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.	Rulemaking 11-02-019 (Filed February 24, 2011)

APPLICATION FOR REHEARING OF DECISION 12-12-030
BY THE CITY OF SAN BRUNO

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I. INTRODUCTION

Pursuant to California Public Utilities Code section 1731 and Rule 16.1 of the California Public Utilities Commission's (the "Commission") Rules of Practice and Procedure (the "Rules"), the City of San Bruno (the "City") respectfully submits this timely Application for Rehearing of the Commission's *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Imposing Earnings Limitations, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering* ("Decision 12-12-030" or "D.12-12-030").[1] In accordance with Rule 16.3(a), the City hereby requests oral argument in connection with this Application for Rehearing of D.12-12-030.

Decision 12-12-030 commits legal error as follows: (A) Commission revisions set forth in D.12-12-030, including the $130 million[2] windfall for Pacific Gas and Electric Company

[1] Decision 12-12-030 was adopted on December 20, 2012, and was mailed on December 28, 2012. Therefore, this Application for Rehearing is timely filed in accordance with Rule 16.1(a).

[2] *See* Notice of Ex Parte Communications of the Division of Ratepayer Advocates at 3 (December 19, 2012) and Notice of Ex Parte Communications of The Utility Reform Network attachment at 3 (December 18, 2012). *See also* PG&E Corporation's October 12, 2012 8-K filing with the Securities and Exchange Commission ("SEC") at 2 (disclosing that PG&E "estimates that the lower rate of ROE [in the Proposed Decision] would reduce total after-tax equity earnings over the relevant period by approximately $130 million...") (the "PG&E 8-K"). The City requests that the Commission take judicial notice of the PG&E 8-K, attached hereto as **Exhibit A**. Commission Rule 13.9 authorizes the Commission to take judicial notice of matters that may be "judicially noticed by the courts of the State of California pursuant to Evidence Code section 450 *et seq.*" California Courts have previously taken (footnote continued)

("PG&E") associated with allowing the utility to earn a return on equity ("ROE") in connection with the Pipeline Safety Enhancement Plan ("PSEP"), represent material and substantive modifications made by the Commission in violation of California Public Utilities Code section 311(e)[3]; (B) the Commission's failure to provide legally sufficient notice concerning D.12-12-030 on the Commission's Public Agenda runs afoul of both the Bagley-Keene Act and Commission Rule 15.2(a); (C) the Commission's decision to provide PG&E with a $130 million windfall in D.12-12-030 and eliminate references to PG&E's inefficient and ineffective management of its natural gas system is not supported by substantial evidence in the record; and (D) Decision 12-12-030 fails to include separately stated findings of fact and conclusions of law on all issues material to the decision in accordance with California Public Utilities Code section 1705. For these reasons, rehearing of D.12-12-030, and oral argument in connection with such rehearing, is both appropriate and necessary.

II. BACKGROUND

On September 9, 2010, the explosion and fire that erupted from PG&E's defective natural gas pipeline main 132 ("PG&E Line 132") caused eight San Bruno residents to lose their lives.[4] Sixty-six San Bruno residents were injured and burned.[5] Thirty-eight homes in the Crestmoor neighborhood were completely destroyed, seventeen homes were deemed uninhabitable and another fifty-three homes suffered damage.[6]

In the wake of the explosion of PG&E Line 132, the Commission initiated Rulemaking 11-02-019 ("R.11-02-019") when it issued an *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* on February 25, 2011 (the "OIR"). On June 9, 2011, the Commission amended the Scope of R.11-02-019 to require utilities to file gas safety plans.[7] In accordance with Commission direction, PG&E filed its PSEP on August, 26

judicial notice of SEC filings. *See Aquila, Inc. v. Super. Ct.*, (2007) 148 Cal. App. 4th 556, 566 (finding SEC filings "are not reasonably subject to dispute and are capable of immediate and accurate verification…").

[3] Unless otherwise noted, all references herein are to the California Public Utilities Code.

[4] NTSB Report at 18.

[5] NTSB Report at 18.

[6] NTSB Report at 19.

[7] Decision 11-06-017(June 9, 2011).

2011. Administrative Law Judge ("ALJ") Bushey issued her proposed decision concerning PG&E's PSEP on October 12, 2012 (the "Proposed Decision").[8]

The Proposed Decision found that "PG&E has been inefficient and ineffective in its management of its natural gas system"[9] ("Finding of Fact No. 39"). In addition, the Proposed Decision concluded, "[d]ue to inefficient and ineffective management decisions, *PG&E's return on equity for investments made pursuant to the [PSEP] should be reduced to the incremental cost of debt"*[10] (emphasis added) ("Conclusion of Law No. 37"). According to the explanation set forth in the Proposed Decision, the reduced rate of return would "allow PG&E to recover its costs, but no more."[11] The Proposed Decision held the reduced rate of return for five years in order to "provide PG&E an incentive to improve its management efforts and to assure shareholders that PG&E gas system safety related capital costs are sound financial investments..."[12] The value of this ROE reduction is approximately $130 million dollars.[13]

The Parties to R.11-02-019 filed opening comments on the Proposed Decision on November 16, 2012. In its comments on the Proposed Decision, the City supported a reduction in PG&E's ROE to ensure that PG&E was only allowed to recover its costs, and not any profits from its well-documented malfeasance and gross negligence.[14] In addition, the City argued that the Proposed Decision must establish more clearly why ROE reduction tolerance was limited to five years.[15] By contrast, PG&E urged the Commission not to reduce PG&E's ROE for PSEP improvements. PG&E claimed that the Proposed Decision's five-year ROE reduction was "an

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[8] *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Imposing Earnings Limitations, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring On-Going Improvement in Safety Engineering* (October 12, 2012).

[9] Proposed Decision at 117, Finding of Fact No. 39.

[10] Proposed Decision at 122, Conclusion of Law No. 37.

[11] Proposed Decision at 108.

[12] Proposed Decision at 108.

[13] See Notice of Ex Parte Communications of the Division of Ratepayer Advocates at 3 (December 19, 2012); Notice of Ex Parte Communications of The Utility Reform Network attachment at 3 (December 18, 2012).; PG&E 8-K at 2.

[14] Opening Comments of the City of San Bruno at 13. (November 16, 2012); Reply Comments of the City of San Bruno at 7-8 (November 29, 2012).

[15] Specifically, the City urged the Commission to "quantify and clarify (i) how an increase in borrowing costs is translated into impacts on ratepayers, and at what levels; (ii) why an increase in "borrowing costs" for the utility is acceptable for five (5) years, and not for ten (10) years or twenty (20) years; (iii) how "potentially diminishing the financial health of the utility" specifically affects ratepayers; and (iv) why five (5) years, results in a tolerable level of diminished health of the utility, and a longer term reduction in ROE would not." Opening Comments of the City of San Bruno at 13. (November 16, 2012).

additional, arbitrary penalty and is contrary to sound ratemaking principles."[16] PG&E's opening comments also recommended deletion of Finding of Fact No. 39 and Conclusion of Law No. 37.[17]

The Commission scheduled the Proposed Decision, which included the five-year ROE reduction,[18] for consideration as Item 50 at its December 20, 2012 business meeting.[19] The Commission's Agenda identified "[r]educes PG&E's return on equity for these investments to 6.05% due to management inefficiency and ineffectiveness" as a "Proposed Outcome" for Item 50. In spite of that description, the Commission covertly released a substantive and material revision to the Proposed Decision the night before the Commission meeting.[20] To wit, the Commission eliminated the five-year ROE reduction set forth in the Proposed Decision with no prior public notice or opportunity to be heard.[21] The Commission unanimously approved this substantive and material revision as D.12-12-030 on December 20, 2012, granting PG&E a $130 million windfall in the form of ROE for PSEP investments.[22]

III. STANDARD OF REVIEW

An applicant for rehearing must "...set forth specifically the grounds on which the applicant considers the order or decision of the Commission to be unlawful or erroneous."[23] California courts have statutory authority to review Commission decisions concerning whether "(1) the order or decision of the commission was an abuse of discretion; (2) the commission has

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[16] Opening Comments of Pacific Gas and Electric Company on Proposed Decision at 14. (November 16, 2012).

[17] Opening Comments of Pacific Gas and Electric Company on Proposed Decision, Attachment A at 4, 9 (November 16, 2012).

[18] *See* Proposed Decision at 122, Conclusion of Law 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.").

[19] *See* Public Agenda 3306 at 46. Item 50 from Public Agenda 3306 is attached hereto as **Exhibit B**.

[20] Despite diligent efforts to locate the Commission's substantively revised version online and elsewhere, it was not available to the City the night before the Commission was scheduled to vote on it. The City only made its serendipitous discovery of the revised decision during review of the "Escutia Table," on the morning of the December 20, 2012 Commission meeting. *See* Declaration of Britt K. Strottman attached hereto as **Exhibit C**.

[21] Interestingly, the Commission's 11th hour effort to expunge all past references to an ROE reduction was not completely successful. See D.12-12-030 at 54 ("As discussed below, however, such management imprudence *does* provide an evidentiary basis for a reduction in Return on Equity due to management ineptitude) (emphasis added); D.12-12-030 at ("As explained in this section, we approve PG&E's Implementation Plan subject to the following...PG&E's return on equity is reduced to the incremental cost of debt for capital costs incurred as part of the Implementation Plan for five years.").

[22] A true and correct copy of the Commission's last minute revisions obtained by the City on the morning of December 20, 2012 are attached hereto as **Exhibit D**.

[23] Commission Rule 16.1(c).

not proceeded in the manner required by law; (3) the commission acted without, or in excess of, its powers or jurisdiction; (4) the decision of the commission is not supported by the findings; (5) the order or decision was procured by fraud; and (6) the order or decision of the commission violates any right of the petitioner under the Constitution of the United States or the California Constitution." [24]

IV. GROUNDS ON WHICH D.12-12-030 IS UNLAWFUL AND ERRONEOUS

A. D.12-12-030 is an Alternate Decision Adopted by the Commission in Violation of Section 311(e) and Commission Rules

The Commission materially changes the resolution of the highly contested ROE reduction issue in a manner that converts D.12-12-030 into an alternate decision.[25]

Per Section 311(e), "alternate" means:

> ...[E]ither a substantive revision to a Proposed Decision (1) *materially changes the resolution of a contested issue*; or (2) makes any substantive addition to the findings of fact, conclusions of law or ordering paragraphs. (emphasis added)

Pursuant to statute,[26] the Commission adopted Rule 14.1(d). Commission Rule 14.1(d) sets forth a much more narrow definition of Alternate:

> "Alternate" means a substantive revision by a Commissioner to a recommended decision not proposed by the Commissioner or to a draft resolution which either: (1) *materially changes the resolution of a contested issue*; or (2) makes any substantive addition to the findings of fact, conclusions of law or ordering paragraphs...
>
> ...A substantive revision to a proposed decision or draft resolution is not an "alternate" if the revision does no more than make changes suggested in prior comments on the proposed decision or draft resolution, or in a prior alternate to the proposed decision or draft resolution. (emphasis added)

[24] *See* Cal. Pub. Util. Code § 1757.1. Public Utilities Code section 1757.1 "describes the scope of review in a proceeding other than a complaint or enforcement proceeding or a ratemaking or licensing decision of specific application to particular parties." *Southern California Edison Co. v. Public Utilities Com.*, 140 Cal. App. 4th 1085, 1096 (June 26, 2006).

[25] ROE reduction was a contested issue amongst various Parties to R.11-02-019. *See, e.g.,* Opening Comments of The Utility Reform Network at 13 (November 16, 2012); Reply Comments of The Utility Reform Network at 5-6 (November 29, 2012)); Reply Comments of the Division of Ratepayer Advocates at 8 (November 29, 2012); and Opening Comments of the City and County of San Francisco at 8,10 (November 16, 2012).

[26] Section 311(e) (authorizing the Commission "adopt rules that provide for the time and manner of review and comment and the rescheduling of the item on a subsequent public agenda the Commission...)." Where the Commission "adopts its rules pursuant to its rulemaking authority, these rules have the force and effect of law." *See Southern California Edison Co. v. Public Utilities Com.* (2006) 140 Cal. App. 4th 1085, 1092, fn 3.

Assuming only for the sake of argument that the substantive revisions set forth in D.12-12-030 were indeed suggested by prior comments, the Commission's "suggested in prior comments" exception proves too much. The breadth of Commission Rule 14.1(d)'s exception essentially swallows the Section 311(e) Rule. Even a cursory review of the legislative history of Section 311(e) makes clear that a core purpose of the statute is to ensure that the Commission conducts its business in an open and transparent manner, with adequate notice and opportunity to comment afforded to all interested parties.[27] Commission Rules cannot be permitted to do violence to the core purpose of the statutes upon which they are based.

Equally important is the fact that a persuasive argument cannot be made that the Commission's modifications were actually suggested by prior comments. The Commission's substantive and material shift in policy on the ROE issue was not suggested by prior comments. The Commission's significant departure from the commitment it made to consider a ROE reduction in the OIR was not suggested in the prior comments of the Parties. For these reasons, D.12-12-030 should be deemed an alternate under Section 311(e). The Commission's failure to serve D.12-12-030 on all parties as an alternate decision and delay consideration of the alternate for 30 days therefore violates Section 311(e) and Commission Rules.[28]

1. Granting PG&E a $130 Million Windfall in Profits on PSEP Investments is a Material Change to the Resolution of a Contested Issue in R.11-02-019

As a threshold matter, D.12-12-030 makes a last minute, $130 million change to the Commission's resolution of the ROE issue. Whether PG&E should be authorized to earn a profit on PSEP investments was a highly contested issue in R.11-02-019.[29] The Proposed Decision reduced PG&E's ROE to the cost of debt for a five-year period. In an abrupt and complete reversal of course, the Commission's last minute and covert determination in D.12-12-030 rejects any such ROE reduction. Standing alone, the Commission's rejection of a ROE reduction

[27] *See, e.g.,* AB 2850, Senate Floor Analyses (August, 9, 1994).

[28] Section 311(e) states that an alternate "may not be rescheduled for consideration sooner than 30 days following service of the alternative item upon all parties." Where an "alternate is mailed less than 30 days before the Commission meeting at which the proposed decision or draft resolution is scheduled to be considered," Commission Rule 15.1(e) states that the "item will be held to the extent necessary to comply with Public Utilities Code Section 311(e)."

[29] *See,* footnote 25 of this Application for Rehearing, *supra.*

in D.12-12-030 and resultant $130 million windfall for PG&E "materially changes the resolution of a contested issue."[30]

2. The Commission's Broad "Suggested in Prior Comments" Exception to the Definition of "Alternate" Swallows the Section 311(e) Rule

In any event, the Commission's definition of "alternate" to broadly exclude revisions "suggested in prior comments" is vague and inconsistent with the definition of alternate set forth in Section 311(e). The specificity with which an issue must be "suggested in prior comments" is undefined and far from clear. Commission Rule 14.1(d) excludes "substantive revisions" that are "suggested by prior comments" from the definition of "alternate." Section 311(e) makes no similar exemption. Subsequent amendments to the law have never disturbed the definition of alternate set forth in Section 311(e).[31]

Furthermore, such an exemption is contrary to the purpose of Section 311(e), which is to make not only the substance, but also the process and rationale for Commission decision-making transparent. Section 311(e), and its definition of "alternate" became law with adoption of Assembly Bill ("AB") 2850 (Escutia). According to Committee Analysis of AB 2850, the legislation was advanced after an alternate decision "was adopted with no public scrutiny."[32] The alternate was particularly controversial "because utility managers were allowed to substantially edit the decision immediately before issuance."[33] Mere suggestion of an issue in opening comments does not ensure that the process and rationale behind Commission decision-making ultimately become the subject of adequate public scrutiny.

3. The Commission's Last Minute Modifications to D.12-12-030 Were Not "Suggested in Prior Comments"

That PG&E's recommended deletion of Finding of Fact No. 39 and Conclusion of Law No. 37 does not nullify D.12-12-030's status as an alternate decision. Per Commission Rule 14.1(d), a substantive revision to a proposed decision or draft resolution is not an "alternate" if

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[30] Section 311(e); Rule 14.1(d).

[31] See, e.g. Senate Bill 779 (Calderon) (Chaptered September 28, 1998), Senate Bill 15 (Escutia) (Chaptered October 6, 2005).

[32] AB 2850, Senate Floor Analyses (August, 9, 1994).

[33] AB 2850, Senate Floor Analyses (August, 9, 1994) (also citing the fact that utility managers held numerous ex parte contacts with PUC decision-makers, without complying with PUC rules requiring disclosure of such comments).

the "revision does no more than make changes suggested in prior comments on the proposed decision..."[34]

Decision 12-12-030 does not fall within the purview of the Commission's "suggested by prior comments" exception to the definition of "alternate." The revisions set forth in D.12-12-030 do far more than merely make changes suggested by prior comments on the proposed decision. Beyond simply adopting prior comments, D.12-12-030 represents a significant shift in policy relative to the Proposed Decision. Under the terms of the Proposed Decision, the Commission dictates whether and when PG&E is entitled to earn a ROE on PSEP investments. Decision 12-12-030 allows PG&E, rather than the Commission, to define the "role of ratemaking for safety related operations" where ROE is concerned. Whether it was appropriate for PG&E, rather than the Commission to dictate the ROE reduction for PSEP investments was not an issue addressed in prior comments.

