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 (Filed February 24, 2011)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON PROPOSED DECISION

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Dated: November 16, 2012

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I. INTRODUCTION

PG&E shares the enthusiasm expressed in the Proposed Decision (PD) of Assigned Administrative Law Judge (ALJ) Maribeth Bushey that we are on the right path to improving safety on the gas transmission system, holding ourselves to higher, industry leading standards, and making significant progress in the implementation of the Pipeline Safety Enhancement Plan (PSEP). The PD reflects a thorough and thoughtful review by the ALJ, the Consumer Protection and Safety Division (CPSD) and intervenors of the complex technical issues presented by the PSEP. The PD properly and appropriately sorts through these issues and approves PG&E's "decision tree" based evaluation process for Pipeline Modernization and Valve Automation, with a few minor changes, all of which are acceptable to PG&E. The PD also approves PG&E's Records Integration Program and orders PG&E to complete it. While PG&E supports the PD's findings on the technical PSEP issues, we strongly disagree with the significant disallowances of cost recovery for these approved programs.

When PG&E submitted the PSEP, it believed that every dollar of cost recovery requested was reasonable and that we had proposed a fair and equitable sharing of these costs by our shareholders. The ALJ has gone through the evidence on cost recovery and adopted a balancing of the positions of PG&E and intervenors. The PD properly recognizes that a fair share of the costs of implementing a new, unprecedented and industry leading safety program must be borne by customers and that TURN's and DRA's arguments for disallowance of all PSEP costs were unreasonable. The PD has gone too far, however, in disallowing PSEP costs that are fairly and appropriately borne by customers. As PG&E has consistently maintained, PG&E will not seek cost recovery for any activities that must be undertaken to comply with preexisting regulatory requirements. However, if PG&E was not obligated to perform the work before Decision 11-06-017, then customers should fund the costs of complying with the new safety requirement.[1]

The following table lists the disallowance recommendations that we do not contest in these comments, and the recommendations that should be modified to correct significant errors of fact and law.

Proposed Decision Disallowance Recommendations	**PG&E's Response**	**Combined Capital Expenditures and Expense Disallowance (2012-2014; $ in Millions)**
Strength testing pipelines installed after 1955	Not Opposed	$56.4
Pipeline replacement adjustment	Not Opposed	$15.5
MAOP Validation	Not Opposed	$107.1
Total Disallowances Accepted		**$179**
Contingency	Modify	$293.3
2012 Total Costs	Modify	$342.7
Reduced return on equity for five years	Modify	$130 (estimated)
Gas Transmission Asset Management Project	Modify	$123.1
Escalation Rate	Modify	$41.5
Total Disallowance Opposed		**$930.6**

As shown above, PG&E does not contest $179 million of recommended disallowances. That does not mean we agree with the PD on these points, but we accept this as an additional shareholder contribution.

PG&E addresses legal and factual errors in five of the disallowance recommendations

[1] In addition, the PD allows for the possibility of further ratemaking adjustments as a result of the related investigations, suggesting that additional punitive disallowances may be forthcoming beyond the significant disallowances included in the PD. PD, p. 4.

and asks that the PD be modified in the following respects:

- Program Contingency: PG&E proposed that it would never collect more than its actual costs for the PSEP program. The PD would disallow all contingency amounts included in PG&E's estimates for PSEP work. This constitutes legal and factual error for three reasons: (1) the PD's understanding of the purpose and intent of an estimate contingency is contrary to accepted industry estimating practices; (2) all parties addressing the contingency issue recognized the validity of including a contingency in estimates; and (3) the PD is incorrect in its assumption that PG&E's base cost estimates are "generous."

- Recovery of 2012 Costs: Having found the automated valve, strength testing, and pipeline replacement programs reasonable, the PD denies cost recovery for these programs in 2012, erroneously failing to address PG&E's motion for a memorandum account on the merits. The result is an arbitrary denial of legitimate cost recovery without any reasoned consideration. In addition, the PD bases its decision to disallow 2012 costs on the Overland Report, which is being reviewed in the separate San Bruno OII proceeding, and has been shown to be misleading and inaccurate.

- Reduced Rate of Return on Equity: The PD's proposed reduction of PG&E's Return on Equity (ROE) to the cost of debt is a punitive action that is contrary to the public interest. The reduction of future returns on investments for needed safety investments will send the wrong message to investors and impact PG&E's ability to attract capital.

- Gas Transmission Asset Management Program: The PD's finding that the costs of the Gas Transmission Asset Management (GTAM) program should not be recoverable in rates rests on the erroneous premise that GTAM is a remedial effort to cure alleged deficiencies in PG&E's recordkeeping. This conclusion is not supported by record evidence, which demonstrates that the GTAM project is a forward-looking effort to incorporate new technology into PG&E's management of its gas transmission assets, transition away from a paper-based asset management system, and retire old legacy systems.

- Escalation and Depreciation Life: The PD's adoption of a 1.5% escalation rate, and a 65 year depreciable life for gas transmission mains installed as part of PSEP, is arbitrary and unsupported by record evidence.

The PD's proposals on the issues described above are without substantial evidentiary support, and are arbitrary and capricious.[2] In addition, these comments discuss the proposed

[2] *See*, *e.g.*, *Yamaha Corp. of America v. State Bd. of Equalization*, 19 Cal. 4th 1, 16-17 (1998).

reporting requirements, CPSD oversight and concurrence regarding changes to the PSEP, and the scope of Phase 1.

II. DENIAL OF PG&E'S CONTINGENCY REQUEST CONFLICTS WITH THE RECORD EVIDENCE, COMMISSION PRECEDENT AND COMMON INDUSTRY PRACTICES

The PD would disallow all contingency amounts included in PG&E's estimates for PSEP work on the grounds that PG&E's base estimates are "generous," the PD adopts an additional "layer" of costs for program management, and PG&E's shareholders should bear the risk of cost overruns. There are three fundamental errors in the PD's contingency recommendation: (1) the PD's understanding of the purpose and intent of an estimate contingency is contrary to accepted industry estimating practices; (2) all parties addressing the issue recognized the validity of including a contingency in estimates; and (3) the PD incorrectly assumes PG&E's base cost estimates are "generous" and include an "implicit allowance for unexpected cost overruns."[3]

A. The PD Misunderstands The Purpose Of An Estimate Contingency

The PD incorrectly defines contingency as an allowance for "the risk of cost overruns."[4] This definition is not supported by the record evidence and directly conflicts with clear guidelines and definitions of contingency established by leading industry groups like the Association for the Advancement of Cost Engineering (AACE)[5] and government agencies, including the U.S. Department of Energy. Accepted industry practices require an estimator to include a reasonable contingency to account for unforeseeable risks associated with a defined work scope considering the information known to the engineers and estimators at the time they

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[3] PD, pp. 99-102.

[4] PD, p. 100.

