BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms	R.11-02-019 (Filed February 24, 2009)

AMENDMENT OF THE OPENING BRIEF OF THE NORTHERN CALIFORNIA INDICATED PRODUCERS

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I. INTRODUCTION AND EXECUTIVE SUMMARY

PG&E's Pipeline Safety Enhancement Plan (PSEP) warrants a departure from the Commission's traditional treatment of requests for safety funding. "*Business as usual*" will not be an acceptable outcome for this proceeding. The Commission must ask PG&E shareholders to bear a greater share of the PSEP costs –through cost disallowances and a reduced return on equity (ROE) -- than PG&E has proposed.

On September 9, 2010, PG&E's Segment 180 of Line 132 exploded killing eight people. Investigations into the accident and into PG&E's management practices reveal that the accident in San Bruno resulted from PG&E's imprudent oversight of its transmission system and noncompliance with preexisting regulations. In particular, the National Transportation and Safety Board (NTSB) and California Public Utilities Commission (CPUC) Consumer Protection and Safety Division (CPSD) have concluded that PG&E's *inaccurate and poor record-keeping was a leading cause* of the accident. The extent of these poor practices is at issue in several pending Commission investigations.

In order to remedy highlighted shortcomings, PG&E seeks cost recovery for a staggering $2.2 billion capital investment and associated expenses over a four-year period. In fact, its 2014 PSEP revenue requirement constitutes roughly 52% of the 2014 gas transmission and storage (GT&S) revenue requirement adopted in Gas Accord V (GA V) settlement. These costs include measures to bring PG&E into compliance with preexisting regulations, as well as costs aimed to increase safety standards to prevent another fatal accident. To ensure that ratepayers are not forced to bear an unreasonable share of these extraordinary costs, the Commission should:

1. Disallow recovery of costs determined to be remedial in nature;
2. Reduce PG&E's PSEP-related ROE by 500 basis points;
3. Require PG&E to secure Commission approval for any changes in the Phase I scope;
4. Require PG&E to recover PSEP costs through a gas pipeline surcharge, rather than disturbing the existing Gas Accord V settlement's rate design;
5. Adopt an equal percent of authorized margin (EPAM) cost allocation method to better reflect the relative benefits of the program to ratepayers; and
6. Allocate gas transmission asset management (GTAM) costs between backbone and local transmission functions in proportion to their share of PSEP costs.

Beyond the rate impact, customers may experience significant service disruptions in the course of PSEP implementation. To minimize these impacts, the Commission should:

7. Require PG&E to comply with a minimum notice protocol that requires it to provide 30 days' notice of minor service disruptions and at least 6 months' notice to customers operating critical energy infrastructure, when complete disruptions are necessary; and
8. Mandate PG&E to provide service disruption credits in the amount of $0.25/therm when PG&E is unable to comply with its notice protocol.

Failure to adopt these recommendations will allow PG&E to impose costs on ratepayers to overcome its own imprudent oversight.

Determining where to draw the line between those PSEP costs that are remedial, which should be borne by shareholders, and those that involve compliance with a new regulatory requirement will be a key issue in this proceeding. Notably, all parties but Coalition of California Utility Employees (CCUE) agree that PG&E shareholders should be responsible for those PSEP costs that are remedial in nature; they do not agree, however, which PSEP costs should be classified as remedial. More specifically, parties dispute whether the requirement to validate maximum allowable operating pressure (MAOP) using "*traceable, verifiable, and complete*" records constitutes a ***new*** regulatory requirement.

The "*traceable, verifiable and complete*" standard is not a new requirement. It is simply a concise articulation of regulators' existing expectations. The record demonstrates that the existing regulatory framework would have required PG&E to maintain the data it needed to support MAOP validation with "*traceable, verifiable and complete*" records. Ignoring this fact, PG&E's cost sharing proposal would allocate merely 14.6% of PSEP costs to shareholders. Its proposal simply does not go far enough.

Rejection of PG&E's cost sharing proposal is critical to ensure that ratepayers do not bear unreasonable costs. PG&E's Phase I PSEP will require expenditures of roughly $2.2 billion through 2014 and will entail capital expenditures totaling $1.4 billion. Costs can surpass these forecasts if PG&E incurs construction premiums. PG&E also estimates that Phase II will involve incremental expenditures that range from $6.8 to $9 billion. More importantly, the record demonstrates that, PG&E's mismanagement is responsible for a large portion of the PSEP costs and that PG&E has profited from this mismanagement. The Overland Audit Report indicates that under the Gas Accord structure, from 1999 through 2010, PG&E's failure to invest in pipeline maintenance and safety yielded shareholders *<u>$430 million</u>* in excess of its authorized ROE.[1] In short, granting PG&E's cost sharing proposal will not only impose duplicative costs on ratepayers, it will also excuse PG&E from its noncompliance with the Commission's regulatory framework.

To balance the interest in promoting safety with ratepayer interests, the Commission should rely on two strategies. First, the Commission should disallow all PSEP costs that are remedial in nature or required to allow PG&E to comply with

[1] Overland Audit Report, at 5-2.

preexisting regulations. This would ensure that ratepayers are not forced to bear duplicative costs. Importantly, the Commission should consider findings in pending Commission investigations before finalizing the PSEP revenue requirement. Second, the Commission should reduce PG&E's PSEP-related ROE by 500 basis points. This would result in a PSEP-related ROE that is equivalent to the cost of debt. This measure is justified by PG&E's past mismanagement and will ensure that shareholders do not unduly profit from PG&E's effort to ensure its system's safety. Notably, the reduced ROE would apply only to 4% of PG&E's total capital investments and amounts to a mere 20 basis point reduction in PG&E's overall ROE. PG&E's PSEP-related ROE can be revisited in the future and increased based on PG&E's performance, creating a strong incentive to improve performance.

This proceeding also requires the Commission to establish mechanisms to allocate PSEP costs among ratepayers. There are three cost allocation issues that the Commission must resolve: use of a surcharge, cost allocation of PSEP costs among customer classes and allocation of GTAM costs between the local and backbone transmission functions. As noted below, PSEP costs should be allocated in a manner that reflects cost causation principles and preserves the settled GA V rate design. First, the record reveals that use of a gas pipeline surcharge, to allocate PSEP costs to end-use customers, is necessary to reflect the balance, achieved by the GA V settlement, among PG&E ratepayers. In comparison, use of a functionalized cost allocation methodology would affect the GA V revenue sharing provision, require re-opening of contentious GA V backbone rate design issues, and necessitate complex updates to GA V's discounted local transmission rates. Second, an EPAM cost allocation method that allocates more PSEP costs to core customers would be appropriate given that the core residential and commercial customers would realize almost all the *direct* safety benefits of the projects contemplated in Phase I. While an EPAM cost allocation method would increase an allocation of PSEP costs to core customers, the percentage increase in noncore customer rates will continue to be higher than the increase in core residential rates. Lastly, to reflect cost causation principles, GTAM costs should be allocated to backbone and local transmission functions in proportion to their share of PSEP Phase I costs. The record demonstrates that the bulk of Phase I PSEP costs involve local transmission projects. Therefore it is appropriate that the bulk of GTAM costs be allocated to the local transmission function.

The PSEP work will inevitably involve some degree of service disruption, and it is important that the Commission require PG&E to provide a minimum amount of notice to customers when their gas service will be impaired. A minimum 30 days' notice for scheduled pressure reductions can significantly limit the operational and financial impacts of these disruptions. For more complete disruptions in service, a minimum of six months' notice would be required to accommodate the safe winding down of critical energy infrastructure. Gas customers who operate critical energy facilities also have vital safety responsibilities that could be impaired if PG&E fails to provide adequate notice of major service disruptions. Where PG&E does not comply with these notice requirements, it should be required to provide customers with a service disruption credit of $0.25/th to mitigate financial impacts.

II. THE PG&E PIPELINE SAFETY ENHANCEMENT PLAN WILL LEAD TO SIGNIFICANT RATE INCREASES

The San Bruno incident demonstrates that it is important that PG&E's natural gas infrastructure be operated in a manner that ensures the safe and reliable delivery of natural gas. The significant rate increases generated by PG&E's PSEP nonetheless warrant the Commission's scrutiny. A "*business as usual*" approach will not do.[2]

Through its PSEP, PG&E seeks authorization for an unprecedented degree of spending to improve its natural gas pipeline system. In Phase I of PG&E's pipeline safety enhancement plan alone, the utility intends to invest about $1.4 billion in capital investments.[3] In comparison, from 1996 through 2010, PG&E spent just $1.6 billion on capital investments.[4] As discussed below, the expedited schedule for improvements may also cause customers to bear construction premiums, which could go beyond the forecast revenue requirements.

A. The PSEP Contemplates An Unprecedented Rate Increase

PG&E's proposed PSEP revenue requirement will lead to material increases in natural gas transportation rates. The most recently adopted PG&E revenue requirements in the GA V in D.11-04-031 gave PG&E GT&S funding in the following amounts: $514.2 million for 2011, $541.4 million for 2012, $565.1 million for 2013, and $581.8 million for 2014.[5] These amounts also increased rates from 2010 levels by at

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2 PG&E acknowledges that over the past 30 years, the Commission has generally granted its requests to fund pipeline safety efforts. This degree of oversight and scrutiny, however, has not led to a safe pipeline system. To the contrary, it has resulted in a devastating explosion that could have been avoided with basic safeguards and good recordkeeping. 9 Tr. 959 (PG&E/Bottorff); 9 Tr. 1076-1077.

3 Exhibit 2, at 1-16.

4 Exhibit 149, at 27-8 (DRA/Sabino).

5 D.11-04-031, Appendix A, at 5, §7.1.

least $52.4 million.[6] PG&E's PSEP will involve an *incremental* average annual increase in PG&E's GT&S revenue requirement of roughly $256.9 million from 2011-2014 million from 2012 to 2014.[7] Notably, by 2014 the PSEP-related revenue requirement increase will constitute 52% of the PG&E GT&S revenue requirement.[8]

This higher revenue requirement will lead to a material increase in rates. If PG&E's revenue requirement increase and cost allocation proposal is adopted, it will, by 2014, increase residential bundled rates by 4.9% and noncore transport-only rates by 18.6-109.8%.[9] Phase II will further increase rates as PG&E contemplates expenditures that range from $6.8 to 9.0 billion.[10]

B. Significant Scope of Work Planned from 2012 Through 2014 Will Require Ratepayers to Bear Cost Premiums

The timing of PG&E's proposed work can increase ratepayers' costs beyond those identified in the PSEP. The increase will result from the short period of time contemplated for these pipeline safety efforts. A shorter investment period could force ratepayers to shoulder costs *incremental* to the forecast revenue requirements due to construction premiums. As TURN points out, PG&E and Sempra safety projects are likely to be undertaken at the same time.[11] The greater focus on pipeline safety work in

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6 Exhibit 149, at 4 (DRA/Sabino). The 2010 revenue requirement was $461.8 million.

