Docket:	:	R.11-02-019
Exhibit Number	:	DRA-09
Commissioner	:	Florio
ALJ	:	Bushey
Witness	:	Sabino

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Pacific Gas and Electric Company

Revenue Requirements, Cost Allocation and Rates

San Francisco, California
January 31, 2012

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SB_GT&S_0355923

I. INTRODUCTION AND BACKGROUND

Pursuant to the Scoping Memo and Ruling of the Assigned Commissioner issued on June 16, 2011 in R.11-02-019, as amended by the Amended Scoping Memo and Ruling of the Assigned Commissioner issued on November 2, 2011, this Exhibit presents the Division of Ratepayer Advocates' ("DRA") analyses and recommendations on whether the Pacific Gas and Electric Company's ("PG&E" or "the Respondent") proposals on the revenue requirements, cost allocation and rate design proposals, including rate of return, as submitted in its Implementation Plan ("IP") should be granted by the California Public Utilities Commission ("Commission") with rates effective beginning January 1, 2012.[1] PG&E filed its "Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan" (also called "Implementation Plan" or "IP") in this rulemaking proceeding on August 26, 2011. The Amended Scoping Memo and Ruling of the Assigned Commissioner provides that parties serve testimony on the PG&E Implementation Plan and associated ratemaking issues on January 31, 2012.

PG&E states that the expenditures outlined in the Implementation Plan are incurred pursuant to Decision (D.)11-06-017.[2] PG&E refers to its IP as the Pipeline Safety Enhancement Plan ("PSEP").[3] PG&E states that there are four main components of their IP: (1) Pipeline Modernization; (2) Valve Automation; (3) Pipeline Records Integration; and (4) Interim Safety Enhancement Measures.[4] DRA's Prepared Testimony reviews, examines, and makes recommendations regarding PG&E's PSEP Phase 1. At this time

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[1] The Amended Scoping Memo and Ruling of Commissioner Florio set forth these three general areas that should be addressed in the parties'ratemaking testimony. Likewise, the Amended Scoping Memo encouraged parties to review the list of issues in Attachment A thereto. Refer to PG&E Prepared Testimony in R.11-02-019 dated Aug.26, 2011, p.1-14 for the requested effective date for rates.

[2] PG&E Testimony in R.11-02-019, p.1-2 (updated with Errata on Nov. 4, 2011).

[3] Id., p.1-1.

[4] Id, pp.1-4 through 1-11.

PG&E is not yet prepared to present the details of PSEP Phase 2 although its broad estimate would put Phase 2 costs at a range from $6.8 billion to $9.0 billion.[5]

This Exhibit presents DRA's Prepared Testimony regarding the revenue requirements, cost allocation and rate design, including rate of return ("ROR"), of PG&E's PSEP Phase 1 as required in the amended scoping memo and ruling.[6]

A. Basis of Review of PG&E's Pipeline Safety Enhancement Plan

DRA's review is based on its analysis of PG&E's Prepared Testimony, including all Errata and supplemental testimony, all workpapers submitted in support of its filing on August 26, 2011, including all responses to DRA discovery as well as PG&E's responses to other parties, and all documents in R.11-02-019, the findings in the NTSB Report, the provisions of General Order 112-E, the recently signed California legislation pertaining to gas pipeline safety, the gas pipeline industry standards which generally governs the behavior of a prudent gas pipeline operator absent explicit state or federal mandated requirements,[7] and the relevant Code of Federal Regulations and relevant state regulations and Commission orders relevant to the four main components of PG&E's proposed Implementation Plan in Phase 1.

D.11-06-017 in R.11-02-019, issued on June 9, 2011, is the Commission decision regarding the maximum allowable operating pressure methodology. In that decision, the Commission ordered PG&E to submit natural gas transmission pipeline replacement or testing implementation plans, including corresponding ratemaking proposals. In brief, the Commission decision includes the following orders:

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[5] PG&E Response to DRA PZS9-6. PG&E's reference is DRA_022-Q06. PG&E states the broad estimate was developed using Phase 1 proxy costs and adjusting them to reflect the larger scope of work and the time value of money.

[6] Amended Scoping Memo and Ruling of the Assigned Commissioner in R.11-02-019 dated November 2, 2011, p.3.

[7] These industry standards began with ASA B31 in 1935 for new construction only. When the Commission adopted General Order 112 in 1961, it adopted ASA B31.8-1958 (a later version of ASA B31.1.8-1955) and strength test requirements applied only to new construction and did not apply to existing pipelines.

1. The pressure test or replace plans submitted be in accord with 49 CF 192.619, excluding subsection 49 CFR 192.619 (c).[8]

2. IP should set forth criteria on which pipeline segments were identified for replacement instead of pressure testing.[9]

3. IP may include alternatives that demonstrably achieve the same standard of safety but must include a prioritized schedule based on risk assessment and maintaining service reliability, as well as cost estimates with proposed ratemaking.[10]

4. In the interim, PG&E should continue to work on its determination of Maximum Allowable Operating Pressure through pipeline features analysis and should use the result of that analysis to impose further pressure reductions as necessary pending replacement or testing. PG&E may use engineering-based assumptions for this analysis where required due to missing records."[11]

5. IP should include a rate proposal.[12]

6. For PG&E only, the IP should have a proposed cost allocation between shareholders and ratepayers.[13]

7. Other elements ordered include specific rate base and expense amounts for each year proposed to be included in regulated revenue requirement as well as proposed rate impacts for each year and each customer class.[14]

8. Other such facts and demonstrations necessary to understand the comprehensive rate impact of the Implementation Plan."[15]

In carrying out the Commission orders in D.11-06-017, one must keep in mind the facts and circumstances that precipitated the unprecedented Commission order in this rulemaking:

> As the detailed history set out above shows, this project to validate MAOP was set in motion by the NTSB's justifiable alarm at PG&E's records being inconsistent with the actual pipeline found in the ground in Line 132. The pipeline features

[8] Excluded section pertains to the provision allowing an operator to operate a segment of pipeline at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date for that segment.

[9] D.11-06-017, Conclusion of Law 6, p.29.

[10] D.11-06-017, p.1

[11] D.11-06-017, pp.1-2.

[12] Ordering Paragraph No.10, D.11-06-017.

[13] Id.

[14] Id. at p.32.

[15] Id. at p.32.

> data for Line 132 were not missing; the recorded data were factually inaccurate. Records containing inaccurate pipeline features are fundamentally different from simply missing records. Curing PG&E's unreliable natural gas pipeline records was the obvious goal of the NTSB's recommendation to obtain "traceable, verifiable, and complete" records and, with reliably accurate data, calculate a dependable MAOP.
>
> PG&E and SoCalGas/SDG&E state that such records are not available, especially for the older vintage pipelines.[16]

Thus, even though PG&E asserts that the expenditures outlined in the Implementation Plan are incurred pursuant to D.11-06-017,[17] the unprecedented Commission order was precipitated by the NTSB discovery regarding the unreliable state of PG&E's records following the San Bruno gas transmission pipeline explosion. D.11-06-017 states that "PG&E admitted that it did not expect to find records that would meet the NTSB recommendation and the Commission's directive for each component of its pre-1970 pipeline."[18]

Since 1996, PG&E GT&S rate cases for its backbone transmission, local transmission, and gas storage revenue requirements and relevant embedded cost allocation have been resolved in settlements referred to as PG&E Gas Accords I through V.

The most recently adopted PG&E revenue requirements in the GA V in D.11-04-031 gave PG&E sufficient funding in the following amounts: $514.2 million for 2011, $541.4 million for 2012, $565.1 million for 2013, and $581.8 million in 2014.[19] These amounts represent increases in revenue requirements over the amount adopted in the year 2010 which was $461.8 million.[20] The PG&E PSEP seeks to add revenue requirements of $768.7 million over 2012 through 2014 on top of these GA V authorized amounts.[21]

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[16] D.11-06-017, pp.17-18.

[17] PG&E Prepared Testimony in R.11-02-019 dated Aug.26, 2011, p.1-2.

[18] D.11-06-017, p.6.

[19] D.11-04-031, p.16.

[20] D.11-04-031, p.9.

[21] See Table 1-5 at line 3 under the column "Total" , PG&E Prepared Testimony, p.1-17.

The Commission ordered the filing of the PG&E PSEP because of concerns following the release of the National Transportation Safety Board ("NTSB") safety recommendations. The NTSB safety recommendations were issued on January 3, 2011 to PG&E, the Commission, and the U.S. Department of Transportations' Pipeline and Hazardous Materials Safety Administration ("PHMSA") on record-keeping and hydrostatic pressure testing. The CPUC responded by issuing Resolution No. L-410 on January 13, 2011, directing PG&E and the other respondent pipeline operators to comply with the NTSB's recommendations. The three safety recommendations to PG&E are described in the NTSB Accident Report on the San Bruno natural gas transmission pipeline rupture and fire accident released on August 30, 2011.[22] These safety recommendations were based on the NTSB's discovery of inaccuracies in PG&E records for the accident pipe, and two of these three safety recommendations were designated as "urgent."[23]

In addition, on October 7, 2011, the Governor of California signed into law several new gas pipeline safety bills, namely, Assembly Bill 56 and Senate Bills 44, 216, 705, and 879. PG&E's compliance with this new gas pipeline legislation as well as with all existing state rules and regulations governing gas pipeline design, testing, maintenance, and operation are also equally important considerations in DRA's review and evaluation of PG&E's Implementation Plan.

B. SUMMARY OF RECOMMENDATIONS

Based on DRA's review and analysis, DRA recommends:

1. That the Commission reject PG&E's proposed PSEP Phase 1 plan , and associated costs, based on the findings of DRA witnesses. Rather, the Commission should instead adopt changes to PG&E's PSEP as recommended in DRA Exhibits 03 through 08.

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[22] National Transportation and Safety Board Accident Report on Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010 ("NTSB Accident Report"), Aug.30, 2011, pp.75-78.

[23] Refer to NTSB recommendations designated as (P-10-2)(Urgent), (P-10-3)(Urgent), and (P-10-4) as presented in the NTSB Accident Report, at pages 75-76.

2. That the Commission reject the PG&E request for incremental revenue requirements over the period 2011-2014 in the total amount of $768.7 million[24], and instead adopt DRA's recommendation that ratepayers should not be responsible for any incremental costs, expenses or return on investment associated with PG&E's PSEP prior to PG&E's next Gas Transmission and Storage (GT&S) rate case proceeding. All expenses incurred prior to 2015 should be borne by PG&E shareholders. Any expenses and recovery of capital investment associated with PG&E's gas transmission and storage operations for 2015 and ensuing years may be requested by PG&E in its next GT&S rate case[25]. The Commission should affirm that PG&E's authorized revenue requirements for gas transmission and storage services should stay at the levels authorized for PG&E in D.11-04-031.
3. That the Commission reject as unreasonable and imprudent, and therefore unacceptable, PG&E's shareholder/customer cost allocation proposal wherein PG&E's shareholders proposes to bear only the actual recorded 2011 PSEP expenses and a certain amount of 2011 capital-related revenue requirements[26] while PG&E's customers bear the cost of the revenue requirements in the final three years of Phase 1 (2012-2014) for a total of $768.7 million.[27].
4. That the Commission should reject as unreasonable, inappropriate and unacceptable, PG&E's proposal that the costs for the post-2011 Phase 1 PSEP

[24] Refer to Table 9-1, PG&E Prepared Testimony in R.11-02-019 dated Aug.26, 2011, p.9-2 (updated with Errata on Nov. 4, 2011). The requested total revenue requirements do not change with the Errata. If the annual revenue requirement for the year 2011 (proposed for PG&E shareholder funding) were included in the total revenue requirements for the 2011-2014 period, then the total revenue requirement amount would be higher at $992.957 million as shown in WP 9-1.

[25] DRA Exhibit DRA-02.

[26] Forecast by PG&E at $220.7 million and $1.4 million, respectively, or a total of $222.1 million.

[27] PG&E Prepared Testimony in R.11-02-019 dated Aug. 26, 2011, p.8-1 (updated with Errata on Nov. 4, 2011). The total requested revenue requirements do not change with the Errata. PG&E clarified to DRA that while the revenue requirements in the final 3 years is $768.7 million, the amount that will be recovered in rates in the final 3 years is about $743.4 million. See PG&E clarification in DRA-059-Q01 mainly because of the dates when the projects become operative and are recoverable in rates.

work, with the exception of the 152 miles of strength-testing expenses and post-1970s MAOP validation and strength-testing work, be recoverable in rates.[28]

5. That with respect to capital expenditures for the PSEP, the Commission authorize PG&E cost recovery for capital additions relating only to pre-1955 pipeline replacements at an ROR reduced by 200 basis points, and to start such cost recovery only in the year 2015. But for pipeline installed after 1955, PG&E should receive no return on rate base for those plant additions.
6. That the Commission deny PG&E's request for incremental cost recovery of PSEP costs in PG&E's rates through a new Gas Pipeline Safety ("GPS") rate component.[29] Instead, PG&E's future PSEP revenue requirements should be fully integrated into PG&E's gas transmission pipeline and storage rates and considered by the Commission in the next GT&S rate case cycle after the GA V period ends in 2014.
7. That the Commission reject PG&E's proposal for balancing accounts and memorandum accounts relating to the PG&E PSEP consistent with DRA's recommendation for no incremental cost recovery for PSEP costs.
8. That the Commission reject PG&E's proposal for no reasonableness review as inappropriate and inconsistent with holding PG&E accountable for its actions and management of ratepayer funds.

[28] PG&E Prepared Testimony in R.11-02-019 dated Aug. 26, 2011, p.8-10 (updated with Errata on Nov. 4, 2011).

[29] PG&E Prepared Testimony in R.11-02-019 dated Aug.26, 2011, p.10-4 (updated with Errata on Nov. 4, 2011). The total requested revenue requirements do not change with the Errata.