[5] See, e.g., Exhibit (Ex.) 2, PG&E Direct, p. 7-47, lines 12-22.

prepare the baseline estimates.[6] Contingency is not a "cushion" or an allowance for cost overruns, but is an integral part of a project estimate.[7]

Using contingency allowances on a project is a normal and accepted industry practice. Large complex projects inevitably experience conditions that could not reasonably be foreseen at the time base estimates are prepared. This is not a function of ineffective project management or poor estimating. Including a contingency in a project estimate is essential because no estimator has perfect foresight.[8]

The PD incorrectly links contingency to the estimated costs of PG&E's Program Management Office (PMO) and attempts to justify disallowance of contingency by adopting what it characterizes as PG&E's "generous" base cost forecasts along with "an added layer for program administration."[9] The PMO costs adopted as reasonable in the PD are not a substitute for contingency. These PMO costs cover the essential management structure to deliver the component projects of the PSEP in a timely, cost effective and high quality manner.[10] The Commission previously rejected a similar argument by DRA that PG&E's use of a PMO reduced the need for a project contingency. Instead, the Commission adopted PG&E's full contingency request.[11] As PG&E's expert noted:

> Regardless of the strength of the project management team, however, unforeseeable factors remain that will affect project costs, thus requiring a contingency. While the structure of the risk management framework and the experience of the management personnel are considerations in establishing a contingency amount, they do not

[6] Ex. 21, PG&E Rebuttal, p. 14-14, lines 15-20.

[7] Ex. 114, p. 13-3, lines 1-4.

[8] See, e.g., Ex. 114, p. 13-3, lines 4-8.

[9] PD, p. 100; Conclusion of Law (COL) 33.

[10] Ex. 2, PG&E Direct, p. 7-20, lines 1-2.

[11] D.06-07-027, COL 3, pp. 64-66.

replace the need for a contingency.[12]

B. All Parties Recognized The Validity Of Including A Contingency In Estimates

There is no disagreement among the parties that a contingency is the industry accepted practice to account for unforeseeable elements of a defined project scope. The record is also clear that the Commission has previously adopted contingencies in project estimates to accommodate the inevitable risks affecting the costs of project implementation based on the specific risk profiles of the projects being considered.[13] Furthermore, the parties in the Sempra PSEP proceeding (A.11-11-002) also advocate the need to include a contingency in project estimates to account for forecasting uncertainties. For example, DRA's prepared testimony in the Sempra PSEP proceeding states: "DRA recognizes that **a contingency amount is necessary** to address the uncertainties in the current forecasts."[14] Similarly, Sempra stated: "Common estimating practices require an estimator to include a risk based allowance (i.e., contingency) to account for the inherent risks in any project estimate."[15]

The only dispute among the parties in this proceeding concerned the approach to contingency and the amount of contingency to add to base estimates.[16] By recommending disallowance of PG&E's full contingency, the PD ignores the evidence and adopts an alternate approach that penalizes PG&E for following industry standard methods for estimating capital projects.

[12] Ex. 114, p. 13-9, lines 1-5.

[13] See, e.g., D.06-07-027, COL 3, pp. 65-66; D.09-03-026, p. 88; Ex. 21, PG&E Rebuttal, p. 14-11, line 31—p. 14-12, line 14.

[14] A.11-11-002, DRA Direct, Ex 2, p. 64, lines 14-15. (Emphasis added).

[15] A.11-11-002, SoCal Gas Rebuttal, Chapter 9, p. 11.

[16] See, e.g., PG&E Reply Brief, pp. 78-80.

C. The Assumption That PG&E's Base Cost Estimates Are "Generous" And Include An "Implicit Allowance For Unexpected Cost Overruns" Is Contrary To Record Evidence

PG&E presented extensive evidence supporting the basis for its estimates and substantiating the underlying estimating approach and assumptions, linking the estimate assumptions to prior experience and adopting recommended practices of the AACE.[17] The fact that PG&E's base estimates are higher than those put forward by other parties does not make them "generous." In fact, the PD acknowledges that PG&E demonstrated the estimates established by intervening parties were flawed and substantially understated.[18]

PG&E's experience to date on PSEP activities demonstrates its base estimates were understated due to unforeseeable factors that had not been historically encountered (such as additional cleaning runs for strength testing efforts). For example, for strength testing, PG&E's estimate ranged from $760,000 to $850,000 per mile.[19] In 2011, the actual cost was $1.4 million per mile, significantly exceeding the base estimate.[20] While PG&E continues to look for ways to reduce the cost of its PSEP work, PG&E's experience shows its base estimates, which were based on preliminary engineering, were low and far from "generous."[21]

Finally, the PD appears to accept DRA's and TURN's unsupported allegation that PG&E's base estimates "include an implicit allowance for unexpected cost overruns."[22] This conclusion is wrong. PG&E provided detailed evidence describing the process it used to estimate each component project of PSEP, the assumptions included in the estimates, the status

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[17] See, e.g., Ex. 2, PG&E Direct, p. 7-30, line 18—p. 7-36, line 25.

[18] PD, pp. 100-101; PG&E Reply Brief, pp. 66–71.

[19] Ex. 21, PG&E Rebuttal, p. 4-2, lines 9-11.

[20] Ex. 21, PG&E Rebuttal, p. 4-2, lines 12-14.

[21] PG&E's actual strength testing costs in 2012 (through June) are continuing to be around $1.4 million per mile.

[22] PD, p. 101.

of project scope definition and the overall risk profile of each component project.[23] The quantitative analysis performed by PG&E's experts from PwC was based on the systematic analysis of risk allowances included in PG&E's base estimates, as well as the identification and quantification of risk-based contingency required to account for both unanticipated events and items expressly excluded from the baseline cost estimates.[24] The engineering reports summarizing the estimating approaches and assumptions expressly state that the base estimates do not include allowances for contingency.[25]

In summary, by recommending a disallowance of all contingency amounts, the PD erroneously rejects accepted industry standard estimating approaches and prior Commission precedent adopting risk based allowances for projects based on the specific risk profiles associated. The Commission should restore PG&E's contingency request in the final decision.[26]

III. THE DENIAL OF PG&E'S REQUEST FOR A MEMORANDUM ACCOUNT AND SUBSEQUENT DISALLOWANCE OF 2012 COSTS IS ARBITRARY AND CAPRICIOUS

The PD approves and adopts full cost recovery for the following PSEP programs: (1) automated gas shut-off valve installations;[27] (2) hydrotesting on pipelines that were installed prior to 1955;[28] (3) pipeline replacements of pre-1955 pipelines;[29] and (4) partial recovery for replacement of gas pipelines installed after 1955.[30] Although the PD finds the costs of these

[23] Ex. 2, PG&E Direct, p. 7-30, line 20—p.7-36, line 25.

[24] Ex.2, PG&E Direct, p. 7-37, lines 2-6.

[25] See, e.g., Ex. 2, PG&E Direct, p. 7-33 (reference to Gulf Engineering Report).

[26] PG&E does not seek contingency for the disallowed amounts that PG&E does not oppose in these comments (*e.g.* MAOP Validation).

[27] PD, p. 79.

[28] PD, p. 58.

[29] PD, p. 72.

[30] PD, p. 70.

2012 PSEP programs are reasonable and should be approved, it denies cost recovery for 2012 costs, on the grounds that PG&E should not be allowed to recover any PSEP costs incurred "prior to the effective date of today's decision."[31] The PD attempts to justify the failure to grant PG&E's timely-filed request for a memorandum account to track 2012 costs by pointing to the Overland Report submitted in I.12-01-007. According to the PD, that report shows "PG&E's management and shareholders used the rule prohibiting retroactive rate adjustments to retain substantial benefits in the past."[32] The PD thus justifies its proposal to disallow over $230 million in 2012 costs on a report that is being reviewed in the San Bruno OII, not this proceeding, and has been shown in that case to be misleading and inaccurate.[33]

The question is not whether the Commission can legally authorize recovery of 2012 PSEP costs but whether the Commission should (or must as a matter of law) exercise its discretion to authorize recovery of 2012 PSEP costs that are found to be reasonable. For the reasons discussed below, the PD should be modified to allow cost recovery for all of 2012 for all PSEP work the Commission approves and finds to be reasonable.