Furthermore, the revisions set forth in D.12-02-030 disregard the Commission's prior commitment to consider ROE reductions in R.11-02-019. The Commission identified "Ratemaking and Other Incentives for Prudent Utility Operations" among its primary objectives for R.11-02-019 as follows:

> Consider available options for the Commission to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the "nuts and bolts" details of prudent utility operations.[35]

In its explanation of this objective, the OIR expressly references reduction of PG&E's rate of return and commits the Commission to consideration of this approach for better aligning ratemaking with prudent utility operations:

> The extraordinary safety investments required for PG&E's gas pipeline system and the unique circumstances of the costs of replacing the San Bruno line are situations where this Commission may use its ratemaking authority to, for example, *reduce PG&E's rate of return on specific plant investments* or impose a cost sharing requirement on shareholders. *We will consider these, and other ratemaking mechanisms, in this proceeding.*[36] (emphasis added)

Rather than follow through with that commitment, D.12-12-030 excises key language regarding an ROE reduction from the Proposed Decision and retreats to the remaining ROE

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[34] Commission Rule 14.1(d).
[35] OIR at 4.
[36] OIR at 11-12.

discussion that previously supported a five-year ROE reduction to reach a contradictory result. Specifically, D.12-12-030 deletes:

- ☐ Finding of Fact No. 39 ("PG&E has been inefficient and ineffective in its management of its natural gas system.");
- ☐ Conclusion of Law 37 ("Due to inefficient and ineffective management decisions, PG&E's return on equity for investments made pursuant to the [PSEP] should be reduced to the incremental cost of debt.");
- ☐ References to PG&E's "poor management," and "management decisions and regarding its records and its untested pipeline [that] were neither efficient nor effective" serving as a justification for a reduction in ROE; and
- ☐ The conclusion that a five-year ROE reduction would "provide PG&E an incentive to improve its management efforts…"

Inexplicably, the midnight deletions executed by D.12-12-030 eliminate express discussion of *the Commission's* position regarding what effect, if any, PG&E's widespread natural gas system mismanagement should have on PG&E's entitlement to profits derived from PSEP investments. The Proposed Decision specifically recommends a five-year reduction in ROE for PG&E's PSEP investments. In D.12-12-030, the Commission abruptly concludes "[w]e, therefore, decline to adopt an adjustment to PG&E's return on equity for investments made pursuant to the [PSEP]."[37] The Commission does so without expressly adopting any novel reasoning or particular line of argument borrowed from the Parties in support of its position. In addition, there is no reference to ROE in the findings of fact or the conclusions of law set forth in D.12-12-030. The basis for the Commission's position on ROE in D.12-12-030 must be surmised. This lack of transparency concerning the ROE issue in D.12-12-030 also represents a material change in the resolution of the contested issue of ROE reductions.

For the reasons set forth above, the Commission's substantive revisions rendered D.12-12-030 an "alternate" within the meaning of Section 311(e) and Commission Rule 14.1(d). Comments filed in R.11-02-019, including PG&E's Opening Comments on the Proposed Decision, do not excuse the Commission from treating D.12-12-030 as an alternate. Section 311(e) and Commission Rule 14.2(d) require that an alternate decision be "filed with the

[37] D.12-12.030 at 106.

Commission and served on the official service list without undue delay." Per Section 311(e), an alternate "may not be rescheduled for consideration sooner than 30 days following service of the alternate item upon all parties." The Commission's failure to serve D12-12-030 as an alternate, and its consideration of D.12-12-030 the day after it was released to Parties constitute violations of Section 311(e) and Commission Rule 14(d).

B. The Commission's Notice Concerning D.12-12-030 Was Legally Insufficient

The Commission's Agenda was sufficiently misleading concerning the contents of D.12-12-030 to make the notice set forth therein legally deficient under the Bagley-Keene Act and Commission Rule 15.2(a). Government Code Section 11125(b) requires:

> The notice of a meeting of a body that is a state body shall include a specific agenda for the meeting containing a *brief description of the items of business to be transacted or discussed.* (emphasis added)

Commission Rule 15.2(a) similarly requires:

> At least ten days in advance of the Commission meeting, the Commission will issue an agenda listing the *items of business to be transacted or discussed* by publishing it, on the Commission's Internet website.[38] (emphasis added)

Decision 12-12-030 was item number 50 on the Commission's Public Agenda.[39] The agenda notice for Item 50 (the "Agenda Notice") provides:

> 50 [11661] **Decision Mandating the Pipeline Safety Implementation Plan**
>
> R11-02-019
> 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.
>
> **PROPOSED OUTCOME:**
>
> □ Approves Pacific Gas and Electric Company's (PG&E) Implementation Plan to pressure test 783 miles of natural gas pipeline, replace 186 miles, upgrade 199 miles to allow f[o]r in-li[n]e inspection, and install 228 automated val[v]es.
> □ Disallows $795.1 million of PG&E's requested $1,963.2 million rate request.

[38] Cal. Code of Regs, tit. 20, § 15.2(a).

[39] Public Agenda 3306 for December 20, 2010 Meeting, Item 50 (Published December 12, 2012). An electronic copy of this agenda notice can be found on the Commission's website as follows: https://ia.cpuc.ca.gov/agendadocs/3306.pdf (last visited January 28, 2013).

- ☐ Reduces PG&E's return on equity for these investments to 6.05% due to management inefficiency and ineffectiveness.

ESTIMATED COST

- ☐ $277,805,000.

(Comr Florio – ALJ Bushey)
Pub. Util. Code § 311 – This item was mailed for Public Comment
Pub. Util. Code § 1701.1 -- This proceeding is categorized as Ratesetting.

Rather than provide "a brief description" or "listing" of the "items of business to be transacted or discussed," the Agenda Notice for Item 50 adopts a misleading impression of the business transacted and discussed by the Commission in regards to ROE. On the one hand, the Agenda Notice lists and briefly describes a reduction in "PG&E's return on equity…due to management ineffectiveness" as a "Proposed Outcome." On the other hand, Decision 12-12-030 ultimately adopted by the Commission under Agenda Item 50 wholly rejects any form of ROE reduction. The discrepancy between the impression given by the Agenda Notice and the Commission adoption of the opposite position in D.12-12-030 renders the former insufficient to put the public on notice that a complete rejection of *any* ROE reduction is the actual item of business to be transacted or discussed by the Commission under Item 50.[40]

C. Rejection of a ROE Reduction is Not Supported by Substantial Evidence in the Record

The Commission's decision to allow PG&E to profit from PSEP investments is not supported by substantial evidence in the record of R.11-02-019. Section 1757.1 requires that Commission decisions be supported by findings.[41] Given this requirement, D.12-12-03's failure

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[40] The ROE reference is not the only misleading element of the Commission's Agenda Notice. The Commission's Agenda Notice also gives the false impression that D.12-12-030 was "mailed for Public Comment," consistent with California Public Utilities Code Section 311. As discussed in more detail in Section II, *supra*, D.12-12-030 was not mailed for public comment in accordance with Section 311 of the California Public Utilities Code. Although the Proposed Decision was served on the Parties to this proceeding, the significant modifications the Commission adopted in D.12-12-030 relative to the Proposed Decision make it an alternate decision and D.12-12-030 should have been served upon the parties separately as such. Also note that the version of D.12-12-030 provided to the public on the "Escutia Table" at the December 20, 2012 Commission Meeting furthered the erroneous impression that the Commission planned a ROE reduction, since it was still entitled, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Imposing Earnings Limitations, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering.* (emphasis added).

[41] *See* Decision 02-04-067 at 24, footnote 6 (April 22, 2002) (identifying Section 1757.1 as the applicable standard of review in a rulemaking).

to disclose the basis for the Commission's rejection of the Proposed Decision's five-year ROE reduction for PSEP investments is problematic in its own right.

Since D.12-12-030 does not make the basis for the Commission's ROE decision clear, the City presumes that Decision 12-12-030 rejects any ROE reduction for PSEP investments because of PG&E's claims that "drastically reducing the [ROE] harms the ratepayers in the long run by increasing borrowing costs and potentially diminishing the financial health of the utility."[42] There is no substantial evidence in the record to support PG&E's assertion to this effect. Support for D.12-12-030's rejection of an ROE reduction rests tenuously on conclusory statements made by the utilities that are the subject of the proceeding, rather than proven "facts" specific to the utility's claims.

Otherwise, there is no evidence in the record (1) that the temporary reduction in ROE would lead to a meaningful increase in borrowing costs, in this specific instance; (2) that any such increase in borrowing costs translates into meaningful impacts on ratepayers, and at what levels; (3) why an increase in PG&E's "borrowing costs" for a temporary period of five years is a less acceptable alternative for ratepayers than ratepayer funding for a ROE on PSEP investments that are necessary because of PG&E mismanagement; (4) how "potentially diminishing the financial health of the utility" specifically affects ratepayers, and what the specific magnitude of that affect may be; and (5) that a temporary reduction in ROE would significantly limit or otherwise prevent PG&E from successfully raising capital at a reasonable cost in practice. Instead, the record is replete with PG&E's generalized fears about the consequences of an ROE reduction, without pointing to specific instances in which a prior ROE reduction actually led to one of the outcomes the utility fears.[43] For these reasons, the Commission's determination that PG&E should be allowed to earn a profit on its PSEP investments is not supported by substantial evidence in the record.

D. The Commission Has Not Satisfied its Section 1705 Obligations

Decision 12-12-030 does not contain adequate findings of fact or conclusions of law concerning the Commission's decision to allow PG&E to earn a profit on its PSEP investments

[42] D.12-12-030 at 105.

[43] *See e.g,* PG&E Opening Brief at 84-85 (citing testimony in support of its contentions that simply echoes the conclusory statements PG&E makes in its brief without providing specific examples of instances in which the negative consequences the utility fears came to pass in connection with a ROE reduction of the magnitude suggested in the Proposed Decision).

to satisfy Section 1705. Section 1705 provides that Commission decisions must contain "separately stated, findings of fact and conclusions of law by the commission on all issues material to the order or decision."[44] Adequate findings and conclusions of law are necessary "to give reviewing courts a meaningful opportunity to ascertain the principles and facts relied on by the Commission in making the decision."[45] It is well settled that Commission findings are required in order to:

> [A]fford a rational basis for judicial review and assist the reviewing court to ascertain the principles relied upon by the commission and to determine whether it acted arbitrarily, as well as assist parties to know why the case was lost and to prepare for rehearing or review, assist others planning activities involving similar questions, and serve to help the commission avoid careless or arbitrary action.[46]

Indeed, the California Supreme Court has made clear that courts "must ensure that an agency has adequately considered all relevant factors, and has demonstrated a rational connection between those factors, the choice made, and the purposes of the enabling statute."[47] Decision 12-12-030 fails to serve this purpose with respect to the material issue of whether PG&E should be allowed to profit from its PSEP investments.

Decision 12-12-030 summarizes the arguments the Parties made concerning the Proposed Decision's five-year ROE reduction.[48] Without expressly adopting any novel reasoning or particular line of argument borrowed from the Parties, the Commission abruptly concludes "[w]e, therefore, decline to adopt an adjustment to PG&E's return on equity for investments made pursuant to the [PSEP]."[49] This is the sole reference to the Commission's position on the ROE issue in D.12-12-030. There is no reference to ROE in the findings of fact or the conclusions of law set forth in D.12-12-030.

Under no circumstances does the scant discussion of the Commission's position on a ROE reduction for PSEP investments "assist [a] reviewing court to ascertain the principles relied

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[44] *See also, al. Mfrs. Ass'n v. PUC,* (1979) 24 Cal. 3d 251, 258 (annulling decision for lack of findings).

[45] *Toward Utility Rate Normalization (TURN) v. California Public Utilities Commission*, 22 Cal. 3d 529, 540 (1978).

[46] *Mfrs. Ass'n v. PUC,* (1979) 24 Cal. 3d 251, 258-259.

[47] *See* D.01-10-031 at 5 (October 10, 2001) (citing *Calif. Hotel & Motel Assoc. v. Industrial Welfare Comm'n* (1979) 25 Cal.3d 200, 212).

[48] D.12-12-030 at 102-106.

[49] D.12-12.030 at 106.

upon by the commission."[50] Decision 12-12-030 never discloses the specific principles the Commission relied upon to justify its determination that PG&E should be permitted to earn a profit on PSEP investments. The absence of findings of fact and conclusions of law to support the Commission's determination that PG&E should be entitled to profit from PSEP investments also makes it impossible for a court to determine whether the Commission acted arbitrarily. The Commission's failure to state the basis for its ROE determination does nothing to "assist parties to know why the case was lost and to prepare for rehearing or review."[51] These deficiencies mean that D.12-12-030 fails to satisfy the Commission's obligations under Section 1705.

V. REQUEST FOR ORAL ARGUMENT

Pursuant to Commission Rule 16.3, the City respectfully requests oral argument concerning its Application for Rehearing. Given the issues raised by the City concerning the process that led to and rationale that forms the basis for D.12-12-030, a direct exchange of views via oral argument can be expected to "materially assist the Commission in resolving"[52] the City's Application for Rehearing. In addition, the City's Application for Rehearing "raises issues of major significance." Adequate public scrutiny of D.12-12-030 is a legal issue of significant "public importance."[53]

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[50] *Mfrs. Ass'n v. PUC,* (1979) 24 Cal. 3d 251, 258-259.
[51] *Mfrs. Ass'n v. PUC,* (1979) 24 Cal. 3d 251, 258-259.
[52] Commission Rule. 16(a).
[53] Commission Rule 16.3(a)(3).

VI. CONCLUSION

For the foregoing reasons, the City respectfully requests that the Commission grant the City's Application for Rehearing in order to remedy the legal errors in D.12-12-030 identified herein.

Respectfully submitted,

/s/ Steven R. Meyers
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January 28, 2013

Attorneys for CITY OF SAN BRUNO

2037781.3

EXHIBIT A

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report: October 12, 2012
(Date of earliest event reported)

Commission File Number	Exact Name of Registrant as specified in its charter	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640

PG&E Corporation.
77 Beale Street
P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 267-7000
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting Material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events

California Public Utilities Commission ("CPUC") Rulemaking Proceeding

The CPUC is conducting a rulemaking proceeding to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. In the rulemaking proceeding, the CPUC is considering proposed implementation plans that were filed in August 2011 by Pacific Gas and Electric Company (the "Utility") and other California natural gas pipeline operators. As directed by the CPUC, the Utility also submitted proposed ratemaking mechanisms to allocate plan costs between ratepayers and shareholders. Several parties, including the CPUC's Division of Ratepayer Advocates and The Utility Reform Network, opposed various aspects of the Utility's proposals. On October 12, 2012, the CPUC administrative law judge ("ALJ") overseeing the proceeding issued a proposed decision regarding the Utility's proposed plan, cost forecasts, and ratemaking mechanisms.

The Utility's proposed implementation plan consists of two major programs, a pipeline modernization program (including valve automation) and a pipeline records integration program. The Utility has proposed to carry out the plan in two phases; the first phase began on January 1, 2011 and the second phase will begin on January 1, 2015. In its application, the Utility forecasted that its total plan-related costs over the first phase would be approximately $2.2 billion, including $1.4 billion in capital expenditures and $750 million in expenses. The Utility requested that the CPUC approve the scope and timing of projects proposed in the plan and authorize the Utility to recover its forecasted capital expenditures. The Utility proposed that most plan-related expenses incurred from 2012 through 2014 be recovered through rates but the Utility did not seek recovery of plan-related expenses for 2011 (forecasted to be $220.7 million).

In general, the ALJ recommends approval of the Utility's plan, but proposes to limit recovery of expenses to $166.6 million (plus $77.4 million for two months in 2012) and to limit recovery of capital expenditures to $1 billion. The reduced amounts reflect the ALJ's recommendation to prohibit the Utility's recovery of any costs incurred before the effective date of the final decision which the ALJ assumes is November 1, 2012. Assuming a final decision is not issued until after December 31, 2012, the Utility would be unable to recover 2011 and 2012 expenses. Under the proposed decision, the Utility would be unable to recover any costs in excess of the adopted capital and expense amounts and the adopted amounts would be reduced by the cost of any plan project not completed and not replaced with a higher priority project. In addition, the ALJ recommends that the Utility's rate of return on equity ("ROE") for capital investments made under the plan be reduced to the cost of debt, currently 6.05%, for the first five years that the investment is included in utility plant in service. The Utility estimates that the lower rate of ROE would reduce total after-tax equity earnings over the relevant period by approximately $130 million based on the ALJ's recommended capital costs and compared to the 11% rate requested in the Utility's pending cost of capital proceeding.

The following table compares the Utility's requested expense and capital amounts with the ALJ's recommended amounts and shows the total estimated reduction in equity earnings over the relevant period based on the ALJ's ROE recommendation:

(in millions)	2011	2012	2013	2014	Total
Expense					
Requested	$220.7 (1)	$231.1	$154.8	$143.9	$750.5
ALJ's recommendation	0	(2)	$73.8	$92.8	$166.6
Difference	(1)	$231.1	$81	$51.1	$583.9
Capital					
Requested	$68.9	$384.3	$480.3	$499.9	$1433.4
ALJ's recommendation	$47.2	$265.2	$352.9	$367	$1032.3
Difference	$21.7	$119.1	$127.4	$132.9	$401.1
ROE					
Estimated total after-tax reduction in equity earnings based on ALJ's recommended rate of ROE and recommended lower capital amounts over the relevant period					$130

(1) The Utility's August 2011 application did not request recovery of forecast 2011 plan-related expenses of $220.7 million.
(2) The ALJ assumed a November 1, 2012 effective date, but the table above assumes a delayed effective date resulting in no recovery of 2012 expenses.

