Exhibit No. ___________
Date: February 28, 2012
Witness: R. Thomas Beach

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)

PREPARED REBUTTAL TESTIMONY OF R. THOMAS BEACH

ON BEHALF OF

THE NORTHERN CALIFORNIA INDICATED PRODUCERS

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Crossborder Energy

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Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Have you previously served direct testimony in this proceeding?

A: Yes, I have. On January 31, 2012, I served prepared direct testimony in this proceeding on behalf of the Northern California Indicated Producers (NCIP). The direct testimony includes a description of the members of NCIP and their interests in this proceeding. **Attachment RTB-1** to my direct testimony summarizes my experience and qualifications, and includes a list of the previous testimonies that I have filed before this Commission.

Q: What is the purpose of this rebuttal testimony?

A: My rebuttal testimony addresses selected proposals presented in the direct testimonies of the other intervenor parties, also served on January 31, 2012.

I. SUMMARY AND RECOMMENDATIONS

Q: Please summarize the proposals addressed in your rebuttal testimony, and your recommendations concerning those proposals.

A: My rebuttal testimony addresses the proposals listed below; I also summarize my recommendation on each one:

1. If the Commission does not adopt the Division of Ratepayer Advocates' (DRA) primary recommendation of no rate changes until 2015, the Commission should reject DRA's apparent proposal to place all safety-related costs into standard backbone and local transmission rates. DRA's proposal is inconsistent with cost causation principles, could result in a customer being assessed two charges for safety-related costs on a single volume of gas, and would greatly complicate the accounting for and transparency of PSEP costs for PG&E, the Commission, and PG&E end-users
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2. If the Commission does not adopt DRA's and The Utility Reform Network's (TURN) recommendations to have shareholders bear the cost of PG&E's Gas Transmission Asset Management (GTAM) program, the Commission should reject TURN's proposal to allocate the costs of the GTAM program on the basis of overall mileage of PG&E's backbone and local transmission pipelines. TURN's proposal would shift more costs to the backbone component of safety-related rates, compared to PG&E's or NCIP's proposed allocations of GTAM costs. PG&E's and NCIP's proposed allocation best reflects the distribution among the transmission functions of the Phase I safety-related improvements that are driving the need for the GTAM.

3. The Coalition of California Utility Employees (CUE) and the United Association of Plumbers, Pipe Fitters and Steamfitters Local Union Nos. 246 and 342 (Local Unions) urge the Commission to provide PG&E with full cost recovery for future safety investments and to maintain current financial incentives, arguing that this will ensure that PG&E undertakes appropriate PSEP investments. However, full recovery of costs and current financial incentives for shareholders will not prevent PG&E from overspending or using PSEP funds in a manner that is not cost-effective. Importantly, the Commission should retain the full range of regulatory mechanisms – including disallowances, penalties, and reasonableness reviews of PG&E's safety-related performance, and not just the financial incentive of assured cost recovery – to provide PG&E with strong incentives to improve its safety-related performance. Use of a forward-looking incentive mechanism such as the one I proposed in my direct testimony – a rate of return reduction until the Commission finds that PG&E's safety performance has improved – is more appropriate given PG&E's past poor management and the impacts that will have on ratepayers. In addition, CUE and the Local Unions overlook the impact of their recommendations on ratepayers. For example, if penalty funds flow into the General Fund, they may not directly offset the safety-related costs that ratepayers will bear. In short, particularly when the public is at risk of serious physical

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harm, the Commission has and should rely on all regulatory options available to ensure public safety.

4. The direct testimonies of DRA and TURN point out several features of PG&E's pipeline safety plan that lead to an inflated PSEP revenue requirement. While questions remain on how their recommendations translate into rate impacts, I recommend that the Commission consider these recommendations to lower the PSEP impacts on ratepayers, and should adopt a well-defined scope of work and cost cap on any Phase 1 costs placed into rates.

II. DRA'S PROPOSAL TO ELIMINATE A SEPARATE SAFETY SURCHARGE

Q: DRA witness Ms. Sabino raises a number of questions about PG&E's proposal to establish a separate PSEP surcharge that would be applicable only to end-users. She suggests that PSEP backbone, local transmission, and storage costs should be treated no differently than comparable costs in existing Gas Accord V (GA V) rates. Does DRA's testimony present a specific proposal for integrating PSEP costs into existing GA V rates?