Table 1 DRA's Comparative Showing on Forecast PG&E PSEP Phase 1
Total Expenses & Capital Expenditures (In $ Millions)

Line No.	Program Description	Year 2011	Year 2012	Year 2013	Year 2014	Total
1	1. Pipeline Modernization					
2	A. PG&E Proposed	155.5	323.8	397.8	458.7	1,335.8
3	B. DRA Recommended	33.1	125.8	221.8	116.2	497.0
	Direct Costs of PM	15.3	108.9	205.0	99.2	428.5
	Other Costs of PM	17.8	16.9	16.9	17.0	68.5
4	Difference (A - B)	122.33	197.99	176.02	342.48	838.82
5	2. Valves Automation					
6	A. PG&E Proposed	15.3	42.1	56.4	29.8	143.6
7	B. DRA Recommended	6.4	8.4	20.4	6.8	42.1
8	Difference (A - B)	8.9	33.7	36.0	23.0	101.5
9	3. Pipeline Records Integration					
10	A. PG&E Proposed	63.1	130.4	59.6	32.9	286.0
11	B. DRA Recommended	0	0	0	0	0
12	Difference (A - B)	63.1	130.4	59.6	32.9	286.0
13	4. Interim Safety Enhancement Measures					
14	A. PG&E Proposed	0	1.1	1.1	1.1	3.2
15	B. DRA Recommended	0	0.4	0.4	0.4	1.1
16	Difference (A - B)	0	0.7	0.7	0.7	2.1
17	5. Program Management Office					
18	A. PG&E Proposed	4.6	10.1	10.1	10	34.8
19	B. DRA Recommended	4.6	10.1	10.1	10.1	34.8
20	Difference (A - B)	0.0	0.0	0.0	-0.1	0.0
21	6. Contingency					
22	A. PG&E Proposed	51.1	108	110.1	111.3	380.5
23	B. DRA Recommended	3.5	11.6	20.2	10.7	46.0
24	Difference (A - B)	47.6	96.4	89.9	100.6	334.5
25	7. Total Phase 1 Implementation Costs					
26	A. PG&E Proposed	289.6	615.5	635.1	643.7	2,183.9
27	B. DRA Recommended	47.8	156.2	272.9	144.1	621.0
28	Difference (A - B)	241.8	459.3	362.2	499.6	1,562.9

Based on the analysis and recommendations of DRA's witnesses with respect to the various program components of PG&E's PSEP, DRA's recommendations will result in the amounts shown in Table 1 for each year over the period 2011 through 2014.[30] If DRA's recommended changes to PG&E's PSEP are adopted, then the PG&E PSEP cost estimates should go down to the total amount of $621 million instead of PG&E's PSEP cost estimate of $2.2 billion,[31] DRA's recommendation on the PSEP would represent a 72% reduction to PG&E's PSEP Phase 1 costs estimates as compared to PG&E's PSEP proposal.

In response to the Commission's Amended Scoping Memo in this rulemaking, DRA shows in Table 2 below the revenue requirements that result from DRA's recommended changes to the PG&E PSEP so that a proper comparison can be made to the Respondent's proposal. The annual revenue requirements should go down to $151.8 million instead of PG&E's revenue requirements of $992.9 million over the 2011-2014 period, or an 85 percent reduction with DRA's adjustments to the PSEP.

Table 2. Summary of DRA's Comparative Showing on PG&E PSEP Phase 1 Annual Revenue Requirements 2011-2014 (in $ millions)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	PG&E Proposed Capital	$1.390	$13.205	$63.981	$154.816	$233.392
2	PG&E Proposed Expense	$222.814	$234.074	$156.852	$145.825	$759.565
3	Total PG&E Proposed	$224.204	$249.279	$220.833	$300.641	$992.957
4	DRA Results Capital	$0.244	$5.563	$27.162	$60.776	$93.745
5	DRA Results Expense	$10.778	$18.024	$10.657	$18.659	$58.118
6	Total DRA Results	$11.022	$23.587	$37.818	$79.435	$151.863

[30] DRA's primary cost recovery recommendations are included in Exhibit DRA-02 and supersede all other related cost recovery recommendations found in this exhibit (DRA-09). DRA's comparative analysis of Forecast PG&E PSEP Phase 1 Total Expenses & Capital Expenditures and PG&E's PSEP Phase 1 Annual Revenue Requirements with DRA's recommended changes is responsive to the Commission's Amended Scoping Memo request for parties to address the reasonableness of the utilities Implementation Plans and the associated cost estimates.

[31] See Tables 8-1, 8-2, and 8-3 in PG&E Prepared Testimony, shown on pp. 8-3 and 8-4. See also Tables 7-1 and 7-2 in PG&E Pipeline Replacement Or Testing Implementation Plan filing in R.11-02-019, p.45.

7	Difference Capital (Line 1 less Line 4)	$1.146	$7.642	$36.819	$94.040	$139.647
8	Difference Expense (Line 2 less Line 5)	$212.036	$216.050	$146.195	$127.166	$701.447
9	Difference Total (Line 3 less Line 6)	$213.182	$223.691	$183.014	$221.206	$841.094

Table 3 DRA's Recommended PSEP Phase 1Recovery Revenue Requirements for 2011-2014 (in $ millions)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	PG&E Proposed Capital	0	$13.205	$63.981	$154.816	$232.002
2	PG&E Proposed Expense	0	234.074	156.852	145.825	536.751
3	Total PG&E Proposed	0	$247.279	$220.833	$300.641	$768.753
4	DRA Recommended Capital	0	0	0	0	0
5	DRA Recommended Expense	0	0	0	0	0
6	Total DRA Recommended	0	0	0	0	0
7	Difference Capital (Line 1 less Line 4)	0	$13.205	$63.981	$154.816	$232.002
8	Difference Expense (Line 2 less Line 5)	0	234.074	156.852	145.825	536.751
9	Difference Total (Line 3 less Line 6)	0	$247.279	$220.833	$300.641	$768.753

Note: PG&E Proposal w/Year 2011 outside cost recovery

II. DISCUSSION AND ANALYSIS OF DRA RECOMMENDATIONS

Section A provides a brief description of the PG&E request included in PG&E's ratemaking proposal. Section B provides DRA's analysis and recommendations regarding those elements of PG&E's ratemaking proposal.

A. SUMMARY OF PG&E'S RATEMAKING PROPOSAL

1. PG&E's Proposed Phase 1 Implementation Plan Costs

In terms of costs, PG&E forecasts spending approximately $2.2 billion to meet standards it characterizes as "new" from 2011-2014 for Phase 1 of the proposed PG&E PSEP.[32] Of the $2.2 billion, PG&E proposes total Phase 1 expenses of $750.5 million and capital expenditures of $1,433.4 million over the 4-year period.[33] Together, the combined PG&E proposed Phase 1 expenses and capital expenditures over the 4-year period amount to $2,183.9 million, or approximately $2.2 billion.[34]

2. PG&E's Total Revenue Requirements Request and Rate Proposals

In terms of revenues required, PG&E requests for revenue requirements in 2012 of about $247 million, $221 Million in 2013, and $300 million in 2014.[35] PG&E has no revenue requirement request for the year 2011 because PG&E proposes that its shareholders bear the actual 2011 expenses. PG&E proposes "a one-time upfront shareholder sharing amount"[36] where PG&E proposes to cover the actual recorded 2011costs. The total amount of annual revenue requirements from 2011-2014 is approximately $993 million, with the year 2011 revenue requirement included in the total for the four-year period.[37]

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[32] PG&E Application in R.11-02-019, p.5.

[33] Tables 8-1 and 8-2, PG&E Prepared Testimony, p.8-3.

[34] Table 8-3, PG&E Prepared Testimony, p.8-4.

[35] PG&E Application in R.11-02-019, p.5.

[36] PG&E Prepared Testimony, p.8-15.

[37] Refer to Line 24 under Total column of WP9-1, PG&E Updated Work papers for Chapter 9.

However, the amount of revenues that PG&E proposes to be actually included in rates is approximately $743.4 million.[38]

3. Proposed Cost Allocation Between Shareholders and Ratepayers and Cost Allocation Structure

In terms of the cost sharing of revenue requirements, PG&E proposes that its shareholders pay for 2011 actual recorded expenses which are currently forecast by PG&E at $220.7 million and the 2011 capital-related revenue requirements expected to be operational which are forecast by PG&E at $1.4 million.[39] PG&E clarified that the correct revenue requirement for the year 2011 is $224.2 million as shown in work papers for Chapter 9 and not $221.1 million as suggested by adding the $220.7 million plus $1.4 million.[40] Although the funding source for the proposal regarding the PG&E shareholder cost for the year 2011 is not explained in the PSEP filing, PG&E clarified that the company's retained earnings will be used by stating:

> PG&E shareholders will receive no funding (revenues) in rates charged to customers for its 2011 PSEP expense costs and operative capital costs. Since these costs have no revenues, PG&E's retained earnings will be reduced.[41]

In terms of total PSEP Phase 1 costs, PG&E proposes that its ratepayers pay for approximately $1,963.2 million out of the $2,183.9 million in total costs expected to be incurred from 2012 through 2014.[42] In terms of pipeline vintage, PG&E proposes that its shareholders bear the MAOP validation and strength testing costs for post-1970s pipeline.[43] According to PG&E, they are not seeking cost recovery for post-1970s pipelines because these segments were not grandfathered under prior regulations.[44]

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[38] PG&E Response to DRA in DRA_059-Q01.

[39] PG&E Prepared Testimony, p.8-4.

[40] PG&E Response to DRA in DRA_060-Q01.

[41] PG&E Response to DRA in DRA_062-Q01.

[42] PG&E Prepared Testimony, p.8-3.

[43] PG&E Prepared Testimony, p.8-10.

[44] PG&E Prepared Testimony, p.8-10.

PG&E states that if strength testing for post-1970s pipes are delayed beyond 2011, PG&E will not seek cost recovery for costs relating to these pipes.[45]

In terms of the cost allocation of the ratepayer-funded portion, PG&E proposes that the cost allocation be based on the PG&E Gas Accord V Settlement Agreement revenue responsibility among customers.[46] According to PG&E, the cost allocation factors shown in Table 10-1 of PG&E Prepared Testimony for the PSEP that is proposed to be used for the PSEP cost allocation are pursuant to the revenue responsibility in the Gas Accord V Settlement Agreement Table A-3 in Appendix A.[47]

In terms of allocating the PSEP common costs to the different lines of PG&E's businesses (backbone transmission, local transmission, and gas storage), PG&E proposes to allocate the common costs based on the percentage share in the direct costs of the PSEP assigned to each line of business.[48] The GTAM program and MAOP Validation programs are examples of common costs while the Pipeline Modernization and Valve Automation programs are examples of direct costs.

4. Proposed Specific Rate Base and Expense Amounts

In terms of the rate base, PG&E confirmed that the amounts shown in Lines 23, 26, and 27 on pages WP 9-5, WP 9-13, and WP 9-21 of PG&E's workpapers for Chapter 9 of its Prepared Testimony are provided to meet the requirements of O.P. 10(b) of D.11-06-017 for the rate base to be specified.[49] Line 23 provides by year the weighted average rate base by gas department line of business as shown below:

	2011	2012	2013	2014
Aug.26, 2011 Filing				
LT from WP9-5	8,617,064	110,628,172	408,421,347	886,237,129
BBT from WP9-13	401,459	28,162,614	70,799,808	99,001,903
STO from WP9-21	0	0	0	0

[45] PG&E Prepared Testimony, p.8-10.

[46] PG&E Prepared Testimony, p.10-2.

[47] Footnote 5, PG&E Prepared Testimony, p.10-2.

[48] PG&E Response to DRA in PZS7-1.

[49] PG&E Response to DRA Data Request PZS6-1.

Total:	**9,018,523**	**138,790,786**	**479,221,155**	**985,239,032**
Updated Nov.4, 2011	2011	2012	2013	2014
LT from WP9-5	7,769,906	105,020,066	369,016,022	810,109,717
BBT from WP9-13	1,132,115	32,818,501	91,939,588	138,308,910
STO from WP9-21	116,457	951,803	18,258,479	36,794,085
Total:	**9,018,478**	**138,790,370**	**479,214,089**	**985,212,712**

The rate base reflects the update on Nov.4, 2011 when PG&E discovered an error in allocating the Implementation Plan costs among its different lines of business (Backbone, Local transmission, and storage).[50]

The following elements of rate base are included for the Pipeline Implementation Plan costs: utility plant in service, plus working capital, less deferred taxes, and less accumulated depreciation.[51]

5. Proposed Cost Recovery and Rates

PG&E is requesting approval of the work scope proposed for both Phase 1 and Phase 2 of the Implementation Plan.[52] In this filing, PG&E only requests authority to proceed with and recover costs in rates for Phase 1.[53] Line 5 of Table 1-4 of Chapter 1 in PG&E's Prepared Testimony shows the net costs that PG&E is requesting for rate recovery, which is $1,963.2 million.[54]

PG&E proposes to recover the annual authorized PSEP revenue requirements through new Gas Pipeline Safety (GPS) rate components included in the Customer Class Charges recovered in the end-use rates paid by PG&E's core and noncore customers.[55]

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[50] Refer to PG&E email in R.11-02-019 on Nov.4, 2011 regarding the Errata Filing.

[51] PG&E Prepared Testimony, p.9-4.

[52] PG&E Prepared Testimony, p.1-11.

[53] PG&E Prepared Testimony, p.1-11. PG&E states that Phase 2 timing and cost recovery will be addressed in a separate filing for the period starting January 1, 2015.

[54] Table 1-4, PG&E Prepared Testimony, p.1-17.

[55] PG&E Prepared Testimony, p.10-4.

PG&E states it is "seeking recovery in rates for the costs of new safety programs and investments that go above and beyond existing regulatory requirements. According to PG&E, the Pipe Modernization, Valve Automation, and Pipeline Records Integration Program are new incremental programs.[56] Whether the PG&E claim that these programs implicate "new" standards are addressed in the analysis in DRA Exhibits 03 through 08.