The ALJ states that the ratemaking recovery authorized in the rulemaking decision, if the proposed decision is adopted by the CPUC, would be subject to refund, noting the possibility that further ratemaking adjustments may be made in the pending CPUC investigations in which the CPUC will address potential penalties to be imposed on the Utility. Comments on the proposed decision are due on November 13, 2012; reply comments are due on November 26, 2012.

The Utility has incurred costs of $483 million in 2011 and $232 million for the six months ended June 30, 2012 for work to validate safe pipeline operating pressures and conduct strength testing, as well as legal and other expenses related to natural gas matters. The costs the Utility has incurred through June 30, 2012 include costs that fall within the amount the Utility requested that the CPUC authorize as a contingency allowance. At June 30, 2012, the Utility also had incurred plan-related capital costs of approximately $95 million. Disallowed capital investments will be charged to net income in the period in which the CPUC orders such a disallowance. Future disallowed expense and capital costs would be charged to net income in the period incurred.

The ultimate amount of pipeline-related costs that the Utility will be allowed to recover from customers will be affected by various factors, including the terms of the CPUC's final decision on the Utility's plan, the outcome of the CPUC's pending investigations discussed below, and the terms of a potential settlement, if any, that may be reached in the pending CPUC proceedings. PG&E Corporation's and the Utility's financial results also will be impacted by additional costs the Utility will incur to address any other pipeline matters identified by the Utility or to comply with new regulatory or legislative requirements.

Order Suspending Hearings in CPUC's Pending Investigations

On October 11, 2012, an order was issued to suspend, until November 1, 2012, the procedural schedule for evidentiary hearings and briefing in three CPUC investigations involving the Utility. The CPUC investigations relate to (1) the Utility's safety recordkeeping for its natural gas transmission system ("Records OII"), (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density ("Class Location OII"), and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the rupture of one of the Utility's natural gas transmission pipelines on September 9, 2010 in San Bruno, California and the ensuing explosion and fire ("San Bruno OII"). The suspension order was requested by the CPUC's Consumer Protection and Safety Division ("CPSD") on October 5, 2012, in order to enable the parties to continue to engage in negotiations to reach a stipulated outcome of these proceedings. The CPSD is required to submit a status report on the negotiations on October 25, 2012.

The revised schedule, which supersedes the schedule set on September 25, 2012, is set forth below. The order states that the briefing schedule for the Records OII, the San Bruno OII, and the financial resources issues, will be determined at a later date, if needed.

Date	Class Location OII	Records OII	San Bruno OII	Consolidated Issues
November 9	Concurrent opening briefs due			Intervener's supplemental testimony regarding financial resources due
November 19	Concurrent reply briefs due			The Utility's reply testimony on financial resources due(1)
November 26		Evidentiary hearings resumed	Evidentiary hearings resumed	Evidentiary hearing on financial resources analysis (if necessary)
December 6		Evidentiary hearings concluded on or before this date	Evidentiary hearings concluded on or before this date	
January 8, 2013				Evidentiary hearings concluded on or before this date

(1) After the parties review the Utility's reply testimony, the CPSD may request an opportunity to provide rebuttal testimony before the hearing on January 8, 2013.

PG&E Corporation and the Utility are uncertain whether the parties will reach an agreement to a stipulated outcome of these proceedings. Any agreement that may be reached would be required to be submitted to the CPUC for its consideration.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned hereunto duly authorized.

PG&E CORPORATION

Dated: October 12, 2012

By: LINDA Y.H. CHENG
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 12, 2012

By: LINDA Y.H. CHENG
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

EXHIBIT B

Regular Agenda - Energy Orders (continued)

50 **Decision Mandating the Pipeline Safety Implementation Plan**
[11661]

R11-02-019
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.

PROPOSED OUTCOME:

- Approves Pacific Gas and Electric Company's (PG&E) Implementation Plan to pressure test 783 miles of natural gas pipeline, replace 186 miles, upgrade 199 miles to allow far in-live inspection, and install 228 automated values.
- Disallows $795.1 million of PG&E's requested $1,963.2 million rate request.
- Reduces PG&E's return on equity for these investments to 6.05% due to management inefficiency and ineffectiveness.

ESTIMATED COST:

- $277,805,000.

(Comr Florio - ALJ Bushey)
Pub. Util. Code § 311 – This item was mailed for Public Comment.
Pub. Util. Code §1701.1 -- This proceeding is categorized as Ratesetting.

EXHIBIT C

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.	Rulemaking 11-02-019 (Filed February 24, 2011)

DECLARATION OF BRITT K. STROTTMAN IN SUPPORT OF THE APPLICATION FOR REHEARING OF DECISION 12-12-030 BY THE CITY OF SAN BRUNO

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Attorneys for CITY OF SAN BRUNO

January 28, 2013

DECLARATION OF BRITT K. STROTTMAN

1. I am an attorney admitted to practice law in the State of California and serve as Special Counsel for the City of San Bruno, California ("San Bruno"). I make this declaration in support of the San Bruno's Application for Rehearing of Decision 12-12-030. I have personal knowledge of the following facts and if called as a witness I could and would testify competently thereto.

2. On December 19, 2012, at around 7:30 p.m., I checked the California Public Utilities Commission ("CPUC") website for an Alternate Decision on Pacific Gas and Electric Company's Pipeline Safety Enhancement Plan in R.11.02.019. I could not locate an Alternate Decision after a diligent search.

3. On December 20, 2012, at around 7:52 a.m., I checked the CPUC website again for an Alternate Decision in R.11.02.019 and couldn't locate one.

4. On December 20, 2012, at around 8:45 a.m., I serendipitously located a copy of the Alternate Decision 12-12-030 in R. 11.02.019 on the "Escutia table" at CPUC's headquarters in San Francisco, California. As Special Counsel for San Bruno, I didn't have notice of Alternate Decision 12-12-030 until fifteen minutes before the CPUC meeting and vote on the Final Decision in R.11.02.019 on December 20, 2012.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct. Executed this 28th day of January 2013 in Oakland, California.

Britt K. [signature]

Britt K. Strottman

2040386.1

EXHIBIT D

ALJ/MAB/avs/jt2 **DRAFT** **Agenda ID #11661 (Rev. 1)**

Ratesetting

12/20/2012 Item 50

Decision PROPOSED DECISION OF ALJ BUSHEY **(Mailed 10/12/2012)**

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.	Rulemaking 11-02-019 (Filed February 24, 2011)

12/19 5:00 p.m.

(See Attachment A for Appearances)

DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, IMPOSING EARNINGS LIMITATIONS, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ONGOING IMPROVEMENT IN SAFETY ENGINEERING

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DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, IMPOSING EARNINGS LIMITATIONS, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ONGOING IMPROVEMENT IN SAFETY ENGINEERING

Summary

This decision requires Pacific Gas & Electric Company (PG&E) to continue its work towards becoming a safe natural gas transmission system operator. The specific actions we authorize and direct today are essential steps on a permanent safety journey that PG&E, its officers, employees, and shareholders, must internalize as a part of every action they will take over the decades that the natural gas pipeline system will be in place. The inherent danger to the public created by a natural gas transmission and distribution system requires a profound and unwavering commitment to safe operations. As described in detail below, the record shows evidence that, at one time, PG&E had the corporate ability and focus to go beyond nominal regulatory compliance to propose and create a long-term engineering-based safety program for the Commission's consideration. The current challenge to PG&E, and this Commission, is that attaining the goal of future decades of safe operations will require detailed, repetitive, and often seemingly unnecessary actions, which are likely to be expensive, with the overall goal of no significant incidents. Ensuring public safety requires that PG&E meet this commitment, and today's decision lays the groundwork for this Commission to oversee and supervise PG&E's safety operations.

corporate operations as well as external events, such as trenching work by other entities, to capture cost-effective safety improvement opportunities. We will require PG&E to demonstrate that its proposed safety investments provide good value to California's families and businesses. We also require PG&E to update its Pipeline data base after the conclusion of its Maximum Allowable Operating Pressure validation and record search effort.

Today's decision evaluates the projects PG&E proposes in its Implementation Plan and establishes forward-looking rates for PG&E's natural gas system operations. Our upcoming decisions in Investigations (I.) 11-02-016, I.11-11-009, and I.12-01-007 will address potential penalties for PG&E's actions under investigation. We do not foreclose the possibility that further ratemaking adjustments may be adopted in those investigations; thus, all ratemaking recovery authorized in today's decision is subject to refund.

1. Background

Pursuant to Pub. Util. Code § 451, each public utility in California must "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities, . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Ensuring that the management of investor-owned gas utility systems fully performs its duty of safe operations is a top priority of this Commission,

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[2] As set forth below, these amounts will be updated in accordance with today's decision.

D. Consider ways that this Commission can undertake a comprehensive risk assessment for all natural gas pipelines regulated by this Commission, and possibly for other industries that the Commission regulates.

E. Consider available options for the Commission to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the "nuts and bolts" details of prudent utility operations.

F. Consider the appropriate balance between the Commission's obligation to conduct its proceedings in a manner open to the public with the legitimate public safety concerns that arise from unlimited availability of certain utility information.

G. Consider if we need further rules or other protection for whistleblowers to inform the Commission of safety hazards.

H. Expand our emergency and disaster planning coordination with local officials.

On September 23, 2010, the Commission created an Independent Review Panel of experts to conduct a comprehensive study and investigation of the September 9, 2010, explosion and fire. The Commission directed the Panel to make a technical assessment of the events, determine the root causes, and offer recommendations for action by the Commission to best ensure such an accident is not repeated elsewhere. The Commission encouraged the Panel to make such recommendations as necessary. Such recommendations could include changes to design, construction, operation, maintenance, and replacement of natural gas facilities, management practices at Pacific Gas and Electric Company (PG&E) in the areas of pipeline integrity and public safety, regulatory changes by the Commission itself, and statutory changes to be recommended by the recommendations include instituting state-of-the-art risk analysis to evaluate the likelihood of various possible failures and to establish a culture of pipeline integrity. The Independent Review Panel's recommendation 5.4.4.5 captures the comprehensive and long-term perspective needed, and is the source of our description of safety as journey:

> PG&E should develop and adopt a maturity framework that reflects the importance and advancement of thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise, where progress is transparent and measurable, and is consistent with the best thinking on pipeline integrity and process safety management.

The Independent Review Panel declared that the goal of natural gas pipeline engineering design is zero significant incidents. To attain this goal, the pipeline operator must consistently practice the following:

1. Identify pipeline segments and threats; assume threats to exist until demonstrated otherwise;
2. Inspect and assess the segments;
3. Mitigate and/or remediate identified threats; and
4. Generate new data and analysis, then repeat entire process.[5]

The Independent Review Panel Report concluded that PG&E's Integrity Management Program lacked effective executive leadership, and that "perpetual organizational instability," including corporate bankruptcy, had undermined PG&E's ability to meet its integrity management responsibilities.[6] The Panel found that PG&E had excessive levels of management, comprised largely of

[5] Independent Review Panel Report at 65-66.

[6] Independent Panel Report at 50, 73.

- Require PG&E to correct all deficiencies identified as a result of the San Bruno, California, accident investigation, as well as any additional deficiencies identified through the comprehensive audit recommended in Safety Recommendation (P-11-22.), and verify that all corrective actions are completed. (P-11-23.)

Among the many recommendations for PG&E, the NTSB issued this comprehensive directive regarding PG&E's integrity management program and risk analysis:

- Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum, (1) a revised risk model to reflect PG&E's actual recent experience data on leaks, failures, and incidents; (2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed; (3) a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and (4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment. (P-11-29.)
- Conduct threat assessments using the revised risk analysis methodology incorporated in your integrity management program, as recommended in Safety Recommendation (P-11-29), and report the results of those assessments to the California Public Utilities Commission and the Pipeline and Hazardous Materials Safety Administration. (P-11-30.)

Since opening this rulemaking, our primary efforts have been focused on ensuring that California's natural gas transmission system operators are properly

In D.11-06-017, the Commission also described the natural gas system records examination project set in motion by the NTSB upon discovering that PG&E's records for Line 132 were inconsistent with the actual pipeline found in the ground in Line 132. This Commission adopted the NTSB's recommendation to require natural gas system operators to obtain "traceable, verifiable, and complete" records and, with reliably accurate data, calculate a dependable MAOP.[12] In response, PG&E and Southern California Gas Company (SoCalGas)/San Diego Gas & Electric Company (SDG&E) explained that such records were often not available, especially for the older vintage pipelines.

After review of the detailed record both in this proceeding and before the NTSB regarding the records and vintage pipeline, the Commission concluded that the historic exemption and the utilities' record-keeping deficiencies had resulted in circumstances inconsistent with the safety, health, comfort, and convenience of utility patrons, employees, and the public. The Commission ordered all natural gas transmission pipelines in service in California to be brought into compliance with modern standards for safety, and that all California natural system operators file and serve a proposed Implementation Plan to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c).

The Commission required that the Implementation Plans include interim safety enhancement measures, and that the analytical focus be a list of all transmission pipeline segments that have not been previously pressure tested,

[12] Commission Resolution L-410; NTSB Safety Recommendation P-10-2 and -3 (Urgent) and P-10-4 (January 3, 2011).

necessary safety improvements, and the Commission encouraged customers to participate in the process for reviewing the Implementation Plans.

In today's decision, we only consider PG&E's Implementation Plan.[14]

2. Description of PG&E's Proposed Natural Gas Transmission Pipeline Pressure Testing Implementation Plan

On August 26, 2011, PG&E filed and served its Implementation Plan. The Implementation Plan is comprised of two major programs, the first focused on pipeline segments and a second program to improve pipeline records.

The first program, PG&E's Pipeline Modernization Program, provides for testing, replacing, reducing operating pressure, conducting in-line inspections as well as retrofitting to allow for in-line inspection, and adding automatic or remotely-controlled shut-off valves. The second program, the Pipeline Records Integration Program will enable PG&E to finish its records review and establish complete pipeline features data for the gas transmission pipelines and pipeline system components, and the Gas Transmission Asset Management Project, a substantially enhanced and improved electronic records system.

Each of the two major Implementation Plan programs are described below, followed by discussion of the cost for each program.

2.1. Pipeline Modernization Program

As part of its August 26, 2011, filing, PG&E included its Pipeline Modernization Program to comply with the Commission's requirement that all California natural gas transmission pipeline be pressure tested or replaced. PG&E's Pipeline Modernization Program provides for two phases. Phase 1

[14] In D.12-04-021, the Commission transferred consideration of SoCalGas and SDG&E's Implementation Plans to A.11-11-002.

Manufacturing Related Threats

With pipeline manufactured from the 1930's to the present, PG&E states that its pipeline segments were fabricated using the manufacturing technology available at the time. Federal regulations adopted in 1971 improved safety standards for manufacturing and testing. Generally, pipeline manufactured before 1971 with certain types of longitudinal welds is considered to have a manufacturing threat. The decision tree requires replacement of all pipeline segments that have not been pressure tested in accord with current federal regulations that operate at or equal to 30% SMYS, and are located in urban populated areas. Segments operating below 30% SMYS and in urban populated areas are slated for pressure testing. Untested pipelines located in rural settings will be pressure tested in Phase 2, unless found to be susceptible to fatigue induced crack growth; then such pipeline segments will be tested in Phase 1.

Fabrication and Construction Threats

For fabrication and construction threats, PG&E uses 1960 as the date when industry standards and Commission regulations significantly improved fabrication and construction standards. Pipeline segments from before 1960 are subject to further review in the decision tree. First, pipeline segments with certain types of bends, couplings, nonstandard fittings, or an excessive number of short pieces of pipeline joined together, will receive an Engineering Condition Assessment to determine whether to replace the pipeline segment. Second, pipeline segments operating at or above 30% SMYS and with specific types of welds, will be removed from service or pressure tested and in-line inspected. Third, pipeline segments that have not been pressure tested and are operating at more than 30% SMYS in densely populated areas will be pressure tested and use fully automated valves that are independently triggered by controls at the valve site only in highly populated areas where the pipeline crosses an earthquake fault. Both types of valves can be easily converted from one type of operation to the other.

PG&E proposes to adopt interim safety enhance measures while it puts in place the measures called for in the Implementation Plan. PG&E currently has in place pressure reductions on approximately 380 miles of pipeline in high consequence areas, and 1,300 miles of pipeline in non-high consequence areas. The decision tree in the Pipeline Modernization Program also calls for additional pressure reductions.

PG&E has increased leak inspections and patrols. PG&E will conduct leak surveys six times per year on all gas pipeline segments included in the Implementation Plan and which lack pressure test records. PG&E will continue patrolling its backbone transmission system on a monthly basis, and the local transmission pipelines will be patrolled 6 times per year.

2.2 Pipeline Records Integration Program

As noted above, the Records Integration Program provides for continuing the document collection, review and verification process underway since the January 3, 2011, pursuant to the NTSB directives. PG&E proposes to assemble these records in a new electronic records management system called the Gas Transmission Asset Management Project. PG&E states that the goal of this project is to provide improved access to detailed pipeline component information for the 6,761 miles of its gas transmission system, of which over 72% was installed prior to 1970.

PG&E states that it will begin by entering critical pipeline information into its existing Geographic Information System from source documentation.

2. Improve traceability and verification of asset data by providing links to source documents;
3. Improve integrity and risk analysis, as well as better schedule inspection and maintenance;
4. Provide the field work force with mobile tools that allow remote access to existing asset information, and to update electronically new maintenance and inspection information; and
5. Offer a data management platform capable of addressing any new recordkeeping obligations in the future.

PG&E plans to do this work in four distinct phases over approximately 3.5 years and expects tangible improvements over the entire time frame. PG&E expects to complete the project in early 2015.