A: No, it does not, because DRA's primary recommendation is that PSEP costs should not be included in rates until after 2015. DRA argues that the Gas Accord V settlement does not permit PG&E's backbone, local transmission, and storage rates to increase until after 2014, absent agreement among all GA V parties.

Q: Please comment on DRA's position on PG&E's separate PSEP surcharge.

A: As a participant in the GA V settlement process, I sympathize with DRA's argument that the GA V settlement does not envision rate changes before 2015, except for those agreed to in that settlement or subsequent changes approved by all settling parties. The GA V Settlement certainly did not contemplate the major rate increases proposed in PG&E's filed PSEP, and the GA V settling parties have not agreed to those rate changes. Nonetheless, the Commission appears to have the authority to modify GA V rates if it so decides. As a result, it is important to develop a means to recover PSEP costs in rates if that is the course which the Commission takes.

Q: Do you support a separate PSEP surcharge in end-use rates, as PG&E has proposed?

A: Yes, for several reasons.

First, and foremost, enhancing the safety of the PG&E pipeline system will benefit all end-use natural gas customers in PG&E's service territory. As discussed in more detail in my direct testimony, the direct safety benefits – in terms of a lower risk of catastrophic accidents – accrue principally to the core end-use customers who live and work near transmission pipelines, while all end users will realize the benefits from a more reliable gas system.[1] Given the safety and reliability benefits that end-users will realize, it is reasonable to recover directly from end-users those PSEP costs that the Commission finds should be recovered in rates.

Second, a separate PSEP surcharge makes sense as a result of the extraordinary nature of these safety-related costs, the public attention to these issues, and the need for ongoing tracking of these costs separately from PG&E's other gas transmission and storage costs. I agree with PG&E's supplemental testimony that, if these costs were to be integrated into the current GA V rate structure, substantial additional effort would be required to segregate PSEP costs from GA V costs and to identify and design a separate PSEP component of each rate component in the GA V rate design.[2] Separate tracking of the PSEP costs is required because of the GA V revenue sharing mechanism. This sharing mechanism uses defined formulas to allocate between ratepayers and shareholders any difference between PG&E's adopted GA V revenue requirements and actual transmission and storage revenues, including a $30 million "seed" value allocated annually to ratepayers. In order to maintain the same sharing balance between ratepayers and shareholders adopted in GA V, PG&E would have to track the amount of revenue collected at the original GA V rates. In addition, many of the intervenors – including NCIP, TURN, and DRA itself – have recommended that the Commission

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1 NCIP Direct Testimony of R. Thomas Beach (NCIP Beach Testimony), at pages 14-16 and 21.

2 PG&E Supplemental Testimony (served December 2, 2011), at pages 6-7.

approve a reduced rate of return on at least some PSEP assets.[3] To implement these recommendations in rates will require a separation of PSEP costs from the rest of PG&E's GT&S rates.

Third, the GA V rate design for backbone rates, in particular, is complex – it involves both reservation and volumetric rates, two rate design options (straight fixed-variable and modified fixed-variable), rates that are differentiated by path on the backbone system, and an allocation of certain "common" costs across all backbone rates. The GA V backbone rate design was the subject of substantial negotiations during the GA V process, and those issues would have to be re-opened if PSEP costs were integrated into GA V rates. For example, the issue of the rate differential between the Baja (Line 300) and Redwood (Line 400/401) paths was a central element of the GA V settlement, and that controversial issue would have to be re-opened if PSEP costs must be integrated into the GA V rate design. Further, the Gas Accord rate cases determine the allocation among the GT&S functions of those operating and maintenance (O&M) costs that are common to the whole GT&S system. Similarly, the PSEP includes certain "common" O&M costs such as the proposed GTAM program whose allocation would have to be reconciled with the GA V's different allocation of "common" O&M costs.

In addition, PG&E's data responses to DRA correctly identify a number of technical issues associated with determining the load factors used to set backbone and local transmission rates which would have to be resolved if there is a significant increase in rates that results from combining PSEP costs into the Gas Accord cost allocation and rate design.[4] Among other things, a certain share of PG&E's backbone contracts include discounted backbone rates, and PG&E also has provided rate credits to certain local transmission customers (Dynegy and the Northern California Generation Coalition) that amount to discounts in local transmission rates. PG&E discounts its rates in order to meet competition with other pipelines or with direct backbone service. These discounts

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[3] NCIP Beach Testimony, at pages 25-27; TURN Direct Testimony of Thomas Long (TURN Long Testimony), at pages 16-17; DRA Direct Testimony of Robert Pocta (Exhibit-02), page 27.

