| | | |
|---|---|---|
| Docket: | : | A.13-12-012 |
| Exhibit Number | : | ORA-03 |
| Commissioner | : | C. Peterman |
| ALJ | : | J. Wong |
| Witness | : | N. Skinner |

**OFFICE OF RATEPAYER ADVOCATES**
**CALIFORNIA PUBLIC UTILITIES COMMISSION**

# Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2015 Gas Transmission and Storage Rate Case

## Chapter 3
## Policy and Core Gas Supply

San Francisco, California
August 11, 2014

# TABLE OF CONTENTS

I. INTRODUCTION ..... 3
II. SUMMARY OF RECOMMENDATIONS ..... 3
III. HYDROTESTING ..... 4
IV. CORE GAS SUPPLY ..... 10

# Chapter 3 – Policy and Core Gas Supply

## I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates (ORA) regarding Pacific Gas and Electric Company's (PG&E) proposals associated with its Test Year (TY) 2015 Gas Transmission and Storage (GT&S) rate case. Specifically, this exhibit addresses PG&E's proposals regarding cost responsibility for post-1955 hydrotesting. This exhibit also addresses core gas supply issues, including PG&E's capacities on the Redwood and Baja paths, reallocation of firm storage capacity, adjustments to the 1-Day-in-10-Year Core Capacity Planning Standards, and Core Procurement Incentive Mechanism changes.

## II. SUMMARY OF RECOMMENDATIONS

Based on the findings in D.12-12-030, PG&E shareholders should continue to pay in this GT&S proceeding for hydrotesting of pipelines installed post-1955 where PG&E has not maintained traceable, verifiable, and complete (TVC) records,[1] and the capital recovery for replacement of post-1955 lines lacking TVC records should continue to be reduced by the estimated hydrotest costs.[2] With regard to PG&E's proposal that there should only be a hydrotest disallowance for pipes installed post-1961 (as opposed to post-1955), PG&E has failed to demonstrate why the Commission's determination in Decision (D.)12-12-030 should be ignored and essentially modified. D.12-12-030 concluded that PG&E complied with, or stated that it complied with, industry standards requiring it to pressure test pipes before placing them in service since no later than January 1, 1956.[3] That decision found that PG&E ratepayers should not pay twice for hydrotesting required now because of PG&E's poor recordkeeping practices.[4]

---

[1] D.12-12-030, Conclusion of Law 15.

[2] D.12-12-030, Conclusion of Law 16.

[3] D.12-12-030, Finding of Fact 18.

[4] D.12-12-030, pp. 60-61, at 60 ("The absence of the records for the 1956 to 1961 pipeline now brings these pipeline segments into the Implementation Plan for re-testing or replacement. Having paid for such testing once, the ratepayers should not be required to pay for re-testing due to PG&E's failures in document management.").

With regard to "Core Gas Supply," ORA analyzed PG&E's testimony supporting workpapers, and data request responses. The following summarizes ORA's recommendations:

- ORA does not oppose PG&E's change in the core Redwood and Baja path capacities.
- ORA does not oppose reallocation of the core firm storage capacity during November to March.
- ORA does not oppose adjustment to the 1-Day-in-10-Year Core Capacity Planning Standard.
- ORA does not oppose adding a monthly price index in CPIM and PG&E's proposed CPIM modification process.

## III. HYDROTESTING

### A. There Is No Basis To Change The Commission-Adopted Hydrotests Disallowances For Both Expenses and Capital Costs For Post-1955 Lines

One of the primary concerns revealed by the San Bruno incident has been PG&E's lack of records and proper record-keeping and maintenance associated with its natural gas system.[5] Every review of the contributing factors to the San Bruno incident

[5] See California Public Utilities Commission, Consumer Protection and Safety Division, Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno, California, released January 12, 2012 (CPSD San Bruno Report), p. 3. The CPSD San Bruno Report was supplemented and submitted as CPSD's testimony in I.12-01-007 on March 16, 2012.