7 Exhibit 2, at 1-17 (PG&E proposes the following annual revenue requirements: $247 million in 2012, $220 million in 2013, and $300 million in 2014).

8 Exhibit 123, at 12 (NCIP/Beach).

9 Exhibit 19, at WP 10-7. Note that PG&E's forecast bundled rate impacts for noncore customers underestimate the rate increase these customers will see because it relies on the core commercial cost of gas as a proxy for the noncore commodity cost of gas. The core commercial cost of gas overstates what noncore customers typically pay for gas commodity costs. Thus the bundled impact should be evaluated by assuming that noncore customers pay the citygate natural gas commodity cost. Exhibit 123, at 12 (NCIP/Beach), (In short, the bundled impact should be evaluated by assuming that noncore customers pay the citygate natural gas commodity cost.)

10 8 Tr. at 837 (PG&E/Bottorff); Exhibit 121, at 8 (TURN/Long).

11 Exhibit 98, at 14 (TURN/Marcus).

the state may lead to increases in the unit cost of labor, equipment, or contractor profits.[12]

In addition, making these investments over a 3-year period increases ratepayer costs. PG&E's PSEP contemplates about $1.4 billion in capital investments in just a four-year period.[13] The net present value of a 40-year revenue requirement for contemplated capital investments is 19% higher if the investments are made over a 3-year time frame rather than a 15-year period.[14] In fact, if the PSEP investments had been made over a 15-year period rather than a 3-year period, it would save ratepayers the same amount of money as a PSEP-related ROE reduction of 1% for the first three years of the investment.[15]

III. PG&E'S MISMANAGEMENT WARRANTS A DEPARTURE FROM TRADITIONAL TREATMENT OF PIPELINE SAFETY FUNDING REQUESTS AND GREATER RESPONSIBILITY FOR SHAREHOLDERS

The Commission should treat PG&E's request for PSEP cost recovery differently than it has historically treated requests for pipeline safety costs. While PG&E contends that the PSEP constitutes an effort to comply with the NTSB's <u>new</u> "*traceable, verifiable, and complete*" standard, the record demonstrates PSEP costs are attributed to PG&E's compliance with <u>*preexisting*</u> regulations. By taking this position, PG&E not only limits its responsibility for 2011-2014 PSEP costs, it also recommends that the Commission continue its currently authorized ROE. As noted below, however, preexisting regulations required PG&E to comply with the NTSB's "*traceable, verifiable, and complete*" records standard. As such, PG&E's costs to produce records that comply

12 Exhibit 98, at 15 (TURN/Marcus).
13 Exhibit 2, at 1-16.
14 Exhibit 123, at 26 (NCIP/Beach).
15 *Id.*, at 26.

with this standard or any preexisting regulations should be disallowed. Finally, to ensure shareholders do not unduly profit from efforts to promote safety and to promote better management in the future, the Commission should lower PG&E's PSEP-related ROE by 500 basis points.

A. Preexisting Regulations Obligated PG&E to Maintain "*Traceable, Verifiable and Complete*" Records

The Commission should reject PG&E's efforts to characterize the NTSB's "*traceable, verifiable, and complete*" standard as a new regulatory requirement. As highlighted in hearings, the line between existing and new regulations is an important issue that should govern cost recovery in this case. While all parties except CCUE appear to agree that PG&E shareholders should bear costs that are remedial in nature, intervening parties and PG&E disagree about the obligations imposed by existing regulations.[16] As noted below, compliance with the Commission's entire regulatory framework would have required PG&E to maintain the records required to comply with the NTSB's "*traceable, verifiable, and complete*" records standard. Treating this <u>*articulation*</u> of a records standard as a <u>*new*</u> standard would excuse PG&E's poor recordkeeping practices and its violations of the regulatory regime that existed prior to the San Bruno incident.

1. Decision 11-06-017 Clarifies that "*Traceable, Verifiable and Complete*" Standard Is Meant To "*Cure*" Use of Inaccurate Data

The "*traceable, verifiable and complete*" records standard memorialized in Decision 11-06-017, and first articulated by the NTSB, is meant to elicit ***accurate***

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[16] The only party that does not appear to support payment of remedial costs by PG&E shareholder is CCUE. Exhibit 126, at 4-5 (CUE/Marcus).

records to validate pipeline information supplied by the utilities; it does not create a new regulatory requirement. It is noteworthy that neither the decision nor the NTSB characterizes the "*traceable, verifiable and complete*" standard as new.[17] Instead, D. 11-06-017 clarifies that PG&E's PSEP is meant to address the NTSB's concern regarding the inaccuracies in PG&E's records, particularly relating to Line 132, which were "*factually inaccurate*."[18] The "*traceable, verifiable and complete*" standard is meant to _cure_ this deficiency by requiring the use of "*reliably accurate data*" that will allow the calculation of a dependable MAOP.[19]

In particular, the decision requires PG&E to calculate MAOP using pipeline features.[20] The decision requires the preparation of a PSEP to "*either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test*."[21] The decision already indicates that PG&E is capable of complying with this records standard for those pipelines for which it has records.[22] As noted below, General Order (GO) 28 and Public Utilities (PU) Code §451 would have required PG&E to retain these basic records of pipeline components as it would be necessary to ensure safe operation of PG&E's system. Calculation of MAOP using pipeline features was also one of the existing ways to establish MAOP under GO 112.[23] For all of these reasons, the record does not support treatment of the NTSB's articulation as a "*new, higher safety standard*."[24]

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17 D.11-06-017; 10 Tr. 1156 (PG&E/Howe).
18 D.11-06-017, at 17.
19 *Id*.
20 *Id*., at Ordering Paragraph 1.
21 *Id*., at 19.
22 The decision notes that PG&E does not have these records for older vintage pipelines which suggests that it has required records for other pipelines. D.11-06-017, at 17.
23 10 Tr. 1157 (PG&E/Howe).
24 8 Tr. 783 (PG&E/Stavropoulos).

2. Existing Regulatory Framework Obligated PG&E to Maintain Records Required of D.11-06-017

Treatment of the NTSB's "*traceable, verifiable, and complete*" records standard as a new standard would require the Commission to overlook important aspects of its regulatory framework. As PG&E's record-keeping witness Mr. Howe acknowledged at hearings, before the NTSB requirement can be deemed new, the state and federal regulations that existed prior to the San Bruno incident must be understood.[25] As detailed below, the Commission's regulatory framework prior to San Bruno was comprised of code sections, such as PU Code §451, that broadly charged PG&E to operate as a prudent operator and more prescriptive regulations, such as GO 28 and 112, which detailed the nature of records that PG&E was obligated to retain. Industry standards also provide valuable insight regarding the prudent operation of a pipeline system. Together the GOs and PU code section required PG&E to retain all records that were required to promote the safety of its system and meet the NTSB standard.

a. Public Utilities Code Section 451 Has Required PG&E to Operate Its System as Prudent Operator Since 1951

Public Utilities Code §451, adopted in 1951, charges PG&E with the obligation to act as a prudent utility operator. Rather than list all efforts required to carry out this responsibility, it specifies that PG&E is obligated to maintain service, secure equipment and do all things "*necessary*" to promote public safety:

> *Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are*

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25 10 Tr. 1201 (PG&E/Howe).

***necessary to promote the safety**, health, comfort, and convenience of its patrons, employees, and the public. (emphasis added)*

As such, it is *more demanding* than the more prescriptive record-keeping regulations of the Commission because it requires PG&E to identify and retain those records it needs to operate its system safely. The CPSD report, issued in the Commission's record-keeping investigation, and industry standards provide additional information on the types of records PG&E is obligated to retain under this code section. A prudent utility operator would have retained the pipeline component records required to validate MAOP as recommended by the NTSB.

(i) CPSD Report Confirms that a Prudent Utility Operator Retains Records Regarding Nature and Functionality of Pipeline Components

The CPSD report issued in the record-keeping investigation and sponsored by Margaret Felts emphasizes the critical nature of records to a prudent utility operator. As a preliminary matter, the report clarifies that retention of records on pipeline components and functionality are important given that the pipeline system is transporting combustible gas:

PG&E has been required by industry standards and by regulations to maintain records about its facilities for the life of the facility. This records retention requirement is fundamental to industry because the transportation of gas is a dangerous activity. Failures in high pressure pipelines, especially those containing hazardous and/or flammable materials such as natural gas can result in destruction to life and property.[26]

It also indicates that records of pipeline fatigue, upgrades, design, specifications and operational history provide critical information about the safety of a pipeline system.[27]

[26] Exhibit 45, at 25.
[27] *Id.*, at 27.

In addition, the report observes that the retention of leak records is necessary and it provides insight into future problems:

> *Information about past leaks in existing pipelines is a category of data fundamental to predicting likely leaks in those pipelines in the future*.[28]

Finally, it notes that pipeline pressure records must be used to evaluate the condition of the pipeline and welds:

> *The operating pressure history over the life of the pipe is a critical record for any piping, including natural gas pipelines. This record should keep track of normal operating cycles showing high and low pressures as evidence of the pressures to which the piping is subjected under normal operating conditions. The highest pressure and durations of that pressure over specified periods (for instance, daily, weekly, or monthly) should always be recorded because they will be used by engineers to analyze such things as the condition of the pipe and welds (especially those known to have a manufacturing threat such as Electric Resistance Welded Pipe), any risk associated with continued operating at routine pressures, the possibility of uprating to a higher MAOP, the risk of failure, or the expected life of the pipe.* [29]

In short, "*[a]ccurate, complete, and useable pipeline records constitute a utility's best and, often, its only means to understand its pipes and other components buried in the ground and out of sight, and to maximize their safety*."[30] In fact, the CPSD concludes that the explosion on Line 132 on September 9, 2010 could have been prevented had PG&E maintained its records "*properly over the years*."[31]

PG&E does not dispute its obligations under PU Code §451 to operate in a prudent manner. In hearings, Mr. Stavropoulos acknowledged that PU Code §451 constituted a preexisting requirement for prudent system operation:

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28 *Id*., at 39.
29 *Id*., at 38.
30 *Id*., at 27.
31 *Id*., at 49.

