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**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)

PACIFIC GAS AND ELECTRIC COMPANY'S COMMENTS ON PROPOSED DECISION DETERMINING MAXIMUM ALLOWABLE OPERATING PRESSURE METHODOLOGY AND REQUIRING FILING OF NATURAL GAS TRANSMISSION PIPELINE REPLACEMENT OR TESTING IMPLEMENTATION PLANS

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Pacific Gas and Electric Company (PG&E) supports Administrative Law Judge (ALJ) Maribeth A. Bushey's forward-looking proposed decision (PD). The PD raises pipeline safety standards by transitioning away from the existing "grandfathering" rules and requiring instead that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety." (PD at 18.) Rather than rely on historic operating pressures, as the regulations currently allow, the PD provides that all gas transmission lines – regardless of age and prior regulatory status – be pressure tested or replaced. (PD at 1.) The Commission should adopt the PD with one addition to allow the use of alternate inspection technologies instead of pressure testing under limited circumstances where taking a pipeline out of service would cause an interruption in service to customers.

I. THE PD APPROPRIATELY RAISES THE SAFETY BAR.

Like the Commission (PD at 17), PG&E is resolute in its commitment to raise the standards for pipeline safety.

In light of the San Bruno pipe rupture and other recent natural gas pipeline accidents in the U.S., the PD rightly makes a very different policy choice from the one historically made. In the Natural Gas Pipeline Safety Act of 1968, Congress made the policy decision to exempt existing pipelines from the new safety standards: "Standards affecting the design, installation, construction, initial inspection, and initial testing shall not be applicable to pipeline facilities in existence on the date such standards are adopted." Pub. L. 90-481, 82 Stat. 720, §3(b) (1968).

The PD proposes to change that standard, now requiring older, grandfathered pipelines will now have to meet "modern standards for safety," requiring them to be pressure tested or replaced.[1]

II. PG&E WILL CONTINUE WITH ITS MAOP VALIDATION AND 2011 HYDRO TESTING PLANS.

The PD supports PG&E's ongoing maximum operating pressure (MAOP) validation work and the methodology PG&E is using. (PD at 28 & COL 1.) That process entails supplementing the available specific documentation with assumptions about components, such as fittings and elbows, based on the material specifications at the time those materials were procured, sound engineering judgment, and excavation and field testing of pipeline systems as

[1] The PD provides that "A pressure test record must include all elements required by the regulations in effect when the test was conducted." (PD COL 3.) As spelled out in its March 15th report, PG&E focused on four of the seven required 49 C.F.R. Subpart J pressure test elements to determine where it has complete pressure test records. These four are 1) name of operator, 2) test pressure, 3) test duration, and 4) test medium. 49 C.F.R. § 192.517(a) includes three additional recordkeeping elements: "(5) Pressure recording charts, or other record of pressure readings; (6) Elevation variations, whenever significant for the particular test; and (7) Leaks and failures noted and their disposition." As PG&E explained in its report (p. 10), unlike the other four elements, these three are only applicable to a minority of pressure tests. With respect to "(5) Pressure recording charts, or other record of pressure readings," the STPR contains a field for contemporaneous entry of the pressure reached, which is "[an]other record of pressure readings." Wherever available, PG&E confirmed that the pressure reached on the pressure chart correlated with the pressure entered on the STPR. Elevation variations, and leaks and failures and their disposition, would not logically exist for every pressure test, but only those where elevation variations were significant for the test or where leaks were found. PG&E documented these elements when applicable and available. PG&E does not believe the PD needs to be clarified, but expects the Commission will adopt a realistic approach in judging the completeness of such pressure test records.

appropriate. *See* March 24, 2011 Compliance Plan, p. 2; March 21, 2011 Request for Approval of Compliance Plan and Supplement to Report of Pacific Gas and Electric Company on Records and Maximum Allowable Operating Pressure Validation ("March 21 Supplement"), pp. 14-15. As PG&E's May 10, 2011 status report on the MAOP validation showed, we are progressing in that work. PG&E agrees with the PD (at 19) that it will reestablish the MAOP based on the lower of the current MAOP or the calculated MAOP on each of its pipelines. *See* March 21, 2011 Supplement, p. 5.

As the PD notes (PD at 7), PG&E is also in the midst of an ambitious program to hydro test approximately 150 miles of Class 3 and 4 and Class 1 and 2 high consequence area pipelines this year. This month, PG&E began hydro testing the 152 miles[2] of pipeline segments with characteristics similar to the San Bruno segment that had not previously been pressure tested. To date, PG&E has completed four successful pressure tests on 3.21 miles of pipe. These were 8 hour tests at a minimum target pressure of 1.5 times the pipeline MAOP. Each test included a ramp test to about 1.6 times the MAOP for one-half hour. PG&E expects this hydro testing will be completed this year as planned.

