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DIVISION OF RATEPAYER ADVOCATES

CALIFORNIA PUBLIC UTILITIES COMMISSION

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

Pipeline Modernization Plan

R.11-02-019

San Francisco, California

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1. SUMMARY OF TESTIMONY

This testimony provides overall analysis of Pacific Gas and Electric Company's (PG&E's) Pipeline Safety Enhancement Plan Pipeline Modernization Plan (PSEP Pipeline Plan) and DRA's recommendations on this portion of PG&E's Pipeline Safety Enhancement Plan (PSEP). This testimony builds upon and incorporates the expert testimonies of the Division of Ratepayer Advocates (DRA) witnesses Rondinone, Delfino, and Scholz, which are provided in Exhibits DRA-4, DRA-5, and DRA-6 respectively. Those testimonies are summarized within this exhibit, and used to develop recommended cost adjustments and general recommendations aimed at improving the effectiveness, and cost-effectiveness, of the PESP.[1]

DRA analyzed the following key elements of the PSEP Pipeline Plan to evaluate the quality and cost effectiveness of the plan, and to support the recommendations herein:

Overall, DRA found that the PSEP Pipeline Plan provides a reasonable "study or feasibility" estimate, consistent with the Association for the Advancement of Cost Engineering (AACE) International Class 4 estimate PG&E requested from its consultant, Gulf International.[2] However, this estimate should not be mistaken for a more detailed and accurate budget authority or bid estimate, provided by AACE Class 3, 2, or 1 cost estimates. Fundamentally, cost recovery for a multi-billion dollar four-year project should not be based on a feasibility study cost estimate. Additionally, DRA found significant flaws within PG&E's decision tree, the project PSEP Pipeline Implementation Plan, project and cost models, and the application of these models. Key findings include:

[1] In this testimony cost effectiveness refers to simultaneously maximizing safety while minimizing costs, rather than a rigorous analysis to determine whether program benefits exceed program costs.

[2] Pacific Gas and Electric Company Pipeline Safety Enhancement Plan Prepared Testimony dated August 26, 2011, as filed in R.11-02-019 (PG&E Testimony), p.7-25, Figure 7-3.

1. PG&E's PSEP Pipeline Plan is based on preliminary and incomplete evaluation of PG&E's records, and results from the Maximum Allowable Operating Pressure (MAOP) validation process. (Section 3)
2. The MAOP validation process should be completed by February 2012 for HCA pipelines, to support updates to the PSEP Pipeline Plan in 2012, but the impact of revised High consequence area (HCA) classifications are uncertain. (Section 3)
3. PG&E's decision tree (DT) requires an excessive number of pipeline segments for replacement, when they should be hydrotested. (Section 4)
4. PG&E's DT requires an excessive number of pipeline segments to be included in Phase 1, rather than later or subsequent Phases. (Section 4),
5. PG&E's PSEP Pipeline Implementation Plan is not consistent with the DT: In Phase 1, it includes many unnecessary segments, and omits some which should be included. (Section 4)
6. Approximately two-thirds of PG&E's Phase 1 costs are driven by engineering evaluation and safety needs; the balance are included for the sake of "efficiency". (Section 4):
    - PG&E's PSEP Pipeline Implementation Plan includes Phase 1 replacement or hydrotesting for many segments which could be addressed in Phase 2 with less expensive mitigation measures,
    - Gulf 's rationale for including Phase 2 segments in Phase 1 is often flawed, based on a review of sample projects.
7. The PSEP Pipeline Plan includes capacity increases, and line re-routes which are not identified or justified in the testimony. (Section 4)
8. Based on a review of a limited number of sample projects, PG&E's PSEP Pipeline Implementation Plan includes multiple flaws that tend to increase the cost of the PSEP Pipeline Plan. (Section 4)
9. Adding low priority segments to Phase 1 hydrotest projects will make sense in many cases, but this is not generally true for replacement projects. (Section 4)

10. PG&E's models include many deviations from those described in the testimony which are not identified or justified in the testimony. (Section 5)

11. Unit costs for replacement and hydrotesting are high compared to industry averages, and analysis provided by DRA Witness Delfino. (Section 5)

12. PG&E shareholders are not paying for the full cost of mitigation, such as hydrotesting, caused by their lack of records. (Section 6)

13. PG&E's contingency request is excessive, and based on an incomplete analysis. (Section 7)

The combined impact of these errors is a gross inflation of the costs PG&E is requesting prior to its next General Rate Case (GRC). This exhibit summarizes DRA's recommendations to correct the PSEP Pipeline Plan, and to reduce PG&E's baseline request for $1,336 million in ratepayer funding by more than $850 million. In addition, PG&E's request for $271 million for pipeline contingency would be reduced more than 75% due to the above reductions in baseline costs, and a reduction in the contingency rate. It is important to note that a significant portion of this reduction is due to shifting costs from Phase 1 to Phase 2, rather than elimination of costs, or shifting them from ratepayers to PG&E shareholders.

DRA performed a thorough analysis of the PSEP Pipeline Plan which culminated in specific cost reduction recommendations, as though PG&E had submitted a detailed and final estimate. This analysis provided much needed insight into the PSEP Pipeline Plan, and required the development of specific knowledge and tools which can be rapidly applied to future evaluations. However, this exhibit includes detailed cost reduction recommendations to illustrate the results of a detailed analysis only, and should not be perceived as support for authorization of any cost recovery based on this plan. Rather, DRA recommends a process to replace PG&E's proposed PSEP Pipeline Plan, while continuing to mitigate high-priority safety threats:

1. **Reject PG&E's current PSEP Pipeline Plan -** based on the findings above.
2. **Use DRA findings and recommendations defined in this testimony for future revisions of the PSEP Pipeline Plan**.
3. **Expedite a revised and vetted test plan for the first half of 2012** – use a streamlined CPUC process to vet projects to be initiated after the 2012 winter heating season, but prior to the summer cooling season.
4. **Initiate work in 2012 required to develop a long term PSEP Pipeline Plan** – including proceeding with the order instituting ratemaking (OIR) process, MAOP validation, and the HCA order instituting investigation (OII).
5. **Redo the pipeline mitigation assignment process, and develop a long-term PSEP Pipeline Implementation Plan for all transmission** segments – incorporate the findings from 2012 work described in recommendation 3 to ensure the resulting plan is robust, safe, and cost-effective.

2. INTRODUCTION

2.1 Definitions as used in this exhibit

- PSEP – PG&E's Pipeline Safety Enhancement Plan
- PSEP Pipeline Plan– The plan set forth in Chapter 3 of PG&E's PSEP Pipeline Plan, and portions of Chapter 7 that address contingency for the PSEP Pipeline Plan
- Decision tree (DT) –the criteria established by PG&E to mitigate pipeline safety threats. A flow chart of this process which resembles a tree is provided in Attachment A to Chapter 3, and a revised version in Attachment C to Exhibit DRA-4
- PSEP Pipeline Implementation Plan – PG&E's plan which assigns segments to one of approximately 350 Phase 1 projects to be performed before 2015

- PG&E Detailed PSEP Pipeline Implementation Plan - An August 13, 2011 MS Excel file which shows each of PG&E 's 25,076 transmission segments assigned to one of approximately 350 Phase 1 projects PSEP Pipeline Plan
- Baseline cost – the costs estimated by Gulf International for PG&E and discussed in Chapter 3 of the PSEP
- Contingency – the additional budget to account for uncertainty, estimated by Price Waterhouse Cooper (PwC) for PG&E and discussed in Chapter 7 of the PSEP
- Threat –anything that could result in a pipeline failure
- Mitigation measure – any action that reduces the risk of failure
- Segment – a section of pipeline with different characteristics (material, diameter) from adjacent sections
- Section – a group of adjacent segments that are subjected to the same mitigation in the PSEP Pipeline Plan
- Project – a number of segments grouped together based on the mitigation required, such as replacement or hydrotest
- Pipeline Replacement – generally requires installing a new pipeline in parallel to the existing line, cutting and welding the new sections to the old ones, and retiring the old line in place
- Hydrotest – isolating a section of pipe in place by excavating and capping each end, filling the line with water, pressurizing the line, then returning the line to service
- Pressure test – see hydrotest
- Strength test – see hydrotest
- Test – see hydrotest
- In Line Inspection (ILI) –running a robot known as a "pig" through the line to inspect for flaws. This requires a launch and receiving port at both ends for the pig

- Gulf Interstate Engineering (Gulf) –the consultant who assisted PG&E in developing the PSEP Pipeline Implementation Plan , and also developed cost models for replacement, hydrotest, and ILI
- Berkeley Engineering and Research (BEAR) – one of DRA's consultants
- Delfino Engineering – one of DRA's consultants
- "All-in" cost – a variable cost per foot used in Gulf's cost estimation models which include a portion of replacement and hydrotest costs. Since this cost does not include fixed costs allocated per project, the name is a misnomer since all costs are not "in"
- Move Around – the process of moving equipment from one part of a hydrotest project to another
- Mob/Demob – mobilization/demobilization. The fixed costs to move equipment between projects. Includes other fixed costs for hydrotests
- Road Bore - A road bore is an industry term for an Auger bore, which is an earlier generation of boring method using an auger to pierce straight through the ground[3]
- HDD – horizontal directional drilling for gas transmission piping is used when trenching or excavating is not practical and the bore length exceeds the length of an auger bore[4]
- ECA – Engineering Condition Assessment
- OD – Outside diameter: the size of a pipeline
- AACE - Association for the Advancement of Cost Engineering International
- MAOP - Maximum Allowable Operating Pressure
- HCA – High Consequence Area

[3] From PG&E response dated 12/8/2011 to data request DRA 30 Q9.
[4] Ibid.

- GIS – Geographic Information System. A computer program that links data, such as pipeline features, to a map, globe, chart, etc.
- PLF – Pipeline Feature List
- TIMP - Transmission Integrity Management Program
- SYMS - Specified Minimum Yield Strength
- CIS - Close Interval Survey, a pipeline inspection technique
- DCVG - Direct Current Variance Gradient, a pipeline inspection technique
- INGAA - The Interstate Natural Gas Association of America
- AGA – American Gas Association
- QRA – Quantitative Risk Assessment

2.2 Scope of the testimony

DRA's mission is to provide reasonable rates consistent with safe and reliable service.[5] The scope of this testimony is consistent with DRA's charter since it considers both the safety and costs for PG&E's plan. The testimony of DRA Expert Witness Rondinone (Exhibit DRA-4) reviews and critiques the criteria and processes in PG&E's Pipeline decision tree, which determines how and when pipeline threats are mitigated. This is the central safety element of PG&E's plan.

DRA also reviewed the cost estimating portion of the plan, identified the primary cost drivers, and performed detailed analysis the largest cost drivers: pipeline replacement and hydrotesting. These cost analyses are included in the Testimony of DRA Expert Witnesses Delfino (Exhibit DRA-5) and Scholz (Exhibit DRA-6), as well as in this exhibit. The remaining costs, which total 6.7% of PG&E's cost request, include:

- Emergency Pipe, Test Head, and Valves ($63.6 million, Capex)
- Pipeline Upgrades for ILI ($30.3 million, Capex)
- Pipeline ILI ($9.6 million, expense)

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[5] Public Utilities Code, Section 309.5.

- Other Pipeline Expenses ($4.9 million)[6]

For these costs, qualitative analysis is provided in Section 8, but alternative costs are neither quantified nor used to adjust costs in this exhibit, or those in Exhibit DRA-9. Findings derived from this analysis were used to formulate recommendations to reduce the risk and costs associated with the PSEP Pipeline Plan.

DRA's analysis was focused on Phase 1of the PSEP Pipeline Plan, and addressed Phase 2 only tangentially in that mitigations deferred from Phase 1 must be addressed later. Nothing should be implied about DRA's evaluation of Phase 2 issues, expect that DRA was focused on Phase 1 based on the assumption that the highest priority pipelines were included.[7]

This exhibit assumes prior knowledge of pipelines, pipeline threats, and threat mitigation measures like hydrotesting, based on information provided in Chapters 2 and 3 of PG&E's Testimony.

2.3 Summary of PG&E filing – Pipeline Modernization

2.3.1 Overall request - $1.6 billion based on a "conceptual" cost estimate

PG&E's proposed Pipeline Modernization defines high priority mitigation projects including replacing 186 miles of pipeline,[8] 783 miles of hydrotesting,[9] and 234 miles of inline inspection (ILI) runs.[10] PG&E requests $1,606.5 million for the PSEP Pipeline Plan Pipeline Plan in its Testimony: $1,335.8 million in baseline costs are requested in Chapter 3, and $270.7 million in contingency is requested in Chapter 7. This includes 2011 costs that PG&E has stated will be

[6] See page 3-6 of PG&E Testimony. These total $108.4 million, out of a total request of $1,606.5 billion, which includes contingency, or 6.7% of the pipeline costs.

[7] As discussed in Section 4.2, this is not universally true.

[8] PG&E Testimony at 3-22

[9] PG&E Testimony at 3-39

[10] PG&E Testimony at 3-26. This also includes 199 miles of retrofits to allow ILI.

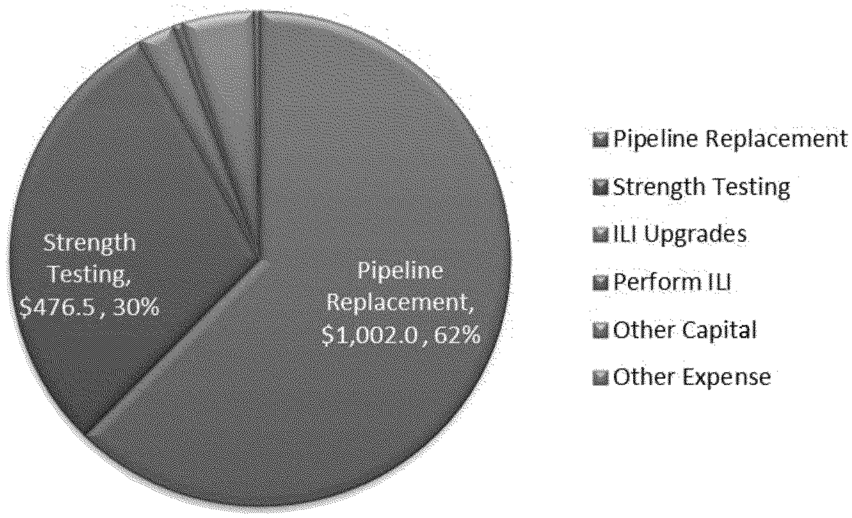
absorbed by its shareholders, but does not include $21.5 million in "post-70" costs which PG&E has also stated will be absorbed by its shareholders.[11] A breakdown of PG&E's request per major cost categories is provided in Figure 1 and Table 1.

Table 1 - PG&E cost request for pipeline modernization program, including contingency

	Cost Category/Heading	Baseline Request	Contingency Request	Total
		$ Millions	$ Millions	$ Millions
	Capital Expenditures			
1	Pipeline Replacement	$ 833.6	$ 167.7	$ 1,001.3
2	IP OIR StanPac Capital – Pipe	$ 0.6	$ 0.1	$ 0.7
3	Strength Test Driven Replacements:Cut-Outs	$ 8.0	$ 1.9	$ 9.9
4	Strength Test Driven Replacements: Emergency Replacements	$ 37.5	$ 3.8	$ 41.3
5	ILI Upgrades	$ 30.3	$ 6.4	$ 36.7
6	Strength Test Capital Equipment	$ 18.1	$ 4.6	$ 22.7
	Capital Sub-total	**$ 928.1**	**$ 184.5**	**$ 1,112.6**
	Expenses			
7	Engineering Condition Assessment	$ 3.1	$ 0.8	$ 3.9
8	Fatigue Analysis	$ 0.3	$ 0.1	$ 0.4
9	Strength Testing	$ 389.1	$ 82.5	$ 471.6
10	IP OIR StanPac Expense – Pipe	$ 4.1	$ 0.8	$ 4.9
11	In-Line Inspections	$ 9.6	$ 2.0	$ 11.6
12	Initial Planning and Rate Case Development – Pipe	$ 1.5	$ -	$ 1.5
	Expense Sub-total	**$ 407.7**	**$ 86.2**	**$ 493.9**
	Total	**$ 1,335.8**	**$ 270.7**	**$ 1,606.5**

[11] See Sections 6.2 and 6.3 of this testimony.

Figure 1 – PG&E cost request for pipeline modernization program, including contingency[12]



This request only includes "Phase 1" which includes costs expected in 2011-2014 and about one-sixth of PG&E's transmission pipelines. The PSEP Pipeline Plan provides neither a detailed mitigation plan, nor cost estimates for the remaining pipelines, to be assessed in 2015 or later. [13] PG&E has stated that they currently plan to file a Phase 2 PSEP once the MAOP validation process is completed "mid to late 2013."[14]

PG&E's cost estimate is an AACE Class 4 estimate which PG&E described as "conceptual in nature."[15] The contingency request is a "P90" estimate, which means there is a 90% probability this request will cover all actual projects costs, based on PG&E's risk analysis.

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[12] In this figure, Pipeline Replacement includes lines 1 and 2 from Table 1. Strength Testing includes lines 9 and 10. Lines 2 and 10 are for replacement and strength testing respectively on StanPac pipeline. See PG&E Testimony, p.2-2 for a discussion of StanPac.

[13] Phase 2 scope is provided in PG&E Testimony at 3-66.

[14] PG&E response dated 1/6/2012 to data request DRA 45 Q2(c).

[15] PG&E Testimony at 7-23.

The scope, in terms of miles of mitigation, and costs per mile are both provided by PG&E in testimony:[16]

Table 2 – Scope and cost of PG&E's pipeline mitigation measures

	Miles	PG&E Provided Cost
		Average $/mile
Replacement	186	$4,514
Strength Tests	783	$502
Retrofit for ILI	199	$152
Pipeline ILI	234	$40
Total*	1,203	
* Doesn't count Retrofit for ILI		

There is a hundred-fold variation in the cost per mile for the various mitigation measures: replacement averaged 10 times more that hydrotests, which are 10 times more than ILI.

2.3.2 Overview of Pipeline Modernization project definition and cost estimate

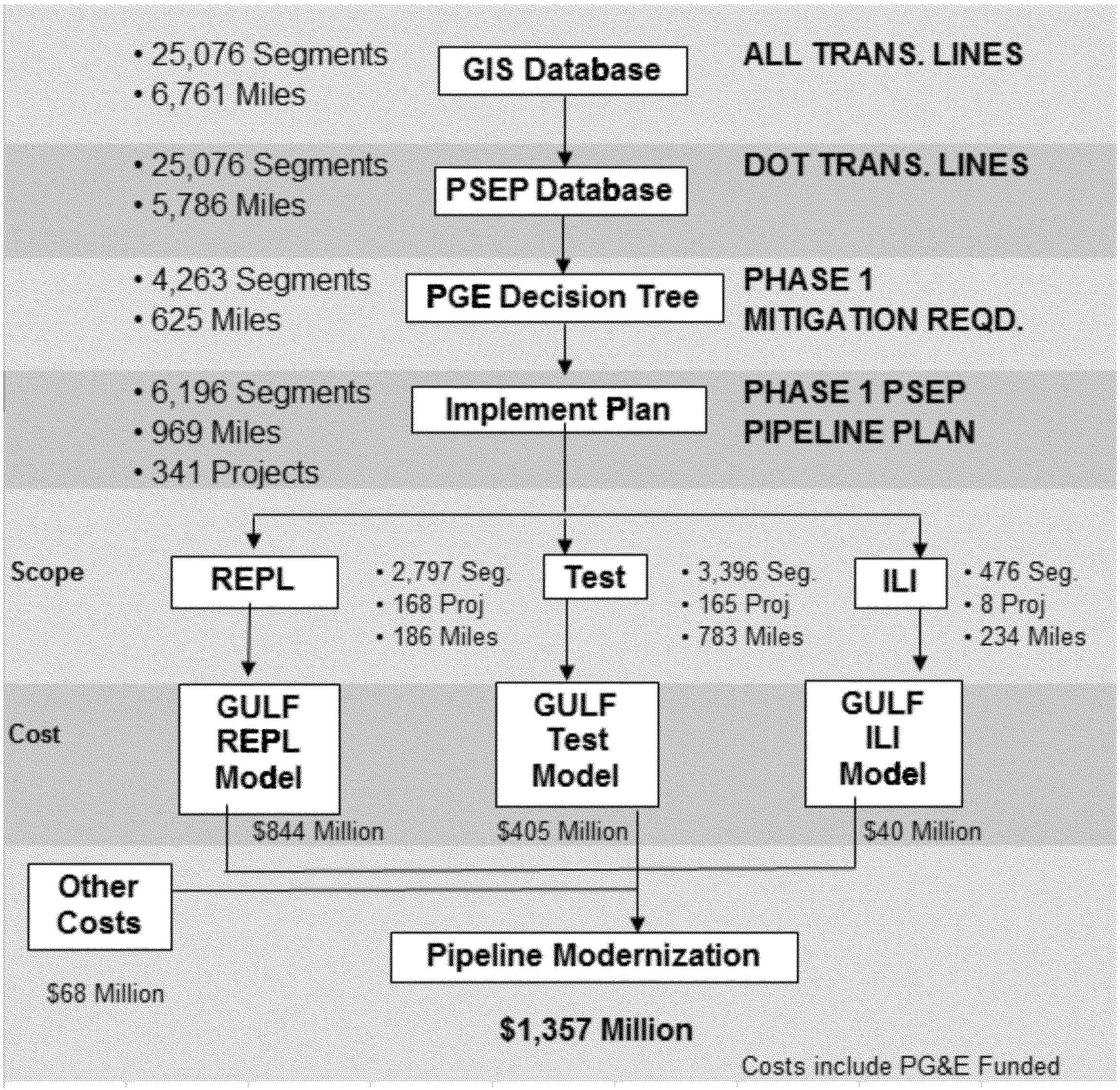
PG&E's PSEP Pipeline Plan was created in four major steps:

1. Develop mitigation DT
2. Assign DT outcomes to each pipeline segment
3. Assign each segment requiring Phase 1 mitigation into a project
4. Provide a cost estimate for each project
5. Allocate costs between ratepayers and PG&E shareholders
6. Estimate a contingency budget

Steps 2 and 3 above lead to the PSEP Pipeline Implementation Plan, which drives the PSEP Pipeline Plan schedule; Steps 4 and 5 drive the baseline cost estimate; and Step 6 leads to a specific contingency budget request. Each is described in more detail in Section 4 and 7 of this exhibit. A road-map of this process is shown in Figure 2:

[16] Costs provided in PG&E Testimony at 3-40 to 3-42.