A. It Is Unreasonable, Arbitrary And Capricious To Deny Recovery Of 2012 PSEP Costs

Having found the automated valve, strength testing, and pipe replacement programs described above to be reasonable, and authorized cost recovery for 2012 after the effective date of the Commission's decision and all of 2013 and 2014, it is reasonable to authorize recovery of these approved, reasonable costs for all of 2012, if necessary approving a memorandum account to enable recovery. The PD correctly notes that a "memorandum account is a recognized

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[31] PD, p. 84.

[32] PD, p. 84.

[33] I.12-01-007, Ex. 10, PG&E Testimony of Matthew P. O'Loughlin.

exception to the rule against retroactive ratemaking."[34] The PD goes on, however, to observe that "the Commission has not granted PG&E's request for a memorandum account in which to record its Implementation Plan costs incurred prior to Commission approval."[35]

With these statements, the PD simply denies cost recovery, erroneously failing to address PG&E's motion for a memorandum account on the merits. The result is an arbitrary denial of legitimate cost recovery without any reasoned consideration.

PG&E initially requested a memorandum account on December 1, 2010 (Advice 3171-G). On May 5, 2011, the Commission approved Resolution G-3453 denying this request without prejudice and stating that the Commission would evaluate the request for a memorandum account in the Gas Safety OIR (R.11-02-019). PG&E filed a motion for a memorandum account in this proceeding the same day. The motion stated that the purpose of the memorandum account was to track PSEP costs and preserve the opportunity to seek cost recovery for such costs at the time of a final Commission decision. The motion has been pending for 18 months without the assigned ALJ or the Commission considering the merits of PG&E's request.

Much has happened in the 18 months PG&E's motion has sat without Commission action. On June 16, 2011, the Commission issued Decision 11-06-017, ordering PG&E and the other gas utilities to file Implementation Plans on August 26, 2011. The initial procedural schedule adopted for the proceeding would have resulted in a proposed decision in early 2012. On DRA's motion, an amended procedural schedule was adopted rescheduling evidentiary hearings to March 12-23, 2012, a delay of more than four months. The PD was issued on October 12, 2012, nearly six months after the close of evidentiary hearings.

[34] PD, p. 83.

[35] PD, pp. 83-84.

In April 2012, the Commission issued D.12-04-021. Among other things, that decision ruled on Sempra's motion for a memorandum account, filed just one day before PG&E's in May 2011. Decision 12-04-021 authorized Sempra to establish a pipeline safety memorandum account to track the costs of implementing PSEP and document review. It expressly authorized Sempra to retroactively record costs to be incurred in 2011 and 2012. There is no rational basis on which to distinguish PG&E from Sempra, and the PD does not even attempt to provide one.

D.11-06-017 ordered PG&E to proceed with the PSEP work pursuant to a "timeline for completion that is as soon as practicable" and directed PG&E to include a ratemaking proposal to address cost recovery for the PSEP work. The Commission stated that "due to significant public safety concerns" the Implementation Plans "shall be completed as soon as practicable."[36] PG&E complied with this directive and implemented on an expedited basis a pipeline and automated valve program of unprecedented scope and scale in the industry. The PD states that "the need for urgent pre-Commission approval action was caused at least in part by PG&E's own actions;"[37] however, this fails to take into account the game changing nature of the new regulatory requirements established in D.11-06-017 and that PG&E voluntarily proposed to forego recovery of close to $300 million in 2011 PSEP activities.

If the Commission had kept to its original procedural schedule, upon which PG&E relied in developing its PSEP scope, schedule and cost recovery proposal, a decision would have been reached by the Commission early in 2012, substantially reducing the risk of proceeding with PSEP implementation prior to a Commission decision on a memorandum account or cost recovery. If the PD is not modified, the delay in the PSEP schedule will cause PG&E to forfeit recovery of hundreds of millions of 2012 PSEP expenditures the PD finds to be reasonable—all

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[36] D.11-06-017, p. 20.

[37] PD, p. 84.

without the Commission ever addressing the merits of the cost recovery. It is arbitrary and capricious to deny recovery of reasonable 2012 PSEP costs simply because the Commission did not act on the motion for a memorandum account that had been pending since May 2011 (and was originally submitted in December 2010).

Finally, failure to authorize rate recovery for reasonable valve automation costs violates Public Utilities Code Section 957(b). That statute requires that the "commission shall authorize recovery in rates for all reasonably incurred costs" of the Commission-adopted automated gas valve shut-off program. The Commission does not have discretion to disallow the reasonable costs of the automated gas shut-off valve program because they were incurred before the Commission acted on PG&E's motion for a memorandum account. Since the PD finds the PSEP automated valve program to be reasonable in its entirety, the Commission must establish a memorandum account and approve recovery of all 2012 costs of the automated valve program.

B. The PD's Reliance On The Overland Report, Which Has Been Refuted In The San Bruno OII, Violates Due Process

The reason the PD gives for denying PG&E recovery of reasonable 2012 costs is that the Overland Report shows "PG&E's management and shareholders used the rule prohibiting retroactive rate adjustments to retain substantial benefits in the past" and therefore these "circumstances do not justify allowing PG&E to recover Implementation Plan costs incurred prior to the effective date of today's decision."[38] The PD thus bases its decision to disallow over $230 million in 2012 costs on a report that is within the scope of the San Bruno OII (I.12-01-007), not this proceeding, and has been shown to be misleading and inaccurate on this topic. On June 26, 2012, PG&E submitted testimony in the San Bruno OII refuting the Overland Report

[38] PD, p. 84.

findings.[39] In particular, PG&E demonstrated that: (1) PG&E did not "underspend" on the gas transmission and storage business; (2) the revenues that PG&E's gas transmission and storage business generated in excess of PG&E's cost of service ($430 million according to Overland's calculation) were not due to any "underspending" (because there was none) but rather due principally to market conditions that were favorable to PG&E's at-risk storage business; and (3) PG&E as a whole did not earn excess returns. On the contrary, PG&E's overall financial returns were close to the authorized amount, which indicates that PG&E used the gas transmission and storage revenues on other utility operations and those revenues did not generate profits in excess of PG&E's overall authorized rate of return.

The Overland testimony has been the subject of cross examination in the evidentiary hearings and PG&E's witness on the subject will take the stand at hearings to resume at the end of November. The cross-examination of the author of the Overland Report further underscored the flaws in Overland's analysis. The PD, however, did not take into account either PG&E's evidence refuting the Overland Report or the impeachment of that report through cross-examination. Adopting a significant disallowance here based on an issue that has been clearly reserved to and disputed in the San Bruno OII would deny PG&E fundamental due process rights.

Furthermore, the amount of the disallowance adopted in the PD to redress the allegation was determined in an arbitrary and capricious manner. The PD sizes the disallowance based upon the timing of the much-delayed decision on the PSEP. By only allowing cost recovery of PSEP costs following the effective date of the decision, the PD estimates that the disallowance of 2012 costs is approximately $230 million. That assumes that the final Commission decision is issued on November 1. Since the final decision will be issued after that date, the size of the

[39] I.12-01-007, Ex. 10, PG&E Testimony of Matthew P. O'Loughlin.

disallowance will increase for each month of delay and could result in a disallowance of 2013 costs as well. On the other hand, if the PSEP decision had been issued as contemplated by the initial procedural schedule in early 2012, then most of the 2012 PSEP costs for pipeline replacement, strength testing, and valve automation would be eligible for recovery and the disallowance on these grounds would have been close to nothing. This is not a rational or reasonable basis for adopting a disallowance. The rationale in the PD for disallowance of the recovery of 2012 PSEP costs is flawed and constitutes clear legal error.[40]

IV. THE ROE REDUCTION IN THE PD IS AN ADDITIONAL ARBITRARY PENALTY AND IS CONTRARY TO SOUND RATEMAKING PRINCIPLES

The Commission should not lower the ROE for needed pipeline investments as a punishment for alleged past management lapses. The ROE is a cost of using capital provided by common equity investors, and is a cost of needed safety improvements.