III. THE IMPLEMENTATION PLAN ENCOMPASSES PG&E'S PIPELINE 2020 PROGRAM.

The PD requires operators to submit a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) within 60 days of adoption of the PD. The Implementation Plan contemplates actions PG&E is already taking (*e.g.*, system-wide accelerated leak survey, increased patrols and leak surveys, pressure reductions on over 190 miles of pipeline, prioritization of pressure testing) as well as the elements of PG&E's

[2] PG&E has located complete pressure test records for additional segments of this pipe, reducing the mileage to be tested to 148. Additional pressure test records may be located as the engineering of the hydro tests progresses.

previously-announced Pipeline 2020 program (*e.g.*, pressure testing, pipe replacement, automated valve installation, modification to facilitate inline inspection). Because of the overlap between the Implementation Plan and PG&E's Pipeline 2020 program, PG&E will incorporate its Pipeline 2020 proposals into its Implementation Plan.

IV. THE COMMISSION SHOULD ALLOW THE USE OF ALTERNATE INSPECTION TECHNOLOGIES TO VERIFY PIPELINE INTEGRITY WHERE PRESSURE TESTING WOULD CAUSE AN INTERRUPTION IN SERVICE TO CUSTOMERS.

As written, the PD would require gas transmission pipelines that have not been pressure tested to be either pressure tested or replaced. As stated above, PG&E generally support this approach. There are some circumstances, however, where taking a pipeline out of service to perform a pressure test would require interrupting service to customers. PG&E's L-177A is an example of such a pipeline.

L-177A is a 150-mile radial feed from Gerber Compressor Station (MP 37.84) to the Eureka area, ending at Ryan Slough Station (MP 192.25). The line serves the Humboldt Bay Power Plant from a tap at MP 185.5. It is the only natural gas feed to the Humboldt Bay Power Plant; without it the plant would be required to run on diesel to meet customer electric loads. It is also the only natural gas pipeline serving approximately 40,000 customers. If PG&E is required to hydro test, it either has to replace the line or face major customer outages for weeks or months.

Because of situations like this, the PD should be modified as set forth in Appendix A to allow operators, after notice to the Commission's Consumer Protection and Safety Division, to use alternative inspection technologies capable of detecting flaws/anomalies at a detection level yielding a safety factor that would not result in a pipeline rupture due to material, fabrication or corrosion threats. Examples of such technologies are high resolution magnetic flux leakage

(MFL) pigging tools combined with transverse flux inspection (TFI) crack detection tools and direct assessment testing (close interval survey (CIS)/direct current voltage gradient (DCVG)).

V. CONCLUSION.

The PD represents an historic and welcome advance in natural gas transmission pipeline safety. By adopting the PD, the Commission will lead the nation in moving away from the reliance on 40+ year-old grandfathering rules. PG&E urges the Commission to adopt the PD.

Respectfully submitted,

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APPENDIX A
PROPOSED ADDITIONS TO PD

Findings of Fact

7. Natural gas transmission pipeline operators should be required to replace or pressure test all transmission pipeline that has not been so tested. Where taking a pipeline out of service to pressure test would require interrupting service to customers, the operator may verify the integrity of the pipeline by use of one or more alternate inspection technologies capable of detecting flaws or anomalies at a detection level yielding a safety factor that would not result in a pipeline rupture due to material, fabrication or corrosion threats. An operator planning to use an alternate inspection technology shall provide the Commission's Consumer Protection and Safety Division (CPSD) 30 days' advance notice and, if CPSD does not object within that time, may proceed with the alternate inspection technology.

Conclusions of Law

5. The Implementation Plan should reflect a timeline for completion that is as soon as practicable and provide for interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing or permitted alternate inspection technology for critical pipelines that must run at or near MAOP values which result in hoop stress levels at or above 30% of SMYS, and other such measures that will enhance public safety during the implementation period.

6. The Implementation Plan should set forth criteria on which pipeline segments were identified for replacement instead of pressure testing or permitted alternate inspection technology.

Ordering Paragraphs

4. No later than 60 days after the effective date of this order, San Diego Gas & Electric Company, Southern California Gas Company, Southwest Gas Corporation and Pacific Gas and Electric Company must file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c).

Where taking a pipeline out of service to pressure test would require interrupting service to customers, the operator may verify the integrity of the pipeline by use of one or more alternate inspection technologies capable of detecting flaws or anomalies at a detection level yielding a safety factor that would not result in a pipeline rupture due to material, fabrication or corrosion threats. An operator planning to use an alternate inspection technology shall provide the Commission's Consumer Protection and Safety Division (CPSD) 30 days' advance notice and, if CPSD does not object within that time, may proceed with the alternate inspection technology. The Implementation Plan should start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing.

6. The Implementation Plan must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing or permitted alternate inspection technology.

7. The Implementation Plan must contain a priority-ranked schedule for pressure testing or permitted alternate inspection technology pipeline not previously so tested, and may provide for Maximum Allowable Operating Pressure reductions to the lowest of the following: (1) a level no greater than 80% of the reliably recorded maximum operating pressure from January 1, 2006 to January 1, 2011, (2) the lowest Maximum Operating Pressure of any High Consequence Area segment (defined per 49 CFR, Part 192) on a pipeline for the five-year period preceding the date of the identification of the High Consequence Area segment or the level to which the segment was lowered after September 9, 2010.