Figure 2 – Roadmap of PG&E's process for estimating pipeline modernization baseline costs



2.4 Analyses performed

Sections 3, 6, and 7 of this exhibit contain all analysis used to develop DRA's findings and recommendations provided in Section 10. Sections 4 and 5 summarize findings from Witnesses Rondinone (Exhibit DRA-4), Delfino (Exhibit DRA-5), and Scholz (Exhibit DRA-6), add additional analysis, and discuss how their findings and recommendations are used in DRA's overall recommendations for the Pipeline Modernization Plan.

DRA performed several separate analyses, each of which is defined in greater detail in Section 3 through 7:

- Reviewed data used to create the PSEP Pipeline Plan
- Reviewed decision tree logic, the resulting PSEP Pipeline Implementation Plan , and how well the former is reflected in the later. A revised decision tree was developed based on this analysis
- Analyzed Gulf 's cost models and unit costs for replacement and hydrotest projects. This analysis resulted in revised unit costs for use within Gulf's cost models
- Reviewed the cost allocations between ratepayers and shareholders under a variety of assumptions. This analysis yielded revised allocation criteria
- Reviewed sample projects – seven projects were selected for detailed review of how the decision tree results were implemented, and whether assumptions in the cost model were both reasonable and correctly applied. This analysis yielded general findings applicable to the entire plan, and overarching recommendations about the PSEP Pipeline Plan
- Reviewed of contingency cost model, and the assumptions used in the contingency analysis regarding baseline costs

The cumulative results of all these analyses resulted in two products. First, the resulting costs adjustments summarized in Section 9 were provided to Witness Sabino and used to derive an alternative revenue requirement (Exhibit DRA-9) Second, modifications to the overall structure of the PSEP Pipeline Plan Pipeline Plan specifically, and the PSEP Pipeline Plan generally, are provided in Section 10.

2.4.1 DRA Segment based models

PG&E provided excel versions of its Replacement, Hydro, and ILI cost models in response to DRA data request 16. These models were slow to recalculate based on changes in input parameters, and did not provide output options desired by DRA. DRA therefore created streamlined spreadsheets which allow rapid calculations for a wide range of scenarios.[17] DRA's models perform cost calculations primarily at the segment level, rather than at the project level as in PG&E's models, which allows costs to be calculated even if PG&E's project groupings are not used. This format also provides insight into cost impacts at the segment, project, and aggregate (e.g. replacement or hydro) level.

The process of calibrating DRA's spreadsheets yielded information about how PG&E's models *actually* work relative to the narrative description of how they are *supposed* to work according to PG&E's Testimony.[18] This process highlighted a number of instances where PG&E implemented exceptions to its cost models, as described in detail below.

Combining the calibrations of both DRA's replacement and hydrotest spreadsheets, DRA's baseline calculation is approximately $23 million lower than PG&E's request, as shown in Table 5.1, or less than .2% of the total cost request of $1.25 billion. [19] This is not an error, but rather a variation due to known differences in the calculations made by DRA and PG&E, discussed in detail in Section 4 and above. Generally, DRA's model implements PG&E's logic formulaically, without the segment or project exceptions added by PG&E.[20] All

[17] DRA only created models for Replacement and Hydrotest projects, not for ILI.

[18] Calibration involved ensuring these spreadsheets produce the same results as PG&E's calculations for the same inputs. DRA's hydrotest spreadsheet produced a calibration error of $1,000 for the aggregate of all hydro projects, using results rounded to the nearest $1,000. DRA's Replacement spreadsheet similarly produced a calibration error of $4,000 for the aggregate of all replacement projects. Project level deviations are discussed later in this testimony.

[19] DRA's replacement costs are $29 million lower than PG&E's model, but hydrotest costs are $6 million higher. Most of this is due to the "Peninsula adder" in PG&E's calculations. See Section 4.2.

[20] For hydrotest projects, aggregate deviations are greater than annual deviations since DRA's calculated costs are always greater than PG&Es. However the opposite is true for replacement projects since DRA's calculation are higher for some projects and lower for others, and thus offset in the aggregate calculations. The best example of this is for replacement projects L-111A and L-118A, which are scheduled in 2012 and 2013 respectively. Combined, they produce a variance of approximately -$5 million, as discussed above. However since they occur in different years, L-111A causes a -$13.7 million variance for 2012, and L-118A causes a +$8.7 million variance in 2013, both figures compared to PG&E's calculations.

the adjustments proposed in this exhibit were calculated using DRA's spreadsheets, which provides annual results for 2011-2014. Annual costs were allocated to backbone, local transmission, or storage based on the UCC codes in PG&E's Results of Operations (RO) model, as further described in Exhibit DRA-9.

2.4.2 Specific anomalies in PG&E's implementation of Gulf's Replacement model

The process of calibrating DRA's spreadsheets highlighted a number of ways PG&E's models inflate costs generally, and also a number of instances where PG&E implemented exceptions to their cost models for specific segments and projects. Overall issues with PG&E's replacement model include the following:

- All costs are based on PG&E's proposed pipeline outside diameter (OD), not the OD of the pipeline being replaced. Since in many instances, PG&E is proposing large size increases, and unit costs in PG&E's model are a function of OD, this increases the project costs wherever upgrades are made.[21]
- Mob/Demob charges are automatically assigned based on the largest proposed OD segment in the project, regardless of whether this segment represents a majority of the segments in the project, or if it is a single 5 foot segment in a 5 mile project. Mod/Demob costs increase from $45,000 to $95,000 as the proposed OD increases, so this anomaly tends to increase the Mod/Demob portion of project costs.[22]

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[21] See Section 4.5 of this exhibit.

[22] First, note that PG&E includes pipeline 12.75" in diameter in the smallest size group they label as ""12"& Under" in their workpapers. See PG&E response dated 12/5/2011 to DRA 26 Q11. Then, referring to PG&E workpapers at WP 3-218, Line 220 segments included in project L-220 REPL are currently 6.625" to 12.75" in diameter, all of which are included in the "12" & Under" category. PG&E Testimony at 3E-13 shows the unit Mob/Demob cost for this size range is $45,000. However, going back to the workpapers at WP 3-217, the Mob/Demob charge is assigned for the "22" to 28" size range at $65,000. This is because PG&E plans to enlarge multiple miles of this line from 6.625" or 8.625" to 24", as shown at WP-3-218, segment 157 for example. This $20,000 increase is applied automatically in PG&E's model, and is not documented in the PG&E Testimony or workpapers.

- Move Around costs are automatically assigned based on the Mob/Demob cost, rather than the segment to which the move is assigned in the PSEP Pipeline Implementation Plan . Since Move Around costs increase from $25,000 to $50,000 as a function of OD, this tends to increase the Move Around portion of project costs.[23]
- PG&E rounds to the nearest $1,000 very early in their cost model. This results in $1,000 or 2,000 variances for many individual projects. However the variances are both plus and minus, and net to an insignificant $4,000 error for the aggregate replacement cost.
- Escalation was tied to completion date of a project, and misses the 10% shifted into the prior year[24]
- Other issues which relate to the allocation of costs between ratepayers and PG&E shareholders are discussed in Section 6.

In addition to these general issues, DRA's calibration runs highlight specific instances where PG&E's calculations deviated from its model. For replacement projects there were significant variances for six projects:

- DFM-603-01: Segment 101.2 was split between non, and semi congested costs. PG&E manually adjusted the "all-in" cost calculation which produced a $123,000 deviation[25]
- L-220: PG&E calculated four Move Around costs at $35,000 each for 14-20" OD pipe, when PG&E's model indicates the cost should be $25,000 each. This resulted in a variance of approximately $45,000[26]

[23] Use the same references for Line 220 above, and that the unit Move Around cost is in the "22" to 28" size range at $35,000, vs. the $25,000 unit cost for "12" & Under" from the PG&E Testimony at 3E-13. Note that four moves are included for this project, which compounds the incremental cost difference. Also note, referring to the MP1 and MP2 columns, that the discontinuities that lead to a move are as follows: two in 10.75" sections, one moving from a 8.625" to a proposed 24", and one between two proposed 24" sections. At least two of these moves should clearly be assigned at the smaller unit cost.

[24] See PG&E response dated 12/6/2011 to data request DRA 26 Q13(a).

[25] As shown in PG&E workpaper at WP 3-284, the "post-70" cost PG&E will pay is also $123,000, but this is for other segments and appears to be coincidental.

- L-191: PG&E calculated four Move Around costs at $50,000 each for 30-42"OD pipe, when PG&E's model indicates the cost should be $35,000 each. This resulted in a variance of approximately $66,000.
- L-21F: PG&E calculated 1 of 4 Move Around costs at $30,000 each for 14-20" OD pipe, when PG&E's model indicates the cost should be $35,000 each. This resulted in a variance of approximately $6,000.
- L-111: 15,000 feet of pipeline is added in the workpaper calculation to account for PG&E moving the line.[27] This resulted in a variance of approximately $13.7 million.
- L-118: 15,000 feet of pipeline was removed, as part of the combined relocation of L-111 and L-118. This resulted in a variance of approximately $8.7 million. Issues with L-118 and L-111 are discussed in detail in section 4.5.4.[28]

The result is that the aggregate cost for replacement projects is increased by approximately $5 million compared to strict application of PG&E's model, without these exceptions.

PG&E also includes a "Peninsula adder" of $200 per foot for six replacement projects on lines 101 and 109, which increases costs by $22.6 million. This adder is not discussed in PG&E's Testimony, but is discussed in Section 4.5.2 of this exhibit.

2.4.3 Specific anomalies in PG&E's implementation of Gulf's hydrotest model

As with replacement projects, the process of calibrating DRA's hydrotest spreadsheet highlighted a number of ways PG&E's model inflate costs generally, and also a number of instances where PG&E implemented exceptions to its cost

[26] All variances described in this section are the gross variance. The actual variance is higher since outreach, program management, and escalation are applied on top of this.

[27] PG&E response dated 12/6/2011 to data request DRA 26 Q10.

[28] Net difference due to none- vs. semi congestion. The escalation rate for this project is higher since it's scheduled a year later, so this offsets part of the difference.

model for specific segments and projects.[29] For Hydro projects there were significant deviations for four projects:

- L-057A-MC: segment 100.3 has an estimated OD, indicated by a -16" listing. PG&E used the costs for a <12" line for this segment. This results in a +$100k variance.
- L-153_2: Move around costs for lines > 22" reduced in half.[30] This results in a +$650k variance.
- L-300B_1: Move around costs for lines > 22" reduced in half, same as above. This results in a +$4 million variance.
- L-300B_2: Move around costs for lines > 22" reduced in half, same as above. This results in a +$1 million variance.

The result is that DRA's calculated aggregate cost for hydrotest projects is approximately $6 million lower than the costs based on strict application of PG&E's model, without these deviations.

3. DATA USED IN PSEP PIPELINE PLAN

The CPUC required PG&E to file the PSEP by August 26, 2011. Since PG&E had not completed its MAOP validation process, this necessitated using the best data available at that time. The PSEP Pipeline Plan requires pipeline data to prioritize mitigations through its DT, and to allocate cost responsibility between shareholders and ratepayers. The accuracy and effectiveness of the plan is highly dependent on the accuracy and completeness of the data used. This section provides an analysis of the data used to produce the PSEP Pipeline Plan. It also describes additional data which could be used in future updates to the PSEP Pipeline Plan.

[29] Calibration involved ensuring these spreadsheets produce the same results as PG&E's calculations for the same inputs. DRA's Hydro spreadsheet produced a calibration error of $1,000 for the aggregate of all hydro projects, using results rounded to the nearest $1,000. DRA's Replacement spreadsheet similarly produced a calibration error of $4,000 for the aggregate of all replacement projects. Project level variances are discussed later in this testimony.

[30] This was per Ed Starke, as noted in Excel workpaper at F40 and M40.

DRA's most important finding regarding data used for the PSEP Pipeline Plan is that it is not verified, accurate, and traceable data, as discussed in the following sections. The Jacobs Report which accompanied the December 23, 2011 CPSD report on PG&E's PSEP Pipeline Plan implies the opposite when is stated the a "third filter [to GIS data prior to application of PG&E's DT] identifies pipeline that has MAOP established based on verifiable calculations or strength testing records."[31] DRA asked PG&E if this was an accurate statement, to which they responded:

> "This is not a completely accurate statement. The decision point or action box 1B in the Pipeline Modernization Decision Tree is there to incorporate the data resulting from the directives issued by the National Transportation Safety Board (NTSB), Pipeline and Hazardous Materials Safety Administration (PHMSA), and the California Public Utilities Commission (CPUC) to validate the Maximum Allowable Operating Pressure (MAOP) of PG&E's pipeline transmission segments into the Pipeline Modernization Decision Tree. This decision point ensures that ***when*** the pipe segment data is updated and verified, this updated data will be used for evaluation of the segments. This decision point is not a filter, but rather a check point to ensure the most accurate data is being used for the evaluation of all pipe segments covered by the Pipeline Safety Enhancement Plan."[32]

As described in the following sections, the PSEP Pipeline Plan is based on a wide range of data quality, including estimated, missing, and incorrect data. Generally, the plan is based on pipeline feature data that was in the geographic

[31] Page 20 of Attachment to CPUC CPSD report dated 12/23/2011, available at http://docs.cpuc.ca.gov/EFILE/REPORT/156326.htm. Also see PG&E response dated10/6/2011 to data request DRA 8 Q11.
[32] PG&E response to DRA 57 Q1a, emphasis added.

information system (GIS) database as of January 3, 2011,[33] and pressure test data from the MAOP validation project as of April 30, 2011.[34] It is only when a project enters the detailed engineering Phase that PG&E's PSEP Pipeline Plan team checks for the latest pipeline data from the MOAP pipeline feature lists (PFLs), and adds this data to the PSEP Pipeline Plan database.[35] In other words, where updated data exists, it is incorporated into a project in the future before project execution. This data, however, was not available during preparation of the PSEP Pipeline Plan, and is not reflected in it. Therefore, the PSEP database does not contain the most up to date pipeline data, either when the PSEP was created or now. PG&E does not plan to include the final results of the MAOP validation process until late in 2013 in preparation for a filing for Phase 2 of PG&E's PSEP Pipeline Plan,[36] and therefore the PSEP database will remain out of date into 2013 given PG&E's current plan. The impact of anomalous data impacts application of the decision tree (see Section 4.1.2 of this exhibit), assigning segments to projects (Section 4.4), costs estimates (Section 5), and allocation of costs to PG&E shareholders (Section 6). Uncertainty in the quality of key data should also directly impact PG&E's calculation of contingency for the pipeline portions of the PSEP, but does not appear to (Section 7).

It may be useful to refer to the roadmap provided in Figure 2 of this exhibit for the following discussion of PG&E's pipeline data.

3.1 GIS database

The primary source of pipeline data used for the PSEP Pipeline Plan is from PG&E's GIS database, as described in Section 3.2.2. After pipeline data was exported to the PSEP Pipeline Plan team on January 3, 2011, the GIS database was

[33] PG&E response dated 10/21/2011 to data request DRA 11 Q5a.

[34] PG&E response to DRA 45 Q1(a).

[35] PG&E response to DRA 45 Q2, many parts.

[36] PG&E response to DRA 45 Q2(c).

not queried again as part of the PSEP Pipeline Plan process. The GIS database has also not been updated based on the results from the MAOP validation process.[37] This is an important point because PG&E has assumed values for some missing data and flags this data with a minus sign. For example, there are many segments with negative diameters, have assumed values that could be incorrect.[38] There are also many examples of missing data, as shown in Figure 3 of this exhibit for the longitudinal seam of segment 139.5. As discussed in Section 4.1, PG&E's DT this missing data directly impacts the assignment of a mitigation measure via PG&E's DT.

In addition to these issues, DRA discovered other data problems in the course of reviewing the PSEP Pipeline Plan. For example, 4,944 segments had a test date before the installation date, which is not possible.[39] Note that these anomalies were not found as part of a rigorous evaluation of data quality, but were found as a byproduct of other analysis. DRA did not have the resources to perform a complete evaluation of the GIS database, and the quality of data therein.

Finding: The primary source of pipeline data used to create the PSEP Pipeline Plan includes estimated, missing, incomplete, and incorrect data. This GIS database has not yet been updated with the results of MAOP validation, but PG&E plans to do so once the MAOP validation process is complete.

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[37] Based on meetings held at PG&E on December 19, 2011 and January 20, 2012, both arranged by Kristina Castrence.

[38] Based on a meeting held at PG&E on December 19, 2011, arranged by Kristina Castrence. Confirmation of the meaning of data preceded by a minus sign is pending in the response to data request DRA XX, TCR 27, issued on January 31, 2012. (Note that DRA issues data requests in this proceeding numbered based on the originator's initials, and PG&E then assigns sequential "DRA XX" numbers.)originators initials, PG&E assigns sequential "DRA XX" numbers.

[39] Results of DRA query of data provided as Attachment 1 in PG&E's response dated 10/6/2011 to data request DRA 8 Q28.

3.2 MAOP Validation

PG&E has been engaged in a MAOP project since early in 2011, based on a recommendation from the NTSB.[40] Chapter 5 of its testimony describes PG&E's MAOP Records Validation Project which includes three parts:[41]

- Part 1 – Search for strength/pressure test records for 1,805 miles of priority pipelines
- Part 2 - Gather pipeline data and validate MAOP for the same 1,805 miles
- Part 3 – Gather data and validate MAOP for all remaining transmission pipelines

As described in Sections 5 and 6 of this exhibit, results from Part 1 of the MAOP validation process are used in both the implementation of the DT and in the allocation of costs between shareholders and ratepayers. Part 2 of MAOP validation results in either verification of pipeline feature data, or updating this data where it is found to be missing or inaccurate. The status of these MAOP verification processes and how interim results are reflected in the current PSEP Pipeline Plan are discussed in the following sections.

3.2.1 MAOP validation Part 1 -Pressure Test Records

This effort involves finding and verifying pressure test records for Class 3 and Class 4 segments, and other HCA segments totaling 1,805 miles. [42]

On March 15, 2011, PG&E submitted its first MAOP status report. At that time PG&E had only partial pressure test records for 133 miles of pipeline, 59 miles of line verified only through a report to the CPUC in 1968, 455 miles where a line was grandfathered per section CFR 192.619(c), and was still reviewing

[40] Accident Report NTSB/PAR-11/01; PB2011-916501NTSB, available at http://www.ntsb.gov/investigations/2010/sanbruno_ca.html.

Recommendations P-10-2 and P-10-3, p.133.

[41] Chapter 5, p.5-9. PG&E states that it will not seek cost recovery for Part 1 and portions of Part 2 costs incurred in 2011. Refer to Exhibit DRA 8 regarding MAOP validation for which PG&E is requesting costs recovery.