PG&E states it is not seeking recovery of the following categories of costs:

1. Costs in this Implementation Plan that are a direct result of the San Bruno accident, personal injuries, property damage, emergency response or civil litigation related to San Bruno accident.[57]

2. Incremental utility expenses for unanticipated gas business activities such as gathering gas system records and documents, leak survey and repair, emergency response, customer outreach, responding to requests for information and documentation, and supporting the NTSB, CPUC, and IRP investigations. These are referred to as "non-Implementation Plan costs."[58] PG&E projects these costs will be $215 million by the end of 2011.[59]

3. Costs to validate MAOP of post-1970s pipeline since these segments were not grandfathered under existing regulations. These will be at shareholder expense.[60]

4. Costs already included in GA V under existing programs for pipe replacement, ILI or valve automation.[61]

6. Proposed Operating and Maintenance Expenses

PG&E states that the "Operating and maintenance expense estimates for 2011 through 2014 include labor, material, supplies, contracts, and other expenses" that relate to the PG&E Proposed Implementation Plan (with expenses estimated in nominal dollars).

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[56] PG&E Prepared Testimony, p.1-12.

[57] Id.

[58] Id.

[59] Id.

[60] Id. at p.1-13.

[61] Id.

According to PG&E, this is consistent with the method PG&E used in its 2011 GRC.[62] PG&E states that "All incremental PG&E labor includes standard burdens such as payroll taxes and direct benefits. Indirect employee benefits such as those associated with post-retirement, long-term disability, workers compensation and casualty insurance are excluded."[63] PG&E's expense-only proposed revenue requirement for the 2011-2014 period is in the total amount of $536.7 million, with $234 million in 2012, $156.8 million in 2013, and $145.8 million in 2014. As mentioned, PG&E shareholders propose to bear actual 2011 expenses in the estimated forecast amount of $220.7 million.

7. PG&E Proposes Balancing and Memo Accounts

PG&E proposes to establish the Gas Pipeline Expense Balancing Account (GPEBA) for purposes of tracking the difference between recorded expenses of the ratepayer-funded portion of the Implementation Plan costs incurred during the Phase 1 over 2012-2014 and the forecast expenses authorized by the Commission.[64] If PG&E spends more than the authorized amount, PG&E will refund the balance to customers through the GPS rate component.[65] If PG&E spends more, PG&E proposes to seek Commission authorization through an Tier 3 Advice letter filing to recover the difference in rates.[66] PG&E proposes that the disposition of the balance of the GPEBA will be in PG&E's AGT process.[67]

PG&E also proposes two Gas Pipeline Safety Balancing Accounts (GPSBAs). One is for core customers and the other for noncore customers.[68] Similar to the GPEBA, each GPSBA will record differences each month for the customer-funded revenue requirements associated with the forecast expenses, actual capital expenditures for in-service capital projects and actual revenue collected through the Core and Noncore GPS rates. PG&E

[62] PG&E Prepared Testimony, p.9-2.
[63] Id. at p.9-3.
[64] PG&E Prepared Testimony, p.8-11.
[65] PG&E Prepared Testimony, p.8-11.
[66] PG&E Prepared Testimony, p.8-11.
[67] PG&E Prepared Testimony, p.8-11.
[68] Id. at p.8-11.

proposes an annual true-up for any resulting over or under collection via PG&E's AGT advice letter.[69]

PG&E also requests that the Commission approve PG&E's pending Motion to establish the Natural Gas Transmission Pipeline Safety and Reliability Memorandum Account.[70] PG&E states that the memorandum account will be modified to reflect PG&E's shareholder allocation proposal.[71]

8. PG&E Proposes No Reasonableness Review of Costs

PG&E proposes that Commission find the forecasts costs and the associated revenue requirements to be reasonable so long as the Phase 1 recorded costs are equal to or less than the forecast cost estimates for expense and capital proposed therein.[72] In case these exceed the forecast cost estimates, then PG&E may request recovery of additional costs through a Tier 3 advice letter filing.[73] Should the Commission approve an increase in the forecast cost, then PG&E proposes that these be found reasonable.[74] PG&E argues that "the absence of after-the fact-reasonableness review is an essential part of the timely cost recovery needed to ensure PG&E's credit quality."[75]

9. PG&E Proposes To Provide Progress Reporting

PG&E proposes to provide progress reporting to the Commission through semi-annual reporting on the progress of the Implementation Plan in the form of Attachment 8E.[76]

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[69] Id. at p.8-12.

[70] Id. at p.8-13.

[71] Id. at p.8-13.

[72] Id. at p.8-13.

[73] Id. at p.8-14.

[74] Id. at p.8-14.

[75] PG&E Prepared Testimony, p.8-14.

[76] Id. at pp.8-14 through 8-15.

B. DRA's ANALYSIS OF PG&E'S PROPOSALS AND RECOMMENDATIONS

This Exhibit uses the PG&E Results of Operations ("RO") model designed by PG&E specifically for the PG&E PSEP filing and the PG&E PSEP rate model to derive the annual revenue requirements for the period 2011-2014 and the rate impact of the new GPS rates. The RO model was modified by PG&E on DRA's request to provide dynamic linkages when changes are made to the PSEP cost based on DRA's recommendations. The revised RO was delivered to DRA on December 29, 2011. DRA reserves the right to issue errata on the PSEP cost and revenue requirements. As inputs to the RO model, this Exhibit relied on the analysis and program cost recommendations and policy recommendations of DRA's various witnesses on the PG&E PSEP components as well as the DRA reference exhibits described below:

a. Pipeline Modernization Plan: See DRA Exhibits 03, including those of DRA Consultants Dave Rondinone in Exhibits 04; Neil Delfino in Exhibit 05, and Sibylle Scholz in Exhibit 06;
b. Valves Program: See DRA Exhibit 07;
c. Pipeline Records Integration Program: See DRA Exhibit 08;
d. Interim Safety Measures Program: See DRA Exhibit 07;
e. Program Management Office: See DRA Exhibit 07; and
f. Contingency Amount: See DRA Exhibit 03.
g. Policy proposals: See DRA Exhibit 02; and
h. Industry Standards and Commission General Orders: See DRA Exhibits 10 and 11.

Having derived the annual revenue requirements from the RO, the results of the RO model are used as inputs to the PG&E PSEP rate model to examine the impact of DRA's recommended changes to the PSEP in terms of rates and customer bills.

1. PG&E's Decision Tree and PSEP

The Exhibits 03 through 08 of DRA's Prepared Testimony describe DRA's evaluation and proposals regarding PG&E's proposed Decision Tree ("DT").[77]

If DRA's recommended changes to the PG&E PSEP were adopted by the Commission, those adjustments to the PSEP would result in reduced revenue requirements for the 2011-2014 period to the extent of $151.8 million as shown in Table 2.[78]

It is clear that PG&E's DT and the proposed IP are resulting in higher overall project costs, and consequently, those higher costs when put into the RO model increase PG&E's revenue requirements, and this in turn translates to a higher base margin. Base margin refers to the utility's basic revenue requirements for its cost of service, in this case, for gas transmission and gas storage. Increases to base margin translate to higher rates charged to customers to recover the increased revenue requirements. In this case, PG&E's proposal will result in rate increases to all its end-use customers as shown in Table 10-3 of PG&E's Prepared Testimony.[79]

(a) PG&E's Proposed PSEP Entails Massive Capital-Expenditure-Intensive Work and Should Be Rejected

Of the $2.2 billion described in Section A1. above, the largest component of PG&E's PSEP costs in Phase 1 involves PG&E's Pipeline Modernization Request.[80] The Pipeline Modernization work within the PSEP Phase 1 has three work components: Strength testing, in-line inspection and retrofit, and pipeline replacement.[81] The capital expenditures portion of the request for Pipeline Modernization over the 2011-2014 period is about $928

[77] DRA's primary cost recovery recommendations are included in Exhibit DRA-02 and supersede all other related cost recovery recommendations found in this exhibit (DRA-09). DRA's comparative analysis of PG&E's PSEP Phase 1 Annual Revenue Requirements with DRA's recommended changes is responsive to the Commission's Amended Scoping Memo request for parties to address the reasonableness of the utilities Implementation Plans and the associated cost estimates.

[78] Please refer to these DRA Exhibits for the specific details and findings with respect to the PG&E Implementation Plan program components and their costs.

[79] Table 10-3, PG&E Prepared Testimony, p.10-7.

[80] Refer to Table 3-1 of PG&E's Prepared Testimony, p.3-6.

[81] PG&E Response to DRA PZS8-4. See PG&E reference DRA_020-Q04.

million.[82] The expense portion of the request for Pipeline Modernization over the same period is about $408 million.[83] Together, PG&E's combined capital expenditures and expense request in Phase 1 over the period for this component alone is $1,335.8 million.[84]

The fact that PG&E's proposed Implementation Plan consists of large capital expenditures, that in turn result in large capital additions is illustrated by Table 4, below, which is reproduced from PG&E's response to a DRA data request.[85]

[82] Refer to Line 6 Total column, Table 3-1 of PG&E Prepared Testimony.

[83] Refer to Line 12 Total column, Table 3-1 of PG&E Prepared Testimony.

[84] Refer to Line 13 Total column, Table 3-1 of PG&E Prepared Testimony.

[85] PG&E Response to DRA in PZS7-5. See PG&E reference DRA-018-Q05Atch01.

Table 4 PG&E PSEP Phase 1 Capital-Only Revenue Requirement ($000)

Line #	Program Component	2011 (a)	2012	2013	2014
1	Pipeline Modernization	0	8,718	41,517	93,385
2	Valve Automation	441	2,700	7,770	14,586
3	Pipeline Records Integration	371	(288)	(2,040)	15,645
4	Interim Safety Enhancement Measures	-	-	-	-
5	Program Management Office	0	(0)	0	1,268
6	Contingency	578	2,075	16,756	29,974
7	Subtotal	1,390	13,206	64,003	154,858
8	RRQ Adj to Match 8/26/2011 Application (a)		(1)	(22)	(42)
9	TOTAL	1,390	13,205	63,981	154,816

PG&E PSEP Phase 1 Capital Additions ($000)

	Program Component	2011 (a)	2012	2013	2014
10	Pipeline Modernization	-	197,139	289,622	441,283
11	Valve Automation	13,310	28,377	47,315	42,589
12	Pipeline Records Integration	2,905	5,793	49,253	44,633
13	Interim Safety Enhancement Measures	-	-	-	-
14	Program Management Office	-	-	-	22,903
15	Contingency	11,988	66,931	82,445	85,703
16	TOTAL	28,204	298,240	468,635	637,112

(a) Outside of recovery request (described in Chapter 8)

PG&E indicated that the Implementation Plan segment count for pipeline replacements is 2,797[86] while the pipeline replacement in miles in Phase 1 is shown as 185.7 miles.[87] PG&E states that pipeline replacement is a capital expenditure.[88] DRA's

[86] PG&E Response to DRA PZS7-8. See also PG&E's reference DRA_018-Q08. In this response, PG&E indicated that of the 2,797 segments identified for pipeline replacement, 157 miles of replacements are on pipe that was installed in 1966 or earlier, 18 miles of replacements are on pipe that was installed post-1966, and 10 miles of replacements are on pipe listed in GIS as unknown install date.

[87] Refer to Line 3 under Total column in Table 3-3 of PG&E Prepared Testimony.

[88] PG&E Prepared Testimony, p.3-61.

review shows that the pipeline replacement cost constitute the largest portion of the capital expenditure request within the Pipeline Modernization program Phase 1. The pipeline replacement account for approximately 90 percent of the Pipeline Modernization capital expenditures in Phase 1, where pipeline replacements are in the amount of $833.6 million out of the $928.1 million in capital expenditures requested as shown in Table 3-1 of PG&E Prepared Testimony.[89] The remaining 10 percent are comprised of capital expenditures for Emergency Pipe, Test Heads, and Valves ($63.6 million), and pipeline upgrades for ILI ($30.3 million). Based on PG&E's PSEP proposal, Table 4 above shows that the Pipeline Modernization capital expenditures revenue requirements account for 61.5 percent of the total PSEP Phase 1 capital expenditures revenue requirements in the 2011-2014 period.[90] When the plants become operative, the capital expenditures become part of capital additions. Table 4 shows that the Pipeline Modernization capital additions account for 64.8 percent of total capital additions in the 2011-2014 period.[91] Since pipeline replacements comprise 90 percent of the Pipeline Modernization capital expenditures, it is thus reasonable to conclude that PG&E's pipeline replacements from the PSEP account for the major portion of PG&E's capital additions in the 2011-2014 period. In a mere span of 4 years, the proposed PG&E PSEP Phase 1 results in $1.4 billion of capital additions which become part of the PG&E rate base.[92] DRA's recommended changes to PG&E's DT will reduce the pipeline replacements from about 186 miles to about 110 miles.[93]

On the other hand, PG&E indicates that 546 miles of pipe segments in Phase 1 will be subject to strength testing assessment method but PG&E will plan to strength test 783 miles of pipe in order to complete the 546 miles of segments.[94] This would translate to the

[89] Refer to Line 2 Total column, Table 3-1 of PG&E Prepared Testimony.

[90] This is calculated from Table 4 as the sum of Line 1 across divided by the sum of Line 9 across.

[91] This is calculated from Table 4 as the sum of Line 10 across divided by the sum of Line 16 across.

[92] Sum of Line 16 in Table 4 above.

[93] DRA Exhibit 03 and 04.