Q	*Do preexisting regulatory requirements include the conduct that would be expected of a prudent pipeline operator?*
A	*I think there's a standard. I think what you're referring to is Section 451, which does get into issues of prudence. And to the extent you're complying with that statute in terms of prudence, that's an issue separate from complying with an existing regulation on how to conduct a pressure test or maintain records.*
Q	*So then prudence would be part of your concept of preexisting regulatory requirements to the extent that it's reflected in Public Utilities Code Section 451; is that right?*
A	*We certainly expect to comply and have complied with Section 451.*
Q	*And would that encompass the concept of prudence?*
A	*Section 451 includes discussion and description of prudence.*[32]

As a result there is no rationale to excuse PG&E from the obligations of a prudent utility operator. As discussed above, PG&E should have retained records on its pipeline components and their functionality.

(ii) A Prudent Utility Operator Relies on Industry Standards to Inform its Practices

A natural interpretation of §451 is that PG&E should operate its system prudently. A prudent utility operator would have also relied on industry standards, such as the American Standards Association (ASA), to guide its understanding of the records required to safely operate its system. While PG&E does not think it should be held accountable for noncompliance with industry standard,[33] it does recognize the merit of using industry standards to inform operation of its system.

As noted in hearings by PG&E's witness Mr. Howe, state regulators have historically looked at the ASA when developing pipeline safety standards.[34] He noted that the ASA respresented an industry effort to recommend appropriate guidelines for

32 8 Tr. at 816-817 (PG&E/Stavropoulos).
33 8 Tr. at 816-817 (PG&E/Stavropoulos).
34 10 Tr. 1115-1116 (PG&E/Howe).

safety and reliability purposes.[35] PG&E's own practices also reflect the merit of complying with industry standards. PG&E states that "*after adoption of [ASA B31.1.8-1955] PG&E's practice was to follow ASA B31.1.8-1955, including pre-service testing.*"[36] Moreover, PG&E was not alone in its compliance with industry standards. Decision 61269, issued on December 28, 1960, memorializes that "*…gas utilities [including PG&E] in California voluntarily follow the American Standards Association (ASA) code for gas transmission and distribution piping systems*."[37] The 1955 standard specifically required PG&E to maintain records, for the useful life of each pipeline and main, of hydrotesting that revealed the type of fluid used and the test pressure.[38] In short, industry guidelines are relevant to determining whether PG&E operated as a prudent utility operator.

b. General Order 28 Required PG&E to Maintain Records That Would Have Provided Fundamental and Critical Information on Components of the Pipeline System

General Order 28, which was approved in 1912 and took effect in 1947, specifically required PG&E to retain pipeline system records for the life of the facility. This GO requires "*each and every public utility and common carrier subject to the jurisdiction of this Commission…shall, from the date of October 10, 1912, preserve all records, memoranda and papers supporting each and every entity in the following general books ….*" In particular, GO 28 requires the preservation of:

- *All records, contracts, estimates and memoranda pertaining to the original cost of property and to Additions and Betterments.*

35 10 Tr. 1115-1116 (PG&E/Howe).
36 PG&E Response to DRA DR 045-07(a), included in Attachments; *See also* Exhibit 143 (DRA/Pocta), at 23; Exhibit 131 (TURN/Kuprewicz), at 76; 8 Tr. (PG&E/Stavropoulos), at 886-887 and 889-890.
37 Exhibit 143, at 23 (DRA/Pocta).
38 8 Tr. at 888 (PG&E/Stravropoulos).

- *All costs pertaining to depreciation and replacement of equipment and plant.*

Moreover, GO 28 specifies that "*no records, memoranda or papers which come within the scope of this order shall be destroyed, except on the written authority of this Commission*."[39]

GO 28 required PG&E to maintain records related to pipeline safety. In hearings, PG&E's record-keeping witness, Mr. Howe, clarified that replacement of a pipeline would qualify as a GO 28 "*replacement of equipment or plant*."[40] As such, if PG&E complied with this GO, the replacement of a pipeline and the materials purchased for replacement could be verified.[41] He also noted that records retained pursuant to GO 28 would have information related to the investment in and changes to the pipelines,[42] as well as materials used and dates on which changes took place.[43] In short, even if the intent of GO 28 was solely to substantiate capital expenditures, the information retained could have provided valuable information related to PG&E's efforts to promote the safety of its system both in high consequence areas (HCA) and non-HCA areas.[44] Importantly, Mr. Howe also noted that he was unaware of any order from the CPUC that permitted PG&E to destroy records retained pursuant to GO 28.[45]

c. GO 112 Required Retention of Records Governing Design, Construction, Testing, Maintenance and Operation of PG&E's Transmission System

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39 GO 28. *See also* 10 Tr. 1208 (PG&E/Howe).

40 10 Tr. 1207 (PG&E/Howe).

41 10 Tr. 1207 (PG&E/Howe).

42 10 Tr. 1209 (PG&E/Howe).

43 10 Tr. 1209-10 (PG&E/Howe).

44 Mr. Howe clarified at hearings that GO 28's record retention requirements did not distinguish between HCA and non-HCA areas. 10 Tr. 1210 (PG&E/Howe).

45 10 Tr. 1208 (PG&E/Howe). It is noteworthy that the CPSD's investigation into record-keeping practices finds PG&E responsible for circulating an order to destroy the retention of pipeline records. See Exhibit 45, at 31 (Ms. Felts discusses October 9, 1987 memo that cancels standard practices requiring retention of pipeline records).

General Order 112 required PG&E to maintain pipeline records. First adopted in 1961, GO 112 was the Commission's first pipeline safety-specific prescriptive regulation and requires PG&E to engage in hydrostatic pressure testing of newly constructed pipelines in Class 3 areas at 1.5 times intended MAOP.[46] Existing pipelines were exempted from the new requirements.[47]

In 1970, GO 112 was revised to include federal standards on natural gas pipeline maintenance.[48] The 1970 regulation required more rigorous hydrostatic testing procedures to substantiate MAOP.[49] It also grandfathered those pipelines installed prior to 1970 from the new MAOP validation process. For those grandfathered pipelines, the utility could rely on the highest operating pressure over the previous five years.[50] Notably, however, the grandfathering provision only applied to pressure testing.[51] Accordingly, by PG&E's own admission, an operator of a pipeline qualifying under the grandfathering provision would have still been obligated, at a minimum, to undertake the work necessary to ensure that the pipeline was in good working condition.[52]

PG&E does not dispute its obligations under GO 112 but noted in hearings that the requirement to comply with specific record retention requirements commenced in

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46 NTSB Accident Report, at 34; Exhibit 131, at 76 (TURN/Kuprewicz).

47 *Id*.

48 *Id*.

49 *Id*. ("Federal regulations issued in 1970 include a requirement in 49 CFR 192.505 that any segment of newly constructed gas transmission pipeline intended to operate at a hoop stress51of 30 percent or more of its SMYS undergo a hydrostatic pressure test for a minimum of 8 hours to substantiate its MAOP. In certain class 1 or 2 locations, the test pressure must be at least 125 percent of the MAOP; in class 3 and 4 locations, the required pressure is 150 percent of MAOP. The MAOP for a newly constructed pipeline segment is derived from the pressure used during this hydrostatic testing.")

50 *Id*.

51 8 Tr. 894 (PG&E/Stavropoulos).

52 8 Tr. 895 (PG&E/Stavropoulos).

July 1961.[53] In addition, PG&E indicated that its shareholders would absorb the cost of strength testing those pipelines installed after 1961.[54]

3. PG&E's Past Mismanagement Has Increased PG&E's Costs To Comply with D.11-06-017

The record demonstrates that PG&E's past practices are increasing the costs to comply with D.11-06-017. This decision requires PG&E to "*either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test*."[55] The decision further requires PG&E to validate MAOP for those segments lacking sufficient pressure test data using pipeline features data.[56] PG&E's failure to maintain records related to pipeline features and pressure testing therefore will increase the costs associated with compliance with D.11-06-017. As discussed above, PU Code 451 and GO 28 would have required PG&E to retain pipeline specification data and at least some pressure testing data. Compliance with industry standards would have ensured that hydrotesting data was retained. The record thus reveals that a significant portion of PSEP costs are designed to bring PG&E into compliance with preexisting regulations.

B. The Commission Should Disallow Recovery of Costs that are Remedial in Nature

The Commission should require shareholders to take responsibility for those costs that are remedial in nature, meaning those costs required to bring PG&E into compliance with preexisting regulations. In quantifying these costs, the Commission should consider evidence presented in this proceeding and findings made in pending

53 10 Tr. 1112 (PG&E/Howe).
54 8 Tr. 834 (PG&E/Stavropoulos).
55 *Id.*, at 19.
56 *Id.*, at 30 (Ordering Paragraph 1).

investigations to determine which PSEP costs are required to bring PG&E into compliance with preexisting regulations. Disallowances are appropriate as they prevent double payment of costs and address PG&E's concern regarding long-term effects of its efforts to attract capital. Both PG&E's and CCUE's cost-sharing recommendations should be rejected because they do not align with these principles.

1. In Concept, All Parties but CCUE Agree that PG&E Shareholders Should Be Responsible for Remedial Costs

All parties but CCUE agree that, in principle, PG&E shareholders should be responsible for those costs required to comply with preexisting regulations.[57] Even PG&E has repeatedly emphasized that it intends for its shareholders to bear responsibility for costs that are remedial in nature.[58] CCUE contends that disallowing recovery of remedial costs will discourage PG&E from undertaking needed investments. CCUE further claims that full cost recovery will best ensure the safety of PG&E's pipeline system. [59] However, there are several flaws with CCUE's position.

First, full cost recovery alone will not encourage PG&E to undertake appropriate, cost-effective investments. CCUE contends that underfunding will incentivize PG&E to put off required work or cut corners in the process.[60] As reflected in hearings, however, the Commission has generally granted PG&E full cost recovery on pipeline safety projects over the last 30 years.[61] Yet, as evidenced by the September 9, 2011 explosion, this history of cost recovery has not led to a safe or reliable gas system.

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57 Exhibit 121, at-3-6 (TURN/Long); Exhibit 123, at 24 (NCIP/Beach); Exhibit 149, at 25-29 (DRA/Sabino); Exhibit 137, at iii and 71 (CCSF/Radigan)

58 8 Tr. at 827 (PG&E/Bottorff) ("*Clearly when we're not in compliance with the federal or state regulation and need to be, we need to bring our records and testing up to those standards. That's where we're agreeing to have our shareholders pay that cost.*")

59 Exhibit 126, at 4-5 (CCUE/Marcus).

60 *Id.*, at 5.

61 9 Tr. 959 (PG&E/Bottorff); 9 Tr. 1076-1077.