See also National Transportation Safety Board, Pipeline Accident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, adopted August 30, 2011, pp. xi and 59-66 (NTSB Report). The NTSB Report is available at http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf. The NTSB found that PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective because its data was inaccurate and incomplete, it was missing mission critical information, and it was not designed to consider the most relevant information – such as pipeline design, materials, and repair history – when determining how to prioritize repairs and replacements. As a result, the NTSB concluded that PG&E's integrity management program "led to internal assessments …. that were superficial and resulted in no improvements." NTSB Report, p. xi.

See also The Report of the Independent Review Panel – San Bruno Explosion – Prepared for California Public Utilities Commission, Revised Copy June 24, 2011, pp. 7-8, available at

has determined that PG&E's failure to maintain accurate records of its system contributed to that explosion.[6]

Ignoring the fact that D.12-12-030 disallowed hydrotest costs for post-1955 lines on the basis that PG&E pressure tested those lines at ratepayer expense and should have retained records of those pressure tests, PG&E proposes to move the date for the commencement of disallowances from 1956 to 1961, when General Order 112 was adopted. In sum, without any acknowledgment, PG&E is attempting to relitigate that issue in this proceeding. PG&E provides five reasons why PG&E should not face continued disallowance of pressure test costs for pipe installed between 1956 and 1961:[7]

> (1) There were no requirements to hydrostatically test pipe when it was installed between 1956-1961;
>
> (2) At the time of enacting pipeline safety regulations, the Commission and federal government consciously chose not to require hydrostatic tests for pipe installed prior to that time;
>
> (3) The hydrostatic test provision in the American Standards Association (ASA) code was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961;
>
> (4) The ASA code did not require pipe operating below 30 percent SMYS [Specified Minimum Yield Strength] to be hydrostatically tested (a point which was not addressed by the recent Commission decisions denying recovery of certain PSEP costs); and
>
> (5) It was unlikely the CPUC would have provided rate recovery for hydrostatic testing activities in 1956-1961 given that it was not a requirement.[8]

The Commission rejected these PG&E arguments in Decision (D.) 12-12-030, which approved PG&E's Pipeline Safety Enhancement Plan (PSEP). The Commission unequivocally found, based on the record in that proceeding, that PG&E stated that its practice from 1956 on was to pressure test pipeline prior to placing it in service, that the

---

http://www.cpuc.ca.gov/NR/rdonlyres/85E17CDA-7CE2-4D2D-93BA-B95D25CF98B2/0/cpucfinalreportrevised62411.pdf

[6] *Id.*

[7] PG&E does not dispute that it had an obligation to pressure test lines and retain the records of those tests after the adoption of General Order 112 in 1961.

[8] PG&E Prepared Testimony, Volume 1 (Barnes), p. 4A-43.

costs of these pressure tests were passed on to ratepayers, and that PG&E should have retained the records of these tests:

> We do not agree that the change from an industry practice to regulatory mandate somehow excuses PG&E's failure to retain the pressure test records. As noted above, the record supports the finding that PG&E stated that from 1956 on, PG&E's practice was to pressure … test pipeline prior to placing it in service and that the costs of such testing was passed on to ratepayers. As required by industry practice and prudent natural gas transmission system operations, PG&E should have created and maintained records of those pressure tests.[9]

Based on these findings, the Commission determined that PG&E's shareholders should pay hydrotest costs, or their equivalent, for all pipelines installed after 1955 that do not have traceable, verifiable, and complete (TVC) records. Thus, D.12-12-030 disallowed hydrotest expenses for post-1955 lines, and disallowed the cost of a hydrotest from post-1955 lines that were replaced, rather than hydrotested, because they did not have TVC records of the hydrotest.[10]

The Commission should not change this well-reasoned determination – which is based on substantial record evidence - by now pushing the date from 1955 to 1961, as PG&E requests. While the conclusions of D.12-12-030 should be dispositive on this issue, ORA addresses each of PG&E's arguments in support of moving the disallowance date to 1961. In sum, none of PG&E's arguments are new or have any merit; they were addressed and dismissed by the Commission in D.12-12-030.