[94] PG&E Prepared Testimony, p.3-29. Refer also to Line 5 under Total column in Table 3-5 of PG&E Prepared Testimony.

strength testing of 43% more miles of pipe segments than suggested by the decision tree (difference between 783 and 546 miles). PG&E explains that this is for reasons of cost efficiency since it could be more cost effective to pressure test the adjacent pipe segments.[95] Whether this difference is reasonable is addressed in DRA Exhibit 03. PG&E indicates that strength testing is primarily performed as an expense activity.[96] The expense request for strength testing is in the amount of $389.1 million out of the $407.7 million expense request for the Pipeline Modernization.[97] However, it appears that strength testing is not entirely an expense-only activity. PG&E's Table 3-5 shows that for pipeline strength test costs, there are also some capital costs to the extent of $18.1 million in Phase 1 associated with these pipeline strength tests. These are indicated by PG&E for the valves and test heads associated with strength tests.[98] The $18.1 million of capital costs for strength testing that are shown in Line 7 of Table 3-5 of PG&E's Prepared Testimony are included in Line 4 (for MAT Code 2H2) of Table 3.1 of PG&E's Prepared Testimony for the overall Pipeline Modernization request. DRA's recommended changes to PG&E's DT and PSEP will reduce the count of required pressure testing in Phase 1 from 783 to 472.[99]

For the In-Line Inspection ("ILI") component of the Pipeline Modernization Program, PG&E indicates that the major part of this work will be done in Phase 2.[100] Although PG&E states it will conduct most of the ILI in Phase 2, DRA found that there will also be some ILI work in Phase 1 as shown in Table 3-4 of PG&E's Prepared Testimony. As shown by PG&E's PSEP, capital expenditures for ILI upgrades in Phase 1 is in the amount of $30.4 million while expenses for ILI digs is in the amount of $9.6 million in Phase 1. Based on PG&E's data response to an Overland Consulting data request, DRA is uncertain whether

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[95] PG&E Prepared Testimony, p.3-30.

[96] PG&E Prepared Testimony, p.3-65.

[97] Refer to Line 8 under the Total column, Table 3-1 of PG&E Prepared Testimony.

[98] PG&E Prepared Testimony, p.3-65. Refer also to Line 7 under Total column in Table 3-5 of PG&E Prepared Testimony.

[99] DRA Exhibit 03 and 04.

[100] PG&E Prepared Testimony, p.3-26.

PG&E's designation of ILI costs between capital expenditures and expenses in the Phase 1 of PSEP is consistent with PG&E's adopted accounting treatment of first time ILI on pipelines. PG&E had indicated in data response to Overland Consultants that beginning January 1, 2008, PG&E had adopted a FERC accounting rule that first time ILI on pipelines are treated as expense.[101] Prior to January 1, 2008, all phases of ILI were considered as capital expenditures.[102]

DRA notes that the total program amount described above does not even include the associated contingency provisions of $270.7 million for Pipeline Modernization.[103] Together with contingency provisions, the Pipeline Modernization Program constitutes an estimated $1,606.5 million out of the $2.2 billion, or roughly 73.5 percent of the proposed total Phase 1 cost. More specifically, the bulk of the contingency is associated with capital expenditures on pipeline replacements, which alone account for the amount of $167.7 million.[104] For the Strength Testing under the Pipeline Modernization Program, the contingency allowance is $82.5 million.[105]

The cost of the Project Management Office ("PMO") and contingencies constitute the second largest component of PG&E's Implementation Plan costs in Phase 1 with $415.3 million over the 2011-2014 period.[106] The total capital expenditures request for this component is in the amount of $270.2 million out of the $415.3 million while.[107] while total expense request for this component is in the amount of $145.1 million.[108] The contingency

[101] PG&E Response to Overland Consulting in OC-211 available from the CPUC website at http://www.cpuc.ca.gov/PUC/sanbrunoreport.htm

[102] PG&E Response to Overland Consulting in OC-211 available from the CPUC website at http://www.cpuc.ca.gov/PUC/sanbrunoreport.htm

[103] Refer to Line 1 under Contingency column, Table 7-2 of PG&E Prepared Testimony.

[104] Refer to Line 2 under column P90 of Table 7-7 of PG&E Prepared Testimony, p.7-41.

[105] Refer to Line 18 under column P90 of Table 7-7 of PG&E Prepared Testimony, p.7-41.

[106] Refer to Table 7-1 of PG&E Prepared Testimony, p.7-2.

[107] Refer to Line 4 Total column of Table 7-1 of PG&E Prepared Testimony.

[108] Refer to Line 8 Total column of Table 7-1 of PG&E Prepared Testimony.

request of $380.5 million makes up 91 percent of the total amount of $415.3 million.[109] DRA understands from PG&E's Testimony that the contingencies represent "a risk-based allowance for the estimated costs included in this filing."[110] PG&E further explains that "PG&E's risk-based allowance is consistent with industry guidelines for contingency percentage considering the status of scope definition and the risk profiles for each component project."[111] DRA's review discussed in DRA Exhibit 03 found that the huge contingency request is unreasonable.[112]

The third largest component of PG&E's PSEP Phase 1 involves the Pipeline Records Integration Program with a total cost forecast of $285.9 million over the 2011 through 2014 period.[113] This program component consists of two projects, one is the Maximum Allowable Operating Pressure Project ("MAOP Project") in the total amount of $162.3 million, and the second is the Gas Transmission Asset Management Project ("GTAM Project") in the total amount of $123.6 million.[114] The Pipeline Records Integration Program cost of $285.9 million does not even include the contingency allowance for this program of approximately $68.3 million out of the $380.5 million contingency request described in the preceding paragraph.[115]

The fourth largest component of PG&E's Implementation Plan costs in Phase 1 involves PG&E's Valve Automation Program Request with a program request of $143.6 million over 2011-2014.[116] Of this amount, the capital expenditures request is in the

[109] Refer to Lines 3 and 7 under the Total column of Table 7-1 of PG&E Prepared Testimony.

[110] PG&E Prepared Testimony, p.7-45.

[111] PG&E Prepared Testimony, p.7-46.

[112] DRA Exhibit 03.

[113] Refer to Line 3 Total column of Table5-1 of PG&E's Prepared Testimony.

[114] Refer to Lines 1 & 2 Total column of Table 5-1 of PG&E's Prepared Testimony.

[115] Refer to Lines 11, 21, and 29 under column P90 in Table 7-7 of PG&E's Prepared Testimony, p.7-41.

[116] Refer to Table 4-1 of PG&E's Prepared Testimony, p.4-7.

amount of $132.5 million while the expense request is in the amount of $11.1 million. The contingency provision associated with the Valve Automation is $34.5 million.

In sum, PG&E's proposed PSEP is would entail massive capital expenditure-intensive work that come mostly from pipeline replacements within a short amount of time in Phase 1. These huge capital expenditures result in $1.4 billion of capital additions to utility assets within four years, and the capital additions ultimately serve to increase rate base and result in rate increases.

(b) The Scope of Work in PG&E's PSEP is Unprecedented in PG&E's Recent History

As PG&E states in Chapter 3 of its Prepared Testimony, the scope of work in the Pipeline Program is defined by the "decision tree."[117] DRA notes that every project provided in the work papers supporting Chapter 3 of the PG&E Prepared Testimony includes this statement in the justification portion: "This Phase 1 project is driven by the results of PG&E's Pipeline Decision Tree." This categorical statement informs the Commission that the scope of work in PG&E's proposed Implementation Plan is driven by the results of the PG&E decision tree.

In turn, PG&E's decision tree relies on the PG&E Geographic Information System ("GIS") database as affirmed by PG&E when it states:

> The Decision Tree was designed to query PG&E's Geographic Information System (GIS) pipe information database by using a sequential decision process to define and categorize pipe segments against each of the three threat groups discussed above. The Decision Tree identifies Manufacturing Threats first, Fabrication and Construction Threats second, and Corrosion and Latent Mechanical Damage Threats third…The Decision Tree provides the foundation for prioritizing the threat assessment work into a two-phased work scope….[118]

If the decision tree relied on the PG&E GIS database, which in 2011 was, and today continues to be a work-in-progress, then that database concern puts into question the results of the decision tree.[119] This Exhibit notes that DRA witnesses found that the PG&E

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[117] PG&E Prepared Testimony, p.3-1.

[118] PG&E Prepared Testimony, p.3-9.

[119] PG&E states on page 3-19 of Prepared Testimony that "PG&E has an extensive records review

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PSEP is based on pipeline records validation results data from April 2011 and is planned for a later update.[120] Whether this records validation update subsequently addresses this concern about the GIS database is another matter. DRA further notes the NTSB Report statement about the GIS data deficiencies:

> PG&E may already be addressing its GIS data deficiencies as part of its response to the NTSB's January 3, 2011, safety recommendations, by beginning to verify the underlying records for the more than 1,800 miles of pipeline covered by the recommendations. Nevertheless, the NTSB is concerned that many unaddressed deficiencies still remain.[121]

More importantly, as noted, DRA's review shows that the PG&E Pipeline Modernization program is driven by the results of PG&E Decision Tree.[122]

The PG&E decision tree results in the enormous scope of work for Phase 1 that entails an estimated $2.2 billion in costs described above. More specifically, the decision tree results in the massive capital-intensive work in Phase 1, the major portion of which consists of unnecessary pipeline replacements.[123] The scope of work in PG&E's proposed Implementation Plan is unprecedented in PG&E's recent history since the Gas Accord.

PG&E indicated in discovery that PG&E has not undertaken a gas transmission project on the scale of its proposed PSEP in the past periods since the 1996 Gas Accord.[124] According to PG&E, the biggest gas transmission project it has undertaken

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(continued from previous page)
underway for all gas transmission pipelines and will update the GIS database to ensure accuracy and dependability, as described in Chapter 5. Where PG&E cannot obtain sufficient and reliable data pertaining to a particular threat, the Pipeline program makes the conservative assumption that the pipeline segment being evaluated is vulnerable to that threat."

[120] DRA Exhibit 03.

[121] NTSB San Bruno Pipeline Accident Report, p.114.

[122] DRA Exhibit 03.

[123] DRA Exhibit 03.

[124] Refer to PG&E Response to DRA Data Request PZS16-3. See also PG&E reference DRA_043-Q03.

before the PSEP involved the construction of Line 401, which was granted a CPCN in 1990 and operated in November 1993, with a final capital cost of $801 million. [125]

DRA's review of PG&E's capital expenditures under the Gas Accord shows that PG&E had spent $1.6 billion over the past 15 years in the period 1996 through 2010.[126] The yearly amounts of these PG&E capital expenditures are shown below:

Table 5 PG&E Historical Capital Expenditures, 1996 – 2010

Year	Capital Expenditures ($)	Annual change in %
1996	$ 47,474,752	
1997	$ 61,629,833	29.82
1998	$ 39,308,128	-36.22
1999	$ 31,664,645	-19.45
2000	$ 66,431,786	109.80
2001	$ 97,715,861	47.09
2002	$ 132,565,919	35.66
2003	$ 89,029,863	-32.84
2004	$ 81,198,651	-8.8
2005	$ 119,176,443	46.77
2006	$ 129,366,876	8.55
2007	$ 158,329,454	22.39
2008	$ 216,751,148	36.90
2009	$ 200,318,022	-7.58
2010	$ 192,994,097	-3.66
Total 1996-2010	$ 1,663,955,479	

Table 5 shows that over 15 years, PG&E had capital expenditures of $1.6 billion for its gas transmission and storage. In the proposed PSEP, PG&E would have $1.4 billion of capital expenditures over 4 years.

The Commission should scrutinize and examine both the logic behind PG&E's decision tree and the resulting projects selected because the scope of work in Phase 1 is truly unprecedented in terms of magnitude of dollars and implementation time period. Over the life of the proposed PSEP assets, the Phase 1 would result in costs of approximately

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[125] Refer to PG&E Response to DRA Data Request PZS16-3. See also PG&E reference DRA_043-Q03. PG&E states that the final capital costs for this project was $801 million; however, only $736 million was included in rate base and rates based on the Gas Accord 1 Settlement.

[126] PG&E Response to Overland Consulting in OC-38 available at the CPUC website at http://www.cpuc.ca.gov/PUC/sanbrunoreport.htm

$5.5 billion.[127] On the other hand, if adopted, DRA's recommendations would result in lower cost over the life of Phase 1 assets of approximately $2.0 billion.

To put the PG&E Implementation Plan Phase 1 costs in perspective, consider the amount spent by PG&E for the PG&E Gas Pipeline Replacement Program ("GPRP") over the last 25 years including the estimated amount to the end of the program in 2014. Based on the 2009 GPRP Annual Report submitted in April 2010, the total expenditures on the GPRP from 1985 to the estimated end of the program in 2014 is in the total amount of $2.005 billion.[128] The GPRP was funded through amounts authorized in PG&E's GRC.[129] The average annual GPRP spending, spread out over the 29 years of implementation, is about $69 million annually. In comparison, the average annual PSEP Phase 1 proposed spending, spread out over the 4 years of implementation, is about $546 million annually, or approximately 7.9 times as much per year.

If PSEP Phase 1 is authorized as proposed, then ratepayers could be asked to shoulder this vast amount of capital-intensive spending within a short period of time.[130] And if PG&E proceeds to Phase 2, where the broad cost estimates of PSEP Phase 2 are an indication, then ratepayers could be in for another round of huge capital-intensive spending within a short period of time.[131]

[127] PG&E Response to DRA PZS16-1. PG&E reference is DRA_043-Q01.

[128] The 2009 PG&E GPRP Annual Report is available at the CPUC website at http://www.cpuc.ca.gov

[129] The 2009 PG&E GPRP states that "PG&E established the GPRP to replace aging gas distribution and transmission pipe throughout its system. The program objective was originally, and remains, to reduce the risk to public safety associated with the highest risk pipelines. The Program was authorized by PG&E senior management in September 1984 and implemented starting in January 1985. The large magnitude of resources required for this Program necessitated a 25-year time frame. The Program was originally targeted for completion by the end of 2009 and subsequently communicated in 2004 to extend the program completion until 2014. However, with the transition to a Distribution Integrity Management Program (DIMP) and changes to risk factors, the GPRP program will become a continuous pipeline evaluation and threat mitigation program."

[130] PG&E's broad estimate for Phase 2 is in the range of $6.8 billion to $9.0 billion. See PG&E Response to DRA in PZS16-2. PG&E reference is DRA_043-Q02.

[131] PG&E Response to DRA PZS9-6. PG&E's reference is DRA_022-Q06.