The PD lowers PG&E's ROE to the "current" cost of debt. This is a punitive action that is contrary to the public interest. It also fails to recognize that the ROE required by investors, as determined in the Commission's cost of capital decisions, is a cost of obtaining and using investors' common equity for utility system investments that are or will be used and useful. The authorized ROE is a cost, just as debt interest is a cost, for which prudence principles would not support a ratemaking disallowance for needed safety improvements.[41]

[40] The PD adopts a revenue requirement for the PSEP assuming a November 1, 2012 effective date of the decision. However, since comments on the PD will not be completed until November 29, it is clear there will not be final Commission action until after that date. If the Commission chooses not to authorize recovery of 2012 costs and a memorandum account as requested by PG&E, the Commission should clarify the PD to specify that the effective date of the decision will be fixed as of November 1 in order to preserve the apparent intent in the PD to authorize recovery of reasonable PSEP costs in last two months of 2012.

[41] C.F. *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944): "it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business." Accord, D.07-12-049, mimeo, p. 9.

Moreover, questions concerning punishment associated with San Bruno are at issue in the San Bruno-related investigations. Punishment using ROE is not appropriate in this case where future safety and reliability investments are the focus. It would misalign ratemaking, safety policy objectives and shareholder interests. And it would do this when PG&E must raise billions of dollars in equity in the coming years to restore its aging infrastructure and make safety improvements. Investors have a choice where to invest: *i.e.*, they can choose to invest in PG&E, another utility, or in an entirely different investment alternative. When the Commission decides to provide a non-compensatory return for an investment it otherwise wants to encourage, the signal sent to investors is counter-productive (*i.e.* that the Commission will not compensate them for the premium over debt costs), and will make it more difficult and costly for PG&E to raise needed capital.

As PG&E experts have testified, to the extent the Commission administers punishment, it is better for such punishment to result in a current earnings impact (*e.g.*, a denial of current or past expense recovery), than to have a lingering impact on future earnings. The PD, however, does both, lowering future returns on the capital investments it finds reasonable for safety, which impacts PG&E's ability to attract capital.

In addition, the PD contains two errors in its discussion of ROE. First, the PD errs when it asserts that a return on equity equal to the cost of debt "will allow PG&E to recover its costs, but no more." The cost of equity is as much a cost as the cost of debt.[42] The Commission has long recognized that the cost of equity exceeds the cost of debt, and warrants a return above the cost of debt to reflect additional risk. Since investors require the opportunity to earn a return on

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[42] PG&E notes that the Commission's affiliate rules require PG&E to maintain a balanced capital structure that has at least 52 percent equity. D.06-12-029 and the PG&E holding company decision, D. 96-11-017, require PG&E to maintain a balanced capital structure consistent with that determined to be reasonable by the Commission in its most recent decision on PG&E's capital structure.

equity commensurate with the return associated with comparable investments available to them, they are harmed when their allowed returns are lowered in the PD. Thus, lowering equity returns to the level of debt costs is punitive since it forecloses the opportunity to earn the cost of equity.

Second, COL 37 is incorrect and conflicts with the discussion regarding the applicable return on equity, appearing on page 108 of the PD. That discussion provides:

> In conclusion, the capital investments authorized by today's decision pursuant to PG&E's Implementation Plan . . . shall be recorded in a separate plant in service account. Such account shall be included in rate base tabulations with the total cost of capital being equal to the cost of debt; that is, the return on equity shall be adjusted to the then-current cost of debt. (Emphasis added.)

The intent of this discussion is clear. It adjusts the ROE to the current authorized cost of debt then being used to determine rate of return of rate base. That rate, however, is not the "incremental rate of debt," in the words of COL 37, but is the cost of debt authorized in PG&E's most recent cost of capital decision.[43]

COL 37 should be deleted from the PD, as shown in Appendix A. If the Commission does not make this change, it must modify COL 37 to conform to the discussion regarding the applicable return on equity appearing on page 108 of the PD.

V. THE DECISION NOT TO ALLOW PG&E TO RECOVER THE COSTS OF ITS GAS TRANSMISSION ASSET MANAGEMENT PROGRAM IS ARBITRARY AND CAPRICIOUS

The PD denies rate recovery of the costs of: (1) validating the MAOP of PG&E's gas transmission pipelines; and (2) PG&E's GTAM Project.[44] The PD lumps these two separate and discrete work efforts together, and concludes that, "PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies.

[43] PG&E requests clarification that, to the extent the cost of debt changes as a result of the upcoming Cost of Capital Decision, that change does not impact the outcome of this proceeding.

[44] PD, pp. 89-99.

Having created the need for this remedial work by its imprudent historic document management practices, PG&E has not shown by a preponderance of the evidence that the costs of the current document search and organization projects can be included in revenue requirement and that the resulting rates will be just and reasonable."[45]

Though denying cost recovery, the PD was careful not to express any opinion "on whether PG&E's natural gas system records violated federal or state law or regulations because those questions are pending in I.11-02-016."[46] Based on that understanding, PG&E does not contest the disallowance for MAOP Validation costs (or the strength testing costs for post-1955 pipelines where PG&E lacks documentation of a previous strength test).[47] PG&E's silence, however, should not be taken as acquiescence. The PD imposes hindsight judgments about how records should have been maintained, without taking into account the inter-play among the Grandfather Clause (49 CFR § 619(c)), historic industry recordkeeping practices, and the Commission's directives and orders eliminating the Grandfather Clause and requiring operators to re-verify MAOP using traceable, verifiable and complete records.[48]

The PD's conclusion that the GTAM Project is a remedial effort is unsupported by the record evidence. The weight of the evidence indicates that GTAM is not a remedial effort to ameliorate any past record keeping deficiencies, but instead is a significant technology upgrade that will benefit ratepayers far into the future. GTAM includes: (1) upgrading PG&E's current GIS to reflect an improved "linear referencing model," considered a best practice for gas

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[45] PD, p. 89.

[46] PD, p. 99.

[47] PG&E does not contest the proposed disallowance of strength testing costs for post-1955 pipelines operating above 30% SMYS where we must test or replace because we lack traceable, verifiable and complete records and where we did not meet the test or records requirements applicable at the time of installation (*i.e.* B31.8 from January 1, 1956 to July 1, 1961).