Traditional ratemaking also gives the utility an incentive to underspend because doing so adds to short-term shareholder returns.[62] In fact, TURN has estimated that shareholders realized benefits amounting to 30-43% of such underspent capital, depending on the years in which underspending occurred.[63] Also, full recovery of the proposed PSEP revenue requirement does not necessarily ensure improved safety. The IRP report recommends, therefore, that the Commission adopt formal standards and increase oversight.[64]

Second, CCUE's recommendations completely disregard the financial impact on ratepayers. Unlike disallowances, penalties or fines are deposited into the state's General Fund. [65] As such, they do not directly offset the costs borne by ratepayers.[66]

Maintaining current incentives and providing full cost recovery is not the only way to ensure PG&E undertakes appropriate PSEP investments. In fact, the Commission's use of incentives has evolved dramatically over the decades.[67] Through the 1980's, the Commission relied on other enforcement methods such as reasonableness reviews and disallowances to ensure utility compliance with its regulatory framework.[68] Overtime, reasonableness reviews in the core procurement incentive mechanisms were supplanted by financial incentives to drive utility behavior.[69] However, PG&E should not

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62 Exhibit 124, at 12 (NCIP/Beach).
63 Exhibit 98, at 12-13 (TURN/Marcus); Exhibit 124, at 12 (NCIP/Beach).
64 Exhibit 124, at 12 (NCIP/Beach) (referencing pages 12-13 of IRP Report).
65 9 Tr. 955-957 (PG&E/Bottorff); Exhibit 123, at 13 (NCIP/Beach).
66 Exhibit 124, at 13 (NCIP/Beach).
67 *Id.*, at 14.
68 *Id.*
69 *Id.*

require upside financial incentives to comply with the Commission's regulatory framework; it should comply because it is obligated to do so by law.[70]

2. Commission Should Finalize PSEP Revenue Requirement Once Pending Investigations into PG&E's Past Practices Conclude

Reports issued in the pending investigations highlight a number of expenses that should be disallowed or applied to offset ratepayer costs of the PSEP:[71]

- The CPSD found that, from 1997-2010, PG&E recovered $39.3 million from ratepayers to cover gas transmission O&M costs and $95.4 million in capital costs for its pipeline system. PG&E never spent this money for these purposes. Based on these findings, ratepayers share of PSEP costs should be reduced by an amount equivalent to this plus interest. [72]

- The NTSB accident report and CPUC's Independent Review Panel (IRP) list several shortcomings in PG&E's record-keeping practices. Based on these shortcomings, it is appropriate for PG&E shareholders to bear the full $107.1 million attributed to PG&E's MAOP validation effort[73]

- The CPUC's IRP report concludes that given GO 112's adoption in 1961, PG&E shareholders should not only be responsible for the strength testing of post-1970 pipelines for which the utility has no records, but also for the $32-48 million associated with testing 1960's vintage pipelines that lack records.[74]

Intervenors have also recommended other disallowances based on their evaluation of the programs required to bring PG&E into compliance with preexisting regulations:

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70 *Id*. For purposes of pipeline safety, adoption of NCIP's PSEP-related ROE recommendation would also encourage better efforts. As discussed in Section III(C), adoption of NCIP's ROE recommendations would lower PSEP-related ROE by 500 basis points for Phase I. It would allow parties to consider future increases in PSEP-related ROE based on PG&E's performance. In short, precluding the use of upside incentives will not hinder the Commission's ability to require compliance with its regulations. *Id*.

71 Importantly, D.11-06-017 indicates that the Commission will take official notice of reports issued in pending proceedings.

72 Exhibit 123, at 22 (NCIP/Beach); PG&E Response to NCIP Data Request 004-A01, attached to Exhibit 123 Attachment.

73 *Id*., at 24; PG&E Response to NCIP Data Request 004-A01, attached to Exhibit 123 Attachment; Exhibit 2, at 5-4.

74 *Id*.; PG&E Response to NCIP Data Request 004-A01, attached to Exhibit 123 Attachment.

- DRA recommends that shareholders bear the full responsibility for all PSEP costs from 2011 through 2014 due to its past mismanagement and in light of GA V settlement terms.[75]

- TURN recommends that the Commission adopt a revenue requirement which reflects the following principles:[76]

    - Costs resulting from PG&E errors and omissions should be disallowed;
    - PG&E should bear the burden of proof;
    - Ratepayers should not have to pay a second time for work that was not done right or work that was funded but never performed, and
    - PG&E should not profit from work required to achieve a safe pipeline system.

- CCSF observes that proposed pipeline modernization and record-keeping work is not incremental and does not recommend recovery of these costs.[77]

However, the full extent of PG&E's mismanagement will not be clear until the conclusion of the Commission's three pending investigations into PG&E's past practices (I. 11-02-016, I. 12-01-007, I.11-11-009).

While intervenors have highlighted a number of regulations that are relevant to this consideration, PG&E's past practices and compliance with existing regulations are being litigated more extensively in the pending investigations. PG&E not only agrees that its past practices should be litigated in those investigations,[78] it has acknowledged that the Commission has the authority to apply the findings in those investigations to this proceeding.[79] TURN has also noted that it would be premature to establish a PSEP revenue requirement while issues related to PG&E's past conduct remain outstanding.[80]

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75 Exhibit 150, at 6 (DRA/Sabino).
76 Exhibit 121, at 3-6 (TURN/Long).
77 Exhibit 137, at 70-77 (CCSF/Radigan).
78 *See* PG&E Motion to Amend Scoping Memo and Reassign Testimony about PG&E's Past Practices to I.11-02-016 and Request for Order Shortening Time to Respond dated February 3, 2012.
79 8 Tr. 905 (PG&E/Bottorff) (Commission has authority in pending investigations to disallow recovery of certain PSEP costs or to issue decision requiring update to PSEP revenue requirement).
80 Exhibit 121, at 8-9 (TURN/Long); 14 Tr. 2065-2068 (TURN/Long). At most, TURN recommends that the final decision address appropriate principles for cost sharing between ratepayers and shareholders. In hearings, TURN witness Mr. Long testified that once factual findings are made in the

In this proceeding, the Commission should disallow those costs listed by the CPSD, NTSB and IRP.[81] However, it should finalize the PSEP revenue requirement only after the investigations conclude to better ensure ratepayers do not shoulder responsibility for other remedial costs.

3. Disallowances Present a Balanced Way to Account for PG&E's Past Mismanagement

Disallowances are an appropriate way to minimize cost impacts on ratepayers. In hearings, PG&E testified that disallowances both directly offset costs that ratepayers have to bear and minimize adverse impacts on PG&E's ability to attract capital.[82] Unlike disallowances, a fine paid into the state's General Fund would not directly offset the costs that ratepayers must bear.[83] A fine is also not tax deductible and therefore has a more significant financial impact on PG&E.[84] Finally a decrease in rate of return will have the same short-term impact as a disallowance but PG&E maintains it will have a greater impact in the long-term because it alerts investors that the cost of doing business in California is more risky.[85] In short, a disallowance ensures that ratepayers are not forced to bear duplicative costs and it addresses PG&E's concern about the broader impacts of other mechanisms.

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pending investigations, it would be appropriate for parties to this proceeding to make specific cost recovery recommendations.

81 Mr. Beach recommends a total $309 million revenue requirement reduction over three years. This reflects adoption of his ROE recommendation which will save rateapayers $67.7 million.

82 9 Tr. 955-957 (PG&E/Bottorff). *See also* Exhibit 2, at 1-15.

83 9 Tr. 955-957 (PG&E/Bottorff); Exhibit 123, at 13 (NCIP/Beach).

84 9 Tr. 955-956 (PG&E/Bottorff).

85 9 Tr. 957 (PG&E/Bottorff).

4. PG&E's Cost Sharing Recommendations Would Unreasonably Limit Shareholders' Responsibility for Past Mismanagement

PG&E's cost sharing recommendations should be rejected as they would significantly limit the financial exposure shareholders will have for PG&E's past mismanagement. PG&E proposes to have its shareholders bear responsibility only for $319.8 million or 14.6% of Phase I costs.[86] This constitutes a mere 2.9% of Phase I and II aggregate costs which can total $11 billion in total expenditures.[87] These recommendations limit PG&E's responsibility for 2011-2014 PSEP costs.

PG&E's cost sharing recommendations result in an imbalanced sharing of risk between shareholders and ratepayers. The Overland Audit Report reveals that GT&S operations have been highly profitable since the Gas Accord Structure was implemented in March 1998.[88] In fact, the actual ROE earned by GT&S operations averaged 14.2% during 1999 through 2010 even though PG&E's authorized ROE was no higher than 11.4% during this period.[89] The Overland Report estimates that "*[o]ver the twelve-year period, GT&S revenues were $430 million higher than the amounts needed to earn the authorized ROE.*" PG&E's recommendations would allow shareholders to profit in the past and without any accountability to its ratepayers. As DRA's cost recovery witness Mark Pocta notes "*[i]t is inequitable to ratepayers to permit PG&E shareholders to keep the extra revenues and profits generated in 'good years'*

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86 Exhibit 131 at 71 (TURN/Kuprewicz). This includes PSEP costs for 2011 as well as post-1970 pipeline MAOP validation work and post-1970 pipeline strength testing. Exhibit 131 at 71 (TURN/Kuprewicz).

87 8 Tr. 838 (PG&E/Bottorff)(based on Phase II estimate of $6.8-9 billion, total for Phase I and II can be $11 billion).

88 Overland Audit Report, at 1-1.

89 *Id.*, at 5-2.

and to require ratepayers to pay more in 'bad years' to protect shareholders from potential negative impacts and risk."[90]

C. Past Mismanagement Warrants 500 Basis Point Reduction in PSEP-Related ROE

PG&E's past practices justify a ROE reduction for 2011-2014 PSEP investments. As noted below, a reduction in PG&E's PSEP-related ROE will provide the financial incentive required to drive timely and beneficial pipeline safety work. It also accounts for significant costs that ratepayers could be forced to bear over such a short period of time.