[4] These data responses are in DRA Direct Testimony of Pearlie Sabino (DRA Sabino Testimony), at pages 50-51.

can be provided both to end-users on the PG&E system or to shippers who move gas across the PG&E system to southern California or other off-system markets. In the Gas Accord rate design, PG&E accounts for the revenue impacts of these discounts either through direct adjustments to its rates or through complex "discount adjustments" to its system load factor and thus to its throughput forecast used in the denominator of Gas Accord rates. PG&E argues that, if it increases GA V backbone rates to add PSEP costs, it would also have to re-compute these discount adjustments and load factors. PG&E and the GA V parties also would have to re-visit the rate credits provided to certain local transmission customers, such as Dynegy and the Northern California Generation Coalition, that amount to discounts in local transmission rates. In short, these rate adjustments have been and can be a source of significant contention and negotiation in Gas Accord rate cases. Resolving these issues would amount to a substantial re-opening and re-litigation of the GA V settlement. Given the wide range of issues already at play in this case, it would be a poor use of the Commission's scarce resources to re-open those already-decided GA V issues before the next PG&E GT&S rate case in 2014.

Q: DRA argues that shippers on the PG&E backbone system who are not end-users – for example, some gas marketers – would not be assessed the new safety-related costs if PG&E's proposed end-use surcharge is adopted. DRA states that this is contrary to "cost causation" principles. Do you agree?

A: No, I do not. The clear focus of this investigation is enhancing the safety of the public that lives, and consumes natural gas, in California. For example, the OIR states that "[t]his rulemaking will consider how we can align ratemaking policies, practices, and incentives to better reflect safety concerns and ensure ongoing commitments to public safety."[5] It is improving the safety of the general public of natural gas end users that is causing PG&E and the other gas utilities to incur additional safety-related costs. Thus, from a cost causation perspective, it is most appropriate to place the new safety-related costs in a surcharge billed directly to end-users, as PG&E has proposed.

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[5] R. 11-02-019, at page 11.

DRA's testimony, at times, appears to agree with this perspective. For example, DRA complains that PG&E's PSEP surcharges "are proposed to be buried within the Customer Class Charges, rather than be shown as a separate discrete line item in the customer bill. The GPS surcharge will not even be visible to the PG&E customer when looking at the monthly customer bill."[6] I agree with DRA that PSEP costs should be shown as a separate, transparent line item on end-use customers' bills. However, if PSEP backbone costs were included in GA V backbone rates as DRA has advocated, they would be even more opaque than what PG&E has proposed. PG&E's backbone costs for core end use customers are thoroughly "buried" within PG&E's core commodity cost of gas, and noncore end use customers who purchase gas in the PG&E City-gate market, downstream of PG&E's backbone system, will not know what backbone-related PSEP costs their upstream suppliers have incurred because those costs will be subsumed in the PG&E city-gate market price. Thus, including PSEP costs in backbone rates would make them far less transparent than even PG&E's proposal to include them in the Customer Class Charge. I agree with DRA that the PSEP charge should be transparent to end-use customers, but that goal will not be achieved if PSEP backbone costs are rolled into PG&E's GA V backbone rates as DRA suggests.

Finally, DRA's proposal to include safety-related costs in the backbone rates charged to gas marketers may result in safety-related costs being assessed more than once on a single volume of gas. If PSEP costs are charged both to end-users and to shippers on the backbone system, as DRA suggests, the shippers would pass these costs through to their customers, and the end-users consuming the gas would again pay a safety surcharge in their end-use rates. Such a structure would be confusing and not transparent to customers, and would complicate the tracking of PSEP costs. Under PG&E's structure, PSEP backbone costs will be assessed just once on every volume of gas that moves on PG&E's pipeline system and is consumed in PG&E's service territory, through the surcharge on end-use rates. I concur with PG&E that PSEP costs should be assessed only once in the transportation of gas from wellhead to burner-tip,

[6] DRA Testimony, at page 49.

and should be charged directly to the end-user, so that these costs are as transparent as possible for the end-users on whose behalf these safety-related costs are being incurred.