2.3. Costs of the Pipeline Modernization and Pipeline Records Integration Programs, Including Management and Contingency

Requested Revenue Requirement Increases

PG&E requests the following increase over its existing authorized revenue requirement for Implementation Plan costs to be recovered from ratepayers:

2012	2013	2014	TOTAL
$247,279,000	$220,833,000	$300,641,000	$768,753,000

PG&E proposes to use currently authorized cost allocation to allocate these costs among Local Transmission, Backbone Transmission, and Storage, in place pursuant to the Gas Accord V Settlement in D.11-04-031.

The following is a breakdown of the components of PG&E's revenue requirement increase request.

incurred in 2011. PG&E is seeking Commission authorization to include in revenue requirement a total of $107. 1 million for recovery from ratepayers for costs related to 2012 and 2013 records validation.

Gas Transmission Asset Management Project

PG&E estimates that during 2012, 2013, and 2014, it will spend $115.7 million for this computer data base system upgrade, which it proposes to include in revenue requirement. PG&E is not seeking recovery from ratepayers for $7.9 million expended in 2011.

Valves

PG&E estimates that its valve automation program will cost a total of $143.6 million in 2011 through 2014. Of that amount, PG&E shareholders will fund $15.3 million. The remaining $128.3 million which PG&E requests authorization to include in revenue requirement is comprised of $118.8 million in capital and $9.5 million in expenses for 2012, 2013, and 2014.

Interim Measures

In D.11-06-017, the Commission directed PG&E to take interim measures to enhance safety. Those measures include pressure reductions and increased patrols of pipeline. PG&E estimates that these measures will cost $1.0 million in 2012, and $1.1 million in each of 2013 and 2014. All of the costs are expenses.

Contingency

PG&E presented testimony calculating a risk-based contingency cost forecast for its entire Implementation Plan programs. PG&E requested Commission approval of a total of $380.5 million as a risk-based allowance. This amount covers costs expected to be incurred in 2011, 2012, 2013, and 2014. Of the total, $247.3 million is capital costs and $133.2 million is expense.

ensure compliance with applicable standards, and (4) PG&E Business Planning and Coordination will provide end-user input and operational advice, including specific business requirements for component projects.

Shareholder Cost Responsibility

As required by D.11-06-017, PG&E included a proposal for shareholders to absorb a portion of the Implementation Plan costs. PG&E proposed that shareholders pay the costs associated with activities in 2011, $222.1 million, and the costs of validating the MAOP or pressure testing pipeline segments installed after 1970, $97.7 million. PG&E also added in $215.4 million in 2010 and 2011 expenses related to document review, answering information and data requests, and responding to investigations by the NTSB, this Commission and the Independent Panel. Although PG&E proposes that shareholders fund the 2011 revenue requirements associated with 2011 capital costs, PG&E proposes to allocate the future revenue requirements for these capital costs to ratepayers. PG&E's tabulation of the total amount to be absorbed by shareholders is $535.2 million. PG&E states that a one-time upfront shareholder assessment is preferable to an on-going disallowance because it reduces the uncertainty about the ultimate cost of the disallowance.

PG&E's Rationale for Revenue Requirement Increase

PG&E argues that its Implementation Plan will make the gas system safer and more reliable for years to come, support future growth, and keep energy costs reasonable.[17] PG&E states that its plan meets all the Commission's requirements, and does so in the most economical, least disruptive, and safest manner.

[17] PG&E Opening Brief at 2 – 4.

DRA begins with the fundamental premise of test year ratemaking that revenue requirement is not adjusted after the test year has been adopted, regardless of whether costs turn out to be higher or lower than adopted in the test year. DRA points out that the Overland report[18] found that PG&E enjoyed several years where its profits were higher than anticipated in the test year revenue requirement, which PG&E shareholders retained, and that the unanticipated costs of the Implementation Plan should similarly be borne by PG&E shareholders without an increase in rates. DRA concludes that PG&E bears the burden of justifying its proposed rate increase as just and reasonable, and that it has not.

Turning to specific costs in the Implementation Plan, DRA argues that PG&E shareholders should be responsible for the costs of pressure testing all pipeline installed after 1935. DRA argues that pressure testing pipeline prior to placing it in service has been industry standard practice since 1935, and that PG&E should have complied with this practice and retained the records of such tests. DRA contends that even though the 1961 Commission and 1970 federal pressure testing directives did not require testing of pipe already in service, this exclusion did not override the industry practice of testing. DRA states that PG&E has agreed that it began in 1955 following industry standards for pressure testing pipeline prior to placing the pipeline in service. Consequently, DRA recommends that where pipeline installed prior to 1955 must be replaced due to

[18] Hearing Exh. 42: Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures For the Period 1996 to 2010, Overland Consulting (December 30, 2011), which concluded that PG&E's gas and storage operations have been very profitable since March 1998, and that PG&E's gas revenues have exceeded the amount needed to earn the authorized rate-of-return by $430 million.

Implementation Plan included unnecessary upgrades in pipeline diameter (37% of the replaced pipeline has an increased diameter) and excessive modifications for in-line inspection tools.

DRA challenges as too high PG&E's cost forecasts for pressure testing. DRA explains that PG&E used estimated fixed and variable costs to forecast the total costs for its hydrotesting projects. DRA analyzed each cost component and concluded that PG&E had not adequately justified a majority of the proposed costs. DRA particularly challenged PG&E's forecast of fixed costs as being without evidentiary support. DRA compared PG&E's mobilization/demobilization surcharge of $500,000 for each pressure test, for which DRA contended PG&E provided no supporting calculations, to its own specific calculations based on actual PG&E cost data which resulted in a cost forecast of between $85,600 and $139,400, depending on the size of the pipeline to be tested. DRA similarly challenged PG&E's indirect cost calculations, 31% of direct costs, and found little support for the assumptions used by PG&E. For example, DRA shows that PG&E added a 5% construction management fee plus a 2.5% project management fee, all in addition to the requested $415 million for the Program management office. Overall, DRA recommended that the Commission adopt substantially reduced fixed and variable hydrotest cost forecasts for the PG&E Implementation Plan.

DRA further recommends a cost escalation rate of 1.1% to 1.5%, rather than PG&E's 3.12%.[20]

[20] Hearing Exh. 147 at 1-16 to 1-17.

program because the valves are not required by the Commission's 2011 decision and the costs are highly speculative.

DRA's final recommendations include putting all Implementation costs into a memorandum account pending further review of the Commission, several directives for the record review process, and denying PG&E's request to use a Tier 3 advice letter for any cost overruns.

3.2. The Utility Reform Network (TURN)

Like DRA, TURN recommended that the Commission issue a comprehensive disallowance from recovery in rates of all costs in the Implementation Plan Phase 1. TURN argued that Pub. Util. Code § 463(a)[21] requires the Commission to disallow costs when PG&E cannot produce adequate competent records, and that disallowances for imprudently incurred costs serve the important purpose of deterring imprudent management actions. TURN argues that the standard of prudence for natural gas transmission system operators is a high standard due to the inherently dangerous nature of natural gas. TURN also notes that public utilities are not entitled to a presumption of prudence but rather, PG&E bears the burden of proving that all of its actions were prudent. TURN also opposed final ratemaking treatment for any of the costs included in the Implementation Plan before the Commission issues final

[21] Pub. Util. Code, § 463(a) provides that: "For purposes of establishing rates for any electrical or gas corporation, the commission shall disallow expenses reflecting the direct or indirect costs resulting from any unreasonable error or omission relating to the planning, construction, or operation of any portion of the corporation's plant which cost, or is estimated to have cost, more than fifty million dollars ($50,000,000), including any expenses resulting from delays caused by any unreasonable error or omission. Nothing in this section prohibits a finding by the commission of other unreasonable or imprudent expenses."

elements - test medium, duration, and pressure - but do not show the test operator's name. PG&E proposes to have ratepayers fund pressure testing for pipelines with pressure test records that lack the operator name but do have all three required elements. TURN contends that the rules in effect at the time for pressure tests, G.O. 112, only required test medium, duration, and pressure, and not operator name. Thus, shareholders should fund any hydrotests for pipeline installed in that time frame for which PG&E does not have the required elements. TURN comments that any re-testing required to bring such pipeline up to current standards (i.e., with operator name and an eight hour duration) should be included in Phase 2.

TURN also challenges PG&E's assumption that when PG&E lacks a valid pressure test record for pipeline which was required to be pressure tested prior to being placed in service, and the decision tree action plan is pipeline replacement, the ratepayers should fund the replacement. TURN contends that the missing record moves the pipeline into the decision tree as requiring action, and therefore PG&E should not be exculpated for its missing records solely because the logical outcome is replacement rather than pressure testing.

TURN recommends a series of changes to the Implementation Plan to re-prioritize segments and to increase the use of hydrotesting instead of replacement. TURN states that Class 2 non-High Consequence Area segments should be moved from Phase 1 to Phase 2. TURN advocates for pressure testing rather than replacing pipeline operating at over 30% SMYS, and questioned the 237 miles of pipeline being included for pressure testing due to engineering efficiencies. TURN supports exempting from the Commission's 2011 test or replace requirement all pipeline operating at less than 30% SMYS. TURN transmission pipeline, with about 500 miles of transmission pipeline. The Commission routinely approved the ratemaking requests for this program from 1985 to 2000, and PG&E replaced an average of 24.1 miles of transmission pipeline each year. In 2000, however, the remaining 212.3 miles of transmission pipeline were transferred out of the Gas Pipeline Replacement Program into the Risk Management Program, where about 4.4 miles per year were replaced through 2010, leaving a pipeline replacement deficit of about 160 miles, including lines 109 and 132.[25] TURN finds this as strong evidence of imprudent system management caused by PG&E prioritizing cost cutting. TURN concludes that PG&E shareholders should absorb the $720 million for replacing these pipelines or, at a minimum, the Commission should use this evidence of imprudent management to reduce PG&E's return on equity.

TURN next addresses PG&E's two-part Pipeline Records Integration Program, and recommends that the Commission disallow rate recovery for the costs of both parts. TURN explains that PG&E's record review process to ensure that its pipeline records are complete and accurate originated with the NTSB report on the San Bruno tragedy which found that PG&E's records were factually inaccurate for the pipeline involved. TURN concludes that PG&E's program to restore accuracy and reliability was needed to remedy record-keeping deficiencies that PG&E should not have allowed to happen.

TURN disputes PG&E's claim that the traceable, verifiable, and complete standard set forth by the NTSB and adopted by the Commission is a new regulatory requirement. TURN argues that accurate and reliable records of

[25] Lines 109 and 132 are located on the San Francisco peninsula, and a segment of Line 132 ruptured in San Bruno.

explains that PG&E offered little supporting rationale for its decision to include Class 2 locations in Phase 1 of its Implementation Plan, in light of the Commission's 2011 directive to prioritize Class 3 and 4 areas, and only high consequence areas of Class 1 and 2. TURN concludes that postponing the Class 2 areas that are not high consequence areas to Phase 2 could save about $162 million in current pipeline replacement costs and $71 million in testing costs.

TURN opposes PG&E's decision to determine that pressure test records which lack the name of the operator should be considered incomplete and re-tested. TURN seeks either shareholder funding for these re-tests due to lack of records or accepting the records without the signature.

TURN takes issue with PG&E's decision to replace rather than hydrotest all pipeline operating at high pressures.[27] TURN argues that the default assumption in PG&E's decision tree that all pipeline which has not been pressure tested and is or is expected to operate at high pressure must be replaced, leads to unnecessary replacement capital costs of $427.5 million. TURN recommends requiring PG&E to put forward a location-specific justification for replacement, rather than assuming all such locations will be replaced rather than pressure tested.

3.3. City of San Bruno

The City of San Bruno challenges the Commission to bring renewed and meaningful regulatory oversight to PG&E to restore badly damaged public

[27] Such pipeline would operate at or over 30% of its Specified Minimum Yield Strength (SMYS), or about a third of the pressure expected to cause the pipeline to become permanently deformed.

definition of quality control and quality assurance that goes beyond mere compliance.

The City implores the Commission to exercise stronger oversight over PG&E's management and execution of the Implementation Plan. The City emphasizes the critical role of CPSD to ensure that PG&E adheres to the Plan, and it makes needed program reporting to all municipalities and counties where residents are affected by timely completion of the work. The City concludes that PG&E and the Commission must take specific steps beyond the Implementation Plan to improve emergency preparedness and community outreach.

3.4. City and County of San Francisco (San Francisco)

San Francisco contends that PG&E's Implementation Plan needs technical improvements because it is unclear that the most pressing work will be performed first. San Francisco points to the decision tree as based on inaccurate data and lacking the best analysis available. San Francisco recommends that the Commission reject the Implementation Plan, order PG&E to start testing or replacing 630 miles of pipeline in high consequence areas, and re-run all decision tree analyses with updated data from the records review.

San Francisco opposes allowing PG&E any rate recovery for its record review or new computer data base program, as PG&E has always had an obligation to keep accurate records. San Francisco strenuously objects to PG&E's cost sharing proposal as unfairly burdening ratepayers with PG&E's costs of coming into compliance with the pre-exist regulatory requirements.
San Francisco contends that PG&E should pay for testing or replacement of the all pipeline installed after 1955, and that any revenue the Commission authorizes PG&E to recover from ratepayers should be subject to refund.

Implementation Plan costs alone will comprise 52% of PG&E's gas transmission and storage revenue requirement.[29] NCIP recommends disallowing all remedial costs, such as record-keeping, and reducing the return on equity by 500 basis points to the cost of debt, i.e., from 11.35% to 6.35%.[30] NCIP supports an end-user surcharge as the most appropriate means to recover the Implementation Plan costs because the purpose of the Implementation Plan is to enhance the safety of the public with regard to natural gas facilities. NCIP also put forward a cost allocation proposal which would allocate more costs to noncore customers than the current allocation methodology, and argues that overly allocating to gas transportation customers, such as electric generators, will lead to increased rates for electricity.

3.8. Southern California Edison Company (EDISON)

Edison argues that the proposals to reduce PG&E's return on equity or disallow capital cost recovery will harm ratepayer interests by increasing the cost of borrowing capital to make the needed safety enhancements. As a natural gas customer of SDG&E and SoCalGas, Edison also emphasizes that the cost allocation adopted for PG&E should not be regarded as precedent for the other gas utilities' Implementation Plans.

3.9. SDG&E and SoCalGas

These natural gas system operators ask the Commission to refrain from ruling on whether the NTSB description of traceable, verifiable, and complete is a new recordkeeping standard, and that the Commission should consider historic recordkeeping and pressure test standards and practices in the industry. These

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[29] NCIP Opening Brief at 1.

[30] Hearing Exh. 123 at 25.

PG&E must meet the burden of proving that it is entitled to the relief sought in this proceeding, and PG&E has the burden of affirmatively establishing the reasonableness of all aspects of the application.[31]

With the burden of proof placed on PG&E, the Commission has held that the standard of proof PG&E must meet is that of a preponderance of evidence. Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth'"[32] In short, PG&E must present more evidence that supports the requested result than would support an alternative outcome.

We have analyzed the record in this proceeding within these parameters.

5. Discussion

Our evaluation of PG&E's proposed Implementation Plan requires that we address broad policy issues as well as specific project cost issues. In the first section below, we analyze the overarching safety challenges confronting PG&E and our assessment of PG&E's current operations and set a course for future PG&E natural gas system operations. In the second section below, we address the specific project proposals in PG&E's Implementation Plan.

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[31] See generally Application of Southern California Edison Company for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009, And to Reflect That Increase In Rates (D.09-03-025, *mimeo.* at 8) (March 12, 2009) and Decisions cited therein.

[32] In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

5.1.2 Learning From the Past

As discussed above, following the tragic events in San Bruno, the Commission appointed an Independent Review Panel of experts to gather and review facts and make recommendations to the Commission to best ensure that such events are not repeated. The Panel found numerous deficiencies in PG&E's data collection and management, with defects in Integrity Management that undermine the safety of PG&E's gas system operations. We adopt the Panel's recommendation for "thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise" and use the safety journey as the description of the long-term regulatory model[33] we require for PG&E.

Maintaining PG&E's focus on its safety journey toward the goal of zero significant incidents is the overall objective of this proceeding. As noted elsewhere in today's decision, pipeline pressure testing and replacement, as well as record-keeping improvements are immediate and necessary actions; but the needed radical changes in PG&E's corporate culture, its Integrity Management, and its pipeline operations are permanent non-negotiable requirements.

In considering the safety journey ahead of us, we look back at PG&E's pipeline safety approach in the mid-1980's, presented in the record by TURN. During that era, we see evidence that PG&E met the Panel's objective of going beyond nominal regulatory compliance and displaying corporate initiative to "analyze whether more or different investments could be appropriate to strengthen public safety."[34] PG&E's 1985 plans for its older pipeline that had not been pressure tested illustrate that *at that time* PG&E was capable of exercising

[33] Independent Review Panel Report at 75.

[34] Id. at 10.

20-year plan, finding that the longer plan would not compromise public safety and would allow the gas line program to dovetail with the sewer and water replacement.[36]

In 1992, the Commission again considered PG&E's Gas Pipeline Replacement Project and determined that, heavily influenced by the 1989 Loma Prieta earthquake, natural gas pipeline replacement was an essential safety improvement. DRA raised objections that PG&E had consistently recovered greater amounts in rates for pipeline replacement costs than it had actually spent, but the Commission overruled DRA and authorized the full amount requested by PG&E:

> On this program we must agree with PG&E as to both the importance and necessity of moving forward with the gas pipeline replacement program as quickly as possible. . . . By authorizing the dollars PG&E requests for all of the accounts that deal with the gas pipeline replacement program, it is our fervent hope that PG&E actually spends the money on this program. We agree that this program is an important element of seismic safety improvement and urge PG&E to exercise due diligence in not only keeping the program on its targeted time line, but where feasible speeding up the program. Therefore, we will authorize all dollars related to the [Gas Pipeline Replacement Program] which PG&E has requested in this proceeding.[37]

The decision-making and priorities driving PG&E's pipeline safety actions in 1985 and 1992 show a different PG&E than the PG&E of the early 2000's. The 1985 plan showed PG&E thinking ahead, coordinating with local

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[36] Id. at 276.