[42] PG&E Testimony, Chapter 5, p.5-9

pressure test records on 140 miles.[43] In total, 787 miles were not considered complete by PG&E based on a detailed Strength Test Pressure Report (STPR). The next report does not breakout the Section 619(c), but rather adds them to the "still reviewing records" category, and reports 134 miles of pressure test records changed to "complete."[44] In the final report submitted by PG&E on September 12, 2011, there were still 630 miles of pipelines in HCA areas which PG&E does not classify as "Complete."[45]

Table 3 – PG&E MAOP validation status for pressure test records[46]

Report Date	3/15/11	5/10/11	6/10/11	7/11/11	8/10/11	9/12/11	10/14/11
Complete	1018	1152	NA	1155	*1163*	1175	NA
Partial	133	132		132	*124*	120	
Pressure test per 1968 report	59	26		26	*26*	23	
Section 619c Documentation	455						
Still Reviewing Records	140	495		492	*492*	487	
Total	1805	1805		1805	*1805*	*1805*	
Not "Complete"	**787**	**653**		**650**	**642**	**630**	

Note that in contrast to the March 15 MAOP report, PG&E currently does not consider pipelines in category "pressure test per 1968 report" to be complete.[47] Also, "partial" above refers to a pipeline where complete pressure test data was found, but the length of pipe on the test record doesn't match the GIS data, so the pipeline as a whole cannot be considered tested.[48] The San Bruno incident highlights the importance of testing every foot and fitting in a pipeline. Based on data from the monthly reports summarized in Table 3 above, the number of miles

[43] PG&E Testimony, pp.7-10 and 13.

[44] PG&E Testimony, pp. 3-4. The 1968 report included only test pressure and medium. PG&E indicated pipeline in this category is not considered complete for purposes of the DT in response to DRA 45 Q9, but this is not consistent with statements on page 10 of the March 15 report.

[45] PG&E also issued a report titled "MAOP Status Report", on October 14, 2011,but this report only stated that PG&E had completed its reporting requirements and provided no detailed data on pressure test records.

[46] All data from PG&E 2011 MAOP status reports filed in R.11-02-019.

[47] PG&E response dated 1/23/2012 to data request DRA 67 Q1.

[48] PG&E response dated 12/21/2012 to data request DRA 38 Q7(c).

for which MAOP validation of pressure test records has decreased very slowly since April 30, 2011. PG&E has either expended less energy on finding and evaluating test records, or these records are becoming increasingly scarce. Either way there is uncertainty resulting from these incomplete or missing records in the current PSEP that needs to be resolved before the final PSEP Pipeline Plan is compiled.

Finding: The PSEP Pipeline Plan only incorporates MAOP validation of pressure test data through April 30, 2011, when the MAOP validation process for pressure test records for approximately 653 miles of HCA line had not been completed. Even when MAOP validation on all HCA lines is "completed" at the end of January 2012, there will still be hundreds of miles of HCA line for which the status of pressure test records in unknown. PG&E plans to review these over the next three years when they design each project.

3.2.2 MAOP Validation Part 2 – Pipeline Feature List (PFL) and MAOP validation

Part 2 includes four subparts:

1. Collect, code, and compile pipeline segment data[49]
2. Review data, and make assumptions where data is missing
3. Build a Pipeline Features List (PFL) and perform quality assurance/quality control (QA/QC) on the data,
4. Calculate MAOP

First, PG&E's Testimony does not adequately discuss *how* it will find, correct, and track erroneous data it uncovers through the MAOP validation process.[50] PG&E has provided some explanations through DRA's discovery process, but this is a critical issue which requires CPUC attention. DRA recommends that PG&E

[49] Chapter 5, p.5-9. PG&E states that much of the source data was compiled during Part 1 of the MAOP validation process.

[50] This is based on DRA's review of PG&E Testimony Chapters 3 and 5.

be ordered to submit detailed written procedures which describe its treatment of data errors, and how they will provide a permanent record of any changes.

The four subparts of Part 2 of MAOP validation includes sequential events which culminate in the calculation of MAOP for each segment. PG&E's Testimony defines four high priority groups of pipeline "based on potential risk and consequences," but does not state how many miles are included in each group.[51]

The following describes and summarizes PG&E's reported activities with respect to complying with MAOP validation Part 2. On March 21, 2011 PG&E submitted a request for Commission approval of a MAOP validation plan covering all 1,805 miles of pipelines in HCA areas.[52] The plan lists seven priority groups with due dates such that all 1,805 miles are validated by the end of 2011. The first four priority groups, which correspond to the descriptions in PG&E Testimony above, include 705 miles to be validated by "Q3 2011."

PG&E's status report on May 10, 2011, stated that by April 30, 2011, PG&E had compiled data for all Priority 1 segments, begun compiling PFLs for these segments, and that they had "not yet completed MAOP validation work for the 705 miles that are covered by the Compliance Plan."[53] Progress continued through 2011 with 35 miles validated by May 30, [54] 152 miles by June 30,[55] 450 miles by July 31,[56] and 750 miles by August 31.[57] While not explicitly stated in this last report, PG&E had begun and completed work on 45 miles of Priority 5 or lower pipeline by the end of August.

[51] PG&E Testimony, Chapter 5, pp. 5-11 to 5-12.

[52] PG&E report filed in R.11-02-019, p.17.

[53] PG&E stated that 705 miles represents the total for priorities 1 through 4 of the compliance plan.

[54] June 10, 2011 report filed in R.11-02-019, p. 6.

[55] July 11, 2011 report filed in R.11-02-019, p. 6.

[56] August 10, 2011 filed in R.11-02-019, p. 4.

[57] September 12, 2011 filed in R.11-02-019, p. 3.

PG&E's final MAOP validation report, dated October 14, 2011, stated that this report was provided "as a courtesy" and that "PG&E had fulfilled the monthly status report requirement."[58] This monthly report was three page summary which did not provide the detailed tables or status included in previous reports. Instead it discussed a re-prioritization whereby 280 miles of non-HCA would be validated in 2011, but all the original 1,805 priority HCA miles plus the additional 280 miles would be validated by January 31, 2012.[59] The report also states that the remaining 4,660 miles of non-HCA transmission pipeline will be validated by "early 2013" and that "[p]riority for these miles will be based on pipelines with the highest perceived risk and system operational impact and consistent with the pipe modernization decision tree included in the Pipeline Safety Enhancement Plan."[60] If PG&E can validate 300 miles per month, as they did in July and August 2011, they should be able to complete an additional 3,300 miles of validation in 2012, and complete the validation effort mid-May 2013. DRA bases its recommendation for 2012 action on this rate of data review (see Section 10.3).

Finding: The PSEP Pipeline Plan generally does not include the results of MAOP validation of pipeline features, and some DT assignments were made based on estimated or incorrect data.

Finding: PG&E plans to incorporate revised pipeline features based on MAOP validation and other data sources during the final project engineering, which will take place over the next three years. PG&E is not updating the Phase 1 PSEP Pipeline Plan based on new PFLs, but plans to use the results from the final MAOP validation in creating a Phase 2 PSEP Pipeline Plan.

Finding: PG&E will have completed records and MAOP validation for all HCA pipeline segments by the time this testimony is served. PG&E has validated

[58] October 14, 2011report filed in R.11-02-019, p.1.

[59] Ibid, p.2.

[60] Ibid.

approximately 300 miles per month in 2011, and this rate is consistent with PG&E's estimate that MAOP validate will be completed "early in 2013."

3.3 HCA re-classification

In Resolution L-403, the CPUC ordered P&GE to review and report on its HCA classifications. PG&E's first report stated that it "identified 1,057 miles of pipeline where the current classification differed from the initial classification."[61] This report doesn't state how the classifications changed, only that their GIS database allowed them to compare current HCA classification to initial HCA classification.[62]

PG&E's second report on June 30, 2011 indicated that 550 miles of pipeline had a change in class designation based on an undefined "system-wide verification" performed by a consultant.[63] Of these, 378.4 miles had a reduction in class (e.g. Class 3 changed to Class 2) which PG&E "believes" is due to more accurate data.[64] The verification also found 172.1 miles with an increase in class, and 100 miles for which they are were still reviewing records.[65] In response to a DRA discovery question, PG&E indicated that the PSEP Pipeline Plan is not based on HCA revisions from the June 30 report:

"The class location changes reflected in the June 30, 2011 report were not available in PG&E's GIS at the time of the rate case filing and are not

[61] October 4, 2010 letter to Paul Clanon.

[62] DRA interprets this as current data was used in the PSEP Pipeline Plan, rather than the initial classification. Confirmation of this is pending in the response to data request DRA XX, TCR 27, issued on January 31, 2012. (Note that DRA issues data requests in this proceeding numbered based on the originator's initials, and PG&E then assigns sequential "DRA XX" numbers.)

[63] June 30, 2011 letter to Paul Clanon. This letter only mentions that "Wilbros" was retained to perform the verification, but includes no discussion of what this entailed.

[64] See footnote 2 of PG&E's June 30, 2011 report, in which they state "PG&E has not yet investigated why segments went down in class."

[65] Pending data request DRA XX, TCR 27, issued on January 31, 2012 asks if the 100 miles are having HCA verified, or other data to establish MAOP.

reflected in the PSEP Pipeline Plan. The class location changes will be reviewed during each project's data validation process."[66]

In other words, PSEP Pipeline Plan is not based on the latest HCA data. The June 30 report at page 5 shows nearly 320 miles of line had a reduction in class, and 106 miles an increase in class, that would change the mitigation outcome from PG&E's DT. Net, over 210 miles had a reduction in class that would trigger a hydrotest rather than replacement, or Phase 2 rather than Phase 1 hydrotest. Based on this information, it appears that HCA classifications, and segment mitigations based on HCA classifications, are subject to change. These changes are not explicitly discussed and the process for making changes in not transparent.

In November 2011 the CPUC initiated Order Instituting Investigation (OII) 11.11.009 to "review and determine whether PG&E has failed to classify its pipelines correctly and whether PG&E failed to comply with federal standards requiring that it regularly study, patrol, and survey these locations for increased population density."[67] The very fact that the CPUC opened this investigation adds uncertainty to the current HCA classifications which is discussed in Section 7.3 of this exhibit.

Finding: The PSEP Pipeline Plan does not incorporate revised HCA classifications from PG&E's June 30, 2011 report. The PSEP Pipeline Plan is based on errors in HCA classification known to PG&E when the PSEP was filed, and which on average tend to increase the cost.

Finding: PG&E plans to incorporate revised HCA classifications based on MAOP validation and other data sources during the final project engineering, which will take place over the next three years. PG&E is not updating the Phase 1

[66] PG&E Response dated December 22, 2011 to DRA 37, Q2.

[67] Press release dated November 10, 2011, available at http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/151457.htm.

PSEP Pipeline Plan based on revised HCAs, but plans to use the results from the final MAOP validation in creating a Phase 2 PSEP Pipeline Plan.

3.4 Other specific data issues

- In Chapter 3, PG&E states that "Project scopes (type of pipe, length, class location) were based on information contained in GIS and the results from the 2011 MAOP strength testing and data validation program results that PG&E has filed with the CPUC through June 30, 2011."[68] DRA's discovery reveals that this is not a complete description, since the most recent data used was from June 24, 2011, and even this data was modulated based on the April 30, 2011 MAOP data.[69] Thus, the PSEP is essential limited by data through April 30, 2011.
- PG&E's May 10, 2011 MAOP report with results through April 30, 2011 shows that of the 1,805 miles of HCA segments there are 132 miles classified as "partial." Analysis of the 969 miles included in Phase 1 replacement and hydrotest projects indicate that 175.6 miles are considered partial, also through April 30, 2011.[70]

5. PG&E'S DECISION TREE AND PSEP PIPELINE IMPLEMENTATION PLAN

4.1 Overview of PG&E Decision Tree and PSEP Pipeline Implementation Plan

Section 2.1 provides a general definition of the Decision Tree (DT) and the PSEP Pipeline Implementation Plan. To correctly interpret this testimony, it is

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[68] PG&E Testimony, p.3-60.

[69] DT outcomes use a field "Sub_J62411" to establish that a segment has a valid Sub-J pressure test. While this data dates back to June 24, 2011, per PG&E, this field is relies on April 30, 2011 MAOP data to establish a full range of values. In essence, the "Sub_J62411" field only adds a further screen to the April 30, 2011 data.

[70] Results of DRA query of "Partial mileage" entries in the MAOPrec430" field in the spreadsheet provided as Attachment 1 in PG&E's response dated 10/6/2011 to data request DRA 8 Q28.

essential to understand the difference between these two terms. The DT is an engineering evaluation of the threats that exist in PG&E's transmission pipelines, and an engineering-based recommendation of how these threats should be mitigated. It also establishes the priority of mitigation by assigning segments to Phase 1, 2011-2014, or Phase 2, 2015 and after. The PSEP Pipeline Implementation Plan builds on the DT outcomes by grouping segments requiring similar mitigation in Phase 1 into projects, and scheduling the projects based on priority from the DT and other input. In addition, PG&E includes many segments not requiring Phase 1 mitigation into Phase 1 projects for the purported reason of increasing efficiency and reducing mitigation costs. Therefore PG&E PSEP Pipeline Implementation Plan includes approximately 344 more miles in Phase 1 than required by the DT.[71] The derivation and interaction between the DT and PSEP Pipeline Implementation Plan are illustrated by an example using Line 220 in the balance of Section 4.1.

4.1.1 PG&E Decision Tree

PG&E states that their DT is the primary tool used to determine the mitigation required for each pipeline segment.[72] A flow chart representing the DT is provided in PG&E Attachment 3A and development and rational for the DT are described in PG&E Attachment 3B. The DT shows conceptual decision points in grey, and mitigation outcomes in yellow. The outcome of the DT is that each of 25,076 transmission pipeline segments is assigned one of 15 DT outcome codes, which designate both the type of mitigation, and when it should be performed. For example, DT outcome M2 requires pressure reduction and replacement in Phase 1, while outcome C1 requires a strength test and Close Interval Survey (CIS), or ILI and CIS, in Phase 2.

[71] Refer to Table 4 of this exhibit. This value is PG&E's request for Phase 1 replacement (783 miles) plus hydrotest (186 miles) Table 4 cells A1 and A2.

[72] PG&E Testimony, p.3-3. Also, PG&E response dated 10/6/2011 to data request DRA 8 Q7.

4.1.2 Implementation of the DT

The DT shown in PG&E Attachment 3A to PG&E's Testimony is implemented in practice by applying logical tests to pipeline segment data from various sources, which ideally should be 100% consistent with PG&E's Testimony. Critical types of input data include:

1. Installation date
2. Pipeline manufacturing and construction details
3. Strength test data
4. Pipeline material - to establish Specified Minimum Yield Strength (SMYS)
5. Pipeline OD, wall thickness, and operating pressure – to establish the level of stress on a pipeline, as indicated by the % SMYS
6. HCA classification

This section, and Sections 5 and 6, will describe why the validity of the PSEP Pipeline Plan depends on the accurate application of the DT on accurate pipeline data. Because of this, DRA spent a significant amount of time working with PG&E to understand the process, tools, and data used. The following discussion of this critical process is based on multiple written discovery responses and information obtained in meetings with PG&E staff.

First, PG&E needed the pipeline data summarized above for each of the 25,076 transmission pipeline segments. This was available from their general GIS database, but rather than working directly with this large database, PG&E pulled the required data on January 3, 2011.[73] This data set is referred to as the "PSEP Pipeline Plan Database." Below is a sample of the data exported for Line 220:[74]

Figure 3 – Example of PSEP Pipeline Plan database pipeline features

[73] PG&E response dated 10/21/2011 to data request DRA 11 Q5a.

[74] This example shows 15 contiguous segments on Line 220. The data columns shown are only a sample of relevant data, and do not include all data used to implement the DT. Also note that the PSEP Pipeline Plan is an ArcView GIS database, but DRA's analysis is based on exports from this database as Excel files.

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
ROUTE	SGMNT_NO	MP1	MP2	YeaR_INSTALL	LONG_SEAM	JOINT_TYPE	SMYS	Wall_THICK	OD	MOP	HCA Class	HCA	TEST_DATE	TEST_PRESS	TEST_DUR	TestPer
220	133.9	22.11	22.14	1/1/1981	ERW	BUTT	35000	0.2500	10.750	792.0	3	YES	1/1/1981	1375.0000	9.0000	1.74
220	134.2	22.14	22.17	1/1/1938	SMLS	BBCR	35000	0.2500	10.750	792.0	3	YES		0.0000	0.0000	0.00
220	134.5	22.17	22.17	1/1/1938	SMLS	BBCR	35000	0.2500	8.625	792.0	3	YES		0.0000	0.0000	0.00
220	135.5	22.17	22.17	1/1/1938	SMLS	BBCR	35000	0.2500	8.625	500.0	3	YES		0.0000	0.0000	0.00
220	136	22.17	22.31	1/1/1937	SMLS	BBCR	35000	0.2500	8.625	500.0	3	YES		0.0000	0.0000	0.00
220	136.3	22.31	22.35	1/1/1937	SMLS	BBCR	35000	0.2500	8.625	500.0	3	YES		0.0000	0.0000	0.00
220	137	22.35	22.41	1/1/1980	ERW	BUTT	42000	0.1720	8.625	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58
220	137.5	22.41	22.58	1/1/1980	ERW	BUTT	42000	0.1720	8.625	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58
220	137.77	22.58	22.73	1/1/1980	ERW	BUTT	42000	0.1720	8.625	500.0	3		1/1/1980	1290.0000	8.0000	2.58
220	138	22.73	22.85	1/1/1980	ERW	BUTT	42000	0.1720	8.625	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58
220	138.5	22.85	23.10	1/1/1980	ERW	BUTT	42000	0.1720	8.625	500.0	3		1/1/1980	1290.0000	8.0000	2.58
220	139	23.10	23.15	1/1/1980	ERW	BUTT	42000	0.1720	8.625	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58
220	139.5	23.14	23.15	1/1/1962		BUTT	42000	0.1880	8.625	500.0	3			0.0000	0.0000	0.00
220	140	23.15	23.37	1/1/1937	SMLS	BBCR	35000	0.2190	8.625	500.0	3		1/1/1962	0.0000	0.0000	0.00
220	141	23.37	23.89	1/1/1937	SMLS	BBCR	35000	0.2190	8.625	500.0	1			0.0000	0.0000	0.00

PG&E then added results of the MAOP validation process, shown in yellow below, which were used in the evaluation of whether a pressure test had been performed to the requirements of 194 CFR Sub-part J:[75]

Figure 4 – Example of PSEP Pipeline Plan database, MAOP validation data added

A	B	C	D	E	K	L	M	N	O	P	Q	R	S
ROUTE	SGMNT_NO	MP1	MP2	YeaR_INSTALL	MOP	HCA Class	HCA	TEST_DATE	TEST_PRESS	TEST_DUR	TestPer	MAOPrec430	Sub_J62411
220	133.9	22.11	22.14	1/1/1981	792.0	3	YES	1/1/1981	1375.0000	9.0000	1.74	Complete	Y
220	134.2	22.14	22.17	1/1/1938	792.0	3	YES		0.0000	0.0000	0.00	Incomplete Record	N
220	134.5	22.17	22.17	1/1/1938	792.0	3	YES		0.0000	0.0000	0.00	Incomplete Record	N
220	135.5	22.17	22.17	1/1/1938	500.0	3	YES		0.0000	0.0000	0.00	Incomplete Record	N
220	136	22.17	22.31	1/1/1937	500.0	3	YES		0.0000	0.0000	0.00	Partial Mileage	N
220	136.3	22.31	22.35	1/1/1937	500.0	3	YES		0.0000	0.0000	0.00	Partial Mileage	N
220	137	22.35	22.41	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y
220	137.5	22.41	22.58	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y
220	137.77	22.58	22.73	1/1/1980	500.0	3		1/1/1980	1290.0000	8.0000	2.58	Complete	Y
220	138	22.73	22.85	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y
220	138.5	22.85	23.10	1/1/1980	500.0	3		1/1/1980	1290.0000	8.0000	2.58	Complete	Y
220	139	23.10	23.15	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y
220	139.5	23.14	23.15	1/1/1962	500.0	3			0.0000	0.0000	0.00	Incomplete Record	N
220	140	23.15	23.37	1/1/1937	500.0	3		1/1/1962	0.0000	0.0000	0.00	Partial Mileage	N
220	141	23.37	23.89	1/1/1937	500.0	1			0.0000	0.0000	0.00		N

PG&E then queried this updated PSEP Pipeline Plan database using computer code it wrote to perform the logical tests defined in the DT. As a result of the querying process, DT outcome numbers were assigned to each segment in a