III. TURN'S PROPOSAL TO ALLOCATE GTAM COSTS BY MILEAGE

Q: TURN proposes to allocate the costs of PG&E's GTAM program on the basis of the overall mileage of PG&E's backbone and local transmission pipeline systems. Do you support this proposal?

A: No, I do not. TURN states that PG&E's proposed allocation of GTAM costs would allocate 91.35% to local transmission, 8.65% to backbone, and none to storage or customer-related service pipes.[7] As a preliminary matter, based on my review of PG&E's PSEP Results of Operations (RO) model, this is not accurate. PG&E's RO model actually shows that the allocation of GTAM costs is 81.0% to local transmission, 16.5% to backbone, and 2.5% to storage, as summarized in **Table 1**.

Table 1: *PG&E's Proposed GTAM Cost Allocation*

	2011	2012	2013	2014	2011-2014	Percent
Local T						
Capital	2,352,640	4,691,241	39,883,972	36,143,041	83,070,895	81.0%
Expense	404,863	4,738,339	6,048,918	5,850,410	17,042,529	81.0%
Backbone						
Capital	480,494	958,121	8,145,750	7,381,716	16,966,081	16.5%
Expense	82,688	967,740	1,235,408	1,194,865	3,480,701	16.5%
Storage						
Capital	72,170	143,909	1,223,481	1,108,725	2,548,284	2.5%
Expense	12,420	145,353	185,557	179,467	522,797	2.5%
Total						
Capital	2,905,304	5,793,271	49,253,203	44,633,482	102,585,260	100.0%
Expense	499,970	5,851,432	7,469,882	7,224,743	21,046,027	100.0%
Total					123,631,287	

Source: PG&E RO Model, tabs LT_IT Input, BB_IT Input, and ST_IT Input.

[7] TURN Direct Testimony of William B. Marcus (TURN Marcus Testimony), at page 16.

TURN's proposal would shift more costs to the backbone component of safety-related rates, compared to PG&E's proposed allocation of GTAM costs.

More importantly, PG&E's proposed allocation is a reasonable allocation of GTAM costs for Phase I of the PSEP, because it best reflects the distribution among the customer classes of immediate safety-related improvements in Phase I that are driving the need for PG&E to implement the GTAM. The substantial majority of PG&E's transmission pipelines in High Consequence Areas (HCAs) are local transmission lines, as can be seen in Figure 2-3 of PG&E's direct testimony. PG&E reports that 858 miles (81%) out of the 1,059 miles of PG&E transmission pipelines in HCAs are local transmission lines.[8] As a result, it is not surprising that most of PG&E's Phase I PSEP costs are on its local transmission system. Because it is safety-related costs on these high-risk pipelines that are causing PG&E to incur Phase I PSEP costs, PG&E's allocation of GTAM costs on the basis of PSEP Phase I expenditures is reasonable.

In addition, TURN's proposed allocation of GTAM costs on the basis of overall pipeline mileage is also inappropriate in view of the fact that, ultimately, GTAM will cover all of PG&E's gas transmission assets, including compressor stations, terminals, line equipment and valving as well as pipelines.[9] Ultimately, in a future GT&S general rate case, once the GTAM program is complete, the Commission can re-examine the allocation of these costs based on the full functionality of the program and data on the allocation of similar information technology costs that is available in GT&S general rate cases. Such data is not readily available in this case, but would be an integral component of a typical GT&S rate case. Until the next GT&S rate case, PG&E's proposed allocation of GTAM costs best represents the safety needs that are driving PG&E's adoption of the GTAM program.

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8 PG&E Response to NCIP Data Request No. 6, Q1.