[37] Re Pacific Gas and Electric Company, 47 CPUC2d 143, 234 (D.92-12-057).

is an essential foundation for bringing PG&E to the level of organization and forward-thinking safety management necessary to meet today's standards for safe natural gas transmission system operations.

In D.11-06-017, the Commission found that historic exemptions to the pipeline pressure testing requirement must end and required all California natural gas system operators to file Implementation Plans to either pressure test or replace all natural gas pipeline for which pressure test records are not available. The Commission specifically ordered that such Plans:

- Start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing.
- Reflect a timeline for completion that is as soon as practicable, and include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near MAOP values which result in hoop stress levels at or above 30% of Specified Minimum Yield Stress, and other such measures that will enhance public safety during the implementation period.
- State criteria on which pipeline segments were identified for replacement instead of pressure testing.
- Include a priority-ranked schedule for pressure testing pipeline not previously so tested, and may provide for MAOP reductions.

[38] Independent Review Panel Report at 11 - 12.

components, located in a high consequence area, and operating at greater than 30% SMYS. Less urgent actions are prescribed in Action Box C1 – Phase 2 pressure testing or in-line inspection, along with close interval surveying - for pipeline that has not been previously pressure tested but is not located in a highly populated area.

PG&E's Decision Tree analysis is a promising beginning of a comprehensive decision-making process based on safety concerns related to historical pipeline manufacturing, fabrication, and testing practices. PG&E's remaining challenges, however, include bringing this level of engineering analysis to all other safety concerns, and then translating the analysis to its on-going gas system operations. This will require a long-term commitment of corporate resources to create and implement a permanent plan putting safety at the core of gas system operations, with continuous improvement and initiative.

5.1.4. Going Forward

PG&E's safety journey will require a lasting commitment to decision-making based on sound engineering analysis with implementation across all aspects of PG&E's natural gas system operations. While PG&E has presented a promising beginning, this Commission will require that PG&E diligently proceed toward the goal of zero significant events.

The record in this proceeding has brought to light three operational areas where significant and immediate action is required – PG&E's quality control, field oversight, and integration of information from on-going operations into the Integrity Management Program. Ensuring that natural gas system management is meeting quality standards and translating corporate directives into actionable information for field personnel are essential components of a safe

Implementation Plan costs are the result of PG&E's imprudent operation of its natural gas transmission system, and that shareholders should bear these costs. TURN points to Pub. Util. Code § 463 as requiring the Commission to disallow all costs associated with the Implementation Plan.

PG&E opposes both these recommendations and contends that the new safety measures ordered in D.11-06-017 could not have been forecast by PG&E in its last Gas Transmission and Storage General Rate Case, which covered gas system costs from 2011 through 2014 and was approved by the Commission in D.11-04-031.[40] PG&E explains that the new safety measures are not routine costs that a public utility would be expected to absorb between rate cases as part of traditional test year ratemaking.[41] PG&E noted that the factors the Commission considers when evaluating a request for a post-test year ratemaking adjustment all focus on whether the utility could and should have included the cost in the test year forecast. Here, PG&E contends, it did not and could not have anticipated the substantial new safety investments required by D.11-06-017 when finalizing the gas rate case settlement. PG&E offered as an example the Commission's treatment of the costs for a new program to install advanced electric metering as a post-test year revenue requirement adjustment that is similar to the costs of the Implementation Plan.[42]

We find that the evidentiary record does not support DRA's request for a comprehensive disallowance of all Implementation Plan costs. While DRA

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[40] This decision is referred to as the Gas Accord V decision and approves a settlement agreement among the parties.

[41] PG&E Opening Brief at 66 - 70.

[42] Id.

institute these improvements, TURN concludes that PG&E's proposal for ratepayers to fund these improvements now is unreasonable.

We do not agree that the Public Utilities Code or Commission precedent support the proposition that due to belated timing, the cost of safety improvements by a public utility become unreasonable and subject to ratemaking disallowance.

TURN argues that PG&E's imprudence and managerial failure was the decision *not* to make these needed safety improvements at an earlier date. We find no case law or statute supporting the assertion that such a failure to act timely could render the currently proposed expenditures unreasonable. As discussed below, however, such management imprudence does provide an evidentiary basis for a reduction in Return on Equity due to management ineptitude. From a ratemaking perspective, PG&E's ratepayers have not been subject to unreasonable costs; rather, as a result of needed but not performed safety improvement projects, ratepayers ended up paying rates lower than may have been reasonable due to the absence of the needed projects. The public utility code standards for rate recovery, i.e., just and reasonable, and the disallowance concept reflected in § 463 do not combine to provide an analytical basis for disallowing reasonable costs on the basis that the utility should have made the expenditures at an earlier date.[44]

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[44] In D.94-03-048, 53 CPUC 2d 452, 477, the Commission disallowed rate recovery for costs stemming from the catastrophic 1985 accident at the Mohave Power Plant. If, hypothetically, Edison had owned a second similar plant and sought Commission authorization and ratemaking approval to make the needed safety improvements at the second plant, the reasonableness standard would not support a disallowance of those costs. Those needed safety measures, although belated, would have met the standard of a just and reasonable expense and would not be subject to disallowance based on the

Footnote continued on next page

Therefore, for the reasons set forth above, we deny DRA's and TURN's requests for a comprehensive disallowance of all Implementation Plan costs.

5.2.2. Adopted Amounts for PG&E's Implementation Plan

In the following subsections, we address each significant component of PG&E's Implementation Plan. As explained in this section, we approve PG&E's Implementation Plan subject to the following:

- PG&E's request to include the costs for pressure testing post-1955 pipelines in revenue requirement is denied;
- PG&E's request to include the costs for the gas system records integration program in revenue requirement is denied,
- The risk of cost overruns is assigned to shareholders,
- PG&E's return on equity is reduced to the incremental cost of debt for capital costs incurred as part of the Implementation Plan for five years.

5.2.2.1. Pipeline Modernization Program

In this section we address the issues related to the Pipeline Modernization Program, which includes pressure testing, replacement, inline inspection, and valves. We find that costs to pressure test pipeline installed between 1956 and 1961 should not be included in revenue requirement, that pipeline segments located in Class 2 areas should be delayed to Phase 2, and that PG&E's proposed pressure testing program is reasonable.[45]

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[45] We also note that projects approved today may displace projects planned and authorized as part of PG&E's Integrity Management Program in the Gas Accord V

Footnote continued on next page

should be assigned to shareholders. TURN estimates that pressure testing approximately 90 miles of 1956 to 1961 pipeline accounts for $45 million of testing expense. TURN applies a similar rationale for pipeline of that vintage which PG&E's proposed decision tree determines should be replaced, and recommends disallowance of $81 million in costs for replacing 18 miles of 1956 to 1961 pipeline.

PG&E states that while it began to follow the industry guidelines in 1955, it did so on a voluntary basis rather than due to a legal or regulatory requirement. Because it was not required to perform pre-service pressure tests from 1955 to 1961, PG&E posits that ratepayers should fund pressure testing for any pipeline placed into service during that time for which PG&E cannot locate pressure test data. PG&E summarizes its position: even though it may have "lost, destroyed, or misplaced" some of its records, it was able to prudently operate its natural gas transmission system by relying on the historical exemption in subpart J, thus the newly required pressure testing or replacement should be at ratepayers expense.[47]

We find that where PG&E undertook or stated that it undertook to comply with industry standards but no longer possesses the records of such compliance, the costs of retesting required by the missing records is a result of an error in PG&E's operation of its natural gas transmission system. Where PG&E's record retention errors have led to re-testing pipeline installed between 1955 and 1961, the costs of such re-testing is not a just and reasonable cost of providing

[47] PG&E Reply Brief at 8.

testing this pipeline in revenue requirement. PG&E argues that because it was not legally required to pressure test these pipeline segments previously, even though it did so in compliance with industry practices, the directive in D.11-06-017 justifies allocating the cost of the re-testing to ratepayers.

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 gas system 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. 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.

For pipeline determined to be in need of replacement, ratepayers should similarly be relieved of the obligation to pay for retesting, but not for complete replacement. That is, absent PG&E's poor document management, ratepayers would not have been required to pay for retesting the 1956 to 1961 pipeline. Certain pipeline segments, for reasons unrelated to PG&E's poor document management, require replacement, rather than just re-testing.[49] PG&E

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[49] As discussed in more detail below, some pipeline segments have features, such as now-suspect welds, that when combined with age of the pipeline and operating

Footnote continued on next page

DRA argues that PG&E's forecasted costs for pressure testing are too high.

DRA presented testimony developed by an outside expert setting forth cost estimates for fixed costs per test and variable cost per foot of pipeline tested. As shown below, DRA's cost forecasts were substantially lower than PG&E's:

Cost Item	DRA	PG&E
Variable Cost – 12″ and under ($/ft)	$8	$30
Variable Cost – 14″ to 20″ ($/ft)	$12	$39
Variable Cost – 22″ to 28″ (4/ft)	$19	$45
Variable Cost – 30″ to 42″ ($/ft)	$37	59
Fixed Cost – Fabricate Test Header	$0	$15,000 to $40,000
Fixed Cost – Move Around/Test Section Charge	$44,700 to $76,700	$200,000 to $500,000
Fixed Cost – Mob/demob	$85,600 to $139,400	$500,000

For comparison purposes, set out below are the total costs for a 2,500 foot length pressure test for both a 12″ diameter pipeline and a 36″ diameter using DRA's and PG&E's costs forecasts:

Comparison of DRA and PG&E Pressure Testing Cost Forecasts		
	DRA	**PG&E**
12″ pipeline, 2,500 feet	$150,300	$790,000
36″ pipeline, 2,500 feet	$308,600	$1,187,500

Thus, PG&E's pressure test cost forecasts are more than triple DRA's estimates. TURN also presented pressure test cost estimates per mile of reasonableness. We will use this conclusion, and our similar conclusion for PG&E pipeline replacement costs, to inform our analysis of PG&E's request for an overall 20% contingency adder.

TURN also challenged PG&E's determination that a valid hydrotest record from 1961 to 1970 must include the name of the operator. TURN cited to D.11-06-017 as requiring records of a valid pressure test consistent with regulations in effect at the time of the test.[53] PG&E counters that while then-effective pressure test regulations did not require an operator's name, such information is "necessary to ensure accountability" for the test.[54]

We agree with PG&E that the operator name adds value to the pressure test record and is required by current PHMSA regulations.[55] Such information, however, was not required by the regulations in effect at the time for pressure tests performed between 1961 and 1970. Thus, consistent with D.11-06-017, we find that pressure test records for tests performed between 1961 and 1970 need only contain the information required by the then-applicable regulations to be valid pressure test records for purposes of inclusion in PG&E's Implementation Plan.

TURN also proposes that all pipeline segments be pressure tested to 90% Specified Minimum Yield Strength (SMYS)(the pressure level at which the pipe would undergo permanent deformation). PG&E explains that pressure testing to this very high level is not required by federal subpart J regulations for existing pipeline, which require up to 150% of MAOP for that pipeline. PG&E

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53 TURN Opening Brief at 25.

54 PG&E Reply Brief at 66.

55 See 49 CFR § 192.517(a)(1).

explains that D.11-06-017 requires PG&E to begin its work with pipeline located in densely populated places, i.e., Class 3 and 4 locations and High Consequence Areas of Class 1 and 2 locations, but that PG&E has also included significant amounts of Class 2 locations that are not High Consequence Areas. TURN recommends that these less densely populated areas be moved to Phase 2.

PG&E responds that when it prepared its Implementation Plan, it included pipeline segments adjacent to segments within the specified scope to determine if cost and construction efficiency could be achieved by doing the adjacent Class 2 segments as part of Phase 1 of the Implementation Plan. PG&E gave particular attention to such pipeline operating at over 30% SMYS. PG&E states that to go back and pressure test or replace these pipeline segments could increase costs and delayed completion of the overall program.[58]

PG&E has presented a valid justification to evaluate Class 2 locations adjacent to Class 3 locations and determine whether including these segments in Phase 1 would be economically more efficient or decrease customer interruptions such that these segments should be included in Phase 1 and not deferred to Phase 2. In rebuttal testimony at 3-15 to 3-17, PG&E states that it looked at "adjacent pipeline segments as well" and explains that going back to pressure test or replace "adjoining pipe segments at a later time" would lead to increased costs.

In D.11-06-017, the Commission directed PG&E to "start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and

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assembly; and, Class 4, where buildings with four or more stories are prevalent. 49 CFR § 192.5

[58] PG&E Reply Brief at 54.

deferred to Phase 2. This reduction and deferral will reduce the total pipeline replacement costs in the Implementation Plan Phase 1.

DRA and TURN challenge PG&E's proposed pipeline replacement costs as excessive. DRA presented a thorough analysis of PG&E's proposed estimates for pipeline replacement costs, and based on this analysis recommended a 20% disallowance. DRA's and PG&E's pipeline replacement cost estimates priced the pipeline replacement based on the project area's residential and commercial development and divided the project areas into three categories of "congestion." Pipeline replacement projects in open desert or agricultural areas are categorized as "non-congested" and have the lowest cost due to minimal need to dig through or under a road. In small towns or outskirts of larger towns where pipeline is placed in existing right of way, with some road drilling and repair, the area is termed "semi-congested." Finally, areas with extensive residential or commercial development where heavy road drilling and repair, and where pipeline is placed under existing roads or parking lots, are categorized as "heavily congested." Generally, the higher the level of congestion the higher the costs for pipeline replacement.

For comparison purposes, set out below are the costs estimates for the middle level of congestion – "semi-congested" – presented by DRA and PG&E.

PG&E counters the attacks on its cost forecasts by stating that PG&E alone has constructed 940 miles of natural gas pipeline in California over the past 20 years and that its forecasts are based on actual experience, rather than DRA's reliance on academic publications.[64]

We agree that DRA's analysis is insufficient to overcome PG&E's experience with the cost of natural gas pipeline construction. We, therefore, authorize PG&E to include in revenue requirement the forecasted costs of its natural gas transmission pipeline replacement projects as requested in the Implementation Plan. This excludes Class 2 locations deferred to Phase 2 and requires the cost offset for pressure testing post-1956 pipeline with missing records from the requested $818. 7 million in capital costs.

DRA's analysis is sufficient, however, to support a finding that PG&E's cost forecasts fall in the high end of the cost range. On average, PG&E's cost estimates are about 20% higher than DRA's. This cost increment, however, does not account for the different treatment of management and contingency costs in the two sets of estimates. DRA's cost estimates include management and contingency costs, which can be significant, and PG&E's base cost estimates do not include management and contingency costs, which are treated as separate line items in the final revenue requirement analysis. Thus, DRA's cost estimate is much less than PG&E's final total cost for replacing natural gas pipeline. Therefore, we conclude that the record shows that PG&E's cost forecast for replacing natural gas transmission pipeline falls in the high end of the range of reasonableness, and that PG&E has used its experience with natural gas

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64 Id. at 3-39.

but for PG&E's imprudent decision to forgo pressure testing or in-line inspection, this work would be completed.

As discussed elsewhere in today's decision, the Independent Review Panel and the NTSB have questioned the efficacy of PG&E's Integrity Management Program. For ratemaking purposes, however, it is not clear how PG&E's failure to perform certain types of pipeline assessment in the past, even if an imprudent decision, justifies disallowing ratemaking recovery for the currently proposed pipeline assessment. TURN is not arguing that PG&E obtained ratepayer funding for the more expensive pressure testing, but opted instead to actually perform less-expensive direct assessment. Delay in implementing needed safety expenditures does not render the current expenditures imprudent and thus subject to disallowance, as we have set forth in detail previously. Therefore, we deny the requested disallowance of TURN and the City and County of San Francisco.

TURN also opposes including $81 million in capital costs to replace 18 miles of pipeline that was installed between 1956 and 1960. TURN argues that this pipeline should have been tested prior to being placed into service and the testing records retained by PG&E. If PG&E had properly retained the records, TURN reasons, these replacements would not be needed now.

TURN also challenges PG&E's proposal to replace, rather the pressure test, all pipeline segments that have certain types of welds and operate at high pressure in heavily populated areas. These pipeline segments end up in

2013, and 2014. Of this amount, $29.2 million will be capitalized and $9.6 million will accounted for as expense.

DRA challenges PG&E's analytical process to arrive at the need to perform these retrofits and additional in-line inspection runs, as well as PG&E's cost forecasts. DRA contends that PG&E has presented no justification for including these additional in-line inspection costs in Phase 1 because PG&E's decision tree does not produce any outcomes requiring these actions. DRA also notes that PG&E's cost forecasts are equally unsupported.