### 1. PG&E's First, Second, And Third Arguments To Move The Hydrotest Disallowance From 1955 to 1961 Are Contradicted By PG&E's Own Statements To The Commission And Were Dismissed by D.12-12-030

PG&E argues that:

> (1) there were no requirements to hydrostatically test pipe when it was installed between 1956-1961; (2) at the time of enacting pipeline safety regulations, the Commission and federal government consciously chose not to require hydrostatic tests for pipe installed prior to that time; [and] (3) the hydrostatic test provision in the American Standards Association (ASA) code was new and not

[9] D.12-12-030, p. 60. See also p. 61 and Conclusion of Law 16.

[10] D.12-12-030, Conclusions of Law 15 and 16.

widely applied in the industry, so it cannot be considered an established practice in 1956-1961.[11]

In sum, these arguments are based on the idea that because no state or federal law prior to 1961 specifically required PG&E to hydrotest its lines, PG&E had no obligation to do so and should therefore not be responsible for the costs of hydrotesting lines installed before 1961. These arguments have no merit and were dismissed by D.12-12-030 in light of PG&E statements contradicting these arguments.

State or federal law or regulations prior to 1961 may not have specifically and expressly required PG&E to hydrotest its lines, but this is not relevant for a number of reasons. First, PG&E has had a statutory obligation to maintain and operate its system safely since 1909.[12] A gas transmission system cannot be operated safely without knowing the pressure tolerance of the lines comprising that system. Thus, conducting a pressure test and retaining the results of that test are critical to the safe operation of a gas transmission system.

Second, PG&E represented to the Commission at the time that General Order 112 was adopted (approximately 1961) that it *complied* with industry standards.[13] Thus, whether or not law or regulations required hydrotesting, PG&E represented to the Commission that it was nonetheless complying with industry standards – and those standards required pre-installation hydrotesting. In light of PG&E's reliance upon those standards, it is disingenuous and misleading for PG&E to now suggest that those standards were irrelevant.

Third, PG&E's suggestion that the hydrotesting standard "was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961" is simply not supported by previous versions of the standards. Industry standards have recommended that gas pipelines be pressure tested since 1935.[14]

---

[11] PG&E Prepared Testimony, Volume 1 (Barnes), p. 4A-43.

[12] CPSD San Bruno Report, p. 5.

[13] Decision 61269, issued December 28, 1960 and effective July 1, 1961, p. 4, adopting GO 112, describes the position of the respondents, PG&E and others: "… the gas utilities in California voluntarily follow the American Standards Association (ASA) code for gas transmission and distribution piping systems."

[14] ASA B31-1935, pp. 55-56.

Further, PG&E specifically represented to the Commission that it believed its practice was to follow the ASME standards regarding pre-service testing after the adoption of those standards in 1955. On March 15, 2011, PG&E filed a report on MAOP validation in the PSEP proceeding, R.11-02-019. At page 13, the report showed that of the pipelines analyzed and installed before July 1, 1961, at least 31% were pressure tested. In response to the question "[w]hat was the justification for performing these tests?" PG&E responded:

> Pressure tests were, and are, a means to confirm or test the strength of pipeline segments. PG&E believes that after adoption of American Society of Mechanical Engineers (ASME) standard ASA B31.1.8-1955, PG&E's practice was to follow ASA B31.1.8-1955, including pre-service testing.[15]

Given PG&E's repeated representations that it followed the standards of the time, its current claims that industry standards, absent mandatory laws or regulations, are irrelevant, or that they were not widely adopted by 1955 are not credible. When the Commission considered similar claims in D.12-12-030, it determined that PG&E was or claimed it was complying with hydrotesting standards starting no later than January 1, 1955, and concluded that a hydrotest disallowance on pipes installed post-1955 without TVC records was appropriate.[16]