9 PG&E Direct Testimony, at pages 5-21 to 5-26.

IV. CUE AND LOCAL UNIONS TESTIMONY ON SHAREHOLDER INCENTIVES

Q: CUE's witness David Marcus recommends that the Commission separate its consideration of issues concerning PG&E's past poor management from the future cost recovery of new safety-related costs. In particular, he supports providing PG&E with full cost recovery for future, Commission-approved safety investments, and imposing any penalties solely based on PG&E's past practices. CUE's recommendation is summarized on page 5 of Mr. Marcus' testimony:

> ***Underfunding future work by requiring shareholders to pay for part of it is wrong because it gives PG&E an incentive to either cut corners on the future work (in order to control costs) or to endeavor not to do it at all (to avoid shareholder losses). The Commission doesn't want shoddy work, and it shouldn't want to have to fight a recalcitrant PG&E to get PG&E to do what needs to be done. The Commission can, and should, have it both ways. It should reassure PG&E that it will fully fund future work that the Commission finds is needed for safety, so that there is no extra incentive for PG&E to avoid doing that work, or to do it on the cheap. But it should also penalize PG&E for past work that was either promised and not done, or should have been done pursuant to then-existing safety requirements, but was not done. And it should also make clear to PG&E, in case there is any doubt, that it is prepared to impose further penalties in the future, if PG&E doesn't do the right thing this time around.***

The testimony of Mr. Peter Bradford for the Local Unions reaches a similar conclusion. Mr. Bradford urges the Commission to review the prudence of PG&E's past safety-related activities and all ratemaking issues in another proceeding (or proceedings), and to focus this case on adopting new safety-related standards and policies. While he recognizes that ratepayers should not pay twice for the same work, he notes that disallowances and reductions in ROE will create incentives to "cut corners."[10] Do you agree that the imposition of penalties needs to be separated from future cost recovery in order to ensure that PG&E will not cut corners in ensuring safety?

A: No, I do not. There are two essential problems with the CUE and Local Unions testimonies: first, they ignore the shareholder incentives that result from the forward

[10] Local Unions Direct Testimony of Peter Bradford (Local Unions Bradford Testimony), at page 5.

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test-year ratemaking process in California, and, second, they fail to consider the impact of their position on ratepayers.

First, the assured cost recovery that CUE and the Local Unions recommend will not provide PG&E with the correct incentives to carry out its safety-related obligations. CUE wants the Commission to "reassure" PG&E that it will "fully fund" work needed for safety. It contends that if PG&E is not assured full recovery of costs, it will not make the pipeline safety investments it needs to make:

> *If utilities know they will recover less than 100 percent of their investments, they will have a direct and strong financial incentive to resist making the investment in the first place, since the more they spend, the more they will lose. Also, if they are told they will only be reimbursed up to X dollars for investments that ought to cost more than X, with shareholders making up the difference, they will have a direct and strong financial incentive to cut corners in order to keep the total investment as close to X as possible.*[11]

The Local Unions appear to take a similar position.[12] However, full cost recovery alone will not ensure that PG&E undertakes appropriate, cost-effective investments. In general, under forward test-year ratemaking, the way in which the Commission "fully funds" safety-related work is to place into PG&E's rates the <u>forecasted</u> costs of future work which has yet to occur.[13] However, once base natural gas rates, such as the GT&S transportation rates at issue in this case, are approved, the utility's incentive is to underspend its approved revenue requirement, because the amount of the underspending adds to shareholder returns, at least for the period until the next rate proceeding.[14] Mr. William B. Marcus' testimony for TURN quantifies the potential shareholder gains from such underspending of capital expenditures approved in a prior rate case. He determines that shareholders benefitted by 30% to 43% of such underspent capital, depending on the

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[11] CUE Direct Testimony of David Marcus (CUE Marcus Testimony), at pages 2-3.

[12] Local Unions Bradford Testimony, at page 5.

[13] The Local Union's witness Mr. Bradford incorrectly characterizes a rate-setting proceeding in California as a case that "looks backward at the prudence and proper accounting and allocation of costs already incurred." Local Unions Direct Testimony, at page 2.

[14] In other cases, such as with electric resource costs recovered through the ERRA balancing account, the utility will recover exactly what it spends.

years in which the underspending occurred.[15] Thus, the "full funding" of safety programs on a forward test year basis actually can provide the utility with the incentive "to avoid doing that work, or to do it on the cheap," the exact opposite of what CUE and Local Unions assert. CUE and the Local Unions agree that the utility should be penalized for underspending on safety – i.e. for work that is "promised but not done" – yet its proposal sets up a shareholder incentive for the utility to do exactly that.