(c) Previous Funding for Some Projects in PG&E's Proposed Implementation Plan Phase 1 in Gas Accords Are Difficult To Verify and Individual Projects Could Not Be Identified

According to PG&E "Costs associated with work on segments of pipe that have been identified as part of the Implementation Plan planning process, but have already been requested as part of the 2011 GT&S Rate Case (A.09-09-013), are not included in this Implementation Plan."[132] In discovery, PG&E explained that the PG&E DT identified ten of the same projects for replacement within MWC 75 for Pipeline Reliability in A.09-09-013. PG&E states that it removed the first nine projects from the PSEP work scope due to duplication with those in MWC 75 funded in GA V. However, one project remained in the PSEP work scope "Because it was forecasted to go in-service after the Gas Accord V time period, this project is not being funded by existing rates."[133]

The easy identification of individual projects in the Gas Accord V that were included in the PSEP work scope described above seems to be an exception. DRA asked PG&E to explain how the Commission and the ratepayers can be assured that the proposed projects in the PG&E PSEP have not been previously funded in rates. DRA found that verification of funding of PSEP Phase 1 for pipeline replacements in previous PG&E requests for funding could prove difficult since PG&E is unable to identify the individual project specific costs against the requests made by PG&E. This is attributed by PG&E to the "black box" nature of settlements. PG&E states:

> "Between 2005 and 2010, cost recovery and rates for PG&E's gas transmission services were negotiated through Gas Accord Settlement agreements and approved by the CPUC. These settlements were various compromises of multiple issues in which some, but not all, of PG&E's forecast was funded in the settlement. Because of the nature of the "Black Box" Settlement agreements, PG&E cannot identify requests and recovery of individual project specific costs."[134]

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[132] PG&E Prepared Testimony, p.8-6.

[133] PG&E Response to DRA PZS1-8. See PG&E reference DRA_002-Q08. The last project kept in the PSEP Phase 1 is PSRS 7845 referred to as "L-103 Reroute Crazy Horse" in the amount of $4 million and had a forecast operative date of 9/15/2015. In the PSEP, PG&E explained that this project has been included in the scope of the bigger L-103 Enhancement Plan Project with an estimated cost of $28.8 million and an operational date of 12/2/2014.

[134] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

DRA notes that the Overland Consulting report similarly noted the lack of visibility into the components of adopted capital expenditures in previous Gas Accords.[135]

PG&E further explains the difficulty of tracking a pipe segment back to a proposed or actual project. PG&E states that pipeline projects are tracked and recorded by pipeline number or route and mile-point, not by segment.[136] It is interesting to note that since 1996, this is how PG&E has tracked and recorded pipeline projects based on its Project Status Reporting System ("PSRS").[137] PG&E states that the segment would have to be converted to a pipeline mile point and manually researched within PG&E's PSRS for any cross reference.[138] In short, since 1996 when PG&E used the PSRS up to the present time, there has been no readily available tracking within the PSRS by pipe segment. The Commission should note that any pipeline projects in the PG&E PSEP will need to be identified according to how these are going to be tracked by PG&E in its PSRS. Otherwise, the Commission could run into this difficulty of tracking down the specific projects funded in the PSEP, unless it has information on the pipeline number or route and mile-point.

In so far as the strength testing of pre-1970 pipe segments are concerned, PG&E claims that "These pipe segments were never required to be strength tested to Subpart J requirements, so they were never performed or funded by ratepayers."[139] PG&E argues that Commission Decision 11-06-017 eliminated "grandfathering" and "set a new standard going forward."[140] PG&E asserts that D.11-06-017 resulted in a change in regulation for PG&E by eliminating the "grandfathering" provision provided in the federal code for pipe installed prior to July 1, 1970.[141] DRA notes that when the Commission adopted General

[135] See Overland Consulting Report entitled "Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures For the Period 1996-2011" dated December 30, 2011 in Chapter 4.

[136] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[137] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[138] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[139] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[140] PG&E Response to PZS1-3(a). See PG&E reference DRA_002-Q03.

[141] PG&E Response to PZS1-7(b). See PG&E reference DRA_002-Q07.

Order ("GO") 112 in Decision 61269 on December 28, 1960, there were already existing gas industry standards for strength tests and record-keeping. The strength test requirement of GO 112 is based on gas industry standards in ASA B31.8-1958. This is described in DRA Exhibits 10 and 11. In addition, although there were record-keeping requirements in ASA B31.8-1955, the matter of record-keeping for pipeline facilities was generally addressed by the Commission in GO _[142] DRA witnesses Mark Pocta and Thomas Roberts discuss the requirements for strength testing of pre-1970 pipe segments in greater detail in DRA Exhibits 02 and 03.

Regarding in-line inspection and pipeline retrofit work, PG&E claims that those included in the PSEP are all new and incremental and never included within rates. Table 3-4 of PG&E Prepared Testimony identify the projects included for the ILI work in the PSEP Phase 1. PG&E provided a list that identifies every gas transmission pipeline included in the BIAP and DRA used this to verify whether any of the PSEP ILI and retrofit work were previously included in PG&E's ILI Baseline Integrity Assessment Plans ("BIAP").[143] DRA examined the list and did not find any projects that were common to those listed in Table 3-4 of PG&E Prepared Testimony and the Attachment 1 to the data response that were supposed to include the project in the ILI BIAP.

For the valve automation program, PG&E categorically states that "There were no project or program costs identified in Gas Accord I through V to provide pipeline segments with automated isolation capability in the event of a line rupture."[144] This could be true as DRA requested for valve related projects that PG&E had completed from 2000 to 2010 and PG&E responded that it did not have a program to install RCV or ASVs and that PG&E did not install any automated valves as a stand-alone project.[145] DRA notes that even the NTSB Accident Report has noted PG&E's consideration of the addition of Automatic Shut-off Valves (ASVs) or Remote Controlled Valves (RCVs) in an internal memorandum dated

[142] DRA Exhibits 10 and 11.

[143] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[144] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[145] Refer to DRA Exhibit 07, Prepared Testimony of Jerry Oh, citing PG&E response to DRA in DRA_014-Q01.

June 14, 2006, where the memorandum came to the conclusion that "the use of an ASV or RCV as a prevention and mitigation measure in an HCA would have "little or no effect on increasing human safety or protecting properties" and did not recommend using either as a general mitigation measure."[146]

PG&E claims "There were no project or program costs identified in Gas Accord settlements I through V related to performing the MAOP Validation work of GTAM system work described in Chapter 5 of the PSEP."[147] At the most, PG&E acknowledges that a modest amount of IT work is contemplated in A.09-09-013 in the amount of $2.7 million. PG&E claims that "there is no duplication of work between the 2011 GT&S Rate Case and Chapter 5 of the PSEP filing." [148] Further, PG&E acknowledges that the 2011 GRC included a request to fund certain mobile and GIS projects which it claims were intended for employees in the Customer Care business unit, which for gas, would include Gas Service Representatives. PG&E argues that for purposes of the PSEP, mobile computing equipment would be provided to PG&E's Gas Maintenance and Construction employees who do preventative maintenance and repair work on PG&E's gas transmission system.[149] However, as discussed in greater detail in DRA Exhibit 08 by DRA's witness Godfrey, this appears to be contrary to this DRA's witness review. DRA has discovered that PG&E has received funding in the previous GRCs for its core systems (SAP and GIS system) as well as other electronic databases, and should have embedded funding that can be utilized for the GTAM project.[150]

For interim pressure reductions and customer service, PG&E states "There were no project or program costs identified in Gas Accord settlements I through V to analyze or implement interim pressure reductions as described in the PSEP."[151] PG&E indicates that

[146] NTSB San Bruno Pipeline Accident Report, pp.56-57.

[147] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[148] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04

[149] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[150] DRA Exhibit 08. Refer to PG&E Responses to DRA in TLG1 in question 4i and question 4p and Responses to PZS8-2.

[151] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

as part of this interim program, it forecasts filling four (4) senior gas transmission engineer positions at a fully loaded cost of $175,000 per position per year.[152] In discovery, PG&E responded to DRA that "No workpapers were developed that support PG&E's determination that four planning engineers are needed to meet the extremely large increase in workload for the Gas System Planning…"[153] DRA is concerned that this may be duplicative labor since the forecast is unsupported.

Similarly, for the PMO, PG&E explains that the resources in the PMO will either be "new hires or if they are transferred from other positions within PG&E, their prior positions will be backfilled."[154] With transfers from other positions occurring within PG&E, DRA is concerned that the extent of any embedded labor costs could be difficult to verify.

(d) The Cost Estimates Are Loaded with Contingency Based on Preliminary Cost Designs Not Any Detailed Engineering Cost Estimates, and Should Be Rejected

PG&E admits that the Pipeline Modernization forecasted project costs were based on preliminary cost designs using one-mile cost models.[155] That means that PG&E could be requesting for more PSEP money than needs to be because project scope has uncertainty. This in turn means that with ratepayer funding of the PSEP, the ratepayers could be saddled with higher rates than needs to be, and consequently, could just end up increasing PG&E's profits even more. In Testimony, PG&E states:

> "In order to fulfill the project's estimating requirements, a set of nominal "one mile" cost models was developed based on project type (e.g., replacement, ILI, or strength test), pipeline diameter, and the project area's level of congestion…Each "one mile" cost model was then divided by 5,280 feet in order to determine a cost per foot that could be applied to multiple projects."156

[152] Refer to DRA Exhibit 07, Prepared Testimony of Jerry Oh.

[153] Refer to DRA Exhibit 07, Prepared Testimony of Jerry Oh, citing PG&E response to DRA in DRA_015-Q01Rev01.

[154] PG&E Response to PZS8-4. See PG&E reference DRA_020-Q04.

[155] PG&E Response to DRA PZS17-2. PG&E reference is DRA_049-Q02.

[156] PG&E Prepared Testimony, p.3-40.

Similarly, PG&E indicates that the Valve Automation forecasted project costs are based on conceptual design.157 Based on this conceptual nature of the estimate, PG&E acknowledges that

"actual project costs could vary from -30 to +50 percent of estimated given significant unknowns such as: land ownership (easement/franchise), project length based on GIS records accuracy and construction access, final pipeline routing, biological surveys for threatened and endangered species and cultural resources, permitting restrictions, etc. Cost estimates may exceed the Class 4 estimate range in unusual circumstances. PG&E must complete detailed design engineering, pipeline routing and permitting before it can further define the project's scope and thus more accurately estimate costs."[158]

PG&E indicates that the contingency provisions are driven by the large percentage of "undefined scope of the project, which is about 85% to 99% of project scope".[159] Details of PG&E's estimation methodology are set forth in Attachment 3E of PG&E's Prepared Testimony.160 DRA witness Roberts provides more insight into DRA's concerns with PG&E's estimation methodology and the provision for contingency in DRA Exhibit 03.

(e) PG&E's PSEP Phase 1 are Loaded with Other Extra Costs

Based on discovery responses, DRA also found that the expense and capital expenditure costs shown in Tables 8-1 and 8-2 of PG&E's Prepared Testimony represent fully loaded costs.[161] This means that the costs include overhead costs and escalation provisions that PG&E deems necessary to support the direct cost investment. Thus, the program costs shown in Tables 8-1 and 8-2 include both direct and indirect costs. PG&E does not have the breakdown between the total direct costs and indirect costs readily available.[162] To get a sense of how PG&E's assumptions on indirect costs could be impacting PG&E's direct cost numbers, DRA asked for PG&E's assumptions regarding overheads, loading factors, and escalation factors for purposes of the PG&E PSEP, and

[157] PG&E Response to DRA PZS17-2. PG&E reference is DRA_049-Q02.
[158] PG&E Prepared Testimony, p.3-39.
[159] PG&E Response to DRA in TCR19-2. See PG&E reference DRA_044-Q02.
[160] Prepared by Gulf Interstate Engineering for PG&E.
[161] Refer to PG&E Response to DRA Data Request PZS1-1(a).
[162] Refer to PG&E Response to DRA Data Request PZS1-(b).

compared them with the assumptions used by PG&E in developing the project distribution and transmission costs in the most recent PG&E Gas Accord V and the PG&E GRC.

DRA found that PG&E's escalation rates assumed for all years after 2011 is a straight 3.12% for both the Pipeline Modernization Program and the Valves Automation Program of the PSEP.[163] In both the 2011 PG&E Gas Transmission & Storage rate proceeding that resulted in the GA V Settlement and the 2011 PG&E GRC, the expense escalation rates for the years after 2011 were substantially lower than those assumed in PG&E PSEP and are given below:[164]

Description	2012	2013	2014
Gas Transmission	1.24%	1.35%	1.56%
Gas Distribution	1.46%	1.5%	1.60%
Gas Storage	1.52%	1.55%	1.65%

Similarly, the capital escalation rates in the GA V and the GRC for the years after 2011 were all likewise substantially lower than those assumed in the proposed PG&E PSEP and are given below[165]:

Description	2012	2013	2014
Gas Transmission	1.1%	1.91%	1.91%
Gas Distribution	1.51%	1.37%	1.37%

PG&E attributes the dramatic difference to the fact that the above escalation rates are from the 2nd quarter 2008 forecast of Global Insight[166] when economic conditions were more depressed than in year 2010. For the PSEP, PG&E relied on the assumptions of Global Insight which according to PG&E were developed during the third quarter of 2010 and

[163] PG&E Data Response to DRA PZS8-2. See PG&E reference DRA_020-Q02.
[164] PG&E Data Response to DRA PZS8-2. See PG&E reference DRA_020-Q02.
[165] PG&E Data Response to DRA PZS8-2. See PG&E reference DRA_020-Q02.
[166] PG&E Data Response to DRA PZS8-2. See PG&E reference DRA_020-Q02.

assumes a straight 3.12% escalation for the 4-year period.[167] DRA is concerned about the escalation factors in PG&E's PSEP. Based on the history of the annual change in the US Consumer Price Index, the inflation rate has never been consistently the same from year to year.[168] Another research group, the Wood Mackenzie, had inflation rate assumptions that were developed in the third quarter of 2010.[169] DRA compared those inflation rate assumptions for years 2011-2014 against the more recent ones that Wood Mackenzie had developed in October 2011.[170] The latter forecast by Wood Mackenzie had gone down from the previous year's forecast. This only means that Global Insight may also have a new set of inflation rate assumptions for the period. A Wall Street Journal news article reported that the Federal Reserve has a long term inflation target at 2.0 percent.[171] DRA is concerned about the escalation rate assumptions used by PG&E since the numbers could serve to increase the PSEP project cost forecast excessively. Escalation rate concerns are also noted in DRA Exhibit 06.