PG&E explains that in-line inspection means that a cylindrical-shaped inspection tool is inserted into and passed through the interior of a pipeline segment, and then retrieved at the end of the inspection run. The tool has hundreds of sensors that obtain data on pipeline conditions including indentations, wall loss, pipe strain, metallurgical variations, and various types and shapes of cracks.[69] PG&E explained that in-line inspection is useful to identify, locate, and remove excessive pups, miter bends, and wrinkle bends. PG&E states that its overall objective is that all its gas transmission pipeline operating at 30% SMYS or greater be capable of accommodating in-line inspection. As of the end of 2010, about 17% of PG&E's pipeline operating at that pressure was capable of in-line inspection and PG&E intends to increase that percentage to 22% by the end of 2014. PG&E is also incorporating improvements

[69] These tools are referred to colloquially as "pigs" with the more advanced models described as "smart pigs," and pipelines through which these tools can pass are described as "piggable."

improve safety by increasing emergency preparedness, and may reduce property damage and danger to emergency personnel and the public in the event of a pipeline rupture. PG&E pointed to recent California legislation and a long-standing NTSB recommendation for automated valves in urban areas with high-pressure natural gas pipelines.[71]

PG&E states that it will design its automated valves to be capable of operation as either remotely controlled by personnel in the gas system control room, or by automatic control where sensors will set to close the valve without further action by PG&E personnel. PG&E plans to operate most valves by remote control due to concern about a valve automatically but erroneously closing under non-rupture circumstances. PG&E presented detailed testimony on the system and customer impacts from unnecessary gas line closures. PG&E plans to use fully automatic valves only on earthquake fault crossings at this time, but will continue studying fully automated valves and may convert some of the remote controlled valves in the future.[72]

PG&E estimates that the overall valve program for Phase 1 will cost $128.3 million which PG&E requests authorization to include in revenue requirement. This total is comprised of $118.8 million to be capitalized and $9.5 million in expenses for 2012, 2013, and 2014.[73]

The City of San Bruno supports automated valves, with manual override options to forestall unnecessary closures.[74] TURN recommends more

[71] Hearing Exh. 2 at 4-30 to 4-33.

[72] Hearing Exh. 2 at 4-25.

[73] Hearing Exh. 2 at 4-7.

[74] City of San Bruno Opening Brief at 5.

major issue for the pipeline industry, with the safety and reliability trade-offs discussed at length in Appendix L to their report.[76] PG&E should monitor the development of this issue in the pipeline industry.

Interim Safety Measures

No party objected to PG&E's proposed interim safety measures of pressure reductions and increased patrols of pipeline, at an estimated total cost of $3.2 million for 2012, 2013, and 2014. Similarly, PG&E's proposed $30.2 million total cost for extra management of the Implementation Plan programs was not disputed as a separate line item. We, therefore, approve these requested elements.

Pipeline Segments Less than 50 Feet in Length

PG&E proposes to capitalize all pipeline replacements, including replacement pipe less than 50 feet in length. PG&E states that where a pipe segment less than 50 feet in length is part of a maintenance project, the pipe is expensed for accounting efficiency.[77] PG&E explains that it considers the entire Implementation Plan to be one project so that all capital portions of the project will be capitalized. DRA contends that PG&E should adhere to its usual accounting rules for the Implementation Plan. We find that PG&E has not justified this deviation from its standard accounting rules. We will, therefore, require PG&E to continue to expense replacement pipe less than 50 feet in length.

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[76] Appendix L is viewable at http://www.cpuc.ca.gov/NR/rdonlyres/5CF0591F-E4B8-4CB4-9325-3DFE1B790A5A/0/AppendixL.pdf.

[77] Hearing Exh. 21 at 17-16.

study, waiting until the next rate case to make this adjustment is not feasible given the scope and magnitude of the Implementation Plan. Therefore, we find that the depreciable life of all natural gas transmission mains installed pursuant to the Implementation Plan shall be recorded as 65 years. To the extent PG&E is required to create a sub-account in its plant records to show this modified amount, we authorize such a sub-account or any other reasonable and auditable mechanism to clearly account for this different service life.

5.2.2.3. Costs Incurred Prior to the Effective Date of Today's Decision

TURN argues that the Commission has no authority to allow PG&E to increase its rates to recover costs incurred prior to the authorization of a memorandum account. TURN explains that the rule against retroactive ratemaking and longstanding Commission doctrine prohibit setting rates that include costs incurred prior to the effective date of a decision, absent an appropriate and authorized memorandum account. TURN states that the Commission and the California Supreme Court have repeatedly found that ratemaking is prospective and the Commission may not increase rates for previously incurred expenses.[82]

PG&E counters that it needs a memorandum account for expenditures already made in 2011 and 2012 for two purposes. The first purpose is to establish an "official tracking of 2011 costs allocated to PG&E's shareholders" because even though these costs will be allocated to shareholders, "the costs still are counted toward the four year binding budget."[83] PG&E's next

[82] TURN Reply Brief at 35.

[83] PG&E Reply Brief at 41.

its Implementation Plan costs incurred prior to Commission approval of the Implementation Plan.

As the Commission said in the Southern California Water Co. Headquarters case, D.92-03-094 (March 31, 1992)43 Cal. P.U.C. 2d 596, 600

> It is a well established tenet of the Commission that ratemaking is done on a prospective basis. The Commission's practice is not to authorize increased utility rates to account for previously incurred expenses, unless, before the utility incurs those expenses, the Commission has authorized the utility to book those expenses into a memorandum or balancing account for possible future recovery in rates. This practice is consistent with the rule against retroactive ratemaking. (Emphasis in original.)

Similarly, it is the Commission's practice not to reduce general rates that have been set on a forecast basis -- to account for costs not incurred -- unless the Commission has previously set up some mechanism to adjust rates for costs not incurred (e.g. a balancing account). This practice is also consistent with the rule against retroactive ratemaking.

The events in San Bruno required that PG&E take immediate action. As DRA and TURN have argued, forecasted test year ratemaking theory generally precludes post-test year revenue requirement adjustments, such as proposed by PG&E here. The Overland Report shows that PG&E enjoyed the protection of the practices described above when, from 1996 to 2010, PG&E consistently underspent Commission-authorized amounts, resulting in approximately $430 million in excess earnings for shareholders. Our ratemaking practices protected PG&E from recaptureof the excess historic profit for ratepayers. Now, PG&E finds itself on the other side of these practices . Rather than unexpected profit, PG&E is now confronting unexpected, and significant, lead to a change in Phase 1 scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital.[90]

TURN recommends that the Commission "soundly reject" PG&E's advice letter proposal as it creates a "loophole" that could lead to "unlimited amounts of additional revenue."[91] DRA also opposes the proposed Advice Letter process and contends that it will allow PG&E to increase the costs of the Implementation Plan.[92]

We summarily reject PG&E's proposal for Advice Letter treatment for increases and modifications to the Implementation Plan. When directing California's natural gas system operators to file Implementation Plans, we required an orderly and cost-effective plan that would provide safety value to ratepayers. Authorizing piecemeal modifications would substantially undermine those requirements.

Notwithstanding our rejection of PG&E's Advice Letter proposal, the Commission's experience and expertise with large programs that include numerous diverse projects such as the Implementation Plan demonstrates that such plans are subject to revision and updating as new information comes to light. Opportunities for cost reductions must be identified and, where feasible, incorporated into the Plan. New safety engineering information may provide the analytical foundation for revising priorities. While the exact order of specific projects may change, the overall objective, scope, and budget must be retained, absent further Commission action. This is especially true here, due to our

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90 PG&E Reply Brief at 43.

91 TURN Reply Brief at 143 – 144 *quoting* Hearing Exh. 123 (Beach, NCIP).

92 DRA Opening Brief at 131 – 132.

The Director of CPSD shall assign staff and allocate resources as may be necessary to perform the duties delegated in today's decision. If the Director determines that additional external expertise or resources are required, the Director shall meet and confer with the Commission's Executive Director to determine the most efficient means of obtaining such expertise or resources. If the Executive Director determines that additional external expertise or staff are required, and that existing Commission funding is inadequate to provide these expertise or resources, the Executive Director is authorized to order PG&E to reimburse the Commission for any contract necessary to carry out the directives in this decision in an amount not to exceed $15,000,000. PG&E may record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery from ratepayers.

Compliance Filings

TURN and DRA have requested that we schedule a formal after-the-fact reasonableness review of PG&E's actions pursuant to the Implementation Plan, and PG&E opposes this request.

At this time, we are not prepared to grant DRA and TURN's request, but we are equally not inclined to foreclose any type of post-construction review. The Implementation Plan represents a massive investment program funded largely by PG&E's ratepayers. Although PG&E has presented sufficient detail of its specific projects currently expected to be performed, substantial amounts of new data on in-service pipeline will be brought to light by the unprecedented number of pressure tests and pipeline replacement construction that will be performed in the upcoming years. In addition, the Commission needs to ensure that project expenditures incurred under the PSEP are clearly distinct from the funding and expenditures that have during 2012, 2013, and 2014, which PG&E proposes to include in revenue requirement. In total, PG&E is seeking Commission authorization to include $222.8 million in revenue requirement for 2012, 2013, and 2014.

As set forth below, we find that PG&E has not justified including the costs of its gas system records search and organization projects in revenue requirement. PG&E became responsible for its natural gas transmission system the day it installed facilities and equipment for the system. That responsibility includes creating and maintaining records of the location and engineering details of system components. Over the years, PG&E has sought and obtained ratepayer funding for its record-keeping functions. PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies. 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.

DRA opposes PG&E's request for supplemental ratepayer funding for PG&E's record keeping deficiencies. DRA argues that PG&E has failed to properly manage its records, which led to the NTSB directing PG&E to obtain "traceable, verifiable, and complete" records on which to determine MAOP. This directive, DRA explains, was not a new standard but rather an articulation of a long-standing requirement found in existing law, regulations, industry standards, PG&E policies and common sense that gas system operators retain accurate and accessible pipeline records. DRA specifically points to § 451, adopted in 1909, for the requirement that PG&E operate its natural gas transmission system to "promote the safety, health, comfort, and convenience of

TURN also opposes any ratepayer funding of PG&E's record review or database upgrade project. TURN contends that the purpose of these projects is to remedy PG&E's past imprudent document management, and TURN focuses on the pressure testing historical exemption found in 49 CFR 192.619(c) and (a)(1)(4) to demonstrate that an accurate and reliable record of key pipeline features is necessary to setting a safe MAOP. TURN explains that for pipeline installed before 1970, the MAOP may be set by maximum operating pressure reached between 1965 and 1970, and that some knowledge of pipeline features would be essential to validating this historic pressure as required by federal regulations. TURN emphasizes that PG&E had an acute need for pipeline features information because an alarmingly high share (70%) of PG&E's pipeline with MAOP set by historical operating pressure had only after-the-fact affidavits by technicians to support the claimed historical operating pressure, rather than any actual pressure recordings.[96] Having needed this information all along to safely operate its natural gas transmission system, TURN concludes that PG&E has no basis to now seek ratepayer funding to bring its records up to the prudent standard.

TURN dismisses as wholly without merit PG&E's argument that the document review and data base projects are necessary to comply with new regulatory requirements.[97] TURN points to D.11-06-017 and contends that the document review for MAOP validation was necessitated by PG&E's unreliable natural gas pipeline records tragically brought to light by the San Bruno rupture. TURN concludes that accurate and reliable records were always necessary to

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[96] TURN Opening Brief at 101.

the Commission's 2011 decision, it could set the MAOP for a pipeline using historical operating pressure and now it must use a pipeline features analysis. To accomplish this new requirement, PG&E concludes, it must institute its gas records integration program, and the cost of complying with this new regulatory requirement is properly included in revenue requirement.

Pursuant to Public Utilities Code Section 451 each public utility in California must:

> Furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities, ... as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

The duty to furnish and maintain safe equipment and facilities is paramount for all California public utilities, including natural gas transmission operators. Furnishing and maintaining safe natural gas transmission equipment and facilities requires that a natural gas transmission system operator know the location and essential features of all such installed equipment and facilities.

The record in this proceeding shows that the NTSB identified "discrepancies" in PG&E's pipeline records and issued recommendations that corrective actions be taken:

> The NTSB's examination of the ruptured pipe segment and review of PG&E records revealed that although the as-built drawings and alignment sheets mark the pipe as seamless API 5L Grade X42 pipe, the pipeline in the area of the rupture was constructed with longitudinal seam-welded pipe. Laboratory examinations have revealed that the ruptured pipe segment was constructed of five sections of pipe, some of which were short pieces measuring about 4 feet long. These short pieces of pipe contain different longitudinal seam welds of various types, including single- and double-sided

> features are fundamentally different from simply missing records. Curing PG&E's unreliable natural gas pipeline records was the obvious goal of the NTSB's recommendation to obtain "traceable, verifiable, and complete" records and, with reliably accurate data, calculate a dependable MAOP.
>
> PG&E and SoCalGas/SDG&E state that such records are not available, especially for the older vintage pipelines. Notwithstanding the utilities' record-keeping challenges, these missing records are particularly needed because the older pipelines were exempted from pressure testing requirements and many have not been pressure tested.
>
> Consequently, the untested pipelines are also some of the oldest in the natural gas transmission system and the more likely to lack a complete set of documents allowing pipeline feature documents to be established without the use of assumptions. We find that this circumstance is not consistent with this Commission's obligations to promote the safety, health, comfort, and convenience of utility patrons, employees, and the public. We conclude, therefore, that all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety. Historic exemptions must come to an end with an orderly and cost-conscience implementation plan.[101]

The Commission went on to require PG&E to complete the records review process because, based on testimony of PG&E's engineering executive, PG&E needed assurance that that its gas system records accurately depicted the pipeline characteristics of segments it was about to pressure test:

> Commissioner Sandoval questioned PG&E's Vice President for Gas Engineering and Operations

101 D.11-06-017 at 17 -18.

PG&E seems to be arguing that until the NTSB recommendations it had no obligation to maintain accurate and accessible records of the components of its natural gas transmission system because the historical exemption provision of 49 CFR 192.619(c) did not require these records.

We disagree with PG&E's reading of the PHMSA regulations and we want to disabuse PG&E and other California natural transmission gas system operators of the notion that superficial compliance with regulations is acceptable. We require our natural gas transmission system operators to exercise initiative and responsible safety engineering in all aspects of pipeline management. Simply because a regulation would not prohibit particular conduct does not excuse a natural gas system operator from recognizing that such conduct is not appropriate or safe under certain circumstances.

Turning to the specific federal regulation upon which PG&E bases its claimed exemption from a duty to create and maintain accurate and reliable natural gas transmission system records, we find that the regulation presupposes an engaged and evaluating system operator, questioning system operating parameters, examining records, and exercising professional engineering judgment. Specifically, the regulation states:

> (c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding [July 1, 1970].[103]

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[103] 49 CFR 192.619(c).

testimony,[104] and multiplying each chapter's cost by a risk contingency percentage. The risk contingency percentages vary from 10% to 28%, and average 21%. The sum of each chapter's contingency costs is $380.5 million over the four years, and, of that sum, $247.3 million is capital costs and $133.2 represents expense.[105]

DRA opposes PG&E's request for a contingency as "pre-determined" and based almost exclusively on PG&E's "judgment" and "intuition."[106] In addition, DRA and TURN presented expert analysis showing that PG&E's cost estimates for pressure testing and pipeline replacement, the largest cost components, greatly exceed the national average and are based on unsupported assumptions drawn from a small sample of such work done on an emergency basis.

We find that for both cost forecasting reasons as well as policy reasons, PG&E shareholders should bear the risk of cost overruns and we do not authorize the contingency allowance for inclusion in revenue requirement.

DRA presented testimony developed by an outside expert setting forth cost estimates for fixed costs per test and variable cost per foot of pipeline tested. As discussed above, DRA's cost forecasts were substantially lower than PG&E's, with PG&E's costs forecasts about three to five times DRA's - a substantial margin. PG&E's costs are orders of magnitude greater than TURN's estimates, although we note those estimates are from 2001. PG&E also analyzed its system to identify locations where costs are likely be higher due to population

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104 See Exh. 2 at 3-6 and 4-7.

105 Exh. 2 at 7-43.

106 DRA Opening Brief at 111 – 114.

Denying this particular contingency allowance request is appropriate because we find that the record shows that the need to do this amount of testing and replacement on an "urgent" basis has been caused, in part, by PG&E's management of its natural gas transmission system over multiple decades. The majority of the pipeline to be tested or replaced has been part of PG&E's system for decades, and the safety value of pressure testing has similarly been well-known for decades. TURN argues that PG&E's long-standing obligation pursuant to § 451 to operate its system in a safe manner required that PG&E pressure test or replace pipeline and that PG&E's historic failure to do so was imprudent, with significant ratemaking consequences.[107] As set forth above, we disagree with TURN's ratemaking theory analysis; however, the fact that these now "urgent" safety improvements are overdue and caused by years of poor management decisions is a valid rationale to support a ratemaking decision that shareholders should not be shielded from the risks created by the poor management decisions. Having let its natural gas transmission system deteriorate to the point where the Commission was required to order a massive and relatively short-term testing and replacement plan, PG&E cannot now seek protection (in addition to a generous cost forecast) from costs caused by quickly doing work that could and should have been over a much longer time period. Such a longer time period may have allowed PG&E to develop better cost forecasting models as well as to improve efficiency and lower overall costs. We find that having had a role in creating the urgent need for this program, sound

[107] TURN Opening Brief at 69 – 74.