CUE's testimony likewise does not address whether its recommended "full funding" for future safety-related work will result in improved safety, except to hold out the possibility that PG&E again could be penalized in the future "if PG&E doesn't do the right thing this time around." CUE thus ignores the conclusion of the San Bruno Independent Review Panel's (IRP) report that both PG&E and the Commission need to adopt more pro-active, comprehensive, and integrated approaches to pipeline safety. The IRP Report recommends that the CPUC should change its past light-handed regulation of pipeline safety, and should "adopt as a formal goal, the commitment to move to performance-based regulatory oversight of utility pipeline safety."[16] Such regulation would include a program for regular risk-based safety and pipeline integrity audits of the utilities, greater coordination between Commission safety staff and ratepayer advocates, and the adoption of "performance standards for pipeline safety and reliability for PG&E, including the possibility of rate incentives and penalties based on achievement of specified levels of performance."[17]

The GA V Settlement and PG&E's proposed cost recovery for the PSEP attempt to address the problem of the incentive to underspend on safety through so-called "one-way balancing accounts," which return to ratepayers any underspending by the utility for approved safety-related programs. However, the one-way balancing accounts only address part of the problem – they ensure that the utility either fully spends its approved safety-related budget, or returns unspent funds to ratepayers. Such accounts do not ensure that what the utility actually does spend is done cost-effectively and results in

15 TURN Marcus Testimony, at pages 12-13.
16 IRP Report, Executive Summary, at page 27.
17 *Ibid.,*at page 28.

real safety improvements. The GA V Settlement took additional precautions by establishing project price caps which limited the costs that could be recovered for a particular project. Moreover, the GA V Settlement permitted PG&E to recover the costs of certain projects only in the year after the projects were completed and placed in service.[18] These additional features were meant to ensure that ratepayers would not be required to pay for projects that were not completed or to overpay for projects that are not completed on budget. In short, to ensure that appropriate safety investments are made, the Commission should focus, first, on preventing underspending, and, second, on spending that results in cost-effective safety improvements. Merely providing full cost recovery and maintaining current shareholder returns will not assure ratepayers that PG&E undertakes the appropriate PSEP efforts.

CUE and the Local Unions also completely overlook the impact of their recommendations on ratepayers. CUE argues that "[g]oing forward, PG&E's shareholders should bear responsibility for past misdeeds through a penalty proceeding, but not by giving counterproductive incentives to avoid doing the work needed to provide safe gas service."[19] If penalty funds are credited to the General Fund, however, they may not directly offset PSEP costs. For example, the proposed decision (PD) issued in this proceeding on February 22, 2012 orders PG&E to pay a $3 million fine to address violations of Resolution L-410 involving MAOP validation efforts.[20] The February 22 PD clarifies that the penalty funds would flow into the General Fund.[21] As such, they may not directly offset any of the safety-related costs that ratepayers will bear. Equally important, even if penalties are returned to ratepayers, they may not be quantified or allocated in a manner that is consistent with cost causation principles. Stated differently, if the Commission were to assess a penalty upon PG&E for its poor recordkeeping practices, the penalty should not only offset ratepayer costs generally, it also should be allocated in such a way to offset the future expenditures required to remedy the past practices that are being penalized. Accordingly, to protect ratepayers

18 See GA V Settlement, at Section 7.4, pages 8-10.
19 CUE Marcus Testimony, at page 4.
20 Proposed Decision issued on February 22, 2012 in R.11-02-019 (February 22 PD).
21 February 22 PD, at 1.

from bearing costs that have already been borne or costs that are associated with PG&E's noncompliance with safety regulations, the Commission should ensure that penalties are quantified and allocated in a manner that directly offsets the costs that arise from PG&E's poor management.

Q CUE's witness David Marcus and the Local Unions' Peter Bradford suggest that maintaining current incentives and providing full cost recovery is the only way to ensure that PG&E undertakes appropriate PSEP investments. Do you agree?

A No, I do not. I think it is important to consider how the Commission's use of incentives has evolved over the last several decades. Before the 1990s, the Commission relied heavily on reasonableness reviews, and the associated disallowances, to ensure that utilities complied with regulations and managed their obligations in a reasonable manner. In the natural gas industry, with the creation of the core procurement incentive mechanisms in the 1990s, the Commission eliminated the use of reasonableness reviews in the context of the procurement of gas supplies for core customers. The same trend was apparent in the electric industry: instead of reasonableness reviews – for example, of the utilities' electric procurement efforts – the Commission relied more heavily on incentive mechanisms and prospective approvals to drive utility behavior. However, nothing should excuse PG&E from their failure to comply with Commission and federal pipeline safety regulations. Moreover, PG&E should not require incentives to do what they are obligated to do under the law.