DRA notes also that the material burden rate on the Valves Automation Program assumed were at 29% while those assumed in the GA V and GRC for material burden rates ranged from a low of 1.0% to a high of 16.0%.[172] PG&E explains that the difference in the assumption lies in the difference in material burden rates for items less than $75,000 and those items over $75,000.[173] First of all, PG&E assumes a 19% material burden rate for all materials in the PSEP which is immediately notably higher than the maximum rate in the GA V and the GRC. According to PG&E, if a significant amount of the material is

[167] PG&E Response to DRA in PZS15-3. See PG&E reference DRA_039-Q03.

[168] The historical Consumer Price Index from 1913 to the present time is available from the US Department of Labor Bureau of Labor Statistics website.

[169] Wood Mackenzie North America Natural Gas Long Term View Macroeconomic Assumptions dated September 2010 available to DRA from a Commission subscription.

[170] Wood Mackenzie North America Natural Gas Long Term View Macroeconomic Assumptions dated October 2011 available to DRA from Commission subscription.

[171] The Wall Street Journal dated January 26, 2012, pp.1-2.

[172] PG&E Response to DRA in PZS15-3. See PG&E reference DRA_039-Q03.

[173] PG&E Response to DRA in PZS15-2. See PG&E reference DRA_039-Q02.

comprised of items valued at over $75,000, then a lower 1% burden rate is used such as those in the case of the large length of pipes.[174] Conversely, if a significant amount is comprised of materials valued at under $75,000, then a higher burden rate is used such as in the case of strength test and ILI projects.[175] PG&E states that the material burden cost is at 5% of total material for pipeline replacement projects and 15% of total material for hydrostatic tests projects.[176] PG&E explains that in so far as the Valve Automation Program was concerned, the materials rarely exceed the $75,000 limit and so they used the 19% burden rate and added a 10% sales tax which was allegedly not previously included, to come up with the 29% material burden rate.[177] PG&E has not sufficiently supported why it is reasonable to have a higher material burden rate of 19% in the PSEP valves compared to those used in the GA V and GRC, the reason for an inconsistent treatment of the sales tax and how the $75,000 is a reasonable cut-off point for high or low material burden rate. As described, the sales tax is sometimes included in the base material cost and at other times it is not included in the base material cost and has to be added separately. The significant differences in assumed material burden rates have not been justified by PG&E.

In addition, the loading factors assumed by PG&E appeared to vary across the different PSEP programs. In the Pipeline Modernization Program, PG&E states that no loading factors were assumed.[178] On the other hand, the Valves Automation Program loading factors were from 0.54% to 4% depending on the project.[179] According to PG&E "For the GTAM project, an 11.85 percent cost factor was added to the individual cost estimates to account for indirect and overhead costs. These costs include material burden, administrative and general (A&G) costs and an allowance for funds used during

[174] PG&E Response to DRA in PZS15-2. See PG&E reference DRA_039-Q02.
[175] PG&E Response to DRA in PZS15-2. See PG&E reference DRA_039-Q02.
[176] PG&E Prepared Testimony, p.3-50.
[177] PG&E Response to DRA in PZS15-1. See PG&E reference DRA_039-Q01.
[178] PG&E Response to DRA in PZS15-1. See PG&E reference DRA_039-Q01.
[179] PG&E Response to DRA in PZS15-1. See PG&E reference DRA_039-Q01.

construction (AFUDC)."[180] DRA Witness Godfrey noted DRA's concerns that the A&G costs may be duplicative.[181]

PG&E indicates that provisions for Project Management costs is based on 2.5% of each order's estimated total cost for the pipeline replacement projects.[182] On the other hand, the Valves Automation Program indicates Project Management costs based on 4% of the project engineering, material and construction direct costs.[183] These Project Management costs are separate and distinct from the Program Management Office, which function at the program level and is responsible for overall program management.[184] When added to the direct project costs, the inconsistencies in some of these assumptions regarding indirect costs are extra costs that serve to increase PSEP project cost.

(a) PG&E's Stated Amount of Shareholder Cost Allocation of $535.2 million is Misleading

The amount of shareholder cost allocation under PG&E's proposal is misleading.

Table 1-1 of Chapter 1 of PG&E's Prepared Testimony shows a summary of PG&E shareholder allocation. Line 8 of Table 1-1 indicates a total PG&E shareholder cost allocation of $535.2 million over the 2010 through 2014 period. It appears that PG&E is proposing to share a total of $535.2 million for total shareholder allocation.[185] DRA's review shows that the PG&E Implementation Plan does not include the amount of $215.4 million. That is, the amount of $215 million out of the $535.2 million that PG&E shareholders purportedly propose to bear are costs for non-Implementation Plan activities, and therefore, are not even part of the $2.2 billion cost of the PG&E PSEP Phase 1 scope of work.[186] The $215.4 Million are non-Implementation Plan costs, and instead, are costs

[180] PG&E Response to PZS15-1. See PG&E reference DRA-039-Q01.

[181] DRA Exhibit 08.

[182] PG&E Prepared Testimony, p.3-50.

[183] PG&E Prepared Testimony, p.4-57.

[184] PG&E Prepared Testimony, p.4-58.

[185] As shown on Line 8 in Table 1-1 of PG&E's Prepared Testimony, p.1-14.

[186] Note (a) under Table 1-1 of Chapter 1 in PG&E's Prepared Testimony explains that these non-Implementation Plan activities "includes gathering gas system records and documents, leak survey

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related to the occurrence of the San Bruno explosion. Based on the NTSB Accident Report findings regarding probable cause, PG&E is at fault, and therefore, PG&E shareholders should be responsible for costs related to the San Bruno explosion.[187] Footnote 6 on page 8-9 of PG&E's Prepared Testimony confirms that the $215.4 million are San Bruno accident related costs that shareholders will bear. It is therefore misleading for PG&E to present the entire amount of $536 million and make it appear as though the $215.4 million amount is part of their shareholder allocation for the Implementation Plan.

Secondly, being non-Implementation Plan costs, the $215.4 million is primarily based on PG&E's business decision to bear these non-Implementation Plan costs. As such, the Commission should not be misled to consider the $215.4 million as part of the PG&E shareholder cost allocation in the PG&E PSEP.

(b) PG&E's Proposal on Cost Sharing Between Shareholders and Ratepayers Fails the Industry Standard of A Prudent Gas Operator

PG&E proposes that the utility's shareholders be responsible only for the cost of Implementation Plan Phase 1 work pertaining to post 1970s pipeline that have not been pressure-tested.[188] Given the industry standards that apply during the period when the PG&E gas transmission pipeline projects were being put in the ground, and based on what PG&E knows and should have known, the costs in PG&E's Implementation Plan for replacing or pressure-testing natural gas transmission pipelines back to 1935 should not be borne by ratepayers to the extent that PG&E cannot provide the appropriate documentation for the performance of these pressure tests.[189] Even though there may not have been explicit federal or state requirements and regulations established before the year 1955, PG&E should be held to an industry standard based on what a prudent gas transmission

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and repair, emergency response, responding to requests for information and documentation, customer outreach, and supporting the NTSB, CPUC, and IRP investigations. PG&E expects to incur additional costs in 2012-2014 related to these unanticipated gas business activities but does not have a forecast for these categories of costs at this time."

[187] NTSB Accident Report, Executive Summary, p.xii.

[188] PG&E Prepared Testimony, p.1-12.

[189] DRA Exhibits 02, 10 and 11.

pipeline operator should know and should have known in order to operate PG&E's system safely and reliably. PG&E should be able to provide documentation for the pressure tests it performed on its gas pipelines, as any prudent gas operator would have done. DRA notes PG&E's membership and representation in the Subcommittee on Gas Transmission and Distribution Piping in the period prior to January 1955 and after 1955.[190] A prudent gas pipeline operator would have been guided by the then prevailing industry standards, absent any explicit federal or state rules and requirements at the time. The review by DRA's witnesses found that "PG&E seeks ratepayer funding to retest lines previously tested to subpart J but where they lost records."[191]

2. Significant Increases to PG&E's Weighted Average Rate base Attributable to the Pipeline Modernization Program

DRA's review indicates that the adoption of PG&E's PSEP will significantly increase PG&E's rate base. If adopted by the Commission, PG&E's weighted average rate base for gas transmission and storage is estimated to increase in 2012 by 7.46%, in 2013 by 24.6%, and in 2014 by 49.1%. The weighted average rate base from the PG&E PSEP in comparison to PG&E's weighted average rate base from the most recent Gas Accord V are shown below.

Table 6 PG&E Weighted Average Rate Base, 2011-2014

Case	2011 RateBase (000's$)	2012 RateBase (000's$)	2013 RateBase (000's$)	2014 RateBase (000's$)
GA V	1,751,251	1,859,366	1,947,112	2,006,109
PSEP	9,018 (a)	138,790	479,214	985,213
Total	1,751,251	1,998,156	2,426,326	2,991,322

Note (a) Excluded from cost recovery

The expected increases to PG&E's weighted average rate base in each year is due to the capital additions from PG&E's PSEP where more pipeline replacements are proposed to be undertaken under the Pipeline Modernization Program. As Table 4 shows, more than 60% of the capital additions as well as the capital-only revenue requirements

[190] ASA B31.1.8-1955, Section 8 of American Standard Code for Pressure Piping as published by the American Society of Mechanical Engineers, 1955, pp.2-3.

[191] DRA Exhibit 03.

during the period 2012 through 2014 could be attributed to the Pipeline Modernization Program component of PG&E's Proposed Implementation Plan.

(a) PG&E's Ratemaking Treatment of Retired Old Pipelines

PG&E's PSEP filing does not explicitly discuss the ratemaking treatment of the retirement treatment of pipelines replaced. Based on the PSEP filed, PG&E had identified that 2,797 segments are for pipeline replacement or approximately 186 miles of replacements.[192] Of this total, PG&E states that 157 miles of replacement are on pipe installed in 1966 or earlier. Also, 18 miles of replacements are on pipe that was installed post-1966. PG&E acknowledges that the remaining 10 miles of pipe replacements are on pipe listed in the GIS as "unknown install date."[193] The pipeline replacements in the Pipeline Modernization Program of PG&E's proposed Implementation Plan Phase 1 raises the question about the accounting treatment of plant retirement. When asked this question PG&E responds that[194]

> "PG&E will continue to follow the standard group accounting rules for retirement transactions. As existing pipe is replaced, it will be retired based on its original cost. The retirement transaction is accomplished by a reduction to gross plant of the original cost, with an equal and offsetting entry to accumulated depreciation. There would be no change to rate base and any unrecovered plant investment would be recovered over the average life of the depreciation group. This treatment is in line with current PG&E practices and in conformance with the FERC Code of Federal Regulations (CFR), Volume 18, Part 101, and CPUC Standard Practice U-4."

The Commission considered the ratemaking treatment for old meters in the recent PG&E GRC decision in D.11-05-018. The ratemaking treatment for old PG&E meters replaced by Smart Meters were contested by the parties to the proceeding. In that case, PG&E's unrecovered balance on the old meters was approximately $340 million. On average the old meters had an expected useful life of 18 years. PG&E would have continued to receive a return on its investment on these meters if they were not replaced by the Smart Meters. The Commission ultimately decided to reduce the 18-year amortization period to six years.

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[192] PG&E Response to DRA in PZS7-8. See PG&E reference at DRA_018-Q08.

[193] PG&E Response to DRA in PZS7-8. See PG&E reference at DRA_018-Q08.

[194] PG&E Response to DRA in PZS11-5. See PG&E reference at DRA_028-Q-05.

The Commission also granted PG&E an overall rate of return on the old meters of 6.3 percent, which is about 2 and a half percent less than the full rate of return. In considering the matter, various commission precedents were presented by parties in the proceeding that resulted in D.11-05-018.[195]

DRA's review indicates that PG&E's plant and accumulated depreciation reserve calculations is based on following standard utility plant accounting practices, similar to what PG&E had proposed to do in the Smart meter case for the old meters' unrecovered balance over the remaining useful life of the assets and to receive the full rate of return. DRA disagrees that PG&E should continue to receive any rate of return on the unrecovered balance of the old pipelines subject to replacement. Not only are the old pipelines no longer used and useful, but more importantly, the pipelines are being replaced on an accelerated basis because strength testing should have been previously addressed by PG&E long ago or for which pressure test records should be "traceable, verifiable, and complete." The ratepayers should not be burdened with continuing to pay for these potentially dangerous pipelines in their rates. Concern for pipeline safety is the main reason behind prematurely retiring the old pipelines. Further, with respect to capital expenditures for the PSEP, DRA recommends that the Commission authorize PG&E to get cost recovery for capital additions relating only to pre-1955 pipeline replacements at a rate of return reduced by 200 basis points, and to start such cost recovery only in the year 2015. With respect to capital expenditures that result in capital additions relating to pipeline from 1955 onwards (i.e., post-1955 years), DRA recommends that PG&E should get no return on rate base for those plant additions at all.

(b) It is Fair and Reasonable for The Commission To Adopt A Lower Rate of Return on Rate Base for PG&E's PSEP

In this Gas OIR rulemaking, the Commission made known its intent to consider reducing the PG&E rate of return. Pursuant to the Commission's ratemaking authority, the Commission can reduce the PG&E rate of return as previously mentioned in the Gas OIR

[195] These Commission precedents cited in D.11-05-018 include D.92-08-036, D.95-12-063, D97-11-074, D.96-01-011, D.83-08-031, D.84-09-089, D.84-05-100, D.85-08-046, D92-12-057, D07-05-026, D.94-10-059, and D92497.