[75] Columns F-K not shown in this figure.

new column of the PSEP Pipeline Plan database, shown in column T and shaded green below:[76]

Figure 5– Example of PSEP Pipeline Plan database, decision tree outcome added

A	B	C	D	E	K	L	M	N	O	P	Q	R	S	T
ROUTE	SGMNT_NO	MP1	MP2	YeaR_INSTALL	MOP	HCA Class	HCA	TEST_DATE	TEST_PRESS	TEST_DUR	TestPer	MAOPrec430	Sub_J62411	DT_Ref_Num
220	133.9	22.11	22.14	1/1/1981	792.0	3	YES	1/1/1981	1375.0000	9.0000	1.74	Complete	Y	C7
220	134.2	22.14	22.17	1/1/1938	792.0	3	YES		0.0000	0.0000	0.00	Incomplete Record	N	F2
220	134.5	22.17	22.17	1/1/1938	792.0	3	YES		0.0000	0.0000	0.00	Incomplete Record	N	F2
220	135.5	22.17	22.17	1/1/1938	500.0	3	YES		0.0000	0.0000	0.00	Incomplete Record	N	C3
220	136	22.17	22.31	1/1/1937	500.0	3	YES		0.0000	0.0000	0.00	Partial Mileage	N	C3
220	136.3	22.31	22.35	1/1/1937	500.0	3	YES		0.0000	0.0000	0.00	Partial Mileage	N	C3
220	137	22.35	22.41	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y	C6
220	137.5	22.41	22.58	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y	C6
220	137.77	22.58	22.73	1/1/1980	500.0	3		1/1/1980	1290.0000	8.0000	2.58	Complete	Y	C5
220	138	22.73	22.85	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y	C6
220	138.5	22.85	23.10	1/1/1980	500.0	3		1/1/1980	1290.0000	8.0000	2.58	Complete	Y	C5
220	139	23.10	23.15	1/1/1980	500.0	3	YES	1/1/1980	1290.0000	8.0000	2.58	Complete	Y	C6
220	139.5	23.14	23.15	1/1/1962	500.0	3			0.0000	0.0000	0.00	Incomplete Record	N	M4
220	140	23.15	23.37	1/1/1937	500.0	3		1/1/1962	0.0000	0.0000	0.00	Partial Mileage	N	C3
220	141	23.37	23.89	1/1/1937	500.0	1			0.0000	0.0000	0.00		N	C1

For example, the second and third segments in this list (134.2 and 134.5) were assigned F2 outcomes, indicating these segments need Phase 1 replacement. This excerpt represents the data used by Gulf to develop the PSEP Pipeline Implementation Plan

4.2 Analysis of PG&E's Decision Tree

In Exhibit DRA-04, BEAR provides a review of PG&E's decision tree which generally confirms PG&E's process, but notes the following concerns:[77]

- Certain manufacturing threats were inappropriately assigned a default designation for replacement in Phase 1
- All Class 2 locations were treated the same as Class 3 by default
- Fabrication and construction threats were inappropriately screened based on previous 49 CFR 192 Sub-part J (Sub-J) pressure tests

[76] Columns F-K not shown in this figure.
[77] Exhibit DRA-4 also raises issues concerning the data used, which are addressed in Section 3 above.

- Mitigation was prioritized based on Sub- J pressures tests only, not based on other strength tests which demonstrate reduced risk

To correct these deficiencies, BEAR revised PG&E's DT, as follows:

1. For clarity, reordered decision points 1J and 1K on manufacturing threats
2. For manufacturing threats, renamed PG&E outcomes M3 and M5 to M12 and M13 respectively, because they are derived differently
3. For manufacturing threats, replaced PG&E outcomes M2 and M4 with new outcome M11, thereby eliminating replacement as a default for manufacturing threats
4. For fabrication and construction threats, removed PG&E decision point 2F, because pressure test is not as effective as replacement as mitigation for these threats
5. Modified decision points 1J, 2G (now 2F), and 3B to reflect that Class 2 segments should not be treated as HCAs by default
6. Modified Decision point 1H to include hydrotest data after 1955 for project prioritization

The impact of BEAR's revised DT on outcomes and **required** mitigation for all transmission pipelines is shown in the following table:[78]

[78] This table compares the outcomes of the decision trees, which reflect required mitigation based on engineering analysis. Changes in the scope of replacement hydrotest projects are discussed in Section 4.3.

Table 4 – Scope of pipeline mitigation required per PG&E and BEAR decision trees

			A	B	C
			PG&E	Bear	Change
	Required Mitigation per DT	Included DT Outcomes	Miles	Miles	Miles
1	Phase 1 Replace	M2 and F2	161.6	110.2	**(51.4)**
2	Phase 1 Hydrotest	M4, M11, C2	463.3	472.4	**9.1**
3	Phase 1 ECA, and possible replacement, phase 1 or 2	F1	-	-	-
4	Phase 2 TBD based on fatigue analysis	M1, M3, M5, M12, M13	254.3	1,079.4	**825.1**
5	Phase 2 hydro & ILI or replace	F3	42.9	127.9	**85.0**
6	Phase 2 hydrotest or ILI+	C1, C3, C4, C5	4,207.1	3,455.7	**(751.4)**
7	TIMP	C6, C7	685.3	568.9	**(116.4)**
8		**Total**	**5,814**	**5,814**	**(0.0)**

BEAR's revised decision tree results in a net reduction in segments requiring Phase 1replacement, an increase in required Phase 1 hydrotests, and a reduction in required Phase 1 mitigation overall.[79] BEAR concludes that "Decision outcomes recommended by BEAR result in a pipeline evaluation that has less risk than the PG&E decisions, while simultaneously reducing scope."[80]

4.3 *Overview* of PG&E's Pipeline Modernization PSEP Pipeline Implementation Plan

The PSEP Pipeline Implementation Plan represents the sum of PG&E's efforts to prioritize and schedule mitigation work in accordance with its decision tree. It converts DT outcomes for 26,076 pipeline segments into a specific list of projects to be completed during 2011-2014. Based primarily on the DT outcome, PG&E grouped segments requiring Phase 1 mitigation into one of 168 replacement projects, 165 hydrotest projects, or 8 Inline Inspection (ILI) Projects.[81] Whereas the DT outcomes were assigned objectively according to fixed criteria described in its testimony, the PSEP Pipeline Implementation Plan

[79] The *decrease* in segments replaced due to manufacturing threats is greater than the *increase* in segments replaced due to fabrication and construction threats.
[80] Exhibit DRA-4, p.3.
[81] Six of the ILI projects include a capital costs request for upgrades, in addition to expenses for performing these tests.

was developed subjectively by PG&E and its consultant Gulf.[82] The PSEP Pipeline Implementation Plan also adds to these projects segments that do not require Phase 1 mitigation per the DT, based on “construction efficiency”.[83] The PSEP Pipeline Implementation Plan is also the basis of PG&E’s cost models.

PG&E provided a copy of the PSEP Pipeline Plan database that included the DT outcome number and pipeline feature data for all 25,076 segments (see example in Section 4.2 above) sometime after June 24, 2011.[84] PG&E’s Testimony provides some of the criteria used, but does not describe the process for grouping segments into projects. DRA developed the following understanding of the process based on PG&E’s data request responses and interviews with PG&E staff:[85]

- Gulf took a first cut at project grouping based on review of satellite images of the segment locations, PG&E GIS data, and other information
- Gulf and PG&E worked together to refine the projects, and finalized the segment groupings
- PG&E determined if segments assigned to replacement projects needed to be expanded in diameter (Prop_OD) or relocated
- PG&E established a project schedule and assigned operational dates (OPDATE) to each project

PG&E describes the process used to prioritize projects in response to data DRA’s request DRA 36 Q3.

[82] PG&E Testimony, Attachments 3A and 3B.

[83] See PG&E workpapers at WP 3-21 and WP 3-785.

[84] This figure is taken from the “Implementation_Plan_08-13-11” tab of File “Test Ph. 1 Projects Rev 1.1 10-31-11” provided as an attachment to the response to DRA 16.

[85] Meetings on December 19, 2011 and January 20, 2012 at PG&E noted previously, and response to DRA 36 Q3 and DRA 26, Q13

"Once the segments were grouped in specific projects (replace, strength-test), PG&E used the prioritization model described in testimony on pages 3-33 to 3-34 to propose an initial schedule for completing the work. This was done by simple Excel code for the factors discussed in testimony and is shown in attachment GasPipelineSafetyOIR_DR_DRA_036-Q03Atch01. This file was used to create project prioritization. PG&E then took into consideration the project scheduling factors discussed in testimony on pages 3-34 to 3-35 to re-arrange the projects into an achievable work plan, the product of which was included as the PSEP Pipeline Implementation Plan Filing on August 26, 2011 for Chapter 3 workpapers. The process to apply the scheduling impacts discussed in testimony was done in several informal meetings with engineering and project management team members from PG&E and Gulf. The biggest driver for schedule shift of all Phase 1 projects were expected permitting delays, but other factors such as expected data validation completion by 2013, work load leveling and an appropriate ramp-up pattern for the work, construction efficiency and/or disturbance mitigation, and coordination with other projects/processes, such as ILI, valve automation, and system gas control, all played a part in the final project scheduling across 2012 to 2014."

This work was completed prior to August 13, 2011, based on the date of PG&E's detailed PSEP Pipeline Implementation Plan as submitted to DRA.[86] Using the example for Line 220 in Section 4.1, new data was added to the PSEP Pipeline Plan database showing project assignments, operational dates, and proposed OD, as shown in blue below: [87]

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[86] "Implementation_Plan_08-13-11" tab of File "Test Ph. 1 Projects Rev 1.1 10-31-11" provided as an attachment to PG&E's response to data request DRA 16.
[87] Columns E-P not shown in this figure.

Figure 6 - Example of PSEP Pipeline Plan database, project data added

	A	B	C	D	E	R	S	T	U	V	W	AC
1	ROUTE	SGMNT_NO	MP1	MP2	YeaR_INSTALL	MAOPrec430	Sub_J62411	DT_Ref_Num	Prj_Type	GIEPrjNum	OPDATE	Prop_OD
2	220	133.9	22.11	22.14	1/1/1981	Complete	Y	C7	REPL	L-220REPL	12/1/2013	10.75
3	220	134.2	22.14	22.17	1/1/1938	Incomplete Record	N	F2	REPL	L-220REPL	12/1/2013	10.75
4	220	134.5	22.17	22.17	1/1/1938	Incomplete Record	N	F2	REPL	L-220REPL	12/1/2013	10.75
5	220	135.5	22.17	22.17	1/1/1938	Incomplete Record	N	C3				
6	220	136	22.17	22.31	1/1/1937	Partial Mileage	N	C3				
7	220	136.3	22.31	22.35	1/1/1937	Partial Mileage	N	C3				
8	220	137	22.35	22.41	1/1/1980	Complete	Y	C6				
9	220	137.5	22.41	22.58	1/1/1980	Complete	Y	C6				
10	220	137.77	22.58	22.73	1/1/1980	Complete	Y	C5				
11	220	138	22.73	22.85	1/1/1980	Complete	Y	C6				
12	220	138.5	22.85	23.10	1/1/1980	Complete	Y	C5				
13	220	139	23.10	23.15	1/1/1980	Complete	Y	C6				
14	220	139.5	23.14	23.15	1/1/1962	Incomplete Record	N	M4	TEST	L-220TEST		
15	220	140	23.15	23.37	1/1/1937	Partial Mileage	N	C3	TEST	L-220TEST		
16	220	141	23.37	23.89	1/1/1937		N	C1	TEST	L-220TEST		

Figure 6 includes segments that PG&E has added to Phase 1 projects even though this is not required based on the engineering assessment embedded in the DT process. For example, segment 133.9 is slated for replacement even though the DT only requires ILI at the next TIMP assessment (DT ref C7), and segment 140 is included in a Phase 1 hydrotest, even though the DT shows a Phase 2 ILI and CIS could be sufficient. In testimony, PG&E directly addresses the issue of "extra" miles included in Phase 1 for hydrotesting by stating:

> "[t]o complete the 546 miles of segments, PG&E plans to strength test 783 miles of pipe. "This 237 mile difference (783 less 546) was created by determination of efficient ending points per project as opposed to the exact start and stop of every pipe segment without a pressure test."[88]

PG&E does not quantify the number of miles of pipeline it recommends replacing where replacement was not identified per the DT.

PG&E also included other modifications to segments designated for pipeline replacement projects, including expanding and relocating lines. PG&E states that:

[88] PG&E Testimony, pp.3-29 to 3-30.

"Typically, PG&E will replace pipe size for size, unless PG&E has known capacity restrictions that can be resolved by increasing the pipe diameter. More importantly, PG&E will attempt to create long sections of the same diameter of pipe to better facilitate ILI."

This is shown for Segment 134.5 in the example in column AC, which indicates they propose replacing the current 8.625" OD line with a 10.75" segment.[89] PG&E does not mention in testimony that the PSEP Pipeline Implementation Plan also includes relocating lines, as discussed in Section 4.5.3 below.

4.4 Analysis of the PSEP Pipeline Implementation Plan

DRA evaluated the PSEP Pipeline Implementation Plan at two Phases. First, an overall review was performed to determine the aggregate impacts of the plan. In Section 4.4.1, the results of a high level review are presented which indicates the need for more detailed review. Section 4.5 provides the detailed analysis of a sample of projects reviewed by DRA, and others reviewed by BEAR.

4.4.1 Review of PG&E's PSEP Pipeline Implementation Plan Scope

4.4.1.1BEAR review of PSEP Pipeline Implementation Plan

Exhibit DRA-4 provides the following table based on DT outcomes for both BEAR and PG&E's decision trees:[90]

[89] Existing OD is shown in PG&E workpapers, p.WP 3-218.

[90] Table 1 from Exhibit DRA-4 was reformatted to aid in the discussion which follows it in this exhibit.

Table 5 – Scope of Phase 1 pipeline mitigation, per PG&E and BEAR

		A	B	C	D	E	F
		PG&E	PG&E: not from DT	BEAR DT Recomm	Unique to BEAR	BEAR DT, w/ neighbor	Unique to BEAR
1	Replace (segments)	2,797	314	788	133	910	166
2	Replace (mileage)	186	18	110	21	113	22
3	Test (segments)	3,396	1,362	3,123	240	3,336	286
4	Test (mileage)	783	270	472	41	502	51

The columns define Phase 1 mitigation as follows:

- A –Per PSEP
- B – Included in PSEP, but not driven by PG&E DT
- C –Per BEAR revised DT
- D – Required by BEAR, but not included in PSEP
- E – Same as C, but with "Neighboring Segment" situation[91]
- F - Same as D, but with "Neighboring Segment" situation[92]

Three overarching observations are summarized here:

- PG&E included 288 miles of pipeline in Phase 1 for reasons other than their DT (Table 5, B2 plus B4)
- BEAR recommends 62 miles to Phase 1 for engineering/safety reasons that are not included in the PSEP (D2 plus D4)

[91] See Exhibit DRA-4, p.12. BEAR defines this situation as "when a segment which has not been flagged for a replacement or testing project by the Decision Tree is surrounded by segments which have been flagged for a project, the non-flagged segment may be included if doing so is more economical. Such a decision would be made on a project-by-project basis."
[92] See Exhibit DRA-4, p.12.

- Including selected "neighbor" segments into Phase 1, which BEAR identifies as an option, leads to only a minor increase in Phase 1 miles (compare column C to E and D to E)[93]

4.4.1.2 DRA review of PSEP Pipeline Implementation Plan scope

DRA evaluated the cost impact of PG&E adding non-priority segments to the PSEP Pipeline Implementation Plan using the models discussed in Section 2.4.1. This exercise also provided an opportunity to independently check BEAR's findings. The first analysis performed was to compare what was required by the decision tree with what was included in PG&E's PSEP Pipeline Implementation Plan for all segments. This was performed by querying PG&E's PSEP Pipeline Implementation Plan for DT outcomes.[94] Table 6 below shows the DT outcomes for all segments, those included in replacement projects, those included in hydrotest projects, and those not included in a Phase 1 project:

[93] This is based on BEAR's DT outcomes. DRA did not test how the same treatment of neighbors would impact Phase 1 projects based on PG&E's DT.
[94] The query was performed on the spreadsheet provided in response to DRA 8, Q28.

Table 6 – PG&E decision tree outcomes for all DOT transmission lines[95]

	A	B	C	D	E	F	G	H
	Overall		Replacement		Hydrotest		Phase 2	
DT Outcome	Segments	Miles	Segments	Miles	Segments	Miles	Segments	Miles
D1	-	-	-	-	-	-		
M1	-	-	-	-	-	-		
M2	1,241	133.6	1,118	100.1	43	15.5	80	17.9
M3	1,166	138.4	2	1.9	22	12.3	1,142	124.2
M4	1,768	253.8	898	21.9	838	225.8	32	6.1
M5	547	115.9	2	0.1	51	22.7	494	93.1
F1	-	-	-	-	-	-	-	-
F2	188	28.0	126	13.9	58	12.9	4	1.2
F3	169	42.9	7	1.9	2	0.1	160	40.9
C1	2,502	1,053.2	2	0.0	158	73.2	2,342	979.9
C2	1,066	209.5	264	6.3	762	195.2	40	8.0
C3	1,952	277.9	78	9.0	537	93.0	1,337	176.0
C4	5,629	2,109.1	83	14.9	177	46.1	5,369	2,048.0
C5	4,253	766.9	44	1.9	193	12.6	4,016	752.4
C6	3,162	432.4	97	7.2	322	41.3	2,743	383.9
C7	1,433	252.9	76	6.3	233	32.4	1,124	214.2
Blank	-	-	-	-	-	-	-	-
Total	**25,076**	**5,814.5**	**2,797**	**185.5**	**3,396**	**783.0**	**18,883**	**4,845.9**

Outcomes in orange or yellow require Phase 1 replacement or hydrotest respectively, per PG&E's DT. This table shows that the PSEP Pipeline Implementation Plan deviates significantly from the mitigations specified *by PG&E's own DT*. For example:

1. 47.6 miles that should be replaced in Phase 1 (M2 or F2) are either hydrotested or deferred to Phase 2
2. 14.1 miles that should be hydrotested in Phase 1 (M4 or C2) are deferred to Phase 2
3. 71.5 miles are replaced in Phase 1, when they could be deferred to Phase 2 and/or subject to less expensive mitigation

[95] In Table 6, columns A and B were obtained by querying the DT outcome on all segments in the PSEP database; columns C and D obtained by querying the DT outcome on all segments included in Phase 1 replacement projects; columns E and F obtained by querying the DT outcome on all segments included in Phase 1 hydrotest projects; column G was generated by subtracting C and E from A: and column H was generated by subtracting D and F from B.

4. 333.7 miles are hydrotested in Phase 1, when they could be deferred to Phase 2 and possibly subject to less expensive mitigation

PG&E's DT does not automatically require replacement in Phase 2 for any outcome, but establishes options, the most expensive of which is to "replace or hydro and ILI" for outcomes M5 or F3.[96] Of the 405.2 miles advanced into Phase 1 by the PSEP Pipeline Implementation Plan, less than 25 miles would eventually require replacement or hydrotest and ILI. For the balance, the PSEP Pipeline Implementation Plan advances them unnecessarily into Phase 1, which results in more expensive mitigation for some segments.

DRA's high level analysis shows that the PSEP Pipeline Implementation Plan shows significant deviations from the results of PG&E's DT which:

1. Provides less safety for many of the highest priority pipeline segments
2. Specifies more expensive mitigation than required according to PG&E's DT
3. Increases the scope of Phase 1 mitigation, which could create resource constraints and cost inflation

4.4.2 Review of PSEP Pipeline Implementation Plan Cost impacts

DRA was able to use the models described in Section 2.4.1 of this exhibit to estimate the cost impact of PG&E's deviations from its DT on its Phase 1 cost recovery request.

[96] PG&E DT outcome F1 provides the possibility of Phase 2 replacement, but only after an ECA. No segments currently have been assigned this outcome. See PG&E response dated12/16/2011 to data response DRA 34 Q4.