History demonstrates that the Commission has other tools available to it to drive utility compliance. For example, my direct testimony on behalf of NCIP recommended that the Commission reduce PG&E's return on equity for investments in its PSEP by 500 basis points (5%) from 2011 through 2014. However, following this period, under my proposal the Commission could consider an appropriate increase based on PG&E's performance. Similarly, the Commission should not hesitate to use other existing tools such as disallowances, reasonableness reviews, and penalties to ensure that PG&E and the other gas utilities comply with federal and Commission safety regulations. Use of all of these regulatory tools is particularly appropriate given that the public is at risk of serious physical harm if a utility does not comply with Commission regulations and orders, as the San Bruno incident so tragically illustrated. The CUE and Local Unions testimonies seem to think that a "business as usual" approach to safety-related investments is reasonable; however, nothing about this proceeding is "business as usual." As I noted in my direct testimony, PG&E's PSEP entails an unprecedented level of spending that has the potential to almost double some gas transportation rates in three years.

Finally, there may not be a difference in the financial outcome for ratepayers between a penalty for past actions and a sharing between ratepayers and shareholders of prospective costs, if the penalty funds are used to offset PSEP costs. For example, assume that the Commission approves a PSEP with a total annual revenue requirement of $200 million per year over three years. If the Commission also adopts a 50%/50% sharing of these PSEP costs between ratepayers and shareholders, ratepayers would bear $100 million per year of PSEP costs in rates. This outcome is no different than if the Commission were to place the entire $200 million per year into rates, but at the same time assess a $300 million penalty on PG&E for its past safety deficiencies, amortized over the three years and allocated to customer classes in the same way as PG&E's proposed rate increase. The net impact of this scenario on ratepayers also would be a $100 million per year rate increase over the three years. The only difference between these scenarios is that the penalty is a one-time adjustment that would expire after three years, while the Commission could condition the end to the ratepayer/shareholder sharing on a future review and finding that PG&E is making adequate progress in implementing the PSEP cost-effectively. Thus, the financial outcome for ratepayers is the same, but the sharing mechanism provides a stronger ongoing incentive for PG&E to improve its safety performance. This would be a more pro-active, incentive-based approach to safety regulation that keeps on the table all regulatory options available to the Commission to ensure public safety, including prospective incentives and penalties as well as retrospective disallowances.

V. Capping PSEP Ratepayer Costs Prior to the Next GT&S Rate Case

Q: In their direct testimonies, DRA and TURN highlighted several factors that have led PG&E to overestimate Phase I costs. Should the Commission review and incorporate such adjustments into PG&E's Phase I revenue requirements?

A: Yes. As I noted in my direct testimony, the Commission should ensure the approved PSEP revenue requirements represent cost-effective safety improvements, due to the significant impact which these new costs will have on noncore industrial customers, electric generators (EGs), electric ratepayers, and bypass of the PG&E gas system. The DRA and TURN testimonies demonstrate numerous areas in which PG&E's proposed revenue requirements should be modified to ensure PSEP funds are used cost-effectively. In particular, DRA and TURN have testified that PG&E's PSEP revenue requirements are too high based on the following factors:

- The revenue requirements should not be based on estimates equivalent to a feasibility cost study.[22] If the revenue requirements are based on estimates, TURN recommends the incorporation of reductions to AFUDC.[23]

- Revenue requirements are based on incomplete data.[24] DRA points out that MAOP validation will not be completed until 2013 in time for PG&E's next GRC. As a result, Phase I costs are based on data that has not been validated and may be overstated.[25]

- Phase I calls for capacity increases and re-routes that are not adequately justified. Both add incremental costs.[26] Pipeline replacement costs are largely governed by diameter so as the pipeline diameter increases, costs increase.[27]

- PG&E's request for $5 million for customer outreach should be rejected.[28] As DRA points out, this is likely related to lobbying efforts and ratepayers should not pay for this.