The Commission should reject the ROE concerns raised by SCE and PG&E. SCE and PG&E oppose the recommended ROE reductions on the grounds that they will affect the cost of debt, violate the regulatory compact, will decrease the incentive to undertake pipeline safety investments, and violate the *Hope* and *Bluefield* standard.[91] However, forecasted PSEP investments constitute only about 4% of PG&E' total capital investments. As a result, the impacts of a reduction in PG&E's PSEP-related ROE will not impact PG&E's ability to attract capital to the degree alleged by SCE and PG&E particularly because PG&E finances its assets companywide rather than individually. In fact, PG&E's recently-filed cost of capital application contemplates an overall ROE reduction that is 17.5 times more significant. Also, neither the regulatory compact nor the *Hope* and *Bluefield* standard supports maintaining the same ROE for PSEP investments. Finally, a lower PSEP-related ROE should not decrease the incentive of PG&E to undertake PSEP investments in light of commitments made by PG&E's executives. Notwithstanding the limited impact of this recommendation, if the

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90 Exhibit 143, at 16 (DRA/Pocta).
91 *See generally* Exhibit 130 (SCE/Hunt); Exhibit 21, Chapter 2 (PG&E/Tierney).

Commission concludes a ROE reduction should not be adopted, it should translate the ROE reduction into a disallowance amount to benefit ratepayers.

1. A Reduction in the PSEP-Related ROE is Warranted In Light of Mismanagement and the Expedited PSEP Timeline

PG&E's past mismanagement and the PSEP timeline warrant a reduction in PSEP-related ROE to prevent PG&E shareholders from unreasonably profiting from current safety efforts. NCIP witness Mr. Beach recommended that the Commission, at least temporarily, reduce PG&E's ROE by 500 basis points from 2012-2014.[92] This would reduce PG&E's PSEP-related ROE to the cost of debt and reduce the PSEP revenue requirement by roughly $67.7 million over this period.[93] If there are no safety incidents that take place during this period, Mr. Beach recommends that the Commission consider increasing PG&E's PSEP-related ROE.[94] TURN also recommends that the Commission reduce PG&E's ROE to the cost of debt.[95] It notes that this reduction in ROE will reduce PG&E's recovery of capital costs by 26% over the life of the assets.[96]

Mr. Beach's ROE reduction is justified in light of past mismanagement and the abbreviated PSEP project timeline. A reduction would provide PG&E a financial incentive to effectively, efficiently, and timely address the deficiencies highlighted in the NTSB and IRP reports.[97] It is also warranted given that ratepayers are being asked to assume a significant financial burden, within a short period of time, to ensure the safety

92 Exhibit 123 (NCIP/Beach), at 25.
93 *Id*.
94 *Id*.
95 Exhibit 121, at 2 and 16-17 (TURN/Long).
96 *Id*., at 2.
97 Exhibit 123, at 25-26 (NCIP/Beach).

of PG&E's pipeline system.[98] Importantly, in the past, the Commission has reduced a utility's ROE for poor utility performance. For example, in D. 82-12-055, the Commission decreased SCE's ROE for *<u>its entire rate</u>* base by 10 basis points for two years because SCE did not pay qualifying facility (QF) prices based on full avoided costs.[99]

Without adopting intervenors' recommended changes in ROE, PG&E will continue earning one of highest ROEs in the country.[100] As noted in Section III(A)(3), it will also earn a return on investments that is due solely to PG&E's imprudence. Moreover under the GA V structure, PG&E would also maintain the ability to earn *more* than its authorized ROE as it has done in the past.[101] Notably, PG&E has earned nearly 300 basis points more than its authorized ROE under the Gas Accord structure from 1999-2010.[102] The GA V settlement agreement's revenue sharing provision would allow PG&E to continue earning more than its authorized ROE.[103]

2. Intervenor Recommendations to Lower PSEP ROE Will Not Affect PG&E's Ability to Attract Capital to the Degree Alleged by PG&E and SCE

PG&E and SCE have overstated the impact of intervenors' recommendations on the ability to attract capital. Together they claim that the recommendations will impact a utility's ability to attract both equity and debt capital. PG&E and SCE's contentions must be tempered with information about PG&E's total capital investments.

98 *Id.*, at 26.
99 D.82-12-055, *mimeo* at 133-142.
100 9 Tr. 1067-1068 (PG&E/Tierney).
101 9 Tr. 1045 (PG&E/Tierney).
102 Overland Audit Report, at 1-3.
103 9 Tr. 1045 (PG&E/Tierney).

Information regarding PG&E capital structure reveals that intervenors' ROE recommendations will have a modest impact on PG&E's overall ROE. At most NCIP and TURN have recommended that the *PSEP-related ROE* be reduced to the cost of debt.[104] The impact of the reduction is thus highly diluted when set in the context of PG&E's overall capital structure. Assuming that PG&E's net plant values, identified in its 2010 Annual Report, remain roughly the same in 2012, the addition of $1.4 billion in *PSEP capital investments will constitute a mere 4% of PG&E's total capital investments*.[105] PG&E's annual report provides PG&E's net plant value as of December 31, 2010.[106] It indicates that PG&E's net plant as of December 31, 2010 amounted to $31.4 billion.[107] Its electric net plant totals at least $23.1 billion and its natural gas net plant totals $6.9 billion.[108] As of December 31. 2010, it had construction work in progress totaling $1.3 billion that has not been classified as either electric or natural gas work.[109] In short, intervenors' recommendations would lower ROE for about 4% of PG&E's capital investments by about 500 basis points, amounting to a mere 20 basis points in PG&E's overall ROE.[110] In comparison, in recently-filed cost of capital applications, PG&E and SCE respectively seek 350 and 400 basis point reductions in their *overall ROE*.[111]

Equally important, historic data demonstrates that PG&E's ROE reductions alone have not been responsible for changes in PG&E's cost of debt. As PG&E testified in hearings the utility's credit rating "*provides an indication about the relative cost of*

104 Exhibit 123 (NCIP/Beach), at 25; Exhibit 121, at 2 and 16-17 (TURN/Long).
105 Exhibit 44, at 66. The 4% is calculated by dividing $1.4 billion by $32.8 billion.
106 *Id*.
107 *Id*.
108 *Id*.
109 *Id*.
110 This number was calculated using PG&E's results of operations model.
111 *See* A.12-04-015 and A.12-04-018.

borrowing."[112] In 1998, when PG&E's ROE was 11.6%, it had a credit rating of A+.[113] The following year, in 1999, its authorized ROE decreased by 40 basis points.[114] Despite the drop in its authorized ROE, its credit rating remained an A+.[115] In hearings, PG&E listed several factors that can impact a utility's credit rating including:

- the ratio of price to earnings,
- the revenue stream that the utility is authorized to collect,
- its rate of return,
- the risk associated with the regulatory climate in the state, what is going on with the business conditions, and
- the degree of competition there is at the margins of the business.[116]

PG&E also acknowledged that the actual ROE can vary from the authorized ROE. PG&E's authorized ROE has been 11.35% since 2007 and yet its actual ROE has ranged from 11.19% to 12.37%.[117] In other words, even if a utility's authorized ROE remains the same, its actual ROE can vary by over 100 basis points.

3. The Regulatory Compact Does Not Justify Maintaining Current ROE

SCE contends that PG&E's ROE should be maintained because of the regulatory compact that applies. First, the regulatory compact does not specify a compensatory ROE. ROE among utilities, even for the same utility, can vary for a variety of reasons. Second PG&E has failed to maintain its part of the regulatory compact.

The regulatory compact is discussed in the Division of Strategic Planning's "*California's Electric Services Industry: Perspectives on the Past, Strategies for the Future*." In that report, it states that regulated utilities should recover expenses and

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112 9 Tr. 1060 (PG&E/Tierney).
113 Exhibit 29; 9 Tr. (PG&E/Tierney), at 1060.
114 Exhibit 29; 9 Tr. (PG&E/Tierney), at 1061.
115 Exhibit 29; 9 Tr. (PG&E/Tierney), at 1061.
116 Exhibit 29; 9 Tr. (PG&E/Tierney), at 1062.
117 Exhibit 29; 9 Tr. (PG&E/Tierney), at 1062-1063.

earn a reasonable return on investment *if* the utility provides safe and reliable service to its customers:

> *Under that compact an investor-owned public utility in California was granted 1) an exclusive retail franchise to serve a specific geographic region; 2) an opportunity to recover prudently incurred expenses; 3) an opportunity to earn a reasonable return on investment; and 4) powers of eminent domain. In return for these privileges, the utility was subject to cost and price regulation by the Commission, and required to provide safe and reliable service to all customers in its service area on a nondiscriminatory basis. This latter feature of the compact is commonly called the utility's "duty," or "obligation" to serve.*[118]

PG&E and SCE would have the Commission maintain PG&E's 11.35% ROE even if there is mismanagement found.[119] However, PG&E's provision of safe and reliable service to its customers is at issue. PG&E has not held its end of the regulatory compact bargain. As a result, the regulatory compact does not support maintaining PG&E's current ROE for PSEP investments.

4. A Lower PSEP-ROE Should Not Decrease the Incentive to Undertake Safety Projects

Lowering PG&E's PSEP should not decrease PG&E's commitment to promote pipeline safety. In its prepared testimony, PG&E noted that adoption of intervenors' ROE recommendations will decrease its "*incentives to undertake PSEP investments*."[120] However, at hearings, it clarified that notwithstanding this reduction, its management would still undertake investments required to ensure safety:

> *Q Okay. So if PG&E's Pipeline Safety Enhancement Plan return on equity were reduced down to 11 percent from 11.35 percent, would PG&E continue to have incentives to comply with existing pipeline safety regulations and Commission directives?*

118 Exhibit 130, at 4 (SCE/Hunt).
119 9 Tr. at 1045-1046 (PG&E/Tierney).
120 Exhibit 21 at 2-14 (PG&E/Tierney).

A *Yes. Technically, yes. Because the -- I have heard the senior executives of the company say that they are going to continue to do things. But would it create a financial disincentive to still continue on that path, yes. That particular return on equity reduction would distinguish and disadvantage financially investments in the PSEP project.*

Q *Okay. If pipe -- if PG&E's pipeline safety related return on equity is reduced to 10.5 percent, would it have less incentive to undertake pipeline safety investments than it would if its return on equity were 11 percent on those same assets?*

A *Yes. That financial disincentive would be created even though I have heard PG&E's senior executives say that they are going to do the right thing on safety, but financially is creating on the margin a disincentive and a lesser priority for PSEP than other investments.*

Q *So is it your position that the extent to which PG&E is attentive to safety will depend on shareholder returns?*

A *No, because of what I just said, which is that I have heard the senior executives of the company say that they are going to do it.* [121]

Based on PG&E's own statements, it will remain committed to pipeline safety even if the Commission lowers its PSEP-related ROE.