### 2. PG&E's Fourth Argument To Move The Hydrotest Disallowance From 1955 to 1961 Is Incorrect

PG&E claims that "the ASA code did not require pipe operating below 30 percent SMYS [Specified Minimum Yield Strength] to be hydrostatically tested."[17] ASA 31-1-8 1955 clearly required testing for pipelines operating at less than 30% SMYS, if in Class Location 2, 3, or 4 areas and operating above 100 psi.[18] It expressly provides:

> Steel piping that is to operate at stress less than 30% of the specified minimum yield strength but in excess of 100 psi in location classes 2, 3 and 4 shall be tested to at least 1.5 times the maximum operating pressure.

---

[15] R.11-02-019, PG&E Response to DRA-DR-045 Q7.

[16] D.12-12-030, Findings of Fact 16, 17, and 18 and Conclusions of Law 15 and 16.

[17] PG&E Prepared Testimony, Volume 1 (Barnes), p. 4A-43.

[18] ASA 31-1-8 1955, p. 50.

Table 841.421 also provides the maximum hoop stress permissible during test for class 1 locations.[19]

For clarity, the Commission should expressly provide in its final decision that the hydrotest disallowance applies to this class of pipes.

### 3. PG&E's Fifth Argument To Move The Hydrotest Disallowance From 1955 to 1961 Is Contradicted By Prior PG&E Statements To The Commission And Has No Merit

PG&E claims that "it was unlikely the CPUC would have provided rate recovery for hydrostatic testing activities in 1956-1961 given that it was not a requirement."[20] This argument is directly contradicted by PG&E's own statements to the Commission in 2011 in the PSEP proceeding, R.11-02-019. As a follow up to PG&E's representations that it had been performing pre-installation hydrotests on pipes since the adoption of the ASME hydrotesting standard in 1955, ORA asked: "Were these tests funded by PG&E ratepayers or PG&E shareholders?" to which PG&E responded "The testing was part of the pipe installation costs and, therefore, would have been funded by ratepayers."[21]

Indeed, the Commission relied upon this evidence to conclude that because ratepayers funded the original pre-installation hydrotests, it was unreasonable for them to pay for a second hydrotest required because of PG&E's records mismanagement.[22] D.12-12-030 further concluded: "[n]o evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirements from January 1, 1956."[23] Even without these clear contradictory statements from PG&E in other cases before the Commission, it would be unreasonable for the Commission to allow such costs to be passed on to ratepayers on the basis that the work was not required by law or regulation. As PG&E is well aware, the CPUC routinely authorizes utility work

---

[19] *Id.* p. 51.

[20] PG&E Prepared Testimony, Volume 1 (Barnes), p. 4A-43.

[21] R.11-02-019, PG&E Response to DRA-DR-045 Q7.

[22] D.12-12-030, p. 60.

[23] D.12-12-030, Finding of Fact 18, p. 118.

not expressly required by law or regulation, and ORA is fairly certain that PG&E would not support the imposition of such a requirement going forward.

## IV. CORE GAS SUPPLY

### A. General Overview

PG&E proposes that its new intrastate capacities be consistent with the interstate ranges proposed in PG&E's Application (A.) 13-06-011 to Set New Core Interstate Pipeline Capacity Planning Range, which is pending a decision. PG&E's current forecasted total annual average daily core demand are comprised of "… interstate holdings total 733 MDth/d in the non-peak months and 927 MDth/d in the peak months."[24] The capacity allocations on each pipeline are:

- Redwood Path Annual capacity reduced 3,678 Dth/d; [25]
- Baja Path Annual reduced 166,000 Dth/d;[26]
- Baja Path Seasonal (November to March) reduced 164,000 Dth/d;[27]

PG&E asserts that the reallocation and reduction of this capacity will result in savings to core customers of approximately $11.7 million.[28]

PG&E proposes to adjust the withdrawal rights of the Core Gas Supply (CGS) Core Firm Storage Contracts, which increase the withdrawal rights for core customers in December to January, and offset the increase by reducing the withdrawal rights in February and March, as shown in Table 03-1:

[24] PG&E Prepared Testimony, Volume 2-2 (Elmore), p 19-5.