[48] *See, e.g.*, Ex. 21, PG&E Rebuttal, Chapter 10.

transmission pipeline operators, which will allow PG&E to view and analyze pipeline features, characteristics and event history relative to specific reference points along the entire length of its gas transmission pipelines; (2) developing a comprehensive process and system to trace and track materials from receipt by PG&E through the operating life of the component; (3) eliminating paper-based work processes and implementing automated work processes that manage leak survey, locate and mark, and maintenance work; and (4) developing tools to support the integration of all pipeline asset data to provide the full picture of asset health and condition with enhanced ability to perform risk and integrity analytics.[49] Furthermore, as demonstrated in PG&E's testimony, the costs for these capabilities have not already been funded by ratepayers.[50]

PG&E submitted evidence demonstrating that, even if PG&E's records were 100% accurate, the GTAM Project is still necessary to substantially upgrade PG&E's asset management capabilities by creating a technology infrastructure that: (1) supports enhanced and new business processes; (2) improves data consistency and reliability; (3) electronically maintains system data on a continuous basis; (4) supports enhanced decision making capabilities related to the risks and integrity of PG&E's gas transmission system; and (5) consolidates multiple systems and adds capabilities to the existing systems.[51]

The PD ignores this evidence in reaching the conclusion that GTAM is necessary to remedy past imprudent behavior. In fact, the PD's discussion of the Pipeline Records Integration Program focuses almost exclusively on the MAOP Validation Project, and then summarily concludes that GTAM is also remedial. This conclusion results from a clear error of fact.

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[49] Ex. 2, PG&E Direct, p. 5-16, lines 8-32.

[50] Ex. 21, PG&E Rebuttal, p. 11-14, line 23—p.11-16, line 16.

[51] Ex. 2, PG&E Direct, p. 5-17, lines 1-12.

If the Commission is not inclined to allow full rate recovery for the GTAM project, it should at least allow PG&E to recover the capital costs of the GTAM Project, in recognition of the long term ratepayer benefits of this significant technology upgrade. This would be consistent with the treatment of capital costs to replace pipelines installed after 1955 that lack adequate strength test records, in which the PD recognizes that allocating all of the capital costs to replace pipelines installed after 1955 to shareholders would mean that ratepayers will receive an ongoing benefit "at no cost."[52] The GTAM Project will benefit ratepayers throughout the life of the capital asset. Therefore, ratepayers should bear the capital costs for GTAM.

VI. THE PD'S RULINGS ON DEPRECIATION AND ESCALATION ARE CLEAR ERROR

A. There Is No Evidentiary Basis For Changing The Service Lives For PSEP Gas Transmission Mains From 45 Years To 65 Years

The PD recommends extending the depreciable life for gas transmission mains installed pursuant to the PSEP from PG&E's proposed 45 years, to 65 years. While the PD concludes that "the record in this proceeding" justifies lengthening the depreciable lives of gas transmission mains installed as part of PSEP, the PD fails to cite to any record evidence supporting this conclusion.[53] The PD cites statistics submitted by TURN regarding the average age of PG&E's transmission pipelines, and states in conclusory fashion that, "[t]he new pipelines will be manufactured to higher standards and pressure tested prior to going into service."[54] The average age of PG&E's pipelines and speculation regarding the expected lives of new transmission pipelines (for which there was no evidence submitted) is not sufficient evidence upon which to depart from the depreciable life of transmission assets adopted in the last GT&S Rate Case.

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[52] PD, p. 62.

[53] PD, p. 81.

[54] PD, p. 81.

In addition to lacking support in the record, this aspect of the PD will require complicated and cumbersome accounting, because PG&E will need to separately book, account for and calculate depreciation for PSEP pipe replacements independent from its accounting practices for the rest of its gas pipeline system, even though they are the same types of assets. For example, if PG&E replaces a gas transmission pipeline as part of its work under Gas Accord V, that pipeline segment will be depreciated over 45 years. If a different segment of the same gas transmission pipeline located 200 feet away is replaced as part of PSEP, that pipeline segment will be depreciated over 65 years. This does not make sense; depreciation rates for transmission pipe should be applied in a uniform and consistent manner.

Because the PD's conclusion regarding service lives is unsupported by the record, the Commission should adopt PG&E's proposed 45 year depreciable life, consistent with PG&E's most recent GT&S Rate Case. However, if the Commission is not inclined to approve PG&E's proposed 45 year depreciable life for gas transmission mains installed under the PSEP now, the Commission should defer this issue until PG&E's next GT&S Rate Case, in which the appropriate service lives for *all* gas transmission plant (whether installed as part of PSEP or not) can be adjudicated in a consistent manner based upon a robust record.

B. The PD's Adoption Of The Consumer Price Index, Rather Than PG&E's Proposed Escalation Rate, Is Arbitrary And Capricious

The PD rejected PG&E's proposed 3.12 percent escalation rate, adopting instead DRA's recommended 1.5 percent, which is pegged to the high end of the projected Consumer Price Index (CPI) over the 2012-2014 period.[55] The decision to reject PG&E's escalation rate is based on the finding that "PG&E's escalation rate is excessive for the three-year term of Phase 1 of the

[55] PD, pp. 102-103.

Implementation Plan."[56] There is no record evidence supporting this finding. In fact, all record evidence suggests that PG&E's proposed 3.12 percent escalation rate was reasonable and consistent with past rate cases.

The escalation rate PG&E proposed was derived from a forecast published by Global Insights in the third quarter of 2010 that is specific to the gas transmission industry.[57] The process of using this index provider and the specification of the index to the business line conforms to PG&E escalation policy as adopted in the last three PG&E GRCs.[58] No party submitted evidence demonstrating that PG&E's proposed 3.12 escalation rate is excessive, and there was no testimony on this point at hearings.

Nor did DRA demonstrate that CPI is a better predictor of the escalation of costs for the labor and materials used in the gas transmission business. In fact, the testimony of Ms. Scholz (which is the sole piece of DRA testimony that the PD relies upon to make the finding that PG&E's proposed escalation rate is excessive) simply cites to the CPI projection and Bureau of Labor Statistics forecast of inflation, with no discussion of how those forecasts relate to costs that PG&E will bear in performing work on its gas transmission system.[59] Ms. Scholz's testimony does not include any discussion of the projected inflation for the types of materials PG&E uses for its gas transmission system, with the exception of steel, for which Ms. Scholz quotes a wide variety of steel price forecasts.[60]

The Commission should adopt PG&E's escalation rate of 3.12 percent because it is a more accurate predictor of the escalation of materials and labor costs specific to the gas

[56] PD, p. 103.

[57] Ex. 21, PG&E Rebuttal, p. 18-5, lines 5-7.

[58] Ex. 21, PG&E Rebuttal, p. 18-5, lines 7-9.

[59] Ex. 147, DRA Direct (Scholz), p. 16.

[60] Ex. 147, DRA Direct (Scholz), pp. 16-17; Ex. 21, PG&E Rebuttal, p. 18-5, lines 23-26.

transmission industry in California, and consistent with prior GRCs, while the CPI is a general inflation index that is not specific to the gas transmission industry or California. The effect of this decision is not academic; setting escalation to track CPI will result in significant underrecovery for the costs of the work for which the PD allows rate recovery.

VII. REPORTING AND OVERSIGHT

A. The PD's Reporting Requirements In Attachment D Should Be Modified

Attachment D to the PD outlines a specification for quarterly "compliance reporting" on PSEP. PG&E is fully committed to provide timely and relevant information to the Commission, the Energy Division and the CPSD related to the status and performance of PSEP work streams. However, the reporting specification outlined in Attachment D includes a complicated combination of "one-time" data requests, work stream progress reporting requirements and overall PSEP scope and performance updates. PG&E believes in its current form, the compliance report outlined in the PD would be a costly and burdensome distraction to PG&E's program management team and is not the best way to achieve the Commission's important program performance monitoring objective.