5. ***Hope*** **and** ***Bluefield*** **Standard Does Not Support Rejection of Intervenors' ROE Recommendations**

The *Hope* and *Bluefield* standard does not support rejection of intervenors' ROE recommendations. PG&E argues that regulators should use ratemaking mechanisms and rate levels to produce a level of capital investment and O&M expenditures that support regulatory goals.[122] PG&E references the *Hope* and *Bluefield* cases, which "*supports ratemaking that assures that the utility has enough revenue to cover operating expenses (including servicing debt and equity requirements commensurate with other*

121 9 Tr. at 1048-1049 (PG&E/Tierney).
122 Exhibit 21, at 2-8 (PG&E/Tierney).

enterprises with comparable risks)."[123] PG&E's reliance on the *Hope* and *Bluefield* standard is misplaced. As discussed in Section III(C)(2), the proposed PSEP ROE reduction will decrease PG&E's overall ROE by only 20 basis points. This is not material when set in context with normal ROE variations among utilities.[124]

At 11.35%, PG&E has one of the highest authorized ROEs in the country.[125] The November 2010 Public Utilities Fortnightly article, for example, lists the authorized ROE for 41 reporting utilities.[126] Of these utilities, there was only one reporting gas utility that had an authorized ROE that was higher than PG&E's, six had authorized ROEs that were above 10.5%, and most utilities had an authorized ROE that was between 10% and 10.5%.[127] As for electric utilities, only one reporting utility had an ROE that was higher than PG&E's, and only four utilities had authorized ROEs that were greater than 11%.[128] The only other gas and electric utility in California, San Diego Gas and Electric, reported an authorized ROE of 10.79%.[129]

PG&E's authorized ROE is already among the highest in the country and even higher than the only other gas and electric utility in the state. A change that would lower its overall authorized ROE by a modest amount will therefore not violate the *Hope* and *Bluefield* standard.

[123] Exhibit 21, at 2-8 (PG&E/Tierney); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works and Improvement Co. v. Public Service Commn.*, 262 U.S. 679 (1923).
[124] *See* Exhibit 29.
[125] 9 Tr. (PG&E/Tierney), at 1045 and 1064.
[126] Exhibit 43; 9 Tr. (PG&E/Tierney), at 1064.
[127] Exhibit 43; 9 Tr. (PG&E/Tierney), at 1065-1066.
[128] Exhibit 43.
[129] *Id.*; 9 Tr. (PG&E/Tierney), at 1067.

6. If the Commission Prefers Not to Lower PSEP-Related ROE, It Should Offset PG&E's Revenue Requirement By An Equivalent Disallowance

While a PSEP-related ROE reduction is warranted, if the Commission decides against this approach, it should disallow recovery of an equivalent amount of costs to keep ratepayers neutral. Shareholders should not be able to profit from PG&E's efforts to promote safety, especially following such a tragic incident. In order to ensure that ratepayers are not paying for these shareholder profits, the Commission should translate the recommended authorized ROE reductions into a disallowance amount and then use this to decrease the PSEP revenue requirement. Notably, PG&E testified that this aligns with its ratemaking principles:

> *Q Is it your position that transforming a return on equity reduction into an explicit fine would make Mr. Beach's proposal acceptable and consistent with your five principles?*
>
> *A Mathematically if you could exactly the same dollar effect into a concrete objective, known and measurable disallowance, for example, it would have the same effect on customers and it would have a very different incentive financially for PG&E. And so in that sense I think it is preferable, would be preferable, all else equal.*[130]

PG&E further contends that compliance with its ratemaking principles would "*provide PG&E with both sound incentives and resources for making the investments and expenditures necessary to enhance its operations and assets consistent with the Commission's safety, reliability and rate-level goals*."[131] If the Commission chooses against a ROE reduction, this would be an appropriate alternative.

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[130] 9 Tr. 1058 (PG&E/Tierney).

[131] Exhibit 21, at 2-7 (PG&E/Tierney).

D. The Commission Must Require PG&E To Seek Approval for Any Changes in Scope

To ensure that PG&E undertakes Phase I PSEP work in a cost-effective manner, the Commission should require PG&E to seek approval in any changes in work scope. In its application, PG&E proposed a one-way balancing account that would return unused funds back to ratepayers.[132] It also, however, seeks authority to move Phase I projects into Phase II if it does not have sufficient funds to cover project costs.[133] This will not adequately safeguard ratepayers from overpaying for PSEP projects as it does not ensure cost-effectiveness on a project-by-project basis.[134] As noted below, the one-way balancing account would allow PG&E to overspend on individual projects and simply shift additional costs into Phase II.[135]

In its request, PG&E seeks approval of its forecast Phase I PSEP costs. This forecast was developed in August 2011.[136] Importantly, ongoing and planned MAOP validation work can reduce the funds needed for Phase I projects. In hearings Mr. Stravropoulos testified that PG&E has already determined it will not be required to test 44 of 152 miles because it found pressure test records through the MAOP validation process.[137] Through this process, PG&E has also found records for 240 miles for which records were originally labeled incomplete.[138] PG&E contends that its inflated revenue requirement forecasts will not harm ratepayers because of the one-way balancing

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132 Exhibit 2, at 8-1 to 8-2.
133 Exhibit 2, at 8-7.
134 Exhibit 123, at 10-11 (NCIP/Beach).
135 *Id*.
136 8 Tr. 871 (PG&E/Stavropoulos).
137 8 Tr. 870 (PG&E/Stavropoulos).
138 8 Tr. 871 (PG&E/Stavropoulos).

account.[139] However, the revenues may not come back to ratepayers if PG&E spends more than anticipated for other projects.

PG&E's proposed one-way balancing account will not sufficiently ensure that PSEP funds are used cost effectively. PG&E contends that its proposed Tier 3 advice letter would address this concern because it would require PG&E to seek Commission approval of changes in scope. However, Chuck Marre clarified that PG&E does not intend to seek approval of changes in scope that would decrease the number of projects in Phase I.[140] It would only use the Tier 3 advice letter process to increase the scope of projects in Phase I or seek additional funding.[141] This would allow PG&E to move projects into Phase II and spend more on remaining Phase I projects.[142] As such, it does not adequately address NCIP's concern. Accordingly, it is important that the Commission require PG&E to seek its approval of *any* changes to the Phase I PSEP scope.

IV. THE COMMISSION SHOULD RELY ON COST ALLOCATION METHODOLOGIES THAT PRESERVE GAS ACCORD V FEATURES AND REFLECT COST CAUSATION PRINCIPLES

The Commission should adopt a cost allocation approach that does not disturb the rates or rate design adopted in the GA V Settlement. As noted by DRA, parties to that settlement did not contemplate rate changes until the next Gas Accord case. Moreover, changing the rates adopted in the GA V settlement will have material impacts on the balance of interests adopted in the settlement requiring rate design issues to be

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139 8 Tr. 872 (PG&E/Stavropoulos).
140 14 Tr. 1962-1963 (PG&E/Marre).
141 14 Tr. 1962-1963 (PG&E/Marre).
142 Exhibit 123, at 10-11 (NCIP/Beach).

re-opened and re-litigated. For this reason, the surcharge approach proposed by PG&E would best accommodate the balance struck in that proceeding.

Maintenance of the GA V settlement rates and consistency with cost causation principles also require the Commission to allocate PSEP costs in a manner that departs from allocation of transmission costs to customer classes in the GA V settlement. Parties to that settlement did not specifically consider PSEP costs at the time the settlement was negotiated and may not have agreed to the same allocation method had PSEP costs been included. In addition, Gas Accord V costs are not allocated strictly using cost causation principles but are based on perceptions of fairness among settling parties. The nature of the GA V settlement requires the Commission to use a different method to allocate PSEP transmission costs to customer classes. Moreover, using the GA V settlement as the basis for allocating PSEP costs results in substantial rate increases for the most price-sensitive noncore customers. Such rate increases can encourage bypass of the PG&E system as customers choose to switch to other pipelines or other sources of gas supply. This will adversely affect all PG&E ratepayers as PG&E will have to recover additional revenues from its remaining customers.

Finally, the Commission should adopt PG&E's recommendation to allocate GTAM costs between local and backbone functions because it better reflects cost causation principles. TURN recommends that GTAM information technology costs be allocated based on pipeline mileage. This would shift more of the GTAM costs to the backbone function even though Phase I of the PSEP primarily involves local transmission work.

A. Recovery of PSEP Costs Through GPS Surcharge Best Preserves Balance Struck in Gas Accord V

PG&E's proposal to recover the PSEP revenue requirement through a new Gas Pipeline Safety (GPS) rate component should be adopted because it maintains the GA V settlement balance. PG&E proposes to recover the annual authorized PSEP revenue requirement through a gas pipeline surcharge (GPS) component that would be recovered in the customer class charge of core and noncore end-use rates.[143] Use of the surcharge avoids several problems that would otherwise arise:

(1) *PSEP and GA V Revenues Would Have To Be Separately Tracked:* The revenue sharing mechanism of the GA Vsettlement provides for sharing of GT&S revenues between shareholders and ratepayers. It requires PG&E to calculate revenues collected at original GA V rates.[144] If the PSEP costs are incorporated into GA V rates, the PSEP revenues would later have to be separated from GA V revenues to allow the settlement's revenue sharing provision to apply.[145]

(2) *Backbone Rate Design Issue in Settlement Would Have To Be Re-Opened:* Use of a functionalized cost allocation method, as proposed by DRA, will impact backbone rate design.[146] GA V backbone rate design was complicated and the subject of complex negotiations.[147] The resulting rates are differentiated by backbone path and include common costs that are allocated to all backbone rates.[148] If a GPS surcharge is not used, it would require the re-opening of these contentious issues.[149] In addition, operations and maintenance costs are dependent on how costs are allocated among the GT&S functions.[150] Therefore if the allocation among these functions changes, it will also affect O&M cost allocations. Finally, "*common*" pipeline safety O&M costs vary from the "*common costs*" that are allocated in GA V settlement.[151] These would have to be reconciled to accommodate a functionalized cost allocation approach as recommended by DRA.[152]

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143 Exhibit 2, at 10-4.
144 Exhibit 124, at 4 (NCIP/Beach).
145 *Id.*
146 *Id*, at 5.
147 *Id.*
148 *Id.*
149 *Id.*
150 *Id.*
151 *Id.*
152 *Id.*

(3) _Discounted Local Transmission Rates Will Need To Be Adjusted_: The GA V settlement provides for discounted local transmission rates for certain customers. If a surcharge is not used, PG&E notes that local transmission rates will reflect higher than appropriate discount adjustments.[153]

DRA recommends rejection of the surcharge on the grounds that it violates the GA V settlement.[154] However, as reflected above, DRA's approach would create complicated GA V issues that would have to be addressed. DRA does not attempt to deal with these problems, however, because it recommends that pipeline safety costs be integrated into rates only after 2015.[155]