[25] PG&E Prepared Testimony, Volume 2-2 (Elmore), p 19-2.

[26] *Id.*

[27] *Id.*

[28] PG&E Prepared Testimony, Volume 2-2 (Elmore), p 19-7.

**Table 03-1: Change in Firm Storage Withdrawal Rights**

| Period | Change (MDth/D) |
|---|---|
| 12/1 through 1/15 | 122 |
| 1/16 through 1/31 | 100 |
| 2/1 through 2/14 | -50 |
| 2/15 through 2/28 or 29 | -100 |
| 3/1 through 3/31 | -250 |

These changes in withdrawal rights will result in additional Core Firm Storage contract costs of $1.86 million dollars per year.

PG&E also proposed adjustments to its 1-Day-in-10-Year Core Reliability Standard. To meet the Reliability Standard, Decision 06-07-010 required PG&E to hold sufficient capacity to meet a 1-Day-in-10-Year total core peak day demand. PG&E proposes that the additional 330 MDth/d required to meet the standard can be acquired through the Citygate; PG&E believes that during a peak winter load event its Citygate will have 330 MDth/d of gas with at least the same degree of reliability that it was available at Topock.

CGS frequently purchases additional gas supplies at PG&E's Citygate. PG&E proposes to start using Inside Federal Energy Regulatory Commission's (FERC) Gas Market Report monthly baseload index to reflect the volume of monthly baseload purchases. Currently PG&E uses a daily price index for its Citygate purchases.[29] PG&E also proposes that the modification process of CPIM in "changes to PG&E's CPIM mechanism for determination of PG&E's benchmark, including the method of calculating the benchmark load, the setting of the benchmark sequence, the items to be included in the calculation of capacity demand charges benchmark, and the determination of benchmark gas index pricing"[30] can be agreed upon between PG&E and ORA. Any proposed changes to resolve disagreements between PG&E and ORA, including additional changes to the CPIM, would be available through the existing application process.

[29] PG&E Prepared Testimony, Volume 2-2 (Elmore), pp. 19-14 to 19-15.

[30] PG&E Prepared Testimony, Volume 2-2 (Elmore), p. 19-15.

### B. Discussion/Analysis of "Core Gas Supply"

ORA agrees that PG&E's intrastate capacity allocation should be consistent with PG&E's Interstate Capacity A.13-06-011 and the Commission's final decision on that application. The reduction of capacity on the intrastate path will result $11.7 million dollars in savings, which will benefit the core customers.[31] However, PG&E should maintain reliable service to core customers.

Regarding PG&E's proposed reallocation of the storage withdrawal right in future winter seasons (November to March), ORA reviewed and analyzed the injection and withdrawal data for the winter periods of 2009 to 2013.[32] The cost of reallocation withdrawal rights is approximately $2.41 million annually.[33] After evaluating the data, ORA does not oppose PG&E's adjustment for the November to March withdrawal rights and the incorporation of existing assets that are available to meet peak load conditions.

ORA agrees with PG&E's request to add "Inside Federal Energy Regulatory Commission's Gas G Market Report" as a monthly Citygate index in the Core Pricing Incentive Mechanism (CPIM) to reflect the volume of actual 30-day baseload purchases at the PG&E Citygate.

ORA does not oppose PG&E's proposal to calculate compliance with the 1-day-in-10-years reliability requirement by purchasing additional gas supplies (330 MDth/d) through a combination of baseload and swing supplies at its Citygate. ORA also does not oppose PG&E's proposal to maintain the current structure allowing ORA and PG&E to agree to minor changes in PG&E's CPIM mechanism.

---

[31] PG&E Response to ORA-DR-048 Q04.

[32] PG&E Response to ORA-DR-029 Q01.

[33] PG&E Response to ORA-DR-048 Q05.