PG&E recommends the Commission adopt an alternative that provides timely and relevant information to the Energy Division and CPSD in a format that is more consistent with common industry practices for project status and compliance reporting. PG&E currently prepares monthly reports for its Executive Steering Committee summarizing safety updates, performance metrics, workstream updates and budget status along with a number of appendices highlighting important project information for PG&E management to effectively oversee program performance.[61] The format and content of these reports is consistent with common

[61] Ex. 21, PG&E Rebuttal, p. 15-6, line 32—p. 15-8, line 16. The specific contents of the reports continue to evolve based on the nature and extent of PSEP activities and the input of Steering Committee members.

industry practices for capital project status and compliance reporting. PG&E is willing to share this information with the Commission on a monthly basis to provide a transparent mechanism to keep the Commission regularly informed of the PSEP status and overall performance.[62] In addition, PG&E prepares updated PSEP work scope and budget summaries on an annual basis, which PG&E could provide to the Energy Division and CPSD to highlight program-wide status and planning, including prioritization and cost allocation.

If the Commission is not inclined to adopt PG&E's alternative reporting proposal, there are a few modifications that PG&E suggests to Attachment D to the PD. First, 30 days following each calendar quarter does not provide sufficient time in which to prepare the report, which includes significant financial and project engineering data. Instead, PG&E requests that it be allowed 90 days following the quarter close to submit the report from the prior quarter. In addition, PG&E's proposed minor changes to the reporting requirements are included as Appendix B.

B. PG&E And CPSD Will Work Together Regarding The Appropriate Level Of Oversight

The PD states that "PG&E must keep CPSD fully informed of all changes it proposes to make to the program, and must obtain CPSD's concurrence in any proposed changes to the Implementation Plan."[63] The PD does not distinguish, however, between minor changes that need not be reviewed and approved by CPSD, and more material changes for which CPSD should be consulted. PG&E has had preliminary consultations with CPSD regarding the scope of CPSD's review, and will continue to work with CPSD to ensure that CPSD's review is at a programmatic level, such as changes to decision trees, program scope changes (*e.g.*

[62] Ex 21, PG&E Rebuttal, p. 15-8, lines 17-22. In addition, PG&E provides a semi-annual Gas Transmission Safety report to the Commission which provides project status updates, costs to date, and forecasted costs for gas transmission projects, including PSP projects.

[63] PD, p. 86.

reduction/increase in program miles or costs for pressure testing, pipeline replacement, or valve automation), or project scope changes due to records validation.

VIII. COMMENTS REGARDING THE SCOPE OF PHASE 1

The PD mandates "pressure testing of 783 miles of pipeline, replacement of 186 miles of pipeline, installation of 228 automated valves, and upgrades to 199 miles of pipeline to allow for in-line inspection," but notes that the amounts may be modified to conform to the decision.[64] The PD also notes that NCIP expressed concerns that PG&E's proposed one-way balancing account would allow PG&E to overspend on individual projects and shift subsequent projects to Phase II to stay within the authorized total.[65] To address this issue, the PD finds that, "to the extent specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects, the expense and capital cost limit of the balancing account is reduced by the amounts associated with the project not completed."[66]

The miles of pipeline that need to be strength tested or replaced in Phase 1 will undoubtedly be less than the mileage noted in the PD—for example, because PG&E locates records of an adequate prior strength test, or because work on non-contiguous segments of Class 1 and 2 pipelines can be deferred in accordance with the decision. PG&E accepts the PD's conclusion that, if the mileage for strength testing or replacement is reduced because PG&E can safely defer some work to Phase 2, and that work is not replaced with other projects, that the balancing account should be reduced by the estimated amounts associated with the deferred project. Of course, PG&E reserves the right to request cost recovery for such deferred projects in Phase 2. However, PG&E requests modification of the PD to *not* require PG&E to reduce the

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[64] PD, p. 3.

[65] PD, p. 112.

[66] PD, p. 112; see also COL 38.

capital and expense limit of the balancing account if work that was proposed for Phase 1 need not be done at all (where, for example, PG&E finds records of a strength test). The PD has placed all forecast risk on PG&E's shareholders, with no ability to offset cost overruns with money saved because PG&E does not have to perform work that it forecasted. Therefore, the Commission should not require that the cost limit of the balancing account be reduced where PG&E does not need to perform a particular project at all, but instead allow those cost savings to offset cost overruns which PG&E expects through the end of 2014.

IX. CONCLUSION

PG&E respectfully requests that the Commission incorporate PG&E's changes to the PD in the final decision in this proceeding. PG&E's proposed revisions to the Findings of Fact and Conclusions of Law are appended hereto as Appendix A.

Respectfully submitted,

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Dated: November 16, 2012

APPENDIX A

PROPOSED CHANGES TO FINDINGS OF FACT AND CONCLUSIONS OF LAW

Modify Finding of Fact 8 as follows:

8. The Implementation Plan calls for pressure testing 783 miles of pipeline and replacing 185.5 miles of pipeline in Phase 1. These amounts may be modified to conform to the decision, or where PG&E can demonstrate a sound engineering rationale.

Modify Finding of Fact 10 as follows:

10. The Implementation Plan calls for replacing, automating and upgrading 228 gas shut-off valves. These amounts may be modified to conform to the decision, or where PG&E can demonstrate a sound engineering rationale.

Modify Finding of Fact 11 as follows:

11. The Implementation Plan calls for retrofitting 199 miles of pipeline for in-line inspection and inspecting 234 miles of pipeline with in-line inspection tools. These amounts may be modified to conform to the decision, or where PG&E can demonstrate a sound engineering rationale.

Strike Finding of Fact 14 in its entirety:

~~14. PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material voluntary cost allocation to shareholders.~~

Modify Finding of Fact 16 as follows:

16. Adopted in 1955, the American Standards Association Code for Pressure Pipeline (ASA B31.8) was a voluntary industry standard that included provisions addressing the strength testing of pipelines and mains. Depending on considerations such as hoop stress and class location, the

strength test conducted may have been a hydrostatic strength test.~~required pre-service pressure testing for natural gas pipelines.~~

Modify Finding of Fact 17 as follows:

17. Prior to the adoption of General Order 112 in December 1960, PG&E generally followed the ~~PG&E admits that it voluntarily complied with American Standard Association Code for Pressure Pipeline (~~ASA B31.8 voluntary industry standards.~~), beginning in 1955.~~

Modify Finding of Fact 18 as follows:

18. Since no later than January 1, 1956, PG&E pressure tested certain gas transmission pipelines prior to placing them in service.~~complied with or stated that it complied with industry standards to pressure test pipeline prior to placing it in service.~~ PG&E has been~~is~~ unable to locate ~~produce~~ the records for certain strength~~pressure~~ tests conducted since ~~that would have been performed in accord with industry standards from~~ January 1, 1956, or for pipeline of unknown installation date. Depending on the circumstances, the lack of a pressure test record~~The lack of pressure test records~~ for pipeline placed into service after January 1, 1956, or with an unknown installation date, may have been inconsistent with ASA B.31.8-1955 voluntary industry standards.~~reflect an error in PG&E's operation of its natural gas system.~~ No evidence was presented that PG&E excluded the costs of strength~~pressure~~ testing ~~pipeline~~ from its regulated revenue requirement on or after ~~from~~ January 1, 1956.

Modify Finding of Fact 28 as follows:

28. PG&E's valve automation proposal will automate and upgrade 228 valves. These amounts may be modified to conform to the decision, or where PG&E can demonstrate a sound engineering rationale.

Modify Finding of Fact 29 as follows:

29. Transmission main pipeline installed pursuant the Implementation Plan will be manufactured according to the requirements of 49 C.F.R. Part 192, Subpart B, and ~~will be manufactured to higher standards than pipe installed 40 or more years ago and~~ will be pressure tested prior to being placed in service.