5.2.5. Shareholders Return on Equity

PG&E proposes to include $384.3 million in capital investments in 2012, $480.3 in 2013, and $499.9 in 2014.[110] PG&E proposes to include these amounts in plant in service at its existing return on equity, 11.35%.[111]

DRA recommends a 200 basis point reduction in return on equity for capital investments that are part of the Implementation Plan.[112]

TURN presents expert testimony explaining that the Commission considers management efficiency and effectiveness when setting return on equity, and that the very need for PG&E to undertake $10 billion in gas pipeline safety investments to address problems that developed over decades demonstrates that PG&E's management has been neither efficient nor effective.[113] TURN's expert concludes that the current authorized return on equity of 11.35%, which the Commission acknowledged was at the "upper end" of the just and reasonable range would be an entirely inappropriate reward for the investment needed to correct these long-standing safety deficiencies.[114] TURN's two experts

110 Hearing Exh. 2 at 1-17.

111 In Application 12-04-015, et al, the Commission is currently considering the 2013 ratemaking return on common equity and return on rate base for Southern California Edison Company, San Diego Gas & Electric Company, Southern California Gas Company and Pacific Gas and Electric Company. The proposed decision recommends test year 2013 authorized return on equity of 10.40% and return on rate base of 8.06% for PG&E.

112 DRA Opening Brief at 20. A change of 200 basis points would reduce PG&E's return on equity from 11.35% to 9.35%.

113 Hearing Exh. 98 at 10.

114 Id.

decisions diminished by adjustments to return on equity.[117] PG&E's witness explained that a "punitive, noncompensatory ratemaking structure" would undermine PG&E's ability to attract capital for needed investments. PG&E also stated that it preferred a one-time cost disallowance to a return on equity reduction because the capital markets will require a higher return for future investments.[118]

When initiating this rulemaking the Commission indicated, at 11-1 2, that adjustments to return on equity would be considered:

> This rulemaking will consider how we can align ratemaking policies, practices, and incentives to better reflect safety concerns and ensure ongoing commitments to public safety. For instance, how do we maintain public and utility management attention to the "nuts and bolts" details of prudent utility operations? How do we foster a culture of commitment to safe utility operations with changing and increasingly competitive energy markets?
>
> The unique circumstances of PG&E's pipeline records and pipeline strength testing program for its pre-1970 pipeline may require extraordinary safety investments. Our ratemaking authority empowers this Commission to impose such ratemaking consequences as the public interest may require. See e.g., Cal. Const. Art. 12; Pub. Util. Code §§ 701, 451 ("every public utility shall...maintain such...equipment and facilities...as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.") The extraordinary safety investments required for PG&E's gas pipeline system and the unique

117 PG&E Opening Brief at 82 - 83.

118 Id. at 84 - 85.

The parties recommend downward adjustments between 200 basis points and 500 basis points, which would result in a return on equity of about the cost of debt, 6.05%, as the permanent return on equity for these investments. TURN, particularly, makes a compelling case for not allowing PG&E to earn a "profit" on its overdue safety investments.[121] Equally compelling, however, for the reasons described above, is PG&E's argument that drastically reducing return on equity harms the ratepayers in the long run by increasing borrowing costs and potentially diminishing the financial health of the utility.

We, therefore, decline to adopt an adjustment to PG&E's return on equity for investments made pursuant to the Implementation Plan.

5.2.6. Cost Allocation and Rate Design

Overall, PG&E proposes to follow the cost allocation and rate design principles adopted in the 2011 Rate Case Gas Accord Settlement, approved by the Commission in D.11-04-031.[122] PG&E proposes to allocate its target annual Implementation Plan Backbone Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Backbone Transmission revenue requirement responsibility as established in D.11-04-031. Similarly, PG&E proposes to allocate its target annual Implementation Plan Local Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Local Transmission revenue requirement responsibility adopted in D.11-04-031. The target annual Implementation Plan gas storage-related revenue requirements will also be allocated to core and noncore based on percentages adopted in the 2011 decision.

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[121] TURN Opening Brief at 121.

[122] Hearing Exh. 2 at Chapter 10.

One-Way Balancing Account

PG&E proposes to include capital expenditures for plant as the plant becomes operational and to use actual expenses incurred each year to true up forecasted costs. Thus, PG&E concludes, ratepayers will only pay for Implementation Plan actions that are completed and any unspent funds cannot be diverted to other uses.[124]

No party opposed the use of a one-way balancing account for the Implementation Plan.[125] For administrative efficiency, we will include capital costs in the balancing account as well, rather than to have annual advice letter filings and resultant rate changes. Therefore, we approve a one-way (downward) balancing account to track Implementation Plan costs from the effective date of today's decision through December 31, 2014. Any accumulated balance on December 31, 2014, plus interest, will be returned to customers through the Customer Class Charge in PG&E's Annual Gas True-Up Filing, to be filed shortly prior to the end of 2014. The accumulated balance will be allocated 59.5% to the core class and 40.5 % to the noncore class.

PG&E may only recover from ratepayers the revenue requirements associated with the actual costs and expenses incurred for projects allowed by this decision, and only up to the revenue requirements we estimate here for Phase 1 work. The amounts to be recorded in the balancing account are limited by the adopted expense and capital amounts set forth in Attachment E for each

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124 Hearing Exh. 2 at 1 -19.

125 But *see* Independent Review Panel Report at 109 and Appendix Q, finding that one-way balancing accounts, such as PG&E proposes here, create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no more or no less than is authorized for a given activity.

Opening comments were filed on November 16, 2012. PG&E supported the Proposed Decision's findings on technical issues but strongly opposed numerous significant disallowances. PG&E contended that disallowing a program contingency is contrary to standard industry practice for estimating program costs. PG&E argued that the failure to authorize rate recovery for 2012 was the result of erroneously failing to grant its request for a memorandum account. PG&E found the proposed ROE reduction to be punitive and contrary to the public interest. PG&E opposed the finding that GTAM project was remedial and should be disallowed. Finally, PG&E argued that the 65-year service life for pipeline and 1.5% escalation rate were both arbitrary and unsupported by the record.

DRA provided extensive and detailed comments contending that the Proposed Decision contained numerous errors. In its comments to the Proposed Decision, DRA asserted that the analysis used to determine the revenue requirement and authorized program budgets was flawed and that more disallowances were warranted. DRA analyzed PG&E's pipeline modernization program database and developed various scenarios for testing and replacement disallowances using different criteria to identify pipe segments without test records. Additionally, DRA recommended using more accurate testing cost values to calculate the disallowance for pipe replacement projects with pipe segments lacking test records. TURN also recommended that PG&E file an advice letter after the decision is issued to remove pipe segments from the Implementation Plan for which the utility found the records. Our evaluation of DRA's and TURN's comments is set forth below.

TURN argued that the Proposed Decision erred by approving without evaluation PG&E's pipeline program. TURN explained that since filing the

Rigorous inspection and testing of high pressure gas transmission lines is critical for safety, and in some cases, replacement of high pressure gas transmission lines, especially those installed prior to 1970 and which traverse heavily populated high consequence areas may be necessary. San Bruno also argued for installation of automatic shut off valves and remote controlled shut off valves for gas transmission lines in high consequence areas. San Bruno stated that PG&E's gas control and gas dispatch operations must have internal coordination as well as with local first responders. San Bruno concluded that until all necessary safety measures are implemented, every community in PG&E's service territory remains just as vulnerable as San Bruno was on September 9, 2010.

Specifically, San Bruno recommended that the Proposed Decision be revised to include rigorous evaluation and explanations for each element of Implementation Plan. San Bruno focused on the rejection of the requested total disallowance and the limited 5-year term of the return on equity disallowance. San Bruno sought independent analysis of PG&E's decision tree and the need for automated shut-off valves. San Bruno also supported the Commission obtaining outside assistance in its oversight of PG&E's execution of the Implementation Plan.

San Francisco criticized the proposed decision for failing to clearly state that PG&E does not safely operate its natural gas system. San Francisco explains that the Proposed Decision incorrectly relies on PG&E's flawed decision tree analysis which does not sufficiently address double submerged arc-welded pipe or the effects of pressure-cycle-induced fatigue-crack growth. San Francisco recommended that PG&E update its Implementation Plan with the more recently available accurate information. San Francisco also challenged the Proposed Decision's application of the burden of proof. Finally, San Francisco

PG&E replied that while it continued to oppose the substantial disallowances in the Proposed Decision, it supported the determinations on Public Utilities Code section 463, the burden of proof, approval of the decision tree and scope of Phase 1, the valve automation program approval, oversight and customer outreach, and rate design. PG&E opposed the DRA's recommended calculation of disallowances.

DRA encouraged the Commission to adopt the proposed allocation of costs to shareholders. DRA opposed PG&E's request to allow the balancing account to transfer cost savings from an unnecessary project to offset cost overruns on another project. DRA contended that such an offsetting process would undermine incentives for cost control. DRA supported the disallowance of PG&E's pre-decision costs due to PG&E's mismanagement and neglect, which, DRA argued, distinguished PG&E from SDG&E and SoCalGas, which were granted a memorandum account. DRA supported the PD's disallowance of GTAM and contingency costs. DRA supported the time-limited ROE reduction as striking an equitable balance between shareholders and ratepayers.

TURN supported the corrections put forward by DRA and San Francisco, and recommended that the Commission disregard the attempts by SDG&E and SoCalGas to litigate in this docket issues pending in A.11-11-002. TURN reiterated its recommendation that the Implementation Plan be updated to reflect pipeline for which PG&E has now located pressure test records as well as for non-adjacent Class 2 pipeline.

SDG&E and SoCalGas recommended that the Commission not decide that pipeline installed after 1955 should have been pressure tested. These operators opposed TURN and DRA's argument that section 463 requires that all costs of search is completed. After the MAOP validation and records search are completed, DRA's larger disallowance, or a portion of it, may be appropriate. Therefore, consistent with TURN's recommendation, we shall require PG&E to file an expedited application 30 days after the conclusion of its MAOP validation and records search work that includes an updated pipe segment database. The specific showing that PG&E will be required to provide in its application will be considered in a workshop to be held no later than 90 days from the effective date of this decision. We expect this expedited application to be limited in scope, but we believe that an expedited application will be a more appropriate means to review the submitted data than an advice letter.

We adopted DRA's recommendation to use better testing costs estimates for pipe replacement projects that had pipe segments without test records.

Findings of Fact

1. On August 26, 2011, PG&E filed and served its Implementation Plan required by D.11-06-017.

2. PG&E's Implementation Plan is comprised of: (A) Pipeline Modernization Program that provides for testing or replacing pipelines, reducing their operating pressure, conducting in-line inspections as well as retrofitting to allow for in-line inspection, and adding automatic or remotely-controlled shut off-valves; and (B) Pipeline Records Integration Program where PG&E will finish its records review and establish complete pipeline features data for the gas transmission pipelines and pipeline system components, and the Gas Transmission Asset Management Project, a substantially enhanced and improved electronic records system.

3. PG&E's Implementation Plan uses a consistent methodology to identify and prioritize recommended actions based on pipeline threat categories and

12. The Implementation Plan calls for pressure reductions and increased leak inspections and patrols.

13. In D.11-06-017, the Commission required PG&E to include in its Implementation Plan a proposed cost allocation between shareholders and ratepayers, and PG&E's Implementation Plan included a discussion of costs to be absorbed by PG&E's shareholders.

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

15. Generally, post-test year ratemaking is disfavored when a forecasted test year revenue requirement is used to set rates.

16. Adopted in 1955, the American Standard Association Code for Pressure Pipeline (ASA B31.8) required pre-service pressure testing for natural gas pipelines.

17. PG&E admits that it voluntarily complied with American Standard Association Code for Pressure Pipeline (ASA B31.8), beginning in 1955.

18. Since no later than January 1, 1956, PG&E complied with or stated that it complied with industry standards to pressure test pipeline prior to placing it in service. PG&E is unable to produce the records for certain pressure tests that would have been performed in accord with industry standards from January 1, 1956, or for pipeline of unknown installation date. The lack of pressure test records for pipeline placed into service after January 1, 1956, or with an unknown installation date, reflect an error in PG&E's operation of its natural gas system. No evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirement from January 1, 1956.

29. Transmission main pipeline installed pursuant the Implementation Plan 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.

30. The Commission has not authorized a memorandum account into which PG&E may record its Implementation Plans incurred prior to the effective date of today's decision.

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.

32. Improvements, efficiencies, and adjustments based on sound engineering practice to the Implementation Plan in furtherance of the objectives of the Plan are within the scope of the Plan and do not require further Commission review.

33. From the date installed, PG&E was responsible for creating and maintaining accurate and accessible records of its natural gas system equipment and facilities.

34. PG&E's failure to possess accurate and accessible records of its gas system caused the NTSB and this Commission to direct PG&E to correct these deficiencies.

35. PG&E's historic gas system revenue requirement has included costs for maintaining gas system records.

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.

37. An escalation rate tied to the overall inflation rate, as proposed by DRA, is a reasonable escalation factor for Implementation Plan projects.

5. The evidentiary record does not support DRA's request for a comprehensive disallowance of all Implementation Plan costs, and we deny the request.

6. The scope and magnitude of the costs at issue in the Implementation Plan justify deviation from the general rule against post-test year ratemaking

7. The public utility code standards for rate recovery, i.e., just and reasonable, and the disallowance concept reflected in § 463 do not combine to provide an analytical basis for disallowing reasonable costs on the basis that the utility should have made the expenditures at an earlier date.

8. TURN's proposal to disallow all Implementation Plan costs should be denied.

9. PG&E's decision tree for the evaluating manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats should be approved.

10. PG&E's proposal to retrofit 199 miles of pipeline for in-line inspection and inspect 234 miles of pipeline with in-line inspection tools should be approved.

11. PG&E's proposal for pressure reductions and increased leak inspections and patrols should be approved.

12. PG&E's proposal to replace, automate and upgrade 228 gas shut-off valves in Phase 1 of the Implementation Plan should be approved, and PG&E should continue to monitor industry experience with automated shut-off valves for possible revisions to its plans.

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

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

21. PG&E's cost forecast for replacing pipeline is substantially higher than DRA's, but is supported by significant operational experience and is therefore reasonable.

22. The request by TURN and the City and County of San Francisco to disallow pipeline replacement costs for alleged Integrity Management failures should be denied.

23. PG&E's proposal to replace, rather than pressure test, pipeline installed prior to 1970, with weld that do not meet current standards, operated at over 30% SMYS and located in high population areas is reasonable.

24. PG&E's proposal to capitalize replacement pipe less than 50 feet in length is not reasonable and is denied. Such pipe must be expensed, consistent with current accounting practice.

25. 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.

26. TURN's proposal to adopt a 65-year service life for transmission main pipe installed pursuant to the Implementation Plan is reasonable, and should be adopted.

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

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.

29. PG&E's request for authority to file Tier 3 Advice Letters to modify the Implementation Plan should be denied.

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.

34. The Commission should impose strong incentives on PG&E to encourage efficient construction management and administration of the Implementation Plan.

35. PG&E's proposal for a 21% contingency adder should be denied.

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

37. 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 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 and not replaced with other higher priority projects, the expense and capital cost limit of the balancing account should be reduced by the amounts associated with the project not completed.

ORDER

IT IS ORDERED that:

1. The Pipeline Safety Enhancement Plan (Implementation Plan) of Pacific Gas and Electric Company (PG&E) is approved. PG&E must expeditiously and efficiently pursue the natural gas system safety improvements as described in the Implementation Plan.

adopted expense and capital amounts set forth in Attachment E for each program. Expense and capital amounts in excess of adopted amounts may not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. The adopted expense and capital amounts for any program shall be reduced by the cost of any Implementation Plan project not completed and not replaced with a higher priority project. Subject to these limits, PG&E is authorized to collect from ratepayers only the revenue requirements associated with actual expenses and capital costs recorded in the balancing account.

7. Pacific Gas and Electric Company is authorized to file a Tier 1 Advice Letter to create a balancing account 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. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

8. The Director of the Commission's Consumer Protection and Safety Division, or designee, (CPSD) is delegated the following authority:

A. CPSD shall review all changes to the Implementation Plan proposed by Pacific Gas and Electric Company (PG&E), shall require such modifications as are necessary to ensure public safety, and may concur in such proposals.

B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

This order is effective today.

Dated ______________________________, at San Francisco, California

Attachment A : Appearances

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ATTACHMENT B

List of Recommendations from Report of the Independent Review Panel

No.	Recommendation
Section 2 – Background	
None	
Section 3 – The Panel and Its Approach	
None	
Section 4 – San Bruno Incident	
None	
Section 5 – Review of PG&E's Performance as an Operator	
5.1.4.1	*PG&E needs to create a culture of system integrity that enables every employee to recognize and understand how his or her day-to-day actions affect system integrity.*
5.1.4.2	*PG&E needs to streamline the organization, reducing layers of management and rebuilding the core of technical expertise.*
5.2.4.1	*PG&E should acquire and develop a staff of professionals with the skills necessary to do state-of-the-art practical analysis of risk management decisions that concern public health and safety, employee health and safety, environmental consequences, socioeconomic consequences, and financial and reputation implications for the company.*
5.2.4.2	*The Board of Directors of PG&E should require that state-of-the-art risk analysis be conducted on every problem included on PG&E's list of top 10 catastrophic risks. The Board should be assessing the quality of involvement of the members of the top management team in every one of these risk analysis, as all risk management decisions that concern the top ten catastrophic risks should be of direct concern to all top PG&E executives, including the President and CEO, as well as the Board.*
5.3.4.1	*PG&E should conduct a comprehensive review of its data and information management systems to validate the completeness, accuracy, availability, and accessibility to data and information and take action through a formal management of change process to correct deficiencies where possible.*
5.3.4.2	*Upon obtaining the results of the review, PG&E should undertake a multi-year program that collects, corrects, digitizes and effectively manages all relevant*

<table>
<tr><td>5.6.4.2</td><td>PG&E should establish a multi-year program that deals with all the capital requirements to assure system integrity, based on sound risk criteria (i.e., a methodology that addresses the likelihood of various possible failures given competing alternatives). This program would include:

• Investments to collect, correct, digitize and effectively manage all relevant design, construction and operating data for the gas transmission system.