For replacement projects, DRA's model can account for $828.5 million of the $843.9 million requested to individual segments with 100% accuracy.[97] Table 7 shows how much of the $828.5 million is driven by each DT outcome, with outcomes requiring Phase 1 replacement in green, and those requiring Phase 1 hydrotest in orange:

Table 7– Phase 1 pipeline replacement costs NOT driven by PG&E decision tree

PG&E DT Outcome	Cost Excluding Mob/Demob	
D1	$ -	
M1	$ -	
M2	$ 447,178,430	
M3	$ 4,585,192	
M4	$ 108,436,821	
M5	$ 572,739	
F1	$ -	
F2	$ 50,656,310	
F3	$ 7,716,638	
C1	$ 24,746	
C2	$ 34,086,651	
C3	$ 35,374,617	
C4	$ 58,661,486	
C5	$ 6,749,473	
C6	$ 42,297,802	
C7	$ 32,146,906	
Total	**$ 828,487,811**	98.2%
Total with mob/demob	**$ 843,921,000**	100.0%
REPL Ph1 per DT	$ 497,834,740	59.0%
Hydro P1 per DT	$ 142,523,472	16.9%
Replacement optional	$ 188,129,599	22.3%

[97] This is PG&E's total cost for replacement, which is the sum of $833.6 million and $0.6 million from table 3-1 (p.3-6) and $9.8 million that PG&E offers to pay (p.3-66). The remaining costs are for Mob/Demob costs which are assigned by PG&E at the project level. These costs can be assigned to the segment level, but not with 100% accuracy.

Of these $828.5 million, DRA calculates that $497.8 million is for segments that require Phase 1 replacement per PG&E's DT. $142.5 million is for segments that were assigned to Phase 1 hydrotest, which at face value increases the cost of mitigation for these segments 10 fold (see Table 9 below). In practice, for short adjacent segments, particularly if they are of small diameter, there may be cases where the fixed cost of hydrotesting is higher than the cost to replace, but this requires a detailed review on a project and segment basis (see section 4.4.2 for an example.)

In addition, PG&E includes $188.1 million for segments that are not a high priority. In total, Table 7 shows that less than 60% of the cost PG&E's request s for Phase 1 replacement are driven by their DT.

For hydotests, PG&E's cost models have high fixed costs that are assigned to projects, and are difficult to assign to specific segments. As a result, DRA's model can account for only $319.3 million of the $404.9 million requested to individual segments with 100% accuracy.[98] Table 8 shows how much of the $319.3 million is driven by each DT outcome, with outcomes requiring Phase 1 hydrotest in blue, and those requiring Phase 1 replacement in yellow:

[98] This is PG&E's total cost for hydrotesting, which is the sum of $389.1 million and $4.1 million from table 3-1 (p.3-6) and $11.8 million that PG&E offers to pay (p.3-66). The remaining costs are for Mob/Demob costs which are assigned by PG&E at the project level. These costs can be assigned to the segment level, but not with 100% accuracy.

Table 8– Phase 1 pipeline hydrotest costs NOT driven by PG&E decision tree

PG&E DT Outcome	Cost Excluding Mob/Demob	
D1	$ -	
M1	$ -	
M2	$ 5,062,634	
M3	$ 4,495,874	
M4	$ 68,525,062	
M5	$ 6,271,596	
F1	$ -	
F2	$ 5,766,414	
F3	$ 23,264	
C1	$ 30,555,018	
C2	$ 102,994,648	
C3	$ 32,770,310	
C4	$ 19,292,765	
C5	$ 5,064,432	
C6	$ 17,582,021	
C7	$ 20,917,781	
Total	**$ 319,321,819**	78.9%
Total with mob/demob	**$ 404,934,000**	100.0%
Hydro Ph1, per DT	$ 171,519,709	42.4%
Replace Ph1, per DT	$ 10,829,049	2.7%
Other	$ 136,973,061	33.8%

Of these $319.3 million, DRA calculates that $171.5 million are for segments that require hydrotest per PG&E's decision tree, and $10.8 million for segments that should have been replaced, but PG&E includes in hydrotest projects instead. Therefore, at least $137.0 million of PG&E's request is for segments that could be addressed after 2014, and possibly with less expensive measures such as ILI or CIS and DCVG. Table 8 shows that even if none of the Mob/Demob costs are unique to the optional segments, over one-third of PG&E's proposed hydrotest costs are NOT required by its decision tree:[99]

4.4.3 Adding segments to replacement vs. hydrotests

For hydrotests, only the beginning and end of the test section, which can include multiple pipeline segments, need to be excavated, unless a failure occurs.

[99] Mob/Demob costs are assigned by PG&E at the project level. These costs would only be reduced if PG&E has defined a project in which none of the segments requires a Phase 1 hydrotest, and the project can be eliminated.

The excavation and setup costs are required regardless of the length of the test section. This leads to high fixed costs per test that are independent of the length of pipeline tested, which can be seen in the wide range of strength test costs per mile provided by PG&E:

Table 9 – PG&E's estimated pipeline mitigation costs per mile from PSEP Pipeline Plan

	A	B	C		D	E	F
	PG&E'sProvided Costs				**Total Cost with Contingency**	**Miles**	**Calculated Cost**
	Low	Average	high		from Table 1		
	$/mile	$/mile	$/mile		millions		$/mile
Replacement	$ 4,118	$ 4,514	$ 5,180		$ 1,011.8	186	$ 5,440
Strength Tests	$ 248	$ 502	$ 13,971		$ 488.3	783	$ 624
Retrofit for ILI	$ 137.0	$ 152.0	$ 158.0		$ 36.7	199	$ 184
Pipeline ILI	$ 16.0	$ 40.0	$ 60.0		$ 11.6	234	$ 50

In contrast, replacement requires excavating the entire length of pipeline to be replaced, such that the cost per mile calculated by PG&E is both much higher and constant across all PSEP Pipeline Plan projects. Based on these findings, DRA concludes that it may be reasonable to include not only adjacent segments to Phase 1 hydrotests, but potentially close segments that are not contiguous. However, the opposite is true for replacement projects: since the fixed Mob/Demob costs for replacement are very low compared to the variable per-mile costs for excavation and pipeline, there should be few cases where it is economically efficient to replace segments unless required per the DT.

It should also be noted that replacement lines will need to be hydrotested prior to being placed into service, per 49 CFR 192. Extending the length of this hydrotest to include additional segments on either side of the replacement should be a low-cost alternative to replacing these segments. In this case, approximately one half of the high fixed costs will already be included in the costs to replace the central replacement section, and the only incremental cost should be the hydrotest cost per foot, which is approximately10 times lower than the cost per foot to replace.[100]

4.5 Sample project review

Conceptually, it is reasonable for PG&E to consider adding segments to Phase 1 projects if it results in a net increase in efficiency, and reduction in costs, when all Phases of the PSEP Pipeline Plan are considered. However the combination of the issues raised above, and lack of justification for the composition of projects in PG&E's Testimony led DRA to review a small sample of projects and evaluate the reasonableness of PG&E's augmenting Phase 1 projects where it was not required by the DT. Based on DRA's evaluation of one randomly selected project, DRA instructed its consultant BEAR to review other projects. Detailed comments on four other projects are provided, as well as a summary of some other minor issues uncovered.

4.5.1 Review of PG&E projects on Line 21F

This project was essentially at random, as the first replacement project in PG&E's workpapers in which "post 70" costs to be funded by PG&E shareholders were included.

Line 21F runs 21.5 miles roughly parallel to the 101 freeway in Marin County, from Petaluma to San Rafael. Of the 125 segments in the line, 60 are included in the PSEP Pipeline Plan for proposed Phase 1 action: replace 29 segments totaling 4.24 miles,[101] and hydrotest 31different segments totaling 5.18

[100] Based on a comparison of the "all-in" costs for replacement, PG&E Testimony, p. 3E-15, with the "all-in" costs for hydrotest, PG&E Testimony, p. 3E-17, for the same sized pipeline.

[101] Project L-021-F REPL, as detailed in the PG&E workpapers starting at WP 3-20

miles.[102] Line 21F consists primarily of 12.75" OD segments with many segments of 16" interspersed, and one 20" section:

Table 10 – Existing outside diameters for PG&E Line 21F

		OD		
	Total	12.75"	16"	20"
Miles	21.150	16.38	4.71	0.06
Feet	111,672	86,486	24,869	317

For the subject replacement project, the segments to be replaced are clustered in three separate locations at the beginning, middle, and end of this line as shown on pages 12 and 13:

- 2.1 miles in Petaluma (MP 0 to 2.13)
- .89 miles in Novato (MP 10.8 to 11.7
- 1.23 miles in San Rafael (MP 19.9 – 21.1)

The hydrotest project includes 4 test sections, two between Petaluma and Novato; one section adjacent and to the south of the Novato replacement section; and one section adjacent to, and north of the San Raphael replacement section. The following observations were made by reviewing PG&E's workpapers, the PSEP Pipeline Plan database, and Google map images of the route:

- The decision tree includes four outcomes (M1, M3, M5, and F3) that are not terminal points (i.e. at least one more decision remains to be made),[103] but that connect to other section of the DT. PG&E should clarify how to treat segments with more than one outcome.

[102] Project L-021-F Test, as detailed in the PG&E workpapers starting at WP 3-785.
[103] Refer to PG&E's DT.

- Many segments that did not have pressure test duration in the GIS database were deemed to have complete pressure test records by the MAOP validation project. The records for these segments should be reviewed.
- For each project, PG&E should determine and report the "pigability" of the lines.[104] This will allow accurate determination of which segments to replace, hydrotest, or ILI.
- This project begins with three segments totaling 1,396 feet of Class 1 lines that do not require replacement. These lines are all same diameter, and with adjacent sections, so there is no obvious impediment to ILI. The north end of the line could be fitted with a permanent pig launch port and test head in a separate dig, and a pig receiving port could be installed at the south end, which would be excavated as part of the replacement project. An ILI could be performed, and the three segments hydrotested when the replacement segments were tested, at a much lower cost than replacing them.
- The first two sections, 101 and 101.3 are classified by Gulf as "highly-congested."[105] Comparing the image of this line on WP 3-583 with a detail on Google maps, these segments appear to be non-congested. The fact that they are listed as Class 1 in the PSEP Database tends to support this observation. This is a moot point if these sections are hydrotested per above, but this discrepancy appears to causes Gulf's current estimate to be erroneously inflated.
- The bulk of Line 21F is 12.75" diameter, but PG&E proposes to replace the north end of the project with 16" line. Since Gulf's cost model assigns a

[104] Pigable refers to a pipeline that can be inspected using a smart pig for ILI. A pipeline must have certain characteristics before ILI is possible, relating the bends, changes in OD, and other obstacles in the line which prevent the passage of a smart pig. DRA seeks a catalog of these impediments to ILI.

[105] Gulf classifies each segment as non-. Semi-, or highly- congested. See PG&E Testimony at pp.3-42 to 3-45. Note PG&E does not explain if or how these classifications relate to HCA classifications.

lower costs for 12.75" line, this upgrade adds a significant cost. PG&E should document why this section of the line, and all OD upgrades suggested by PG&E, requires a large OD to justify this cost increase.

- Over 10,000 feet of line, nearly half of the replacement project total, was installed after 1960, but test records are incomplete. All but 20 of these were installed after 1971. PG&E shareholders should pay for these replacements since strength test recordkeeping requirements were clearly established by CPUC GO 122 in 1960[106]
- For the Novato section of the replacement project, segments from MP10.84 to 11.73, are directly adjacent to the majority of the hydrotest project, MP 11.73 to 13.92. By coordinating the hydrotest project with the post-replacement hydrotest on the replacement project, as least half of the fixed costs ($215,000) should be avoided, and other efficiencies should also be gained.
- Segment 125, which constitutes the bulk of the Novato section of the replacement test, is classified by Gulf as highly congested. Google maps images seem to indicate the northern end of this line, around the intersection of San Marin Drive and Redwood Blvd., is actually semi-congested.
- For the hydrotest section between Novato and San Rafael, MP 11.73 to 13.92, most of the segments were hydrotested after installation, primarily in 1982 or 1983. Only 3% of the footage in this section has complete test records. PG&E should pay to test these sections. A similar situation exists for the most of the San Raphael replacement portion of the line.

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[106] These dates relate the dates of state and federal pipeline safety standards. DRA believes that PG&E should also be liable for pipeline installed or tested prior to 1960, as discussed in Section 6 of this exhibit, and Exhibit DRA-2.

- In the southernmost section of this line, a hydrotest segment is located immediately adjacent to a replacement project. As above, this section should be tested as part of the replacement project.
- The southernmost segments on the line, 153, 153.5, and 154 have DT outcomes C5 or C6 and don't require replacement or even hydrotesting in Phase 2. These segments should not be included in Phase 1, certainly not replaced. If PG&E can provide a compelling reason, these segments could be hydrotested as part of the post-replacement hydrotest of this section of the line.

DRA did not calculate the total cost impact of these findings, but can do so if requested. In summary, the review of line 21F showed that:

1. PG&E did not attempt to coordinate replacement and hydrotest projects for the line. As such, it missed opportunities to reduce costs
2. PG&E planned to replace segments that did not require Phase 1 action, and some which did not require hydrotesting
3. Gulf overestimated the congestion class for some sections, leading to an inflated cost estimate
4. A significant portion of Line 21F was hydrotested after installation, in most cases after 1970. In most of these cases, PG&E does not have complete test records. PG&E's process for allocating costs for "post 70" pipelines did not capture this, resulting in an erroneous request for ratepayer funding
5. PG&E proposed to enlarge the OD for part of the replacement project, but no reason is provided in the testimony, and there is no clear technical reason given the size of the balance of the line. Since enlargement will significantly increase replacement cost, PG&E should provide a justification

6. PG&E should investigate and report the "pigability" of lines before assigning non-priority segments to Phase 1 projects, if this is the reason for replacing them

4.5.2 Review of PG&E projects on Lines L101 and L109

DRA discovered that PG&E's hydrotest costs include $22.6 million for a so-called "peninsula adder" which is added to six projects. This adder is not discussed in the testimony or in the narratives for each project in the workpapers. The only indication of this adder is in one line in six of the nearly 350 individual spreadsheets for each project in the workpapers.[107] When asked to explain the purpose of this adder, PG&E responded:

> "The adder increases the cost forecast of the five L-109 pipeline replacement projects by $200/foot. The L109_1 project was the first PSEP Pipeline Plan pipe replacement project to be initiated in 2011, with the engineering and job estimate completed and a portion of construction completed in 2011. The L109_1 job estimate (based on detailed estimate based on sites visits, detailed permitting and routing discussions and securing of third-party facility information) exceeds the L109_1 rate case estimate by over 30% when contingency is removed from both estimates. The $200/foot adder was created to increase the rate case cost estimates of the L-109 projects (the major PSEP Pipeline Plan pipe replacement projects on the Peninsula) to reflect the high cost of pipe replacement on the Peninsula. The congestion, lack of third-party utility records, and permitting are just a few of the cost drivers that PG&E believes will increase replacement costs on the Peninsula above those in other areas within PG&E's system. The adder also covers higher than estimated costs

[107] For example, see page WP 3-44 and look for a $18,000 cost. DRA only noticed the magnitude of this adder by noting a $20+ million variance when calibrating its models.

due to the long length of the L-109 project replacement, traversing through numerous cities, counties and San Francisco Public Utilities Commission land, as well as permitting of numerous creek crossings and compliance with the California Environmental Quality Act. The adder allowed the rate case estimated costs for the L-109 pipeline replacement projects to reflect these additional cost drivers. The adder reflects expected costs and is not a contingency item. These issues are not expected to affect the other PSEP Pipeline Plan work as significantly, and therefore, the adder was not applied to any other PSEP Pipeline Plan projects."[108]

This response is inaccurate because it fails to note that this adder was also applied to a sixth test on Line 101.[109] When asked to "Provide all workpapers which show and describe how the $200/foot adder was derived, PG&E responded:

"See response to part (a). The $200/foot adder was identified in the L109 workpapers on pages WP 3-68, WP 3-72, WP 3-76, WP 3-79, and WP 3-82. The adder was not calculated, but was created as a result of the refined cost estimate work performed on the L109_1 pipeline replacement project vs. pipeline modernization cost estimating basis."[110]

Thus, even when directly asked, PG&E was unable to provide support for this adder. We do not know why the cost is applied on a per foot basis, nor what is so unique about the Peninsula or SFPUC land compared to similarly dense regions in PG&E's service territory.

[108] PG&E response to data request DRA 33 Q1a.
[109] See PG&E Testimony at WP 3-44.
[110] PG&E Response to data request DRA 33 Q1c.

4.5.3 Review of PG&E projects on Lines L103 and L108

BEAR reviewed these two projects, as discussed in Exhibit DRA-6, Section 6. BEAR also reviewed approximately 20 other projects and found their quality to be similar to L103 and L108, which were randomly selected. For Line 103, BEAR found:

- Applying the revised BEAR DT reduced the mileage replaced by over 25%
- Mismatches in the congestion class within the PSEP
- Misclassification of the congestion class by Gulf
- An "all-in" cost savings of 61% when adjustments were made for all anomalies

For Line 108, BEAR found:

- Application of the revised BEAR DT *more than doubled* the mileage replaced
- Misclassification of the congestion class by Gulf
- The entire line is 16" OD currently, but PG&E proposes replacement with 24" OD line, which significantly increases the cost estimate

4.5.4 Review of PG&E projects on Lines L111 and L118

DRA discovered many anomalies for these two lines while calibrating our cost models. First, it was noticed that for Project L-118A REPL (WP 3-101) proposes to replace existing 8" and a 12" pipe with 24" diameter pipe. PG&E stated that:

> "[t]he reason for the significant increase in pipe size is to serve increasing gas customer demand from Fresno to Modesto along the Highway 99, L-118 gas transmission corridor. PG&E developed a gas transmission

capacity plan for the Central San Joaquin Valley. That plan required several new pipelines to be constructed southwest of Fresno."[111]

DRA later asked for a copy of the referenced plan, to which PG&E provided only two confidential powerpoint presentations prepared in 2007 and 2009 that offer minimal details for this multi-million dollar project.[112]

It was also discovered that PG&E has included relocation of Lines L118 and L111 in the same area, even though PG&E's Testimony says new lines will be installed adjacent to existing pipelines.[113] This project is revealed only by a single large number in one cell of one workpaper.[114] When asked, PG&E responded that this was part of the same plan referenced above, and provided a drawing dated December 1, 2011, many months after the PSEP Pipeline Plan was filed.[115] PG&E's response correctly notes that 15,000 ft of line were removed from project L-118A, and the same amount was added to project L-111A. However, it fails to address the fact that the footage removed was at a lower cost than the footage added, resulting in a net $5 million cost increase.[116]

4.5.5 Other findings regarding particular projects

- L-132_1 TEST: Many segments requiring replacement based on an F2 DT outcome were included for hydrotest, also a couple of M2 segments

[111] PG&E response to data request DRA 26 Q8.
[112] PG&E response to data request DRA 37 Q1. In response to another portion of this question, PG&E stated that "[n]o other upgrade plans exist that include the projects identified within the PSEP Pipeline Plan."
[113] PG&E Testimony at p.3-51 states "[i]t was assumed that all new pipeline replacement projects would be installed adjacent to existing pipelines and by widening ROWs, easements and staying with franchise areas. However, local cities, counties, permitting agencies and property owners may challenge the routing and location of new gas pipelines, which could significantly increase overall project length, constructability and cost."
[114] See WP 3-85 and look for an anomalous entry of "15000." This number was manually entered in the spreadsheet. This error was also discovered while calibrating DRA's models.
[115] Response to data request DRA 26 Q9, Attachment 1.
[116] This is discussed in greater detail in Section 5.3 of this exhibit.

- L-1181: PG&E acknowledged that the PSEP Pipeline Plan erroneously proposed to increase 6 5/8" and 12 ¾" sections of the line to 24" OD, thereby increasing the cost[117]

4.5.6 Summary of sample project review

Overall, DRA finds that the unsupported inclusion of segments in Phase 1 projects provides one of the most compelling reasons to reject the proposed PSEP Pipeline Implementation Plan.

- It is necessary to review all segments in a project (e.g. replacement), and in other types of projects on the same line (e.g. hydrotest) to determine if a project is correctly defined
- Many sections are enlarged (larger proposed OD), but no justification is provided
- Gulf's estimate of congestion is often too high
- Errors were found in the pipeline segment database
- In many cases, mitigation for a large number of segments is driven by the classification of a single segment. In some cases, this segment classification is marginal
- PG&E seeks ratepayer funding to retest lines previously tested to subpart J, but where they lost the records

4.6 Cost adjustments based on changes to the decision tree and PSEP Pipeline Implementation Plan

The following cost adjustments were implemented in both DRA's replacement and hydrotest cost models, in addition to other adjustments described in Sections 5.5. and 6.4. The overall impacts of DT changes, provided in Table 17, were not

[117] Response to DRA 26 Q 8.

calculated separately from these other cost adjustments, but can be calculated upon request by the CPUC.