Strike Finding of Fact 31 in its entirety:

~~31. The record shows that PG&E retained amounts in excess of its authorized rate of return during years when it did not spend its full authorized budget for gas pipeline improvements.~~

Modify Finding of Fact 33 as follows:

33. From the date a gas transmission pipeline was installed, PG&E was responsible for creating and maintaining records that were needed to comply with gas pipeline safety rules and regulatory requirements.~~accurate and accessible records of its natural gas system equipment and facilities.~~

Modify Finding of Fact 34 as follows:

34. On January 3, 2011~~PG&E's failure to possess accurate and accessible records of its gas system caused~~ the NTSB sent a letter to PG&E noting a discrepancy between the installed pipe and as-built drawings for a segment of Line 132, and issued an urgent recommendation to all pipeline operators recommending that they validate—through records—the MAOP of all gas transmission lines located in HCAs. On January 3, 2011, the ~~and this~~ Commission directed ~~to direct~~ PG&E to meet the safety recommendations included in the NTSB's January 3, 2011 letter.~~correct these deficiencies~~.

Modify Finding of Fact 35 as follows:

35. PG&E's historic gas system revenue requirement has included costs for maintaining gas system records. The costs of the Gas Transmission Asset Management Project have not been included in revenue requirements historically.

Strike Finding of Fact 36 in its entirety

~~36. PG&E's imprudent management decisions to delay pipeline pressure testing and replacement contributed to the need for and timing of the projects needed pursuant to the Implementation Plan, which led to increased risk of cost overruns on projects.~~

Modify Finding of Fact 37 as follows:

37. An escalation rate of 3.12 percent,~~tied to the overall inflation rate~~, as proposed by PG&E,~~DRA,~~ is a reasonable escalation factor for Implementation Plan projects.

Strike Finding of Fact 38 in its entirety:

~~38. The scope of and timing for the extraordinary capital investment needs of the Implementation Plan were caused, in part, by PG&E's imprudent management decisions regarding pipeline records and pressure testing older pipeline.~~

Strike Finding of Fact 39 in its entirety:

~~39. PG&E has been inefficient and ineffective in its management of its natural gas system.~~

Modify Finding of Fact 40 as follows:

40. The amounts in Attachment E are program-based upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the Implementation Plan. To the extent specific authorized Phase 1 projects are not completed by the end of 2014 because they are deferred to Phase 2, and not replaced with other higher priority projects, the

expense and capital cost limit of the balancing account is reduced by the estimated completion amounts associated with the deferred project~~. not completed~~.

Add the following new Findings of Fact:

[1.] Adding a reasonable contingency to a base estimate is an accepted industry practice to account for unforeseeable risks associated with a defined work scope considering the information known to the estimators at the time baseline estimates are prepared.

[2.] PG&E's proposed base cost estimates for Implementation Plan work performed to date have generally underestimated the costs of the work included as part of the Implementation Plan.

[3.] PG&E's base cost estimates do not include an implicit allowance for cost overruns.

[4.] PG&E's contingency forecast was based on a reasonable Quantitative Risk Assessment prepared by experienced industry experts.

[5.] A memorandum account is a recognized exception to the rule against retroactive ratemaking.

[6.] PG&E initially requested a memorandum account on December 1, 2010 (Advice 3171-G). On May 5, 2011, the Commission approved Resolution G-3453 denying this request without prejudice and stating that the Commission would evaluate the request for a memorandum account in the Gas Safety OIR (R.11-02-019).

[7.] PG&E filed a motion for a memorandum account in the Gas Safety OIR on May 5, 2011. The motion has been pending for 18 months.

[8.] The initial procedural schedule for PG&E's Implementation Plan would have resulted in a proposed decision in early 2012.

[9.] Based on a request from DRA, an amended procedural schedule was adopted rescheduling evidentiary hearings to March 12-23, 2012, a delay of more than four months.

[10.] In April 2012, the Commission issued D. 12-04-021, which authorized Sempra to establish a pipeline safety memorandum account to track the costs of implementing Sempra's Implementation Plan, and document review. It expressly authorized Sempra to retroactively record costs to be incurred in 2011 and 2012.

[11.] Public Utilities Code Section 957(b) states that the Commission "shall authorize recovery in rates for all reasonably incurred costs" of the Commission-adopted automated gas valve shut-off program.

[12.] The Return on Equity is a cost of using capital provided by common equity investors.

[13.] The Gas Transmission Asset Management program is a significant technology upgrade that will (1) upgrade PG&E's GIS to reflect an improved "linear referencing model"; (2) develop a comprehensive process and system to trace and track materials from receipt by PG&E through the operating life of the component; (3) eliminate paper-based work processes and implement automated work processes that manage leak survey, locate and mark, and maintenance work from scheduling of work, field capture of information, verification and quality review of field-captured data, and updating of the integrated information management systems; and (4) develop tools to support the integration of all pipeline asset data to provide the full picture of asset health and condition with enhanced ability to perform risk and integrity analytics.

Modify Conclusion of Law 13 as follows:

13. It is reasonable for PG&E's shareholders to absorb the portion of the Implementation Plan costs which were necessary to comply with preexisting regulations.~~caused by imprudent management.~~

Strike Conclusion of Law 14 in its entirety:

~~14. Because PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material voluntary cost allocation to shareholders, notwithstanding the Commission's directive to do so, and due to the scope and consequence of PG&E's imprudent management actions, it is reasonable to use exceptional ratemaking measures when considering shareholders' return on equity.~~

Modify Conclusion of Law 15 as follows:

15. It is reasonable for shareholders to absorb the costs of pressure testing pipeline placed into service after January 1, 1956, or for which PG&E has no known installation date, and for which PG&E is unable to produce pressure test records, as an additional shareholder contribution. This Conclusion of Law has no bearing on whether PG&E's natural gas system records violated federal or state law or regulations because those questions are pending in I.11-02-016.

Modify Conclusion of Law 16 as follows:

16. It is reasonable to impose an equitable adjustment to the replacement cost of pipeline installed from January 1, 1956, to July 1, 1961, for which pressure test records are not available, but which require replacement rather than pressure testing, as an additional shareholder contribution. Such an equitable adjustment shall be equal to the forecasted cost of pressure testing the pipeline and shall reduce the cost of the pipeline replacement included in rate base and revenue requirement. This Conclusion of Law has no bearing on whether PG&E's natural gas system records violated federal or state law or regulations because those questions are pending in I.11-02-016.

Modify Conclusion of Law 25 as follows:

25. There is no record evidence to support a conclusion that~~It is reasonable to conclude that~~ pipe installed pursuant to the Implementation Plan will have a longer service life than pipe installed over 40 years ago. Therefore, a 45 year depreciable life is adopted for gas transmission mains installed as part of the Implementation Plan.

Modify Conclusion of Law 26 as follows:

26. TURN's proposal to adopt a 65-year service life for transmission main pipe installed pursuant to the Implementation Plan is not reasonable, and is not~~should be~~ adopted.

Strike Conclusion of Law 27 in its entirety:

~~27. PG&E has not justified recovering from ratepayers its Implementation Plan costs incurred prior to the effective date of today's decision.~~

Strike Conclusion of Law 28 in its entirety:

~~28. Absent extraordinary circumstances, the rule against retroactive ratemaking prevents ratepayer representatives from recovering for ratepayers amounts authorized but unspent by PG&E for gas pipeline improvements.~~

Modify Conclusion of Law 31 as follows:

31. The Executive Director should be delegated authority to order PG&E to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision, not to exceed $15,000,000 and PG&E should be authorized to record any incremental amounts so expended in its ~~Annual Gas True-Up~~ Balancing Accounts for recovery from ratepayers.