11-02-019 where the Commission states "The extraordinary safety investments required for PG&E's gas pipeline system and the unique circumstances of the costs of replacing the San Bruno line are situations where this Commission may use its ratemaking authority to, for example, reduce PG&E's rate of return on specific plant investments or impose a cost sharing requirement on shareholders. We will consider these, and other ratemaking mechanisms, in this proceeding."[196] In comments filed in this proceeding, DRA expressed support for reducing the PG&E rate of return or imposing a cost sharing requirement on shareholders.[197]

In the PG&E GRC Phase 1 decision issued May 5, 2011, the Commission explained the rationale behind the decision on the appropriate rate of return for prematurely retired assets, where it said that one should consider the reason the asset has been prematurely retired and the cost implications of the early retirement on ratepayers. In a concurrence filed in D.11-05-018 that supported the decision as one that takes "a fair and balanced approach to cost recovery," Commissioner Timothy Alan Simon pointed out that "even as the Proposed Decision offers a comprehensive case history offered for support of parties' positions, there are unique elements in this particular case that warrant a somewhat creative solution." The Commissioner was referring to the fact that this Commission issued policies that caused the Smart meter deployment which led to the early retirement of the old meters. The concurrence to the decision points out that the shortening of the amortization period into fewer years (from 18 years proposed to 6 years in the decision) was designed to "reduce the impact of the decision point of whether PG&E should earn a rate of return. Thus, shareholders get full recovery of the undepreciated plant balance while ratepayers pay less for rate of return over the proposed 6 years amortization period than they would under PG&E's proposed 18 year period." In conclusion, Commissioner Simon's concurrence added that "since the Smart Meter program was deemed cost-effective insofar as it will provide net benefits to ratepayers over the long run, it is critical

[196] Gas OIR 11-02-019, pp.11-12.

[197] DRA Comments on OIR 11-02-019, p.3.

that we send the proper signal to investors about future technology replacements."[198] In short, in the Smart Meter case, a fair and balance approach on cost recovery would consider the cause of the early plant retirement and the cost-effectiveness of the plant replacement, and the impact on ratepayers.

In this rulemaking, it is pipeline safety concerns from the NTSB safety recommendations and the Commission order in D.11-06-017 that would lead to the early retirement of any pipelines that are identified in the PG&E PSEP for replacement. DRA notes that it was the discovery by NTSB of PG&E's record-keeping failures that have led the NTSB and the Commission to this point. It is clear that PG&E's own missteps and litany of failures in the past have led to this point and not Commission issued policies. Since the pipelines that will be retired are no longer used and useful for cost of service, the ratepayers should not be continuing to provide cost recovery on the unrecovered balance of the old pipelines.

With respect to capital expenditures for the PSEP, DRA recommends that the Commission authorize PG&E to get cost recovery for capital additions relating only to pre-1955 pipeline replacements at a rate of return reduced by 200 basis points, and to start such cost recovery only in the year 2015 as explained in DRA Exhibit 02. With respect to capital expenditures that result in capital additions relating to pipeline from 1955 onwards (i.e., post-1955 years), DRA recommends that PG&E should get no return on rate base for those plant additions. For the valves automation project, PG&E will be earning its full return on capital additions with its ensuing GT&S rate case.

(c) The Commission Should Reject PG&E's Proposal to Capitalize the Replacement of Sections of Pipe Less Than 50 Feet in Length

Every bit helps in keeping capital additions from increasing PG&E's rate base. DRA notes that PG&E proposes to change a current practice they have on the expense treatment of pipes less than 50 feet. According to PG&E, their current practice is to expense replacement of sections of pipe less than 50 feet. For purposes of the PG&E

[198] Refer to the concurrence of Commissioner Timothy Alan Simon in Decision 11-05-018 in A.09-12-020 dated May 31, 2011.

Proposed Implementation Plan, PG&E proposes that this expense treatment be changed so that sections of pipe less than 50 feet will be capitalized. In discovery, PG&E states that "there are 37 pipe segments within 27 unique projects where the total project length is less than 50 feet."[199] Further, the 27 unique projects account for a total of approximately $1.74 million. Should the Commission disagree with the proposed capitalized treatment, PG&E's Proposed Implementation Plan Phase 1 capital expenditure costs will be reduced by $213,002 in 2012, $649,000 in 2013, and $875,758 in 2014.[200]. The estimated reductions in annual capital revenue requirements based on PG&E's PSEP are (1) $9,419 in 2012; (2) $63,443 in 2013; and (3) 173,364 in 2014. PG&E justifies the proposed change in treatment by stating that "Given the systematic and programmatic approach of the Implementation Plan, PG&E has planned for such replacements to be capitalized."[201] According to PG&E, this simply means that PG&E views the pipeline replacement activities in the PSEP as a single approved scope of work and PG&E does not intend to differentiate the accounting for the same type of work by the size of any given project in the approved program.[202] There is no justified basis for PG&E to change their current practice to expense replacement of sections of pipe less than 50 feet and the Commission should reject it.

3. The Commission Should Reject PG&E's Proposal for a Tier 3 Advice Letter Filing That Would Further Increase the Original PSEP Authorized Cost

PG&E proposes that it be permitted to seek approval from the Commission to increase the authorized expense forecast for recovery through the use of a Tier 3 Advice Letter. [203] In discovery, PG&E states that no maximum amount has been proposed as a

[199] PG&E Response to PZS2-5(b) as revised. PG&E states that 23 of the 27 projects listed are Local transmission projects.

[200] PG&E Response to PZS2-5(c) as revised.

[201] PG&E Prepared Testimony, p.8-9.

[202] PG&E Response to DRA in PZS6-2. See PG&E reference DRA_013-Q02.

[203] PG&E Prepared Testimony, p.8-14.

limit under the Tier 3 Advice Letter process.[204] That means PG&E could ask for any amount in a Tier 3 Advice letter filing. PG&E admits that if adopted, those amounts in the Tier 3 AL could increase PSEP Phase 1 cost. PG&E states: "The amounts PG&E contemplates under the Tier 3 Advice letter could increase (if authorized) the original PSEP authorized forecast."[205] This will only serve to drive up the costs of PG&E's PSEP even more. This is another opening for new incremental revenue requirements, after a PSEP Phase 1 cost is approved. Further increases to the PSEP will in turn increase the PG&E rate base for any capital expenditures that become capital additions. An increase in the PG&E rate base means more opportunity for profits since the PG&E authorized rate of return will have a higher amount of used and useful operating assets against which to multiply in order to generate PG&E's net return. The Commission should reject PG&E's proposal for a Tier 3 Advice Letter filing that would further increase the original PSEP authorized cost.

4. PG&E's Proposal for New Gas Pipeline Safety Surcharges in Customer Class Charges Beginning January 2012 Should Be Rejected As Violative of Section 12.1 of the PG&E Gas Accord V Settlement Agreement

PG&E proposes incremental cost recovery in rates beginning January 2012 through new Gas Pipeline Safety (GPS) surcharges to end-use customers. PG&E proposes to accomplish this by including the GPS surcharges in Customer Class Charges. As such, according to PG&E, it avoids making adjustments to its gas transportation rates under the Gas Accord V Settlement Agreement during the Settlement period. Under Section 12.1 (Rate Certainty) of the Gas Accord V, rates specified in the Settlement Agreement are not subject to adjustment during the settlement period except as provided therein, or as agreed to by the Settlement parties, and approved by the Commission.[206] By the proposed rate treatment, PG&E is clearly trying to get around the Section 12.1 prohibition on rate adjustments

[204] PG&E Response to DRA in PZS10-5(b).

[205] PG&E Response to DRA in PZS10-5(c). See PG&E reference DRA_024-Q05.

during the settlement period. PG&E explains this proposed rate treatment in Supplemental Testimony dated December 2, 2011.[207] According to PG&E, its proposed incremental rate treatment for the PSEP cost would be a more direct approach for the collection of PSEP costs.[208] PG&E also states that the proposed rate treatment allows for separate tracking of the Gas Accord V revenues and the PSEP revenues.[209]

However, DRA found that under PG&E's proposed incremental cost recovery in rates through GPS, none of the marketers who subscribe to PG&E's backbone capacity will pay the GPS backbone rate component.[210] Hence, certain PG&E customers would not be subject to the payment of the GPS rates.[211] This fact was not readily apparent as PG&E had initially indicated to DRA that the GPS would be "recovered in the end-use rates paid by all of PG&E's core and noncore customers, without any exemption for PG&E customers or non-parties to the GA V Settlement."[212]

The Customer Class Charges are paid only by PG&E's end-use customers. PG&E's marketer customers who subscribe to PG&E's backbone transmission are not subject to the end-user rates that include Customer Class Charges. Instead, PG&E explains that the marketers pay the backbone rates established in the GA V settlement.[213] PG&E justifies the exemption of this group of customers by saying that the GPS charge is a more direct approach to the collection of PSEP costs.

(continued from previous page)

206 D.11-04-031, Appendix A, p.19.

207 See PG&E Supplemental Testimony in R.11-02-019 dated December 2, 2011, p.6.

208 See PG&E Supplemental Testimony in R.11-02-019 dated December 2, 2011, p.6.

209 See PG&E Supplemental Testimony in R.11-02-019 dated December 2, 2011, p.6.

210 PG&E Response to DRA in PZS9-7. See PG&E reference in DRA_022-Q07.

211 PG&E Response to DRA in PZS9-7. See PG&E reference in DRA_022-Q07.

212 PG&E Response to DRA in PZS7-2. See PG&E reference DRA_018-Q02.

DRA disagrees. It is unreasonable for certain backbone customers to not pay for PSEP costs. There are PSEP costs that support backbone transmission pipelines, and therefore, all users of PG&E's backbone transmission, including marketers who subscribe to PG&E's backbone, should be subject to the charge for PSEP costs. This principle is consistent with cost causation for purposes of cost allocation. Those customers who cause the cost to be incurred should pay. Therefore, PG&E's proposed new GPS Surcharge Rates will put the burden of paying the cost to fix PG&E's Gas Transmission System only on end-use customers and will fail to get other PG&E customers who are also users of PG&E's gas transmission system (but do not pay Customer Class Charges) to contribute their fair share, hence, the new GPS surcharge should be rejected.

Further, in discovery, DRA also found that under PG&E's proposal, the new GPS 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.[214] The GPS surcharge will not even be visible to the PG&E customer when looking at the monthly customer bill. According to PG&E, the Customer Class Charge is a term that "includes a broad category of costs that are typically associated with balancing accounts and certain forecast period costs."[215]

If the Commission adopts DRA's recommendation of no cost recovery of PSEP costs during the 2011-2014 period, including the review of PSEP Phase 1 costs to be considered in the next PG&E rate case as part of normal backbone and local transmission and storage costs in the GT&S, then the issue of new GPS surcharges should become moot.[216] In Supplemental Testimony, PG&E argues

(continued from previous page)
213 PG&E Response to DRA in PZS9-7. See PG&E reference in DRA_022-Q07.

214 PG&E Response to DRA in PZS4-9(c). See also PG&E reference DRA_006-Q09.

215 PG&E Response to DRA in PZS4-9(a). See also PG&E reference DRA_006-Q09.

216 Please refer to DRA Exhibit 02, Prepared Testimony of Mark Pocta, for a discussion on netback as it relates to the GPS surcharges.

against the treatment of the PSEP as part of normal backbone, local transmission and storage. PG&E asserts that:

> Treating the Implementation Plan costs as "normal Backbone Transmission, normal Storage or Local Transmission" under Gas Accord V would result in certain anomalous outcomes that would need to be fixed. As shown in the comparison tables below, PG&E's approach avoids these anomalies and results in rates that differ only slightly from the rates that would result from a "pure" Gas Accord V rate allocation approach.[217]

When asked to explain the above, PG&E states:

> The types of anomalous outcomes resulting from changing the rates established in the GA V Settlement include the following:
>
> - Local Transmission rates would reflect higher than appropriate discount adjustments, since the Local Transmission discount adjustment is dependent on Local Transmission rate levels, and higher Local Transmission rates would result in higher discount adjustments
>
> - The load factors adopted each year to calculate Backbone Transmission rates would be inaccurate. This is because certain adjustments to the load factor (e.g., the discount and premium adjustments) depend on the rate level, which in turn depends on the backbone revenue requirement underlying the rates.
>
> - Tracking revenue would become difficult because the combination of the Implementation Plan revenue with GA V Settlement revenue would require a separation of the revenue collected through PG&E's Local Transmission, Backbone Transmission and Gas Storage rates into individual GA V Settlement and Implementation Plan buckets. To transparently show and calculate GA V Settlement sharing mechanism revenue versus Implementation Plan balancing account revenue, would require a separation of GA V Settlement and Implementation Plan rate components in PG&E's gas tariffs. Accordingly, two Reservations Fees would need to be shown in PG&E's tariffs for each Backbone rate by path, one to show the GA V Settlement portion and the other to show the Implementation Plan portion. The same would need to be done for all of the Usage Charges included in PG&E's Backbone rates. Moreover, this same separation would need to be performed for PG&E's bundled and unbundled Gas Storage and Local Transmission rates. This would result in an excessively complicated tariff structure.[218]

PG&E further states:

[217] PG&E Supplemental Testimony, p.4-5.

[218] PG&E Response to DRA in DRA_053-Q01.

> It is important to note that cost of the Backbone Transmission and Gas Storage services provided to most of PG&E noncore customers and all core unbundled customers (who elect to receive gas procurement service from a non-utility third party) are not directly paid to PG&E. The costs of these services are, instead, incurred by third-party service providers, who then pass the costs on to their customers through the rates they charge. Customers, therefore, may not be aware of how much they are paying for Implementation Plan costs. Furthermore, PG&E's current Backbone and Storage billing and revenue reporting systems do not support this type of tariff structure."[219]

If the above PG&E assertions are true, then the Commission should order PG&E to fully explain the reasons for these expected so-called "anomalous" outcomes and should address them in the next rate case cycle filing when they treat the PSEP cost as normal backbone, normal local transmission, and normal gas storage. DRA did not have sufficient time to investigate these alleged "anomalous" outcomes but even assuming these assertions are true, they appear to involve rate design issues rather than a question of cost allocation methodology.