BEAR's revised DT resulted in a modified PSEP Pipeline Implementation Plan which eliminates many of PG&E's projects, significantly modifies others, and adds new projects. DRA estimated cost adjustments based on BEAR's revised DT. For Phase 1 replacement, DRA essentially created a modified and simplified PSEP Pipeline Implementation Plan to allow a reasonable model run using the revised segment lists as follows:

- Where the BEAR DT eliminated all segments from a PG&E project, the project was eliminated,
- PG&E project costs were recalculated based on the segments retained, within the project, where at least one segment was retained,
- New segments were assigned to new projects based on the facility type for the segments,

In addition, the schedule represented by PG&E's project operational dates (Ops Dates) became outdated and invalid using BEAR's DT. This required an assumption, included with other assumptions in Section 4.4.1.

DRA did not attempt to perform a project level analysis where new segments were added to Phase 1 replacement or hydrotest, but rather grouped new segments together by facility type.[118] DRA's model using BEAR DT outcomes eliminated 103 of the 168 replacement projects defined by PG&E, while adding 6 new projects. These new replacement projects include 21 miles of new segments, and segments which were formerly included in PG&E's hydrotest projects.[119] At the

[118] Ideally, each new segment would be compared to the segments in existing projects on the same line and a decision would be made to add the segment to the existing project based on proximity or other factors, or grouped into a new project.
[119] These segments are described in PG&E's response dated 1/6/2011 to data request DRA 45 Q10.

same time, DRA's model using BEAR DT outcomes eliminated 21 of the 168 hydrotest projects defined by PG&E, while adding 8 new projects. These new hydrotest projects include new segments totaling 41 miles, and segments formerly included in PG&E's replacement projects.

For both models, these new project lists induce unknown cost variances since they do not represent actual projects that could be implemented. For example, new segments in DRA project "new-LT-REPL" includes local transmission (LT) segments on lines 021H, 111A, 118A, and 210A which are not in close proximity to each other, and would not be included in the same project. For this project, actual costs will likely be higher than DRA's estimate, since fixed costs will be incurred for each project. However, the new projects also include many segments which might reasonably assigned to an existing project. Moving new segments to an existing project would result in a reduction in costs compared to DRA's estimate. Overall, the net cost could be higher than DRA's calculated value in Table 5.1 if more than 14 projects are required for new segments not absorbed into existing projects, if more moves are required, or based on the need for road bores or excavation requiring horizontal directional drilling (HDD).

In addition to implementing BEAR's DT, DRA also eliminated the Peninsula adder described in section 4.5.2 because the need for it was not adequately established.

4.6.1 Assumptions

DRA's models were modified to accommodate BEAR's revised PSEP Pipeline Implementation Plan. For segments retained, all data used in PG&E's cost estimate was used. For segments added based on the BEAR DT, the replacement model was modified as follows:

- The actual OD was used to estimate costs, since there was no proposed OD

- All segment footage was classified as "semi- congestion"
- No HDD or Road bore adders were assigned to these segments,
- No move adders were assigned to these segments
- A Mob/Demob adder of $95k was assigned to each of the new projects
- Escalation was calculated using an OpsDate of 12/1/2013
- New project names were assigned based on facility type (e.g. backbone (BB) or distribution main feeder (DFM))

The hydrotest model was modified as follows:

- No move adders were assigned to these segments,
- Mob/Demob adder of $500k was assigned to each of the new projects,
- Escalation was calculated using an OpsDate of 12/1/2012,
- New project names were assigned based on facility type (e.g. backbone (BB) or distribution main feeder (DFM)),

5 Cost Models and Unit Costs

5.1 Gulf Cost models and project costs

PG&E's estimates for project costs are generated by three models developed by Gulf, one each for replacement, hydrotest, and ILI.[120] Each of these models is an Excel spreadsheet which applies the unit costs listed on pages 3E-13 and 3E-16 of PG&E's Testimony to the pipeline segments included in the 341 Phase 1 projects. Each model has a tab with the full detailed PSEP Pipeline Implementation Pla , including all 25,076 segments, and a tab representing each project. Each project tab pulls data from the PSEP Pipeline Implementation Plan

[120] DRA prioritized the review of these models, and was not able to perform a detailed review of the ILI model.

tab, and from other files. Each project tab has the format provided in the workpapers, at WP 3-9 for example. The models do not provide cost calculations at the segment level, for reasons to be discussed. They also do not provide summary information in aggregate, for all replacement projects as an example.

Most costs are particular to the type of mitigation and the model used, so these will be discussed separately. However, some costs are applied consistently across all models, including the following:

1. Customer outreach is estimated by applying a 2.9% adder to the project costs
2. Project management is estimated by applying a 2.5% adder to the project costs
3. Escalation is applied on top of project costs and the customer outreach and project management adder. Escalation is calculated semi-annually, and applied based on the Ops_Date for the project
4. "Post-70" costs to be funded by PG&E shareholders are calculated as a last step (as described in Section 6)

5.1.1 Segment data estimated by Gulf for use in their cost models

For the replacement projects in particular, additional information on segments was required by Gulf's model, including data on the population congestion at each segment location, and information on the type of excavation required:[121]

[121] Hydrotests also required segment level information on the number of tests performed within a project, but this data is not shown in the figure.

- Estimates of population density/congestion[122] (replacement only)
- Estimates of special excavation requirements (road bores or horizontal directional drilling (HDD) (replacement only)
- Estimates of how equipment will be moved during the project (replacement only)
- Estimates of the number of tests per project (hydrotest only)

PG&E described how the data on replacement projects was estimated in response to a DRA data request:

> "Gulf's engineers utilized a Geographic Information System with aerial photography, road maps, and bodies of water/water ways overlaid with the PG&E gas transmission system to determine need and distance for bores, auger or HDD, and the congestion type for estimating and work planning."[123]

The criteria used by Gulf engineers are also provided in this response. For replacement projects, Gulf assigned each foot of each segment to one of the three defined congestion classes, and estimated the footage of special excavation required for each segment. Note that there are 186 miles and 3,396 segments planned for replacement, and each of these had to be reviewed in this way. Continuing the Line 220 example, this estimated data was added to the PSEP Pipeline Plan database, as shown in columns Y to AB below: [124]

Figure 7 - Example of PSEP Pipeline Plan database, Gulf estimated segment cost data added

[122] See PG&E Testimony, p.3-42.
[123] PG&E response to data request DRA 26 Q7
[124] Columns E-P not shown in this figure.

	A	B	C	D	R	S	T	U	V	W	X	Y	Z	AA	AB
1	ROUTE	SGMNT_NO	MP1	MP2	MAOPrec430	Sub_J624 11	DT_Ref_ Num	Prj_Type	GIEPrjNum	OPDATE	Prop_OD	Non Cong	Semi Cong	High Cong	Total Bored
2	220	133.9	22.11	22.14	Complete	Y	C7	REPL	L-220REPL	12/1/2013	10.75	0	193	0	150
3	220	134.2	22.14	22.17	Incomplete Record	N	F2	REPL	L-220REPL	12/1/2013	10.75	0	0	154	154
4	220	134.5	22.17	22.17	Incomplete Record	N	F2	REPL	L-220REPL	12/1/2013	10.75	0	0	5	0
5	220	135.5	22.17	22.17	Incomplete Record	N	C3								
6	220	136	22.17	22.31	Partial Mileage	N	C3								
7	220	136.3	22.31	22.35	Partial Mileage	N	C3								
8	220	137	22.35	22.41	Complete	Y	C6								
9	220	137.5	22.41	22.58	Complete	Y	C6								
10	220	137.77	22.58	22.73	Complete	Y	C5								
11	220	138	22.73	22.85	Complete	Y	C6								
12	220	138.5	22.85	23.10	Complete	Y	C5								
13	220	139	23.10	23.15	Complete	Y	C6								
14	220	139.5	23.14	23.15	Incomplete Record	N	M4	TEST	L-220TEST						
15	220	140	23.15	23.37	Partial Mileage	N	C3	TEST	L-220TEST						
16	220	141	23.37	23.89		N	C1	TEST	L-220TEST						

5.1.2 Summary of PG&E's replacement cost model

The replacement model includes the following unit costs that apply at the segment data discussed above, and vary directly with the length of pipe:

- "All-in" costs
- Road bores
- HDD

"All-in" cost in a misnomer since it only account for 80% of replacement costs (See section 5.2.) This "all-in" cost is assigned to each segment based on both congestion classification estimated by Gulf, and the OD proposed by PG&E. Road bores and HDD vary only with the proposed OD. The Gulf model applies one of 12 "all-in" unit costs, one of five road bore costs, and one of five HDD costs to each segment.[125]

In addition to these variable per foot costs, Gulf assigns two costs for each project, based on the largest diameter segment in the project: a "Move around charge" and a "Mob/Demob" charge. Neither of these are defined in the testimony or workpapers. These fixed costs add from $60,000 to $145,000 to each project,

[125] Since a segment may not have a road bore or HDD, there are five possible unit costs for each, including zero. See page 3E-13 of PG&E's Testimony.

depending on the size of the largest proposed pipeline segment. Note that the fixed per project cost increases substantially if PG&E proposes increasing the size of even a single segment in the project.

5.1.3 Summary of PG&E's Hydrotest cost model

The hydrotest model includes only one unit cost that is applied to each segment and varies with length: the "all-in cost". This "all-in" cost is even more of a misnomer in this instance, since it only accounts for 44% of hydrotest costs (See Section 5.2, Figure 9.) The hydrotest "all-in" unit cost varies only the actual OD, not with congestion class.[126]

Two additional unit costs are assigned at the segment level, but implemented at the project level: "Move Around costs" and "test header charges". PG&E's hydrotest project often include multiple test section which typically are not connected, and might be located many miles apart.[127] In these situations, two new access holes for each additional test section and another 8 hour pressure test must be performed. For some costs, like excavation and shoring, it is as though a separate test is performed. For other costs, like water supply and treatment and equipment moves, the costs should be much lower. As such, move-around costs should be lower than Mob/Demob costs.

Gulf assigns a move around cost ranging from $200,000 to $500,000, depending on pipe diameter, to each move within a project, and a flat $500,000 Mob/Demob cost for each project.

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[126] PG&E did not assign proposed ODs to hydro projects, since the lines are not replaced.
[127] See Section 5.4 of this exhibit for a discussion of "leaf-frogging."

In addition, Gulf assigns a $15,000 to $40,000 adder to each move for test heads.[128] DRA asked PG&E:[129]

> "PG&E appears to be requesting between $15,000 - $40,000 for temporary test heads for each pressure test performed, and then disposing of them. Explain if DRA's interpretation is correct, and why PG&E is not using existing permanent test heads, or building additional permanent test heads?"

Rather than providing a direct answer to this question, PG&E responded:

> "PG&E uses both permanent test heads and temporary test heads to complete the hydrostatic testing work. Permanent test heads are used on the ends of the tests where there is typically a large work space, water injection or removal equipment, and pressure testing equipment attached to the test heads. Permanent test heads are transported and used throughout the system to hydrostatically test new and existing pipelines. Temporary test heads or test-caps are used to seal off the various taps or branch connections that are tested either with the mainline, sometimes independently of the main line, or in locations where excavation space only allows for temporary piping and test heads. Per PG&E Standard A-37, temporary test heads may only be used a maximum of 3 times if the test pressure exceeds 72% SMYS of the test head or test cap. The temporary test heads must then be destroyed."

See Section 8 for further discussion of test header costs.

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[128] For a general description of test heads, refer to the presentation from May 6, 2011 Educational Symposium on Hydrostatic Testing of Natural Gas Pipeline, p.41, available at http://www.cpuc.ca.gov/NR/rdonlyres/1A47C67C-4398-49CA-B52A-A8B5CD13457B/0/HydrostaticTestingSymposiumPresentationMaterialsversiontopost.pdf

[129] PG&E response to data request DRA 26 Q3.

To implement move around costs and test header costs, Gulf reviewed all segments in a hydrotest project and inserted a "1" value where a line was not contiguous. The hydrotest model counts all the values in the filed for each project, and multiples it by the unit move around and test header costs to get the total cost per project.

The difference between the move around and Mob/Demob unit costs for replacement vs. hydrotest is striking and lead to the following data request question:[130]

> "Hydrotest project Mob/Demob cost of $500k appears high compared to PG&Es estimated Mob/Demob for replacement projects, which range from $45k to $95k per project. Explain the reason these cost estimates are so different."

PG&E responded:

> "Both cost estimates were derived from models used to predict future costs of pipeline projects based on the aggregate totals of previous projects. Although both line items are called "Mob/Demob costs," they are not the same, and an apples-to-apples comparison cannot be made. The Mob/Demob cost of $500K for hydrotest work represents the fixed costs of performing the entire hydrotest, regardless of line length or diameter. This estimate covers the fixed price for the strength test, pipe cleaning, water handling/storage/disposal, bell-hole excavations, and drying of the pipeline, all of which takes approximately 3 to 5 weeks to complete. The Mob/Demob costs for the pipe replacement projects represent the movement of excavation, welding, and pipe movement equipment and man power to and

[130] PG&E response to data request DRA 26 Q6.

from the project site. All the other variables of completing the pipe replacement are including in the construction price per foot, and not in the "Mob/Demob" line item."

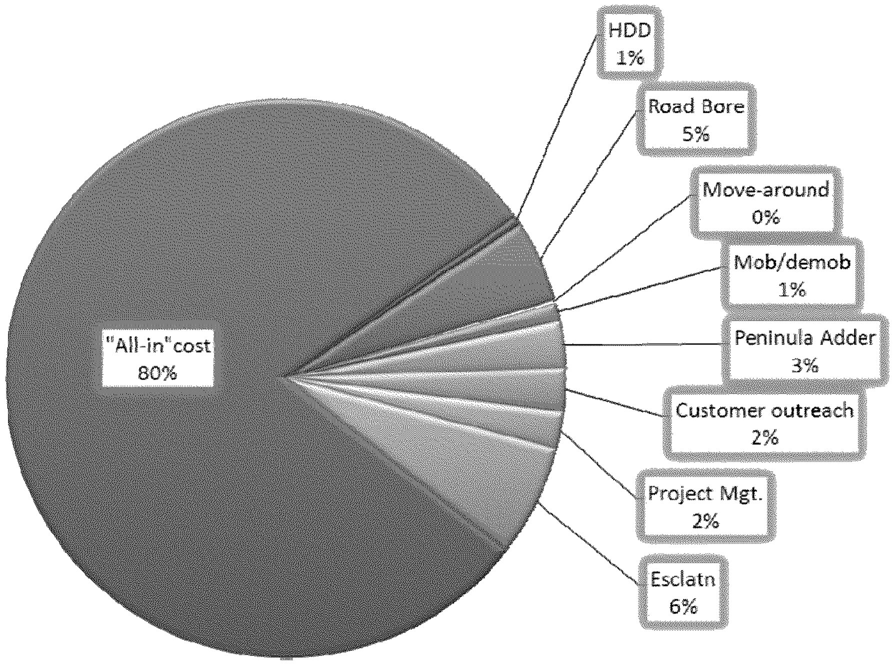
As discussed by Delfino Engineering in Exhibit DRA-5 and BEAR in Exhibit DRA-6, this description overlaps with descriptions of Gulf's "all-in" cost, and made it difficult to determine if Gulf is double counting costs. DRA has issued a data request question seeking further clarification of this issue.[131]

5.2 Cost drivers in PG&E's cost estimate

DRA was able to calculate the share of total project costs generated by each major element of Gulf's model. For replacement, the variable "all-in" cost per foot leads to 80% of the costs, dominating all other costs:

[131] Pending data request DRA XX, TCR 27, issued on January 31, 2012. (Note that DRA issues data requests in this proceeding numbered based on the originator's initials, and PG&E then assigns sequential "DRA XX" numbers.)

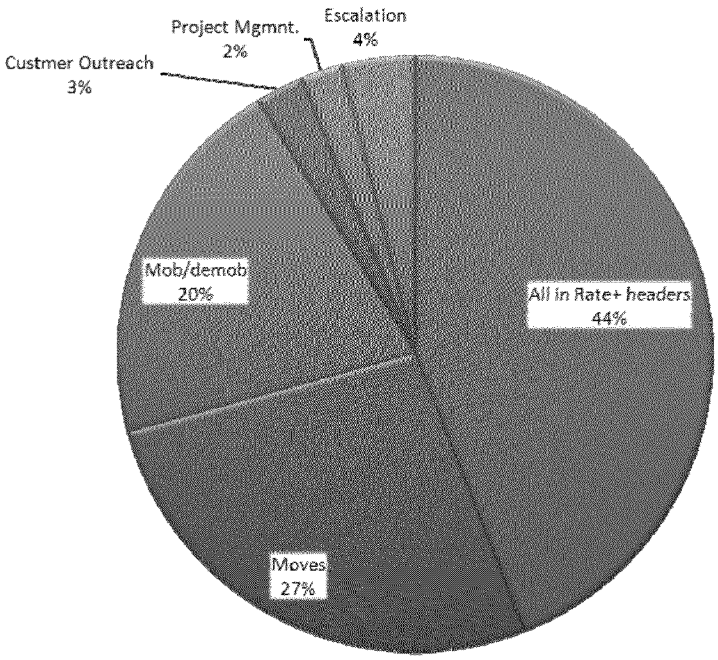
Figure 8 – PSEP Pipeline Plan pipeline replacement cost drivers[132]



[132] Chart developed by DRA using data provided in attachments to PG&E response dated 11/4/2011 to data request DRA 16 Q1.

For hydrotests, costs broke down as follows:

Figure 9 – PSEP Pipeline Plan hydrotest cost drivers[133]



This figure clearly shows that for hydrotest, variable "all-in" costs is still the largest cost driver, but fixed project level costs, moves and Mob/Demob, combine for an even larger impact.

5.3 Replacement Project unit costs

Given that variable "all-in" costs per foot are responsible for 80% of PG&E's cost request for replacement, DRA analysis focused on these costs. Exhibit DRA -5 provides a "bottom-up" calculation of these costs based on a detailed analysis of the major elements of pipeline replacement, namely the pipe material, welding, trenching, and indirect costs.[134] Each of these elements includes both labor and materials, and PG&E's indirect costs were used. Table 11

[133] Chart developed by DRA using data provided in attachments to PG&E response dated 11/4/2011 to data request DRA 16 Q1.
[134] A "bottom-up" analysis determines and calculates values for elemental variables, and sums them to get a total value. In contrast, a "top-down" starts with a high-level or aggregate value, then attempts to separate the impact of the elemental variables.

shows how these costs combine, and show the derivation of the Delfino Engineering costs for non-congested areas:

Table 11 – Example of Delfino Engineering pipeline replacement cost elements

Non-Congested Areas					
Pipe Size Range	Pipe & Coating	Welding	Trenching	Indirect Costs	Total
10"	$33	$5	$47	$37	$122
16"	$73	$11	$72	$54	$210
24"	$163	$25	$112	$86	$386
36"	$364	$55	$180	$154	$753

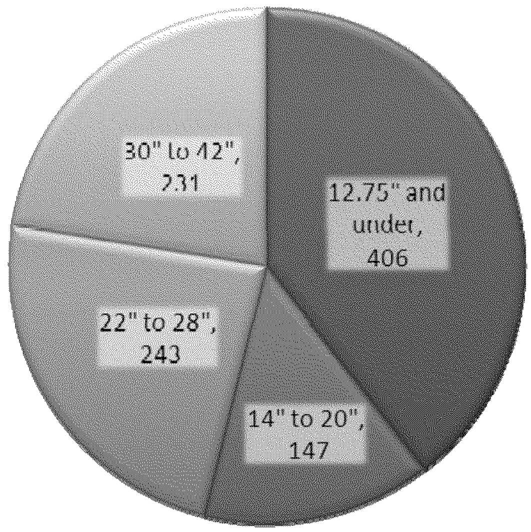
These calculations were performed for the three congestion areas used in Gulf's cost models, and also by DRA, as summarized below:

Table 12 - Summary of Delfino Engineering pipeline replacement " All-in per foot" unit costs

Pipe Size Range	Non-Congested Areas	Semi-Congested Areas	Highly Congested Areas
10"	$122	$242	$400
16"	$210	$383	$610
24"	$386	$650	$985
36"	$753	$1,170	$1,678

Exhibit DRA-5 shows that on average, these costs are 30% lower than PG&E's. In addition, Delfino Engineering's costs are very close for (93% to 94%) for large pipelines, but the error increases as the size decreases, and is 43% to 51% lower than PG&E's for the smallest pipe sizes. DRA reviewed the pipeline sizes for lines classified by PG&E as HCA and found that the average size, weighted by miles, is 19.8". Alternatively, grouped by PG&E size groupings:

Figure 10 – Mile of PG&E DOT classified transmission pipeline per PSEP Pipeline Plan size group



Based on this information, the actual reduction from using Delfino Engineering "all-in" costs results in a reduction of more than 30%.