Modify Conclusion of Law 32 as follows:

32. PG&E should file monthly compliance reports summarizing safety updates, performance metrics, workstream updates and budget status in the form of the reports currently prepared for the Executive Steering Committee. ~~as specified in Attachment D~~.

Strike Conclusion of Law 33 in its entirety:

~~33. It is not reasonable to adopt a cost overrun contingency allowance because PG&E's imprudent management decisions contributed to risk of such overruns and we adopt cost forecasts at the high end of the range of reasonableness with an added layer for program administration.~~

Modify Conclusion of Law 35 as follows:

35. PG&E's proposal for a ~~21%~~ contingency adder on the amounts approved for cost recovery in this decision should be approved~~denied~~.

Modify Conclusion of Law 36 as follows:

36. A rate of 3.12~~1.5~~% should be adopted to escalate costs from the effective date of today's decision to the date of project completion.

Strike Conclusion of Law 37 in its entirety:

~~37. Due to inefficient and ineffective management decisions, PG&E's return on equity for investments made pursuant to the Implementation Plan should be reduced to the incremental cost of debt.~~

Modify Conclusion of Law 38 as follows:

38. A one-way balancing account should be approved for all Implementation Plan projects, subject to the following limitation: To the extent PG&E incurs costs beyond the amounts set forth in Attachment E for projects approved in today's decision, the expense and capital overruns

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should not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. Similarly, where specific authorized Phase 1 projects are not completed by the end of 2014 because they are deferred to Phase 2, and not replaced with other higher priority projects, the expense and capital cost limit of the balancing account should be reduced by the estimated completion amounts associated with the deferred project.~~ not completed.~~

Add the following new Conclusions of Law:

[1.] It is reasonable for PG&E's request for a memorandum account to be granted, and for PG&E to recover the 2012 costs of the programs that are approved for cost recovery in this decision.

[2.] The Return on Equity for PG&E's Implementation Plan should not be reduced from the Return on Equity approved in the most recent Cost of Capital decision.

[3.] The Gas Transmission Asset Management program is a significant technology upgrade, the costs of which are reasonably included in customer rates.

Modify Ordering Paragraph 7 as follows:

7. Pacific Gas and Electric Company is authorized to file a Tier 1 Advice Letter to create~~ a~~ balancing accounts to record the amount of revenues collected from ratepayers through the Implementation Plan Rate as compared to the adopted revenue requirement. The balance, if any, as of December 31, 2014, shall be collected from or refunded to ratepayers through the next Annual Gas True-Up filing. Amounts~~ny Accumulated balance~~ will be allocated 59.5% to the core class and 40.5% to the noncore class.

Modify Ordering Paragraph 9 as follows:

9. The Executive Director is delegated authority to order Pacific Gas and Electric Company (PG&E) to reimburse the Commission for any Commission contract necessary to carry out the

directives in today's decision, not to exceed $15,000,000. PG&E is authorized to record any incremental amounts so expended in its ~~Annual Gas True-Up~~ Balancing Accounts for recovery from ratepayers.

APPENDIX B

PROPOSED CHANGES TO ATTACHMENT D

1) Describe PG&E's project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.
2) Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties?
3) For work contracted out to other parties, what criteria did PG&E use to select the contractors and did PG&E use a competitive bidding process to select the contractor(s)? If not, explain why.
4) How does PG&E monitor the quality of work performed by outside contractors? Has PG&E found any instances where a contractor failed to do the work properly? If so, what actions did PG&E take in response?
5) What quality assurance procedures does PG&E have in place to determine whether the project, work is being done correctly by its own employees? Has PG&E found any instances where the work is being done correctly by its own employees? Has PG&E found any instances where the work was not done properly? If so, what actions did PG&E take in response?
6) Describe the role of the Program Management Office (PMO) (see p. 7-10 of Prepared Testimony) in containing project costs. Provide specific examples where the PMO's recommendations lead to cost savings.
7) Provide the costs incurred by the PMO year-to-date and describe the specific work they did for the benefit of PG&E customers.
8) Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.
9) Describe PG&E's procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.
10) What was the disposition (e.g., sold) of replaced pipe and other material. Identify all the amounts earned for the disposition of the material, costs incurred to transport or dispose of the material and regulatory treatment of the incurred costs and revenues.

11) Provide a complete description or a specific reference to proceeding work papers, of projects completed during this reporting period and those completed Year-to-Date, include the start and finish dates. On a project-by-project basis, provide the amount budgeted for the project and an itemized list of the costs, including labor and material, incurred completing of the project. Identify the amount that a project was over or under-budget. Indicate whether the work was done in-house or by outside contractor(s). ~~Identify the outside contractor(s).~~ Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project. Identify costs that shareholders will absorb.
12) Provide a complete description, or a specific reference to proceeding work papers, of projects that have begun but are currently unfinished, include the start and anticipated completion dates. On a project-by-project basis, provide the amount budgeted for each project. Explain how the work is being done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project.
13) Provide a complete description, or a specific reference to proceeding work papers, of projects that were forecasted for Phase 1 that have yet to start, include the anticipated start and anticipated completion dates. Rank the priority of these projects and explain the ranking. On a project-by-project basis, provide the amount budgeted for the project. Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, identify the Decision Tree outcome identifier associated with each project.
14) Describe, in detail, projects that PG&E has completed, are work-in-progress, or have yet to start that were not included in the work papers submitted in R.11-02-019. Explain why these projects have been included in Phase 1 and whether these projects have lowered the priority of other projects identified in proceeding work papers and, if so, why. Explain how this work complies with D.11-06-017 and PG&E's Decision Tree and provide the Decision Tree outcome identifier associated with each project.
15) For completed projects that are 10% or more over estimated costs, provide a detailed explanation why the overrun occurred.
16) Provide a list and map of pipelines that are currently piggable, highlighting pipe that was made piggable as a result of projects conducted under the PSEP. Provide the total mileage of transmission pipelines, the total mileage of pipelines that are currently piggable and percentage of the total that is piggable.
17) Describe any lessons learned from undertaking the Phase 1 work that has led to cost efficiencies and quantify any cost savings.
18) How will the work PG&E conducts in Phase 1 influence how PG&E will plan and estimate the costs of its proposed projects for Phase 2
19) What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?
20) Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydro testing, pipe replacement).

21) Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g., hydro testing, pipe replacement).
22) Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.
23) Provide a table showing the mileage of pipe PG&E forecast to hydrotest in R.11-02-019 and the mileage PG&E has tested year-to-date. Identify the location, Line #, milepost, Class of the pipe tested. Indicate whether the pipe is located in a High Consequence Area.
24) Provide the costs of the public outreach PG&E has incurred year-to-date by month as compared to the amount authorized by the final decision in this case. Explain in detail what public outreach activities PG&E has engaged in.
25) Describe (e.g., provide date(s), location, Line #) all planned and unplanned service outages PG&E experienced in conducting the project work and explain how PG&E addressed customer needs during the outages. Were customers notified of any outages beforehand?
26) In the final quarterly report following completion of the PSEP, ~~D~~describe or provide a specific reference to PG&E's work papers of the projects that were not completed or replaced by a higher priority project. If applicable, ~~and show the uncompleted project's associated costs. C~~compute the corresponding reduction to the Implementation Plan adopted amounts set out in Attachment E, as required by Ordering Paragraph 6.
27) Any additional relevant information not listed above as specified in hearing Exh. 2 at 8E-1 and 8E-2.