be far more extensive. For example, under cold weather that could occur as often as once every four years, approximately 80,000 to 500,000 core residential and small business accounts could be curtailed, impacting about 250,000 to 1.5 million people. For cold weather that occurs about once every 20 years, approximately 150,000 to 775,000 core residential and small business accounts could be curtailed, impacting as many as 450,000 to 2.3 million people. Such widespread losses of heat to residential customers during very cold weather would pose significant health and safety risks.

PG&E believes its ambitious pipeline testing plan, together with the pressure reductions already implemented, provide an additional margin of safety in its pipelines while validating the field safety of those lines, and maintaining reliable service to customers. Significant additional pressure reductions could jeopardize PG&E's ability to execute the proposed field action plan described above and to serve its customers. Such pressure reductions could well create public health and safety risks far exceeding any perceived public safety benefit from reduced pipeline pressure.

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ATTACHMENT 2

DESCRIPTION OF OPERATIONAL IMPACTS CAUSED BY

TWENTY PERCENT PRESSURE REDUCTIONS UNDER PROPOSED RULE 145

PG&E has serious concerns about the short term impacts of Rule 145 on public safety and customer supply if the proposed rule is not phased in appropriately. As discussed in our March 15 filing, a 20 percent reduction in the backbone system pressure can bring an immediate and high risk of uncontrolled outages and the associated serious public safety risks. For local transmission systems, the impact will vary by system. For all line segments that raise potential public safety concerns, PG&E has prioritized its plans for pressure testing, in-line inspection, field inspection, or other appropriate action, in its Compliance Plan in order to minimize the potential for adverse impacts.

PG&E has analyzed the impact of a 20 percent reduction to MAOP on the 152 miles that are similar in specification to that involved in the San Bruno incident. The results in the table below show that the MAOP of some segments (and the affected systems) can be reduced by 20 percent immediately with no expected impact to customers. If its proposed revision to Rule 145 authorizing temporary pressure increases to accommodate hydro tests, unexpected weather conditions and other exigent circumstances is adopted, PG&E could reduce pressure by twenty percent in these systems. On the other hand, there are certain segments as shown in the table that raise significant concerns.

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Route No	Customer Impacts of 20% Pressure Reduction from Original MAOP
L-21A	Core and noncore curtailments on moderately cool days (warmer than CWD).
L-101	Reduction in place, core curtailments expected at colder than CWD.
L-105A	Reduction feasible with little curtailment risk to customers
L-105A-1	Reduction feasible with little curtailment risk to customers
L-105C	Reduction feasible with little curtailment risk to customers
L-105N	Reduction feasible with little curtailment risk to customers
L-107	Reduction in place due to class change, not CPUC order
L-109	Reduction in place, increased noncore curtailments at colder than CWD.
L-114	Reduction feasible with little curtailment risk to customers
L-131	Reduction in place with little curtailment risk to customers.
L-132	Reduction in place, except downstream of Martin Station. Pressure reduction downstream of Martin Station results in core curtailments at colder than CWD conditions. Pressure reduction upstream of Martin Station results in increased noncore curtailments at colder than CWD.
L-132A	Reduction in place, core curtailments expected at colder than CWD.
L-147	Reduction in place, core curtailments expected at colder than CWD.
L-153	Reduction in place with little curtailment risk to customers.
L-191	Reduction feasible with little curtailment risk to customers
L-300A	**Backbone:** High risk of uncontrolled system outages
L-300A-1	**Backbone:** High risk of uncontrolled system outages
L-300B	**Backbone:** High risk of uncontrolled system outages
L-301G	Pipe records found except for 3' of pipe which will be replaced. Reduction feasible with little curtailment risk to customers.
L-400	**Backbone:** High risk of uncontrolled system outages
L-400-3	**Backbone:** High risk of uncontrolled system outages
SP-3	Pipe records found. No longer an issue.
SP-5	Reduction feasible with little curtailment risk to customers
0821-01	Pipe records found. No longer an issue.

PG&E can reduce pressure in all local transmission pipe listed above without pressure test records and that have not already had pressure reduced, provided PG&E can temporarily raise the pressure in these lines to complete the planned hydro testing without risking system outages. This includes L-21A, L-105A, L-105A-1, L-105C, L-105N, L-114, L-191, L-301G, and SP-5. These lines will be hydro tested and returned to normal operating pressure prior to this winter.

In addition, PG&E has analyzed the impact of a 20 percent reduction on the 152 miles above combined with a reduction on the 295 miles of pipe identified as "Certain other seams and joint efficiencies" in PG&E's March 21 Supplemental Filing. Those results were also discussed in our March 15 filing. The table below provides more detail on the impacts by local transmission system.

Local Transmission System	Customer Impacts of 20% Pressure Reduction from Original MAOP
Systemwide	390,000 to 775,000 core curtailments at a 1 in 20 year cold event or colder. 285,000-455,000 core curtailments in a 1 in 5 year cold event or colder. 28,000 to 57,000 core curtailments on moderately cool days (warmer than CWD). Noncore curtailments on moderately cool days (warmer than CWD).
Peninsula	Core curtailments at colder than Cold Winter Day conditions.
Humboldt	Reduced allowable usage of power plant in Humboldt at moderate temperatures.
North Bay	Core and noncore curtailments on moderately cool days (warmer than CWD).
Sacramento	Core and noncore curtailments on moderately cool days (warmer than CWD).
East Bay	Core and noncore curtailments on moderately cool days (warmer than CWD).
San Jose/Gilroy	Core and noncore curtailments on moderately cool days (warmer than CWD).
Central Coast	Core curtailments at colder than Cold Winter Day. Noncore curtailments on moderately cool days (warmer than CWD).
Stockton	Core curtailments at colder than Cold Winter Day. Noncore curtailments on moderately cool days (warmer than CWD).
Yosemite	Core curtailments at colder than Cold Winter Day. Noncore curtailments on moderately cool days (warmer than CWD).
Fresno	Core curtailments at colder than Cold Winter Day. Noncore curtailments on moderately cool days (warmer than CWD).

The above results show that 20% pressure reductions have significant safety and reliability impacts, with large numbers of core and noncore customers without gas service on many days a year. PG&E is now analyzing the following scenarios to determine if smaller pressure reductions are feasible for the 152 miles plus the 295 mile case:

1. Backbone segments reduced 5%:
    - With segments on local transmission systems reduced 5%
    - With segments on local transmission systems reduced 10%
    - With segments on local transmission systems reduced 15%
2. No reduction on backbone segments:
    - With segments on local transmission systems reduced 5%
    - With segments on local transmission systems reduced 10%
    - With segments on local transmission systems reduced 15%

PG&E expects to have its analyses of these alternate scenarios completed for reporting to the Commission by May 13, 2011.