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[22] See DRA Direct Testimony of Thomas Roberts (Exhibit DRA-03) (DRA Roberts Testimony), at page 10; DRA Direct Testimony of Neil Delfino (Exhibit DRA-05) (DRA Delfino Testimony), at pages at 1.

[23] See TURN Marcus Testimony, at pages 11-12.

[24] See TURN Direct Testimony of Richard Kuprewicz (TURN Kuprewicz Testimony), at pages 13-14; DRA Roberts Testimony, at page 20.

[25] See DRA Roberts Testimony, at pages 3-20.

[26] See DRA Roberts Testimony, at pages 2 and 15; TURN Kuprewicz Testimony , at page 81.

[27] See DRA Roberts Testimony, at page 15.

[28] See DRA Roberts Testimony, at page 107; DRA Direct Testimony of Sibylle Scholz (Exhibit DRA-06), at page 17.

- PG&E's contingency request is excessive.[29]

- Unit costs for pressure testing, replacement and hydrotesting are too high.[30]

- Pipeline replacements less than 50 feet should be expensed.[31]

- Depreciation for plant in FERC Account 367 should be extended from 45 years to 60 years[32] (with 15% negative net salvage rate).

- Undertaking this unprecedented level of work in a four-year period can require ratepayers to shoulder a construction premium.[33]

- PG&E's use of a 3.12 % escalation factor is too high and should be 1.1% to 1.5% through Phase I.[34]

The DRA and TURN testimonies also recommend a number of scope changes in the PSEP which would reduce costs. For example, TURN's witness Richard Kupriewicz recommends that PG&E should:

- Defer all segments in Class 2 locations to Phase 2, unless the segments are part of a high priority project.[35]

- Attempt hydrotesting where possible, rather than replacement. This will impact a significant amount of the 100 miles scheduled for replacement. The Decision Tree may require excessive pipeline replacement because hydrotesting is not considered as an alternative to replacement in several instances.[36] Importantly, TURN and DRA's analysis indicates that the average cost of pipeline replacement is 10 times higher than hydrotesting.[37]

- For pipes operating at <30% SMYS, make greater use of leak survey monitoring, rather than more expensive strength testing.[38]

- Use internal line inspection (ILI) as the best tool for more than 493 miles scheduled for testing due to the corrosion decision tree, if the pipe can be retrofit for piggability.[39]

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29 See DRA Roberts Testimony, at page 107.
30 See DRA Roberts Testimony, at pages 70 and 75; DRA Delfino Testimony, at pages 10, and 16.
31 See DRA Sabino Testimony, at page 45.
32 See TURN Marcus Testimony, at page 10.
33 *Ibid.* ,at pages 14-15.
34 See DRA Roberts Testimony, at page 107
35 See TURN Kuprewicz Testimony, at page 16.
36 *Ibid.,* at pages 20-21.
37 See DRA Roberts Testimony, at pages 3-11; TURN Kuprewicz Testimony, at page 82.
38 TURN Kuprewicz Testimony, at pages 19-21.
39 *Ibid.*, at pages 3 and 26-28.

- Install Automated Safety Valves (ASV) on pipelines larger than 24 inches in diameter, with a maximum spacing not to exceed eight miles. This will result in a reduction of approximately 61 valves on smaller pipelines.[40]

DRA's witnesses Roberts, Rondinone, Delfino, and Scholz conclude that:

- PG&E's decision tree relies too heavily on replacement rather than testing. The plan includes capacity increases and re-routes that are not identified or explained.

- Low priority segments do not need to be replaced in Phase I.

DRA estimates that the combined impact of these errors, and adoption of DRA's recommendations, would reduce PG&E's baseline forecast request by more than $850 million. In turn, PG&E's contingency request could be reduced by $271 million. DRA notes that a significant portion of the reduction is the result of shifting costs from Phase1 to Phase 2.[41]

DRA's and TURN's primary recommendations are not to include PSEP costs in rates at this time. If the Commission does decide to allow some PSEP costs to be included in rates at this time, the above issues underline the need for the Commission to adopt a well-defined scope of PSEP activities for Phase I, with a cap on total Phase I revenue requirements until the next GT&S rate proceeding.

Q: Does this complete your prepared rebuttal testimony?

A: Yes, it does.

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40 *Ibid.*, at pages 4 and 34-61.

41 DRA Direct Testimony of David Peck (Exhibit-01), at pages 6-7.