It is important to note that Delfino Engineering calculations are self-classified as "conceptual cost estimates" which are consistent with industry practice and represent a conservative estimate that could be as much as 40% higher than actual costs. In other words, they represent an upper bound of costs, based on the analysis of Delfino Engineering.

Exhibit DRA-6 reviews two studies on pipeline replacement costs summarized in Table 5 of that exhibit, which is reproduced here:

Table 13 – Summary of BEAR research on pipeline replacement "all-in"costs

	Non-Congested	Semi-Congested	Highly Congested
	UC Davis compared to PG&E		
Diameter		***Average Reduction***	***21%***
10	73%	83%	85%
16	78%	80%	80%
24	76%	78%	79%
36	81%	80%	80%
	PNNL compared to PG&E		
Diameter		***Average Reduction***	***20%***
10	76%	76%	76%
16	80%	80%	80%
24	77%	77%	77%
36	88%	88%	88%

Table 13 compares costs from each study evaluated by BEAR to PG&E's "all-in" costs from page 3E-15 of PG&E's Testimony. The percentage for each combination of pipeline diameter and congestion classification indicates is the study value divided by PG&E's value. The average of these values yields the Average Reduction in grey. Note that BEAR did not include PG&E's contingency request in this comparison, and that if they had, the Average Reductions in this table would be higher.

BEAR recommends using costs derived from Oil and Gas Journal (OGJ) data, which are either UC Davis or PNNL values.[135] BEAR also found that "The

[135] See Exhibit DRA-6.

PNNL study showed that California is not the most expensive area to replace gas pipelines."[136]

5.4 Hydrotest Project unit costs

As with replacement projects, DRA and its consultants focused on reviewing the largest cost drivers first. For hydrotests, this required reviewing fixed move around and Mob/Demob costs as well as "all-in" costs. Exhibit DRA - 5 provides alternatives for each of these costs separately.

For "all-in" costs, Delfino Engineering provided a bottom-up approach as with replacement costs, this time calculating the water needed for the test, and the air needed for line drying for each size of pipeline. Delfino Engineering then applied specific estimated unit costs for water supply, water treatment, "hydrotest" personnel and equipment, and critical equipment like pumps and air compressors needed to dry the lines when the test is completed.[137] The resulting costs, which range from $7 to $33 per foot, are significantly lower than Gulf's estimates of $30 to $59.[138] Delfino Engineering points to two clear reasons why their costs are lower. First, cleaning lines prior to test should be performed as part of routine

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[136] Ibid.

[137] In this instance, "hydrotest" refers to the process of pressurizing the line and documenting that an accurate test was performed. This is a subset of the overall hydrotest process. PG&E provided general hydrotest procedures as confidential attachments in its 10/12/2011 response to data request DRA 10 Q5. PG&E stated " Please note the attachments to this response contain sensitive personal information pertaining to PG&E employees, such as employee names and Lan IDs. For this reason, and only for this reason, PG&E is providing this response pursuant to Public Utilities Code section 583." A test-specific procedure for the failed hydrotest T-117 of PG&E pipeline 300B was also provided as confidential attachment to PG&E's response dated 11/2/2011 to data request DRA 17 Q5, requesting Section 583 treatment for the same reason.

[138] See Exhibit DRA-5.

maintenance, and should not be included in PSEP Pipeline Plan costs.[139] Second, water from one test be reused in the next test.[140]

For fixed costs, Mob/Demob was estimated first by Delfino Engineering using a bottom-up estimate that considers the specific processes, material, and equipment need for the hydrotest. For the cost to excavate each end of the pipeline, Delfino Engineering used a figure supplied by PG&E in response to a question regarding ILI costs, and scaled in for the size of holes required for a hydrotest.[141] Delfino Engineering calculates Mob/Demob costs of $85,600 to $139,400, which are significantly lower than Gulf's costs, which are fixed at $500,000 per test regardless of the line size.

For move around costs, Delfino Engineering started with its calculated Mob/Demob cost, then adjusted downward based on the assumption that PG&E was able to "leap frog" equipment from one test to the next.[142] The resulting cost ranges from $44.7 to $76.7 which are significantly lower than Gulf's costs, which ranges from $200k to $500k. DRA and its consultant have not evaluated how many "move arounds" involve such a leap frog vs. a non-contiguous segment.

Both Delfino Engineering and BEAR note that the analysis of fixed costs was complicated by the lack of clear definition of what was included in the Mob/Demob cost, compared to the move around charge.[143]

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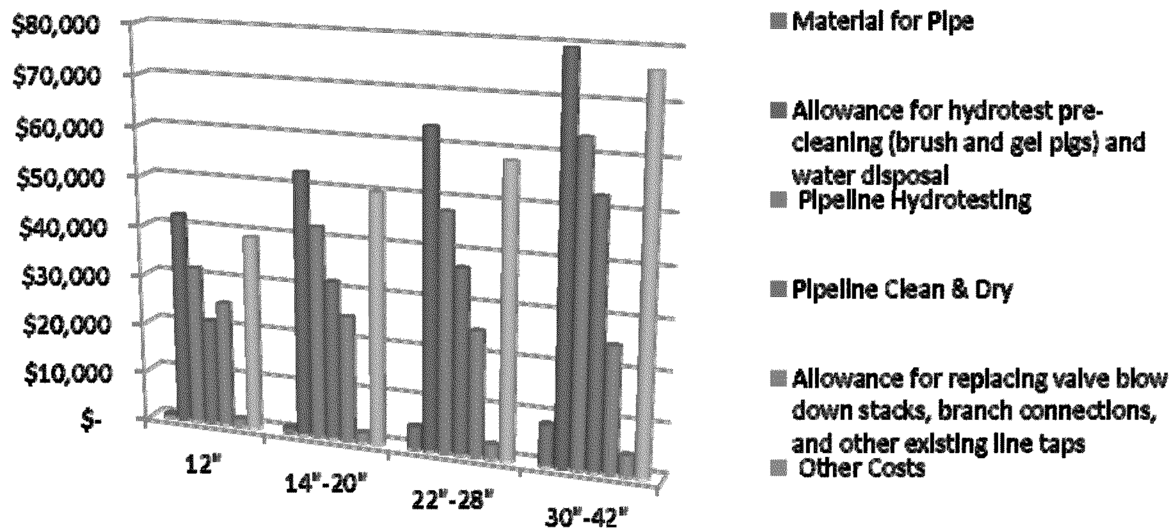
[139] Exhibit DRA-5.
[140] Exhibit DRA-5.
[141] Test heads are a separate line item and not included here. – See section 5.5 of this exhibit
[142] In Exhibit DRA-5, Delfino Engineering discusses how equipment at one end of a hydrotest can be left in place when testing contiguous pipeline sections. For example, if a line is running north to south, equipment from the south end of the first test can be left in place while the equipment on the north end of the first test is "leap-frogged" to become the south end of the second test.
[143] Exhibit DRA-5 and DRA-6.

In Exhibit DRA-6, BEAR provides an analysis of PG&E's hydrotest costs, and a review of studies on hydrotest costs. As shown in Graph 2, reproduced here, the cost of cleaning a line prior to filling it with water is the highest cost component:

Figure 11 – Breakdown of PG&E costs for hydrotesting



In Table 9 of this exhibit, DRA calculated that the average cost of PG&E's cost request for hydrotesting is $624,000 per mile when contingency is included. In Exhibit DRA-6, BEAR reviewed the limited cost data available on hydrotests for comparison to PG&E's request. BEAR found:

1. The median cost of hydrotesting per the American Gas Institute (AGA) is less than $200,000 per mile
2. Costs for long interstate transmission lines range between $58,000 and $124,000 per mile
3. Shorter intra-state transmission line hydrotest costs range between $250,000 and 500,000

BEAR summarizes:

"PG&E's costs for hydro testing pipelines are in the upper range of industry standards and are 150% higher than the median industry cost. PG&E has not sufficiently explained nor justified its higher cost, especially when considering that half of its hydrotests are on small, 12" diameter [or smaller] pipelines. The high fixed cost of mobilization and demobilization ("mob/demob") have been questioned repeatedly, and PG&E's answers have been essentially unresponsive."

In addition BEAR found that there is currently a federal rulemaking in which the costs and benefits of proposed revisions to pipeline safety regulations, but this will not be provided in the current comment period.[144] BEAR proposes conducting an independent study to verify hydrotesting cost data, particularly since hydrotesting will be an on-going maintenance requirement whose cost needs to be managed.

5.5 Cost adjustments based on changes in unit costs

As mentioned previously, DRA calculated costs adjustments using the model described in Section 2.4.1, which is primarily based on the Gulf models. DRA's cost model was modified based on the costs adjustments described in this section, and the adjustments calculated are included in the total cost adjustments provided in Table 17. The overall impacts of these changes were not calculated separately from cost adjustments due to the revised DT, but can be if required. In addition, it was not possible to include some of the cost adjustments recommended by BEAR or Delfino Engineering quantitatively, based on the timing of this filing. These costs including customer outreach, escalation, and test headers are discussed in Section 8 of this exhibit.

[144] Docket PHMSA-2011-0023.

5.5.1 Replacement cost adjustments

First, the Replacement model used by DRA implemented Gulf's model without exception. As discussed in section 2.4.1, specific variances were discovered in PG&E's calculations during calibration, and excluding these exceptions decreased DRA's baseline cost by $29.2 million.

Second, DRA used a set of "all-in" costs recommended by BEAR in Exhibit DRA-6, Table 2 which are reproduced here:

Table 14 - BEAR recommended "all-in per foot" costs for hydrotests

Diameter	Non-Congested	Semi-Congested	Highly Congested
10	$ 214	$ 370	$ 598
16	$ 278	$ 494	$ 784
24	$ 398	$ 648	$ 978
36	$ 704	$ 1,098	$ 1,577

Note: These are 2011 dollars.

BEAR recommended using costs based on OGJ data, which includes both the UC Davis and PNNL studies. DRA used the PNNL numbers rather than UC Davis numbers since they were the first available and the difference between the costs was relatively small.

DRA did not adjust PG&E's road bore, HDD, move around, or Mob/Demob unit costs. This was because DRA did not perform analyses of these unit costs and should not be construed as an endorsement of these unit costs.

Note from Table 17 that the total adjustment for BEAR's revised DT and unit costs reduced PG&E's $843.9 million request to $374.4 million. Based strictly on 76 miles of replacement eliminated by BEAR, and an average 20%

reduction in cost, this figure would be $401.4 million. The difference highlights that costs are highly dependent on line diameter and congestion classification, and that changing the mix of segments in a project or the PSEP Pipeline Plan in whole impacts the aggregated costs.

5.5.2 Hydrotest cost adjustments

As above, the model used by DRA implemented Gulf's model without exception. However, in this case the hydrotest model used by DRA has a baseline cost $6.2 million *higher* than PG&E's.

Delfino Engineering costs were the primary basis of the costs used in DRA's cost adjustments. DRA used a fixed Mob/Demob cost of $160,000 for all pipeline sizes, based on Delfino Engineering's highest cost of $139,400. While developing DRA's cost adjustments, DRA did not fully understand that the Delfino Engineering numbers already provided a "+40% estimate", and scaled up the Delfino Engineering value to be conservative, and to simplify calculations in the DRA hydrotest model. DRA used Delfino Engineerings "all-in" costs as provided, and rounded up the Delfino Engineering move around costs slightly. The following "all-in" and move around costs were used by DRA:

Table 15 – Delfino Engineering recommended "all-in per foot" hydrotest costs

	"All-in" cost per foot	Move around
12.75" and under	$9	$45,000
14" to 20"	$11	$50,000
22" to 28"	$17	$60,000
30" to 42"	$33	$80,000

DRA did not adjust PG&E's test header charge, but believes PG&E's requested costs to be excessive, as discussed in Section 8.

Delfino Engineering has provided a detailed estimate of moving dirt, water, men, and machines to actually perform hydrotesting. Delfino Engineering makes logical assumptions not included in PG&E's estimate that significantly reduce costs. BEAR showed that the cost to clean lines prior to hydrotest is the single largest component of the "all-in" cost per foot, and it is one of the costs specifically excluded from the Delfino Engineering calculations. DRA understands that other costs, such as pipeline clearance, may contribute to the higher costs used by Gulf and PG&E. Since PG&E did not sufficiently define how their costs were derived, DRA used the Delfino Engineering costs in its illustrative calculations. The burden is on PG&E to specifically define anything Delfino Engineering may have missed, and quantify the impacts.

Cost issues raised by DRA in Section 5, but for which cost adjustments were not calculated are discussed in Section 8 of this exhibit.

6 Shareholder/Ratepayer cost allocation

6.1 Overview of PG&E request

PG&E proposes that two groups of costs will be excluded from the ratepayer funding request: mitigation initiated by PG&E in 2011 and mitigation for lines installed "Post-1970 without verifiable records." The later exclusion applies only to replacement and hydrotest portions of the pipeline plan, not ILI, ILI upgrades, or other capital expenditures and expenses.

PG&E states that "[c]osts to strength test or replace any pipe installed post-1970 without verifiable test records have been excluded from PG&E's request for cost recovery in this proceeding."[145] PG&E calculates that a total of $21.6 million has been removed from the cost forecast based on this assertion.[146] PG&E summarizes its calculation method concisely: "The cost associated with pipe replacement of any post-1970 pipe without a verifiable strength test was allocated by multiplying the total project cost by the ratio of footage of post-1970 pipe compared to the total footage within each project."[147] This calculation has two steps. First, PG&E evaluates each pipeline segment included in a replacement or hydrotest project to determine if it is a pipe installed after November 12,1970 without verifiable test records. PG&E used a spreadsheet to apply the following logical test to each of these segments: If "installation date" > 11/12/1970 AND "MAOPrec430" = "Incomplete". Segment footage is classified as "Post-70", and removed from the ratepayer cost request, where this statement is true. Second, for each project, the ratio of post-70 pipeline feet vs. the balance of pipeline footage in the project was calculated, and this ratio was multiplied by the total project cost to determine the portion paid by shareholders. For example, PG&E estimates the total cost of Project L-21FREPL to be $20.449 million to replace 22,397 feet of pipeline. They state that 42 feet meet their criteria for shareholder funding, and calculate that they should pay $38,000 ($20.449*42/22397).[148]

6.2 PG&E shareholder funding for Pipeline Modernization work performed in 2011

PG&E's Pipeline Witness Hogenson states that "The 2011 expenses and capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in

[145] PG&E Testimony, p. 3-65.
[146] PG&E Testimony, p. 3-66. $11.8 million is for strength testing expenses, and $9.8 million is for replacement capital expenditures.
[147] PG&E Testimony, p. 3-66.
[148] PG&E rounds all figures to the nearest $1,000.

Chapter 8."[149] PG&E further states that "PG&E proposes that PG&E shareholders absorb the actual 2011 PSEP Pipeline Implementation Plan revenue requirement for the PSEP Pipeline Implementation Plan work planned for 2011.[150] PG&E requests $32.8 million in capital expenditures and $122.7 in expenses for Pipeline modernization work 2011, all of which should therefore be funded by PG&E shareholders.

PG&E's November report on hydrotesting stated that some of the work planned for 2011 was delayed.[151] PG&E subsequently stated that "PG&E will not seek cost recovery for strength testing and MAOP records validation of Priority 1 pipeline segments (i.e., the approximately 152 miles of pipeline with features similar to the pipe that ruptured in San Bruno) if delayed, for any reason, beyond 2011.[152] This statement does not cover all of PG&E 2011 requests which include ILI upgrades, pipeline replacement, and other expense and capital activities.[153]

6.3 PG&E shareholder funding proposal for "Post-1970 pipelines without verifiable records"

DRA reviewed PG&E's method for allocating shareholder responsibility for "post-70" pipelines by addressing three questions: Is the calculation method reasonable? Is the calculation performed correctly?, and Is the allocation logic reasonable?

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[149] PG&E Testimony, Chapter 3, footnote "a" to Table 3-1, p. 3-6.
[150] PG&E Testimony, Chapter 8, p.8-9.
[151] PG&E report dated November 30, 2011 in R.11-02-011.
[152] PG&E response to data request DRA 38, question 6.b.
[153] See Table 2 of PG&E workpapers, lines 173 to 183, p. WP 3-6; Table 3 of PG&E workpapers, lines 181 and 182, p. WP 3-757; PG&E response to DRA 30 question 10, dated December 9, 2011.

6.3.1 Is the calculation method reasonable?

PG&E's basic method is to use a ratio of pipeline footage to allocate project costs between ratepayers and shareholders. The reasonableness of this method depends on two important features of PG&E's cost models. The first is that both hydrotest and replacement projects have substantial fixed costs which are independent of the pipeline length tested or replaced. PG&E's method allocates these fixed costs in proportion to the variable per foot costs to be paid by shareholders, which is reasonable. The other issue is that for replacement projects, variable costs in PG&E's model are based on whether a segment is in a low, semi-, or highly congested area. PG&E's method lumps all segments together, regardless of the level of congestion. It thus would underestimate the cost responsibility for shareholders in the situation where the segments without records are in congested areas, but the balance of the project is in less dense areas. DRA did not attempt to quantify the potential impact of this simplification by PG&E, particularly since Given that the current PSEP Pipeline Plan includes only a rough AACE Class 4 cost estimate, DRA does not challenge PG&E's calculation method at this time, but instead recommends that PG&E address the feasibility of allocating project costs based on the segments costs, not the segment miles.[154]

6.3.2 Is the calculation performed correctly?

DRA confirmed that PG&E's allocation calculations were accurate at an aggregate level (for all replacement and all hydrotest projects) and for a random selection of projects. This verification was achieved through the calibration runs of DRA's spreadsheets discussed in detail in Section 5.1.1. However, DRA investigated each criterion used by PG&E in the allocation process and found a number of anomalies. For the installation date, DRA first discovered that 1,031

[154] PG&E Testimony, Table 7-3, p.7-25.

segments (12.5 miles) in PG&E's database[155] do not have an installation date, which automatically assigns these costs to ratepayers.[156] Second, we found that for many segments, only the year of events such as installation and pressure testing, were in the database.[157] PG&E's database had 68 pipeline segments which total 5.0 miles with the installation date of "1/1/1970", and these segments were also assigned to ratepayers, since PG&E uses a filter date of 11/12/1970.[158] Third, PG&E determines if MAOP verification records are incomplete using the criteria "MAOPrec430 equals incomplete."[159] PG&E's database provides four possible results in the MAOPrec430 field for MAOP validation:

1. Incomplete,
2. Complete,
3. Partial mileage,
4. No data (blank cell in spreadsheet)

PG&E's PSEP Pipeline Plan includes 915 segments (175.6 miles) listed as "partial mileage" and 1,092 (317.9 miles) segments with blank fields. PG&E's allocation criteria assigns these segments, in addition to those with "complete" records, to ratepayers. Finally, PG&E's database contains other fields that relate to records validation, or other data that might impact cost allocation. In particular, PG&E includes a "test date" field indicating when segments were pressure tested. 2247 segments (512.2 miles) without complete data were installed before 1955, but tested afterwards. These segments are slated by

[155] The statistics in this section relate to the 969 miles of pipeline assigned by PG&E to replacement or hydrotest projects in Phase 1 of the PSEP Pipeline Plan.
[156] DRA query of pipeline data provided by PG&E in response to written data requests.
[157] PG&E response dated 12/8/2011 to data request DRA 30 Q8(a) indicates that the source of GIS data prior to "the mid-1990's" only provided the year.
[158] DRA query of pipeline data provided by PG&E in response to written data requests.
[159] PG&E response dated 12/8/2011 to data request DRA 30 Q8, parts (a) to (d).

PG&E for ratepayer funding. DRA's cost adjustments described in Section 5.4 adjust for each of these anomalies.

6.3.3 Is PG&E's allocation logic reasonable?

Overall, PG&E should pay for mitigation where they have not complied with state, federal, or industry standards. PG&E's selection of November 12, 1970 as a dividing point is not consistent with these standards. In addition, ratepayers should not fund testing through the PSEP Pipeline Plan that repeats previous ratepayer funded pipeline tests, but for which test records are missing, incomplete, or erroneous. PG&E filed a report on MAOP validation dated March 15, 2011 in R.11-02-019. At page 13, the report shows that of the pipelines analyzed and installed before 7/1/1961, at least 31% were pressure tested. PG&E's allocation process fails to account for these tests. In response to the question "[w]hat was the justification for performing these tests?" PG&E responded:

> "Pressure tests were, and are, a means to confirm or test the strength of pipeline segments. PG&E believes that after adoption of American Society of Mechanical Engineers (ASME) standard ASA B31.1.8-1955, PG&E's practice was to follow ASA B31.1.8-1955, including pre-service testing."[160]

DRA also asked "Were these tests funded by PG&E ratepayers or PG&E shareholders?" to which PG&E responded "The testing was part of the pipe installation costs and, therefore, would have been funded by ratepayers."[161]

[160] PG&E response dated 1/6/2012 to data request 45 Q7(a).
[161] PG&E response dated 1/6/2012 to data request 45 Q7(f).