If the Commission approves the recovery of some PSEP costs before 2015, the use of a GPS surcharge is also appropriate because it is consistent with cost causation principles. DRA claims that the use of a surcharge runs counter to cost causation principles because it would recover PSEP costs only from end-use customers.[156] However, the focus of this rulemaking is to enhance the safety of the public that lives and consumes natural gas in California.[157] In fact, the rulemaking provides that it "*will consider how [to] align ratemaking policies, practices and incentives to better reflect safety concerns and ensure ongoing commitments to public safety*."[158] This supports an allocation of PSEP costs to just end-users. Moreover, if PSEP costs are assessed on marketers and on end-users, tracking PSEP costs would be difficult.[159] If PSEP

153 Exhibit 149, at 50 (DRA/Sabino).
154 *Id.*, at 147-155.
155 Exhibit 124, at 3 (NCIP/Beach).
156 Exhibit 149, at 147-155 (DRA/Sabino).
157 Exhibit 124, at 6 (NCIP/Beach).
158 R.11-02-019, at 11.
159 Exhibit 124, at 7 (NCIP/Beach).

costs are assessed only on end-users, it would be clearer that PSEP costs are assessed just once on a single volume of gas.[160]

Finally, use of a surcharge provides additional benefits. PG&E correctly notes that the use of a distinct GPS rate allows more transparent tracking of PSEP costs.[161] If PSEP costs are rolled into local and backbone transmission rates, these costs cannot be tracked. PG&E's backbone costs are "*buried*" within PG&E's core commodity cost of gas and noncore customers purchasing gas at the PG&E citygate are unaware of the specific backbone costs that upstream shippers bear.[162] Separate tracking is also important given the recommendations of intervenors to lower, at least temporarily, the rate of return on PSEP investments.[163]

B. The Commission Should Reject PG&E's Proposal To Allocate PSEP Costs Among Customer Classes Similar to Gas Accord V Transmission Costs

Use of the Gas Accord V Settlement cost allocation methodology to allocate PSEP costs should be rejected because it does not reflect cost causation principles. PG&E's proposes to allocate PSEP costs among customer classes using the GA V method.[164] The GA V settlement specified the percentage of backbone transmission, local transmission and storage costs that should be allocated to core and noncore customers.[165] It allocates about 42% of backbone transmission costs, 64% of local transmission costs and 58% of storage costs to core customers.[166] PG&E contends that use of this allocation methodology for PSEP costs would ensure consistency with

160 *Id.*, at 7.
161 Exhibit 2, at 10-4.
162 Exhibit 124, at 7 (NCIP/Beach).
163 *Id.*, at 4-5.
164 Exhibit 123, at 13 (NCIP/Beach),
165 Exhibit 2, at 10-4.
166 *Id.*, at 10-4.

the Gas Accord V allocation of costs.[167] While NCIP supports preservation of the GA V rate structure, PG&E's proposal ignores the nature of the settlement's allocation factors and the potential distortion that could result from their use in the PSEP. PSEP costs were not specifically considered by settling parties at the time that the Gas Accord V settlement agreement was negotiated. Moreover, in hearings, PG&E acknowledged that at most, the GA V allocation methodology was selected because it was equitable, not because it was based on cost causation principles.[168] The allocation factors included in the GA V settlement may have been intended by parties to counterbalance other settlement concessions. Consequently, the use of these factors would disturb the settlement balance.

Given the extraordinary degree of costs involved both in Phase I and Phase II, it is appropriate to consider a different allocation approach to better align with cost causation principles. Data on cost causation supports the allocation of PSEP costs using the EPAM method proposed by SoCalGas/SDG&E and by Mr. Beach. Under the EPAM allocation, each customer class bears a rate increase that is equivalent to the percent increase in that class' base margin portion of transportation rates.[169] The percent increase is derived using PG&E's authorized margin for end-use transportation costs which bundles together distribution and local transmission costs.[170] The PSEP costs would be separately allocated to backbone and storage costs based on an equal percentage share of the core's and noncore's respective backbone and storage

167 Exhibit 123, at 13 (NCIP/Beach); PG&E Testimony, at 10-2.
168 14 Tr. 2025 (PG&E/Blatter).
169 Exhibit 123, at 14 and 20 (NCIP/Beach).
170 *Id.*, at 19.

costs.[171] If the EPAM method is used to allocate PG&E's PSEP costs, 76.5% of 2012-2014 PSEP costs are allocated to core customers while 23.6% are allocated to noncore customers.[172] In comparison, PG&E's GA V allocation factor method, would allocate 60% of its PSEP revenue requirement to core customers and 40% to noncore customers.[173]

The EPAM method allocates PSEP costs in proportion to the benefits received. SDG&E/SoCalGas data clarifies that 97% of the premises structures found within the Potential Impact Radius (PIR) of their transmission pipelines are typically those associated with core residential and commercial customers.[174] This demonstrates that customers who live or work within the PIR of a gas transmission line will receive the direct benefits of enhanced safety, in terms of reducing their own risk of harm from a pipeline incident.[175] When the same question was asked of PG&E, it noted that it does not track buildings in this manner. At hearings TURN witness Bill Marcus, however, did not disagree that structures in the PIR of pipelines were *primarily* residential and commercial.[176]

The high concentration of residential and commercial structures near gas transmission pipelines supports a cost allocation method that better reflects cost causation principles. The EPAM method is more reasonable given that core and commercial customers will realize almost all the *direct* safety benefits of the projects

171 *Id.*
172 *Id.*
173 *Id.*, at 14.
174 Exhibit 123, at 15 (NCIP/Beach).
175 *Id.*
176 13 Tr. 1785 (TURN/Marcus).

contemplated in Phase I.[177] This supports a greater allocation of PSEP costs to core customers than the GA V allocation used to apportion the costs of standard gas transmission service. In addition, the consideration of distribution costs in base margin is appropriate given that the stated purpose of the rulemaking is "*to adopt new safety and reliability regulations for natural gas transmission and* ***distribution*** *pipelines*."[178] Finally, the PSEP will improve safety at the distribution level through better record-keeping, more coordination with first responders, and enhanced Commission oversight.[179]

Selecting the wrong cost allocation method can have significant adverse impacts for all natural gas ratepayers. For example, use of the Gas Accord V cost allocation methodology can lead to major increases in noncore natural gas transportation rates. A significant increase in these rates can increase the potential for bypass of PG&E's system. Notably about 4,300 MW of efficient gas-fired combined-cycle power plants have been connected to interstate pipelines or California production in the last ten years.[180] In addition the percentage of gas use served from non-utility pipelines has increased from 29.7% in 1999 to 34.3% in 2009.[181] With transport-only rates increasing from 18.6% to 108% under PG&E's proposed cost allocation, there is good reason for the Commission to consider the long-term impacts on gas utility rates of physical bypass or "*bypass by wire*," which results when gas throughput shifts to electric

177 Exhibit 123, at 15-16 (NCIP/Beach). All customers will realize indirect benefits of the contemplated safety improvements as the efforts will create a more robust and resilient gas system that faces less safety risks. Exhibit 123, at 16 (NCIP/Beach).
178 R.11-02-019, at 3-15 (emphasis added); Exhibit 123, at 21 (NCIP/Beach).
179 *Id*.
180 Exhibit 123, at 16 (NCIP/Beach).
181 *Id*., at 16.

generators supplied from non-utility pipelines.[182] The bypass of customers will lead to higher costs for remaining customers on the PG&E system. This is one reason SoCalGas/SDG&E have proposed to use the EPAM methodology to allocate their PSEP costs.[183]

Reliance on the GA V cost allocation methodology can also lead to significant increases in electric rates because of its impact on gas costs for gas-fired electric generators. PG&E's recommendations will increase the transportation rate for electric generation (EG) customers on the local transmission system by roughly $0.25 per MMBtu in 2012 and $0.32 per MMBtu in 2014.[184] This amounts to a doubling of this EG transportation rate by 2014.[185] Increases in EG transportation rates can increase electric rates in three ways:

1. Wholesale electric market prices typically are based on the costs of the marginal generator, which will be higher with the new pipeline safety charges.[186] This means that the market clearing wholesale electric prices will increase as a result of new pipeline safety charges.[187] All generators receive the market-clearing price, even EGs who do not pay the pipeline safety surcharges because they secure gas supplies from an interstate pipeline or California production.[188] Importantly, gas-fired generation produced 109,481 GWh of power in 2010 (comprising 38% of statewide generation).[189]

2. The pricing for 85% of electricity imports (roughly 72,000 GWh in 2010), particularly the imports of short-term energy will be affected by higher California electric market prices resulting from pipeline safety costs.[190]

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182 *Id.*, at 16.
183 *Id.*, at 14-15.
184 *Id.*, at 17. Importantly the EG rate increase will also impact the ability of these customers to compete. PG&E's proposed surcharges would increase the burnertip gas costs of EG customers by 4% more than the EPAM allocation. This could shift generation to facilities outside the state or to generators served by interstate pipelines or California production. *Id.*
185 *Id.*
186 *Id.*, at 17-18.
187 *Id.*
188 *Id.*
189 *Id.*
190 *Id.*, at 18.

3. The prices applicable to some generators not burning natural gas are priced with formulas that rely on the gas utilities' tariffed EG transportation rates.[191] Renewable generation purchased at short-run avoided cost energy prices, AB 1613 feed-in tariff programs and AB 1969 feed-in tariff programs all use pricing that is based on EG transportation rates.[192]

Electric rate increases can be 2.4 times higher than the increase in gas transportation costs.[193] Mr. Beach notes that an increase of $0.19 per MMBtu in the cost of marginal electric generation with a market heat rate of 8,000 Btu per kWh will raise electric market prices by $1.50 per MWh.[194] Assuming that such an increase will impact the cost for electric ratepayers of (1) in-state gas-fired generation (109,000 GWh), (2) 50% of electricity imports (36,000 GWh), and (3) SRAC-priced renewable generation (15,000 GWh), the increase in electricity costs would be $1.50 per MWh times 160,000 GWh per year, or $240 million per year.[195] This amounts to 2.4 times the direct increase in gas costs for electric generators.

Importantly, even a shift to the EPAM cost allocation methodology will not exempt noncore customers from paying PSEP. In fact, under the cost allocation proposals of both PG&E and NCIP, noncore customers will see a more significant percent increase in transport-only rates than will core customers. The table below demonstrates how core transport-only rate increases would compare to the rise in noncore transport-only rates. For the purposes of this comparison, core retail residential transport-only rates are compared to noncore-transport-only rates.[196]

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191 *Id.*

192 *Id.*

193 *Id.*, at 17.