It does seem odd that, as argued by PG&E, the local transmission discount adjustments and backbone load factors adjustments would be "anomalous" once treated as normal backbone, normal local transmission and normal storage, as these costs are traditionally considered in the PG&E Gas Accords. The Commission should review the way those adjustments were developed because it is illogical that the cost allocation of normal backbone, normal local transmission, and normal storage treatment for pipeline safety costs should be resulting in so-called "anomalous" outcomes. The work activities in the PSEP programs would have been a normal part of PG&E's gas pipeline operations and maintenance revenue requirements. A separate PSEP program would not have been necessary if PG&E had done its job properly as a prudent gas pipeline operator.[220]

PG&E also asserts that with the normal treatment of the PSEP costs pursuant to the traditional Gas Accord such as those in GA V, there would be difficulty in tracking a combined Implementation Plan revenues and GA V revenues and PG&E also predicts an

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[219] PG&E Response to DRA in DRA_053-Q01.

[220] Refer to findings by the NTSB, the IRP, CPSD, Jacobs Consultancy, and the Overland Consulting audit in their recent reports relating to PG&E.

excessively complicated tariff structure. PG&E even goes to the extent of suggesting the possibility of “two Reservations Fees” in PG&E’s tariffs for each Backbone rate by path, in order to show the GA V Settlement portion and the other to show the Implementation Plan portion. Similarly, PG&E argues the same for all of the Usage Charges included in PG&E’s Backbone rates. PG&E claims that the same separation would need to be performed for PG&E’s bundled and unbundled Gas Storage and Local Transmission rates. DRA would argue that none of these will be true with DRA’s recommendation that PG&E stay at the GA V revenue requirements and for the PG&E shareholders to bear all PSEP Phase 1 costs.

Moreover, DRA found that for purposes of the PG&E Supplemental Testimony in this rulemaking, PG&E did not develop a revised RO model, and instead used the PSEP RO to examine the potential Implementation Plan rates using the GA V Settlement cost allocation and rate design principles.[221] The PSEP RO model would allocate the PSEP costs among PG&E’s different lines of business differently compared to how those costs would have been allocated in the RO for the GA V revenue requirements. Had a GA V RO model been in use for the PSEP costs for purposes of the PG&E Supplemental Testimony, the direct costs of the PSEP local transmission would have been directly allocated to the local transmission unbundled cost category, the direct costs of the PSEP backbone transmission would have been directly allocated to the different unbundled cost categories for the backbone transmission lines, the direct costs of the PSEP for gas storage would have been directly allocated to the unbundled cost category for gas storage, and the PSEP “common costs” would either have been allocated to the different backbone transmission paths as a common cost on the basis of firm capacity at delivery point or to local transmission since most of them support local transmission. That is the basic difference between the PSEP and the GA V RO model. In the PSEP RO model, the GTAM and MAOP projects are considered as common costs. In the PSEP RO model, these common costs are allocated to the different lines of business based on the percentage share in the direct costs of the PSEP assigned to each line of business.[222] Under the PSEP RO model, each line of PG&E’s business would receive a cost allocation for the common costs of the PSEP. This

[221] PG&E Response to DRA in DRA_056-Q01.

[222] PG&E Response to DRA in PZS7-1.

is easily verified from the PSEP RO model by going to the tab indicated for the UCC factors (meaning unbundled cost categories).[223] On the other hand, in the GA V RO model, the common costs pertain to those costs for the facilities for gas gathering, the Bay Area Loop, and the monthly load balancing costs of gas storage. The common costs in the GA V are allocated to the different backbone transmission paths based on the percentage share of the transmission path in the total firm capacity at delivery point (which is the PG&E citygate) for all backbone transmission paths combined. The common cost allocation in the GA V RO is fundamentally different from the PSEP RO cost allocation on the basis of percentage share in the direct costs of the PSEP.

In the Supplemental Testimony, the PSEP revenue requirements from the PSEP RO model were used as inputs to the different GA V rate models. In the GA V backbone transmission rate model, the PSEP revenue requirements for backbone were allocated to each of the backbone transmission paths in the same way as the GA V common cost. In the GA V local transmission rate model, the PSEP revenue requirements for local transmission were allocated to the different customer classes using the cold January peak month demand forecast by customer class. Finally, in the GA V gas storage rate model, the PSEP revenue requirements for storage were allocated using annual cycling capacity by function. By using the same PSEP RO model to generate the revenue requirements for the PG&E Supplemental Testimony, PG&E may not be actually treating the PSEP costs for purposes of cost allocation as "normal backbone transmission, normal local transmission, and normal gas storage", which was the expectation based on the directive in the Scoping Memo for the submission of supplemental testimony.[224]

[223] The enhanced PG&E RO model that was provided to DRA by PG&E dated Dec.29, 2011.
[224] Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge in R.11-02-019 issued November 2, 2011, p.5.

DRA's review shows that there is a slight difference between the cost allocation factors shown in PG&E's Table 10-1 of its Prepared Testimony and those in the GA V Settlement as shown in Appendix _ of the GA V Settlement Agreement. PG&E has claimed that for the PSEP, it is using the cost allocation factors shown in Table 10-1 which are supposedly pursuant to the GA V Settlement revenue responsibility. A comparison of the cost allocation factors for backbone and local transmission and storage for PG&E core customers is presented pin the Table below:

Table 7 Cost Allocation Factors for PG&E Core Customers

Line No.		2011	2012	2013	2014
1	Backbone Transmission:				
2	Table A-3 GA V	41.89%	40.98%	41.49%	41.77%
3	Table 10-1 PSEP	Na	42.12%	42.57%	42.83%
4	Difference		-1.14%	-1.08%	-1.06%
5	Local Transmission:				
6	Table A-3 GA V	65.91%	65.68%	64.62%	63.80%
7	Table 10-1 PSEP	na	65.68%	64.62%	63.80%
8	Difference		0	0	0
9	Gas Storage:				
10	Table A-3 GA V	57.91%	58.46%	58.77%	59.07%
11	Table 10-1 PSEP	na	58.46%	58.77%	59.07%
12	Difference		0	0	0

Table 7 shows that the cost allocation factors applicable to backbone transmission for core customers used in the PSEP and shown in Table 10-1 of PG&E's Prepared Testimony were higher by a little over 1 percent compared to those in the GA V Settlement based on the revenue responsibility of the core customers. Line 4 of Table 7 shows the difference between the PSEP cost allocation factors and the GA V. However, no differences were observed in the local transmission and gas storage cost allocation factors as shown on lines 8 and 12 of the above Table. Footnote 8 of Chapter 10 of PG&E's Prepared Testimony states that the GA V Settlement Local Transmission and Backbone Transmission revenue requirements and the Implementation Plan cost allocation factors shown in Table 10-1 will be revised, if needed, annually to reflect actual adder project in-service dates and/or adder project capital expenditures that are under the established caps. As calculated by DRA, the cost allocation factors shown on lines 2, 6, and 10 of Table 7 for the GA V already reflect the effect of the estimated adder amounts and includes the G-XF revenue responsibility. The exclusion of the G-XF customers in the calculation of PG&E's customer revenue responsibility appears to be the source of difference between the PG&E and DRA cost allocation factors for the backbone transmission. G-XF customers are PG&E customers who subscribe to PG&E's backbone transmission capacity. Hence, the G-XF customers are among the PG&E customers who have revenue responsibility in the GA V Settlement for the backbone transmission. PG&E's calculation in Table 10-1 of PG&E's Prepared Testimony excluded the G-XF customers, resulting in slightly higher percentage of cost allocation to the core customers, as shown in Table 7 above at line 3. PG&E had represented in a data response to DRA that no PG&E customers will be exempted from payment of the GPS surcharge rates.[225]

5. PG&E Proposal Will Result in Average Monthly Increases to Customer Gas Bills

PG&E's PSEP proposals will result in increases to the average monthly bills of the residential and small commercial customer classes. The PG&E calculations of the monthly average bill impact is based on the average monthly gas use of 37 therms for residentials and 287 therms for small commercial customers. Based on those assumed average monthly gas uses, the average monthly bill increase for residential customers would be $1.93 in 2012, $1.67 in 2013, and $2.30 in 2014. On a percentage increase basis, those average monthly bill increase represent 4.26 percent increase in 2012 over the 2011 monthly bill, a 3.68 percent increase in 2013, and a 5.09 percent in 2014. For small commercial customers, the average monthly bill increase will be higher compared to residential because of the higher amount of therms used per month on average. DRA's recommended changes to PG&E's PSEP should bring down PG&E's PSEP costs substantially. Also, DRA is not recommending any incremental rate increases for the PG&E PSEP in 2011-2014 nor is DRA recommending the adoption of any new GPS

[225] PG&E Response to DRA in PZS7-2. See PG&E reference in DRA_018-Q02.

surcharges. Simply for purposes of a comparative showing, DRA presents in Table _ the rates that would have been comparable to the PG&E proposed GPS surcharge rates that are based on DRA's recommended corrections to PG&E's PSEP. DRA recommends that PG&E stay at the GA V Settlement revenue requirement levels authorized in the Commission decision and should not be allowed to implement new GPS surcharge rates. The Commission should bear in mind that the estimated increases to PG&E's residential customer rates from the proposed PSEP will be on top of the expected rate increases from the GA V Settlement approved in D.11-04-031 of 0.7 percent for residential customers and 0.8 percent for small commercial customers.[226] Hence, if adopted by the Commission, DRA's recommendation will avoid all these average monthly increases to customer gas bills.

Table 8 DRA Comparative Showing on GPS Rates for Core Customers ($/therm)

Line No.	PG&E Proposed:	2011	2012	2013	2014
1	Residential	$0.00000	$0.04994	$0.04439	$0.05964
2	Small Commercial	$0.00000	$0.04994	$0.04439	$0.05964
3	Large Commercial	$0.00000	$0.04994	$0.04439	$0.05964
4	NGV Compressed	$0.00000	$0.04994	$0.04439	$0.05964
5	NGV Uncompressed	$0.00000	$0.04994	$0.04439	$0.05964
6	**DRA Showing**				
7	Residential	$0.00000	$0.00393	$0.00585	$0.01577
8	Small Commercial	$0.00000	$0.00393	$0.00585	$0.01577
9	Large Commercial	$0.00000	$0.00393	$0.00585	$0.01577
10	NGV Compressed	$0.00000	$0.00393	$0.00585	$0.01577
11	NGV Uncompressed	$0.00000	$0.00393	$0.00585	$0.01577
	Difference				
12	Residential	$0.00000	$0.04601	$0.03854	$0.04387
13	Small Commercial	$0.00000	$0.04601	$0.03854	$0.04387
14	Large Commercial	$0.00000	$0.04601	$0.03854	$0.04387
15	NGV Compressed	$0.00000	$0.04601	$0.03854	$0.04387
16	NGV Uncompressed	$0.00000	$0.04601	$0.03854	$0.04387

6. The Commission Should Reject PG&E's Proposal for Balancing and Memo Accounts In Line With DRA's Recommendation for No Cost Recovery in the 2011-2014 Period

[226] Refer to Table B-1 of Appendix B of the GA V Settlement Agreement dated August 20, 2010 for the illustrative rates to end-use customers.

DRA recommends no cost recovery in the 2011-2014 period for PG&E, which means, it will not be necessary for PG&E to establish balancing and memorandum accounts for the PSEP Phase 1 in order to track or record any difference between authorized revenue requirements and the actual recorded amounts. DRA has explained the reasons for no cost recovery in the previous sections of this Exhibit.[227]

7. The Commission Should Reject PG&E's Proposal for No Reasonable Review

DRA opposes PG&E's proposal for no reasonableness review of the PG&E PSEP Phase 1 costs. Instead, PG&E should be prepared to make a showing in the next GRC rate cycle (which is technically the GT&S for gas transmission and storage) on the reasonableness and prudence of its revenue requirements request for the period starting in 2015. The proposal for no reasonableness review is inconsistent with holding PG&E accountable for its actions. This appears to be another attempt for flexibility and discretion in terms of spending by PG&E. Given the NTSB Accident Report's findings on PG&E, the Jacobs Consulting Report findings for the Independent Review Panel, the Overland Consulting Focused Audit Report on PG&E, and the findings by the CPSD in the investigation of San Bruno, the PG&E proposal for no reasonableness review should be rejected. DRA recommends that the Commission reject PG&E's proposal for no reasonableness review because it will be inconsistent with holding PG&E accountable for its actions to operate and maintain a safe and reliable gas system. Consistent with the Commission's Gas Accord V decision D.11-04-031 and Safety Phase decision (D.11-07-004) in PG&E's GT&S proceeding, PG&E should be prepared to account for all its spending of the Gas Accord V authorized revenue requirements, including the submission of semi-annual reports to the Commission.

8. PG&E's Proposal for Semi-Annual Progress Reporting Should Be Modified to Provide More Detail at the Project Level

[227] See also DRA Exhibit 02, Prepared Testimony of Mark Pocta for the policy reasons.

PG&E's proposed semi-annual reporting is shown in Attachment 8E-1 to PG&E's Prepared Testimony. As described, the proposal is not clear on what is considered a "project or work activity" exceeding $250,000 that will be identified in the proposed report as a capital project as well as O&M activities or those $250,000 or less that will be reported as an aggregate total by Major Work Category ("MWC"). The Commission needs to make sure that PG&E's project reporting and status monitoring system is able to identify individual projects as laid out in the PSEP that are included in any major work category. It is possible that an MWC has many "projects" and those "projects" may in turn be comprised of individual pipeline segment replacement projects. There are a number of MWCs in the PG&E PSEP.[228] Table 3-3 of PG&E's Prepared Testimony indicate project counts over the 2011-2014 period with a total of 169 individual projects for pipeline replacements in Phase 1, a total of 165 projects for pipeline strength tests, a total of 200 valves and 12 permanent test heads associated with pipeline strength tests, a total of 228 isolation valves as part of replacement, automation, and upgrades in the Valves program. PG&E would have to provide more detail in the reports in line with however many individual projects comprise a "project."

[228] PG&E Response to DRA in PZS9-3. See PG&E reference in DRA_022-Q03.