• Investments to retrofit existing pipelines to accommodate in-line inspection technology, to test or replace uncharacterized or anomalous pipe has needed, and to reroute pipe in the HCAs where accessed.</td></tr>
<tr><td>5.7.4.1</td><td>PG&E should restructure the Pipeline 2020 document to enhance effectiveness and assist in monitoring for both PG&E and the CPUC, by incorporating the following:

• Vision Statement, which will describe "the transmission pipeline system of the future." This should be a clear statement as to how PG&E sees the role of the transmission system of the future. This will facilitate decisions made in the strategic parts of 2020 that can be focused and relevant to more than just compliance. It should demonstrate the asset profile, and how it will support safety, and operational goals. PG&E should identify specific measures to define what an effective program will deliver.

• Delivery Strategies, which will set out the goals of the strategy and steps to deliver the vision. The delivery strategies should be fully developed based on other recommendations for pipeline integrity management and related improvements.

• Execution Plan, which will define the tasks to be accomplished, how they will be accomplished, an associated timeframe and projected costs.

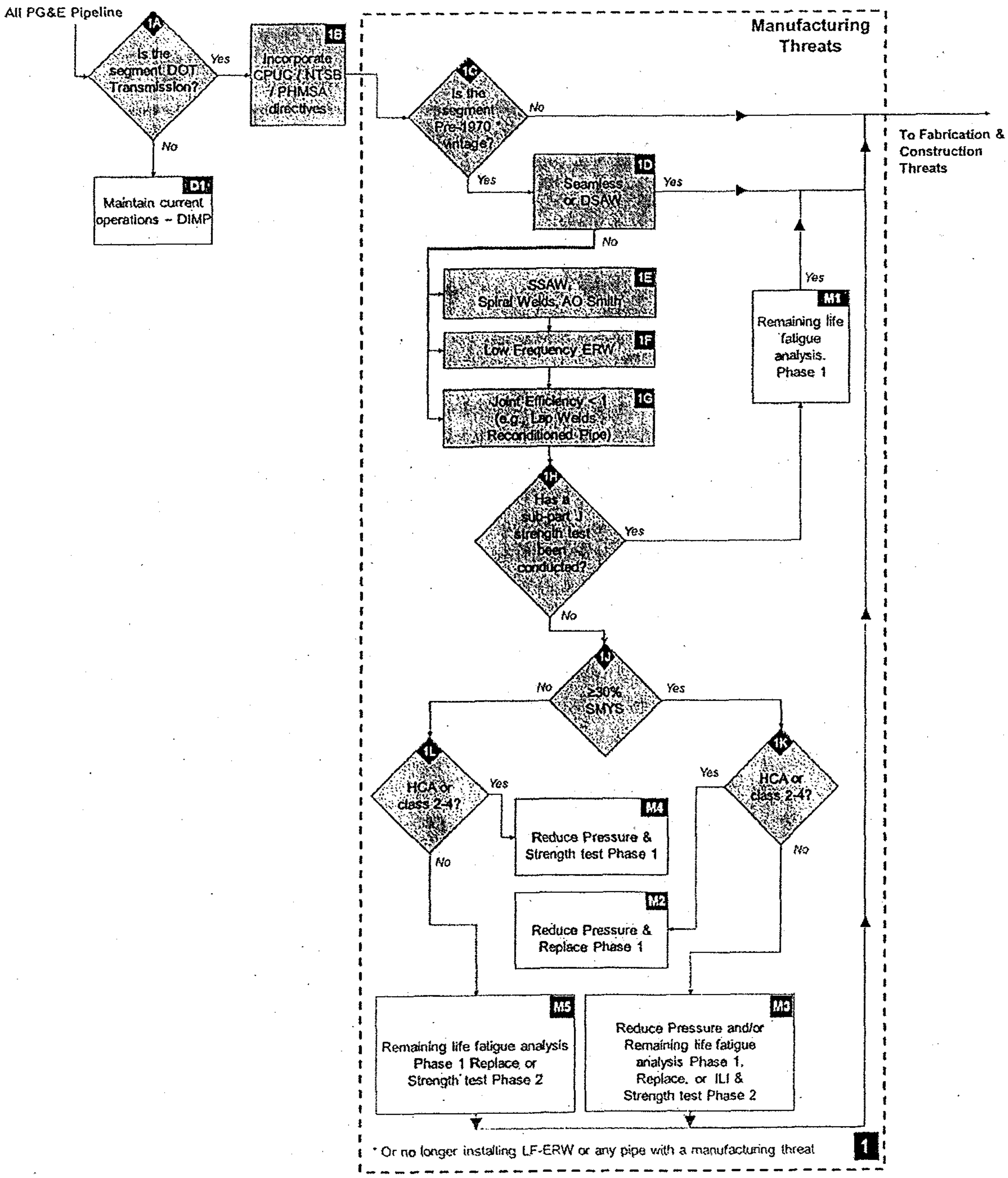
• Analysis of Alternatives, which will document various alternatives considered, complete with costs and consequences. A thorough analysis of alternatives will ultimately result in support of the program.

• In lieu of or in addition to R&D funding for new technology, entertain reasonable opportunities to serve as a testing ground for improved ILI technology.

The CPUC or its designated consultant should review the plan and collaborate with PG&E in the development of clear objectives, measures, and schedule.</td></tr>
<tr><td colspan="2">Section 6 – Review of CPUC Oversight</td></tr>
<tr><td>6.2.4.1</td><td>Adopt as a formal goal, the commitment to move to more performance-based regulatory oversight of utility pipeline safety.</td></tr>
</table>

6.3.3.5	*USRB should augment its current use of vertical audits that focus on specific regulatory requirements such as leak records or emergency response plans with: •* • *Horizontal audits that assess a segment or work order of the operator's system through the entire life cycle of the current asset for regulatory compliance.* • *• Focus field audits based on an internally ranking of the most risk segments of the gas transmission system assets in the state, regardless of the operator.*
6.3.3.6	*To raise the profile of the audits among all the stakeholders, add the following requirements to the safety and pipeline integrity audits of the utilities that includes the following features: (1) posting of audit findings and company responses on the CPUC's website; (2) use of a "plain English" standard to be applied for both staff and operators in the development of their findings and responses, respectively; and (3) a certification by senior management of the operator that parallels that certifications now required of corporate financial statements pursuant to Sarbanes-Oxley.*
6.4.3.1	*CPUC should consider seeking approval from the State Budget Director for an increase in gas utility user fees to implement performance-based regulatory oversight for all gas utilities.*
6.4.3.2	*Request the California legislature pass legislation that would replace the mandatory minimum five-year audit requirements with a risk-based regime that would provide the USRB with the needed flexibility in how it allocates inspection resources.*
6.5.3.1	*Adopt as a formal goal, the commitment to move to performance-based regulatory oversight of utility pipeline safety and elevate the importance of the USRB in the organization.*
6.5.3.2	*Develop a holistic approach to identifying pipeline segments for integrity management audits based on intrastate pipeline risk as opposed to simply auditing each operator's pipeline.*
6.6.3.1	*The CPUC should significantly upgrade its expertise in the analytical skills necessary for state-of-the-art quality risk management work. The CPUC should have an organizational structure for individuals doing this work such that they have an equal stature and access to management of the CPUC as those who deal with rate issues or legal or political issues. Although the CPUC's role is to provide oversight of the operator's compliance with federal and state codes, its role should not be to provide management of risk direction to the utilities.*
6.7.3.1	*The CPUC should seek to align its pipeline enforcement authority with that of the State Fire Marshal's by providing the CPSD staff with additional enforcement tools modeled on those of the OSFM and the best from other states.*

ATTACHMENT C
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
MANUFACTURING THREAT DECISION QUERY



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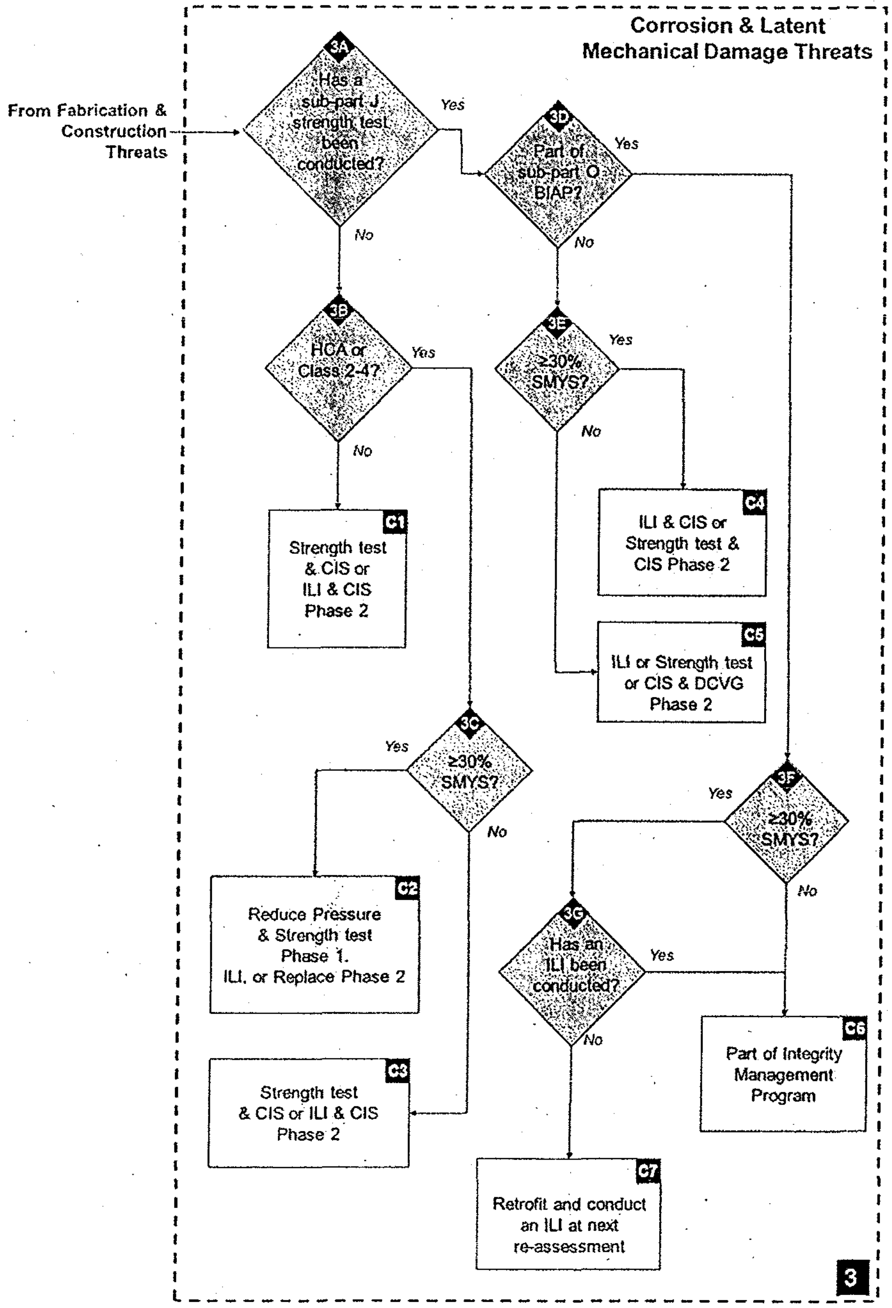
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
CORROSION AND LATENT MECHANICAL DAMAGE THREAT DECISION QUERY



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Attachment D

Specifications for PG&E Implementation Plan Compliance Reports.

Frequency of Filing: No later than 30 days after the conclusion of each calendar quarter.

Availability: Posted on PG&E web site, and served on all parties and Directors of Energy Division and CPSD.

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 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.

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, hydrotesting, 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, hydrotesting, 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. 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) 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 and show the uncompleted project's associated costs. Compute the corresponding reduction to the Implementation Plan adopted amounts set out in Attachment E, as required by Ordering Paragraph 6.

Attachment E – Authorized Revenue Requirement Increases

E- 1 Authorized Revenue Requirement Increases

E- 2 Authorized Program Expenses

E- 3 Authorized Capital Costs

E- 4 Authorized Combined Expense and Capital

Table E-1
Pacific Gas and Electric Company
Implementation Plan Authorized Revenue Requirements
2011-2014
($ in thousands)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	Capital-Only Revenue Requirement	–	$9,191	$41,076	$90,605	$140,872
2	Expense-Only Revenue Requirement		$79,399	$74,267	$90,353	$244,020
3	Total	–	$88,590	$115,343	$180,958	$384,892
4	Disallowance of months in 2012		-$85,678			
5	Decision Increase in Revenue Req.		$2,913	$115,343	$180,958	**$299,214**

Note (1) - Disallowance based on effective date of decision

E- 3 Authorized Capital Costs

TABLE E-3
PACIFIC GAS and ELECTRIC COMPANY
Authorized Capital Expenditures (w/escalation adjustment)
($ IN MILLIONS)

Line No.	Description	2011	2012	2013	2014	Total
1	Pipeline Modernization Program	30.5	214.9	290.1	317.0	852.5
2	Valve Automation Program	13.7	38.9	51.6	24.8	129.0
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	0.0	0.0	0.0
5	Program Management Office	3.0	6.5	6.5	6.3	22.3
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Capital Expenditures	$47.2	$260.3	$348.2	$348.0	$1,003.8

Note - Adopted Revenue Requirement includes 2011 and 2012 adjustments associated with authorized capital expenditures

E- 4 Authorized Combined Capital and Expense

Table E-4 - Authorized Combined Expense and Capital
w/Escalation Adjustment
($ IN MILLIONS)

Line No.	Description	2011(a)	2012 (b)	2013	2014	Total
1	Pipeline Modernization Program	30.5	217.3	356.0	398.2	1,002.0
2	Valve Automation Program	13.7	39.0	54.6	28.4	135.7
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	1.1	1.0	2.1
5	Program Management Office	3.0	6.6	9.8	9.5	28.9
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Cost	$47.2	$262.9	$421.5	$437.2	$1,168.8

(a) The 2011 expenses will be funded by shareholders.
(b) The 2012 expenses will be funded by shareholders until effective date of decision.

Attachment F

Table F – 1 Implementation Plan Rate component by Function

Table F – 2 Illustrative Class Average Present and Proposed Rates

Table F – 3 Implementation Plan Rate Component by Customer Class

TABLE F-1
PACIFIC GAS AND ELECTRIC COMPANY
IMPLEMENTATION PLAN RATE COMPONENTS
($ PER THERM)

Line No.		2012	2013	2014
1	**Core**			
2	PSEP - Local Transmission	$0.01492	$0.02024	$0.02953
3	PSEP - Backbone Transmission	$0.00312	$0.00327	$0.00600
4	PSEP - Storage	$0.00010	$0.00033	$0.00113
5	Total GPS Rate	$0.01814	$0.02384	$0.03667
6	**Noncore - Local Transmission/Distribution Level**			
7	PSEP - Local Transmission	$0.00687	$0.00946	$0.01439
8	PSEP - Backbone Transmission	$0.00272	$0.00274	$0.00492
9	PSEP - Storage	$0.00004	$0.00014	$0.00048
10	Total GPS Rate	$0.00963	$0.01234	$0.01979
11	**Noncore - Backbone Transmission Level**			
12	PSEP - Backbone Transmission	$0.00272	$0.00274	$0.00492
13	PSEP - Storage	$0.00004	$0.00014	$0.00048
14	Total GPS Rate	$0.00277	$0.00288	$0.00540

Table F-3
Pacific Gas and Electric Company
IMPLEMENTATION PLAN RATES
($ PER THERM)

Line No.		2011 (A)	2012 (B)	2013 (C)	2014 (D)
1	Core Customer Classes				
2	Residential	$0.00000	$0.01814	$0.02384	$0.03667
3	Small Commercial	$0.00000	$0.01814	$0.02384	$0.03667
4	Large Commercial	$0.00000	$0.01814	$0.02384	$0.03667
5	Natural Gas Vehicle (Compressed)	$0.00000	$0.01814	$0.02384	$0.03667
6	Natural Gas Vehicle (Uncompressed)	$0.00000	$0.01814	$0.02384	$0.03667
	Noncore Customer Classes				
7	Industrial - Distribution	$0.00000	$0.00963	$0.01234	$0.01979
8	Industrial - Local Transmission	$0.00000	$0.00963	$0.01234	$0.01979
9	Industrial - Backbone Transmission	$0.00000	$0.00277	$0.00288	$0.00540
10	Electric Generation (Distribution/Local Transmission)	$0.00000	$0.00963	$0.01234	$0.01979
11	Electric Generation (Backbone Transmission)	$0.00000	$0.00277	$0.00288	$0.00540
12	Natural Gas Vehicle - Distribution (Uncompressed)	$0.00000	$0.00963	$0.01234	$0.01979
13	Natural Gas Vehicle - Transmission (Uncompressed)	$0.00000	$0.00963	$0.01234	$0.01979
14	Wholesale Customers				
15	Alpine Natural Gas	$0.00000	$0.00963	$0.01234	$0.01979
16	Coalinga	$0.00000	$0.00963	$0.01234	$0.01979
17	Island Energy	$0.00000	$0.00963	$0.01234	$0.01979
18	Palo Alto	$0.00000	$0.00963	$0.01234	$0.01979
19	West Coast Gas - Castle	$0.00000	$0.00963	$0.01234	$0.01979
20	West Coast Gas - Mather Distribution	$0.00000	$0.00963	$0.01234	$0.01979
21	West Coast Gas - Mather Transmission	$0.00000	$0.00963	$0.01234	$0.01979

(END OF ATTACHMENT F)