194 *Id.*, at 18-19.

195 *Id.*

196 A comparison of transport-only rates is more appropriate than a comparison of bundled rates because noncore customers do not secure natural gas commodity from the utility. *Id.* , at 12. A transport-only rate comparison not only allows an apples-to-apples comparison of rates, it also better focuses on the services actually secured from the utility.

Transport-Only Rate Increases: PG&E Cost Allocation

Customer Class	Percent Increase in 2014[197]
Core Retail-Residential Non-CARE (Transport Only)	9.2
Industrial Distribution	18.6
Industrial Transmission	45.9
Industrial Backbone	19.1
Electric Generation-Transmission	109.8
Electric Generation-Backbone	108.5

The table reveals that under PG&E's revenue requirement and cost allocation proposal, the core residential transport-only rate increases by 9.2% by 2014 while the noncore transport–only rate increases by 18.6-109.8%. Even where an EPAM allocation is used, residential customers will see a smaller percent increase than noncore customers:

Transport-Only Rate Increases: EPAM Cost Allocation

Customer Class	Percent Increase in 2014[198]
Core Retail-Residential Non-CARE (Transport Only)	12.1
Industrial Distribution	23.5
Industrial Transmission	24.2
Industrial Backbone	19.1
Electric Generation-Transmission	55.6
Electric Generation-Backbone	108.5

While the core residential transport-only rate increases by 12.05% by 2014, under EPAM, the noncore transport –only rate increases are still higher, rising by 19.1-108.46%.

197 Data drawn from Exhibit 19, at WP-14.
198 Data drawn from Exhibit 22, at 19-6.

C. The Commission Should Reject TURN's Recommendation to Allocate GTAM Based on Mileage

The Commission should adopt PG&E's proposed approach to allocating GTAM costs. PG&E proposes that GTAM costs be allocated in proportion to backbone and local PSEP costs. Under PG&E's proposal, 81% of GTAM costs would be allocated to the local transmission function and 16.5% would be allocated to the backbone function. It is appropriate for the bulk of GTAM costs to be allocated to the local transmission function because the bulk of Phase I PSEP costs will primarily involve local transmission projects. [199] In fact, 858 miles out of 1.059 miles (*i.e.* 81%) of PG&E's high consequence area (HCA) pipelines are local transmission pipelines.[200] Since local transmission safety costs are causing PG&E to incur Phase I GTAM costs and because the focus is on HCA pipelines (81% which are transmission), it is appropriate that the allocation of GTAM costs be based on Phase I PSEP expenditures.

The Commission should reject TURN's recommendation to allocate GTAM costs based on overall mileage of backbone and local pipelines. TURN notes that the GTAM "*collects, validates, and stores data for all transmission pipelines on the PG&E system, not just segments being worked on under Phases 1 and 2 of the current program*." TURN's recommendations would shift more costs to the backbone component of safety-related rates when compared to PG&E's proposal. In comparison to PG&E's proposal, TURN's proposal would allocate 61.57% of GTAM costs to local transmission and 34.85% of GTAM costs to backbone transmission despite the fact that most Phase I costs mainly involve local transmission pipelines.[201] This cost allocation method fails to

199 14 Tr. 2023 (PG&E/Blatter).
200 Exhibit 124, at 9 (NCIP/Beach).
201 Exhibit 98, at 17 (TURN/Marcus).

reflect how the PSEP funds will be used or the relative mileage of the local and backbone lines in HCAs. Accordingly, it should be rejected.

V. COMMISSION SHOULD REQUIRE PG&E TO MITIGATE OPERATIONAL AND FINANCIAL IMPACTS OF SERVICE DISRUPTIONS WITH NOTICE AND DISRUPTION CREDITS

While service disruptions will be an inevitable consequence of PG&E's pipeline safety efforts, PG&E acknowledges that PSEP projects can result in service disruptions that will have operational and financial implications for large-volume noncore industrial and electric generation customers.[202] To mitigate these impacts, the Commission should require PG&E to provide a minimum amount of notice to this subset of customers to limit the operational and financial impacts of these disruptions. It should also adopt a $0.25 per therm credit mechanism through which shareholders will compensate noncore customers for local transmission disruptions or pressure reductions for which PG&E fails to provide adequate notice.

A. Service Disruptions Will Have Financial and Operational Impacts on Noncore Customers

Service disruptions will have financial and operational impacts on noncore customers. Service disruptions can prevent customers from using firm transportation rights.[203] It can also limit the ability of noncore customers to meet contractual obligations to deliver electricity or other energy-intensive products and cause noncore customers to incur higher operating costs.[204] Importantly, even if service reductions and disruptions take place over the weekend, they will still have financial and

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202 14 Tr. 1895 (PG&E/Berkovitz).
203 Exhibit 123, at 28 (NCIP/Beach).
204 *Id*.

operational impacts on customers.[205] Moreover, the risks of financial and operational impacts is greater given the scope of work that is contemplated in PG&E's PSEP.[206]

B. PG&E Currently Has No Protocols in Place To Ensure Large Noncore Customers Will Receive Notice of Disruptions

The Commission should require PG&E to provide a large-volume noncore customer with notice of service disruptions. PG&E acknowledges that it is important to provide notice of service disruptions to its customers. In its testimony, PG&E states that it "*will conduct extensive customer and community outreach to notify and educate affected customers of any field activities that may impact them, respond to safety concerns, and [ ] inform the public and local government officials of PG&E's schedule and progress*."[207] Rule 14(A) also provides that PG&E "*shall give Customers reasonable notice as circumstances will permit, and PG&E shall complete repairs or improvements as soon as practicable and with minimal inconvenience to Customers*."[208] However, in hearings PG&E's witness testified that if NCIP's notice recommendation is not adopted, the amount of notice PG&E would provide to customers would "*vary depending on the circumstances of the situation*."[209] Stated differently, PG&E has not committed to any minimum notice period.[210] Moreover, PG&E revealed that less than 30-day notice of disruptions is possible:

> Q *Okay. Does PG&E object to the provision of 30 days notice prior to undertaking work that could disrupt transmission service?*

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205 *Id.* (Service disruptions can limit the ability of noncore customers to meet contractual obligations to deliver electricity or other energy-intensive products. It can also cause noncore customers to incur higher operating costs.)
206 *Id.*
207 Exhibit 2, at 1-6.
208 PG&E Rule 14. See also Exhibit 123 (NCIP/Beach), at 27.
209 14 Tr. 1893-1894 (PG&E/Berkovitz).
210 14 Tr. 1894 (PG&E/Berkovitz).

> A *PG&E doesn't believe that it's necessary to have a 30-day notice because we already provide extensive communication with our customers. It is not always possible to provide a 30-day notice because the schedule is not necessarily -- there are a lot of factors that go into scheduling and work, and they are not necessarily within our complete control.*[211]

PG&E also acknowledges that it is familiar with the impact a disruption can have on a noncore customer operating critical energy infrastructure such as a refinery.[212] However, it has not committed to a minimum notice period for these customers.[213] It appears PG&E believes its customers should just trust that it will provide adequate notice.

C. NCIP Credit Would Mitigate the Financial Impact of Service Disruption When Adequate Notice Cannot Be Provided

To mitigate the impacts of service disruptions on customers, the Commission should require PG&E to provide service disruption credits when it cannot comply with minimum notice periods.[214] In particular, the Commission should require PG&E to provide all customers with a minimum 30 days' notice prior to scheduled pipeline enhancement activities that may result in pressure reductions or minor service reductions and disruptions.[215] Where a complete service curtailment is required, PG&E should provide much more notice -- at least six months' notice -- to large noncore customers operating critical energy infrastructure such as a refinery or electric generator. This notice period is required for large noncore customers operating energy infrastructure to ensure they have sufficient time to safely wind down or change

211 14 Tr. 1893 (PG&E/Berkovitz).
212 14 Tr. 1895 (PG&E/Berkovitz).
213 14 Tr. 1893 (PG&E/Berkovitz).
214 Under NCIP proposal, provision of notice would obviate payment of any credit.
215 Exhibit 123 (NCIP/Beach), at 28.

operations.[216] Failure to provide this amount of notice can have safety impacts and will cause customers to incur costs discussed in Section V(A).

The Commission should base the service disruption credits on the existing credit that PG&E provides to backbone transmission customers and on SoCalGas' Rule 23 Service Interruption Credit.[217] Since June 2011, PG&E has provided its firm backbone transportation customers with credits to reservation charges when customers have been unable to use their full firm capacity due to pressure reduction or related work.[218] To mitigate financial impacts on backbone customers, the Commission should require PG&E to continue crediting firm backbone customers reservation charges when they are unable to use their capacity.[219] Under the Gas Accord V settlement, 50% of these credits are funded by shareholders.[220] This credit is not currently memorialized in PG&E's tariffs.[221] To compensate local transmission customers for financial impact associated with local transmission disruptions, the Commission should adopt a service disruption credit based on SoCalGas' Rule 23 credit.[222] Under SoCalGas' Rule 23, customers with qualifying service interruptions, not noticed by at least 30 days' prior notice, are entitled to a flat $0.25 per therm of gas curtailed or diverted.[223] The same credit should apply to customers not receiving 30 days' notice or 6 months' notice, where applicable. Notably, SoCalGas' Rule 30 credit applies only to scheduled maintenance. As such, it should not affect PG&E's ability to respond to emergency situations.

216 *Id.*, at 28.
217 *Id.*, at 28-29.
218 *Id.*
219 *Id.*, at 29.
220 *Id.*
221 14 Tr. 1899 (PG&E/Berkovitz).
222 Exhibit 123, at 29-30 (NCIP/Beach).
223 SoCalGas Rule 23(K). See also Exhibit 123 (NCIP/Beach), at 29.

VI. CONCLUSION

For the foregoing reasons, the Commission should:

1. Disallow recovery of costs determined to be remedial in nature;
2. Reduce PG&E's PSEP-related ROE by 500 basis points;
3. Require PG&E to secure Commission approval for any changes in Phase I scope;
4. Require PG&E to recover PSEP costs through a gas pipeline surcharge as recommended by PG&E;
5. Adopt the EPAM cost allocation method;
6. Allocate GTAM costs between backbone and local transmission functions in proportion to their share of PSEP costs, as PG&E recommends;
7. Require PG&E to comply with a minimum notice protocol that requires it to provide 30 days' notice of minor service disruptions and at least 6 months' notice to customers operating critical energy infrastructure, when complete disruptions are necessary; and
8. Mandate PG&E to provide service disruption credits in the amount of $0.25/therm when PG&E is unable to comply with its notice protocol.

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