DRA proposes and utilizes alternative allocation logic, as described in the next Section.

6.4 Cost Allocation adjustments

The following adjustments were implemented in both DRA's replacement and hydro cost models, on top of the other adjustments described in Sections 4.6 and 5.1. The overall impacts of these changes, provided in Table 9.1, were not calculated separately from these other cost adjustments, but can be calculated upon request by the CPUC.

DRA's position regarding cost allocation is presented in Exhibits DRA-2 and DRA-9. Treatment of the shareholder allocation of costs incurred in 2011 is discussed in the Exhibit DRA-9. The revised cost sharing discussion in this section is primarily to illustrate how costs should be allocated, if ratepayers are to be responsible for any Phase 1 costs.

DRA adjusted the criteria used to allocate segment costs such that PG&E shareholders are responsible if:

- There is no installation date
- The installation date is after December 31, 1954[162] and the results of MAOP validation do not indicate complete test records OR
- The segment was hydrotested after December 31, 1954 and results of MAOP validation do not indicate complete test records

This is accomplished in the DRA spreadsheets by applying logical tests consistently for each segment. If any of the statements above is true for a segment, the cost to replace or hydrotest the segment is assigned to PG&E

[162] Section 4.3 of this exhibit describes why this date was used, rather than the date ASTM 31.8 was revised.

shareholders. DRA's spreadsheet uses PG&E's "ratio of footage" method to adjust project level costs based on the revised ratio of ratepayer pipeline footage per project to total pipeline footage per project.

DRA utilized PG&E's basic process for allocating costs, but modified the criteria used by PG&E, and added a new criteria. First, PG&E's data was tested to determine if an installation date was present and segments without a date were assigned to PG&E. Second, December 31, 1954 was used as the first filter criteria, rather than PG&E's filter date of November 12, 1970. This December 1954 date was used based on the ratification of American Standard ASA B31.1.8-1955, which established explicit recordkeeping requirements for pressure tests of newly installed pipelines.[163] PG&E indicated that its GIS database only has the year of installation prior to "the mid-1990's", so a filter date at the end of 1954 was selected to capture all pipelines installed in 1955, per PG&E's records.[164] Third, recall that from Section 3.3.2 that PG&E's database provides four possible results in the MAOPrec430 field for MAOP validation:

1. Incomplete,
2. Complete,
3. Partial mileage,
4. No data (blank cell in spreadsheet)

Records for each foot of pipeline have not been verified for segments with blank or "Partial Mileage" entries in the MAOPrec430 field.[165] DRA's criteria

[163] Per section 841.417. Additional details in the Testimony of DRA Witness Pocta, Exhibit DRA-2, Attachment A.
[164] PG&E response dated 12/8/2011 to data request DRA 30 Q8(a).
[165] In response to DRA 38 Q7.c, PG&E provides the following definition: The term "Partial Mileage" is defined as a complete strength test report that has been located for the pipe segment, but the footage in the document does not match the footage in GIS, as-builts, or other record information. Further documentation review will be required to resolve these discrepancies.

provides the same outcome as PG&E for the first two results. However, costs for segments where MAOP results were not given, or where they indicate "Partial Mileage", are assigned to PG&E shareholders using DRA's criteria. This is the correct assignment given the current data provided by PG&E, since segments with results 3 or 4 above cannot be considered as fully validated. As PG&E updates the results of the MAOP validation project, missing or "partial" results will be reduced, and ideally eliminated, and this difference should become moot, but the burden to demonstrate adequate records lies with PG&E.

DRA added a second allocation criterion to account for those segments which were hydrotested after ASA B31.8-1955 was adopted. Segments with a test date after Dec. 31, 1954 and MAOPrec430 not equal to "complete" were assigned to PG&E.[166] Since industry best practices, as codified in ASA B1.1.8-1955, required retention of pressure test records, and PG&E has stated that these tests were previously funded by ratepayers, ratepayers should not be required to pay twice to pressure test the same segment.[167]

DRA assigns segment costs to PG&E shareholders if either the installation or test date criteria above indicate a "true" result. This process was used on both replacement and hydrotest projects.

Using DRA's revised shareholder allocation and the BEAR DT, ratepayers pay 95% of the cost for replacements, primarily because the segments were installed prior to 1955. For hydrotest projects however, PG&E shareholders should be funding nearly 75% of the costs.

[166] For this criterion, blank entries in the test date field did not impact the outcome.
[167] PG&E response dated 1/6/2012 to data request DRA 45 Q7(f).

7 Contingency request

7.1 Summary of PG&E Request

In Chapter 7, PG&E discusses the uncertainty embedded in their baseline estimates included in Chapter 3, and provides a request for $380.5 million in overall contingency. DRA acknowledges that the CPUC has previously adopted contingency budgets for other PG&E projects, and does not dispute the need for a contingency budget for the PSEP Pipeline Plan. However, DRA does not believe PG&E performed a contingency analysis as described in their testimony.

There are uncertainties in key elements of PG&E's PSEP Pipeline Plan, beginning with the data used by the DT through to the allocation of estimated costs between ratepayers and shareholders. These uncertainties create risks that the costs actually incurred by PG&E and ratepayers will vary from the baseline estimates, whether the baseline was calculated by PG&E, DRA, or any other party. One method used by the CPUC to account for this risk in ratemaking is to calculate a contingency budget. PG&E's Testimony describes the key elements of quantitative risk assessment, which includes:

- Determining key cost drivers in the baseline estimate.
- Estimating the uncertainties for each cost driver.
- Applying a probabilistic model to run scenarios, such as one cost driver being at 50% while others are at 75%.
- Determine a contingency rate based on the risk of overspending the adopted budget.

This analysis focused on the $251.1 million[168] in contingency budget requested for the replacement and hydrotest portions of the PSEP Pipeline Plan, since it represents the contingency request for the majority of the baseline costs shown in

[168] The difference between this figure and the $270.7 in Table 1 of this exhibit is due to other cost elements such as ILI.

Table 7-3 of PG&E's Testimony, but many of the comments in this section also apply to PG&E's overall contingency request for $380.5 million.[169]

7.2 Quantitative Risk Assessment ("QRA")

In Figure 7-4, PG&E lists the Government Accountability Office's (GAO) best practice checklist for sensitivity analysis, which PG&E states is "a key component of conducting Quantitative Risk Assessments."[170]

Figure 12 – GAO sensitivity analysis best practices, as provided by PG&E

10. Best Practices Checklist: Sensitivity Analysis

- ☐ The cost estimate was accompanied by a sensitivity analysis that identified the effects of changing key cost driver assumption and factors.
  - ✓ Well-documented sources supported the assumption or factor ranges.
  - ✓ The sensitivity analysis was part of a quantitative risk assessment and not based on arbitrary plus or minus percentages.
  - ✓ Cost-sensitive assumptions and factors were further examined to see whether design changes should be implemented to mitigate risk.
  - ✓ Sensitivity analysis was used to create a range of best and worst case costs.
  - ✓ Assumptions and performance characteristics listed in the technical baseline description and GR&As were tested for sensitivity, especially those least understood or at risk of changing.
  - ✓ Results were well documented and presented to management for decisions.
- ☐ The following steps were taken during the sensitivity analysis:
  - ✓ Key cost drivers were identified.
  - ✓ Cost elements representing the highest percentage of cost were determined and their parameters and assumptions were examined.
  - ✓ The total cost was reestimated by varying each parameter between its minimum and maximum range.
  - ✓ Results were documented and the reestimate was repeated for each parameter that was a key cost driver.
  - ✓ Outcomes were evaluated for parameters most sensitive to change.
- ☐ The sensitivity analysis provided a range of possible costs, a point estimate, and a method for performing what-if analysis.

DRA agrees that quantifying uncertainty is the first step in quantifying risk and calculating an accurate contingency budget. DRA queried PG&E about how well

[169] PG&E Testimony, Chapter 7, Table 7-10, p. 7-46.
[170] PG&E Testimony, Chapter 7, p. 7-29.

PG&E and its consultants complied with this checklist, and found they did not follow many key aspects described:[171]

- **"The sensitivity analysis was part of a quantitative risk assessment and not based on arbitrary plus or minus percentages."** PG&E's QRA analysis was driven by the use of arbitrary percentages as described in section 7.4 below.
- **"Key cost drivers were identified."** PG&E does not identify key cost drivers in the Gulf cost estimate models such as the diameter of pipelines and the congestion level where they are located.[172]
- **"The total cost was re-estimated by varying each parameter [that was a key cost driver] between its minimum and maximum range."** PG&E provided only an aggregated estimate of uncertainty based on the types of projects, not of the specific uncertainties generated by Gulf's cost models.[173]

7.3 Uncertainty in PG&E cost estimate

PG&E generally classifies the current PSEP Pipeline Plan project cost estimate as an AACEI Class 4 estimate, which according to the AACEI classification standard PG&E provides, is a cost estimate for a preliminary /study stage of project definition.[174] The AACE Classification Standard indicates that actual project costs could vary between -30% to +50% of the baseline costs for Class 4 estimates, and as shown in Table 7-6 of PG&E's Testimony, most project elements of the PSEP Pipeline Plan are considered by PG&E to Class 4.

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[171] DRA asked many questions in data request DRA 52 that are pertinent. Only a few are reflected here.
[172] PG&E response to DRA data request DRA 52 Q6.
[173] PG&E response to DRA data request DRA 052 Q7.
[174] PG&E Testimony, Chapter 7, p. 7-24.

PG&E's QRA analysis treats individual projects as cost drivers, and applies the same generic risk to each type of project, as described in Section 7.4 below.[175] This is not a correct treatment since cost drivers vary by each project. Based on DRA's review of the PSEP Pipeline Plan, uncertainties for which risk should have been quantified include:

1. Incomplete and incorrect pipeline data in PG&E's GIS database
2. Incomplete results for the MAOP validation project
3. Uncertainty in HCA classifications
4. DT outcomes like M1 and F2, which require an engineering evaluation before assigning mitigation
5. Gulf's cost models and unit costs used
6. Gulf's estimates of the congestion for each segment
7. Gulf's estimates of road bores and HDD
8. Gulf's estimates of the number of Move Arounds
9. Allocation of shareholder funding which is based on MAOP results
10. Uncertainty in the availability of sub-contractors to meet PG&E's schedule, and the level of competition for PSEP Pipeline Plan work that could drives costs down

Analyzing the uncertainties is a key to determining the magnitude of risk as well as whether the uncertainties are likely to increase or decrease the actual costs compared to the baseline estimate (i.e., "direction of risk"). The following describes some of these examples in greater detail to show that the direction of some risks is known to lead to either cost increases or cost reductions, while others have symmetric risk profiles, with equal probability of cost increases or reductions compared to the base estimate.

[175] PG&E response to data request DRA 52 Q6 and DRA 52 Q7.

For data uncertainties, PG&E should have evaluated the completeness of the MAOP project data (e.g. the number of blank or "partial mileage" entries in field MAOPrec430), and evaluated how this data impacts both the Implementation Plan and allocation of costs to shareholders. The available evidence indicates that there is significant risk due to data uncertainties, but does not know if the MAOP project will uncover more data errors than PG&E found as of April 30, 2011, or less. Therefore, the direction of this risk is likely symmetric, with a chance that project costs paid by ratepayers could be higher or lower than the baseline estimate.

Risk due to Gulf's estimates of congestion for each segment should similarly be symmetric, unless Gulf deliberately biased their estimates. Gulf reviewed aerial photographs and PG&E's GIS database of pipeline locations to allocate each segment to one of three congestion classes, which drives significant differences in the unit costs used to estimate project costs. Uncertainty could be generated due to errors in the GIS database, changes in the region after the photos were taken, or human error comparing the two data sets. The same is true for Gulf estimates of road bores, HDDs, and move around. Significant risk exists due to Gulf project estimates, but this risk should be symmetric unless Gulf purposefully biased its estimates.

Not all risks are symmetric. For example, DT outcome F2 requires replacement in either Phase 1 or Phase 2 depending on the outcome of an engineering condition assessment (ECA). Neither PG&E nor BEAR assigned any segments to Phase 1 based on this outcome, because the evaluation will be performed in the future, during final project engineering. This induces a one-way risk profile that can only lead to higher costs, because the baseline assumes no costs for this outcome, but it may later be determined that more segments must be replaced.

Risk can also be biased the other way. PG&E's second HCA report on June 30, 2011 indicated that 378.4 miles had a reduction in class (e.g. Class 3 changed to Class 2) which PG&E "believes" is due to more accurate data.[176] Since the PSEP Pipeline Plan was not based on the June 30 HCA calcifications, and the DT assigns many segments to Phase 1 based on HCA class, this new data should result in segments being eliminated from Phase 1 during project engineering, and a lowering of project costs. This is an example of a risk that should have been considered in the QRA and that in hindsight, we know would lead to lower costs.

Overall, it appears that the uncertainties inherent in many of the key cost drivers in PG&E's baseline estimate are symmetric. Consequently, there is a significant probability that actual costs could be both either higher or lower than PG&E's baseline estimate.

In response to a data request from DRA concerning what uncertainties are included in PG&E's contingency request, PG&E explains:

> "the intent of the contingency is to account for uncertainties in the baseline estimates, exclusions expressly defined in the Basis of Estimate (BOE) for the baseline estimates, and risks due to unanticipated events, it is not possible to fully predict unforeseeable events and other factors that will inevitably affect the performance of the component projects in the PSEP Pipeline Plan. For example, during the 2011 pipeline hydrotesting projects, PG&E detected elemental mercury within pipeline segment downstream from major control stations. This resulted in hazardous waste disposal costs, increased project duration and resulting construction costs (see

[176] See footnote 2 of PG&E's June 30, 2011 report, in which they state "PG&E has not yet investigated why segments went down in class."

Estimate basis exclusions on testimony page 3E-6). These costs were unforeseeable and were not included in the QRA methodology and risk allowances" [177]

In response to another data request from DRA concerning whether PG&E's QRA model considers project specific risks and uncertainties in its contingency request, PG&E explains "the risks associated with project specific risks will be identified, documented, managed and quantified in future updates of the project risk contingency." [178]

It does not make sense that PG&E's QRA model should ignore the actual 2011 experience for the PSEP Pipeline Plan project simply because such information was not available when PG&E filed its original application. PG&E makes many arbitrary assumptions about the magnitude of various project risks in its QRA analysis. PG&E states it does not plan to update its current estimate, and does not provide any reasons why it cannot or should not.[179]

7.4 Review of PG&E's Contingency Calculations

PG&E generally classifies the current PSEP Pipeline Plan project cost estimate as an AACEI Class 4 estimate, for the purposes of calculating contingency. However, PG&E applied a narrower range of variability to its baseline cost estimate. PG&E shows this narrower range in Table 7-6 and calls it "Range Applied." For Pipeline Replacement costs (lines 1 and 2 in Table 7-6) PG&E uses a "Range Applied" from a Low value of 0% to a High value of 17.5%. For Strength Test expense costs (lines 14 and 15 in Table 7-6), PG&E uses a "Range Applied" from a Low value of 0% to a High value of 20%.

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[177] PG&E's response to DRA data request DRA 52 Q1.
[178] PG&E's response to DRA data request DRA 52 Q23.
[179] PG&E's response to DRA data request DRA 41 Q5.

To quantify risk, PG&E's QRA model uses Monte Carlo simulation technique, in which both risk and uncertainty values are recalculated over may iterations to provide confidence level curves for the potential final costs of the Implementation Plan and each component project. In response to a data request from DRA, PG&E explains that the "Low" value determines the lowest end of the range of possible risk variables which are applied to increase or decrease the base estimate in the Monte Carlo simulation.[180] However, in the same response PG&E explains that cost items in Table 7-6 with a "zero" Low value in the "Range Applied" column actually have <u>no</u> Low value. In these cases, the Monte Carlo simulation runs for estimating uncertainty only used the "High" value for all iterations. Consequently, the contingency for Pipeline Replacement capital costs and Strength Test expense costs are *primarily* based on a <u>point</u> estimate of uncertainty (at High value of 17.5% and 20%, respectively).[181] In its testimony PG&E does not explain why it did not run the Monte Carlo simulation for all possible uncertainty outcomes either for the -30% to +50% AACE recommended range or its own narrower "Range Applied" scenarios in Table 7-6.

In response to a data request from DRA, PG&E explains that "Based on estimate assumptions and exclusions, and discussions with PG&E and its third-party engineers, PwC concluded there was a need for contingency, over and above the base estimate, and that the use of a low range would be inappropriate in establishing a reasonable contingency for certain component projects. Given this view, a point estimate was more appropriate than a range for the estimate uncertainty component of the contingency for specific projects."[182] PG&E has

[180] PG&E response to DRA data request DRA_041-09.
[181] PG&E workpapers at WP 7-4 indicate that an additional "risk occurance" element of uncertainty was considered in the analysis that increased the contingency amount by approximately 1.25% to 2.5% for Pipeline Replacement. DRA based this estimate by applying the 25% risk occurrence to the "Best Case" and "Worst Case" percentages (5% and 10%) PG&E used for "Risk Impacts" shown on WP 7-4.
[182] PG&E response to DRA data request DRA_052-24.

essentially predetermined the outcome of its Monte Carlo simulation results for these costs by completely ignoring the variability of outcomes for Pipeline Replacement capital costs and Strength Test expense costs above the Baseline costs. When all the zero "Low value" items in the "Range Applied" column in Table 7-6 are added, DRA finds that contingency amounts for almost 78% of Baseline Capital costs and 65% of Baseline expense costs of the entire PSEP Pipeline Plan project are not subject to any variability, but rather are predetermined and entered as fixed point values in PG&E's Monte Carlo simulation model.

PG&E asserts that its contingency recommendation is based on 1,000 iterations, corresponding to 1,000 potential outcomes,[183] but, in fact, the contingency amount (before adding a "risk allowance") is <u>fixed</u> at 17.5 % for all of the 1,000 iterations for the Pipeline Replacement capital costs and at 20 % for the Strength Test expense costs in the Monte Carlo simulation. Indeed, PG&E's recommendation of a 20 percent contingency allowance for Pipeline Replacement capital costs (Table 7-10, lines 2 and 3) is very close to this 17.5 percent fix value, when the additional "risk allowance" PG&E includes in its calculations is considered.[184] Similarly, PG&E's recommendation of a 21 % contingency allowance for pipeline Strength Test expense costs (Table 7-10, line 16) is very close to the 20 % fix value in the model, when the additional "risk allowance" is included. Because PG&E's analysis fixes contingency at 20 percent (capital) or 21 percent (expense) for these baseline costs, the contingency amount changes only very little between PG&E's "P90" contingency estimate ($167.8 million) and its "P80" estimate ($165.4 million).[185] Even at a much lower 50% probability (i.e., "P50") PG&E's contingency amount drops to only 19% for Pipeline

[183] PG&E Testimony, Chapter 7, p.7-39.
[184] See footnote 175.
[185] PG&E Testimony, Chapter 7, Table 7-7, p. 7-41.

Replacement capital and remains at 21% for Strength Test expense costs.[186] Note that even at P0, the contingency is approximately $156.5 million or 18.8%.[187] In the opinion of this witness, PG&E's QRA model results give a false sense of thoroughness, as it predetermines most of the outcome of contingency analysis for the Pipeline Replacement capital costs and the Strength Test expense costs. PG&E should run its Monte Carlo simulation model using the entire estimating variability range (i.e., "Range Applied" in table 7-6) for _all_ of the cost items shown in Table 7-6. Furthermore, the additional "risk allowance" PG&E uses in calculating its recommended contingency amount is not justified because it is not based on any detailed analysis but is simply a 5 to 10 percent contingency adder for portions of simulation iterations. As explained in DRA's contingency recommendation in Section 7.6 below, such a "risk allowance" is not justified given that PG&E's contingency analysis is highly biased towards further inflating PG&E's already excessive baseline costs. These adjustments alone will lower the overall contingency amount far below the 20 to 21 percent PG&E requests in its testimony. DRA estimates that a uniform distribution of outcomes over the 0% to 17% contingency range would result in a contingency amount of approximately 8.5% (i.e., middle of the range).

7.5 Relationship between contingency request and baseline estimate

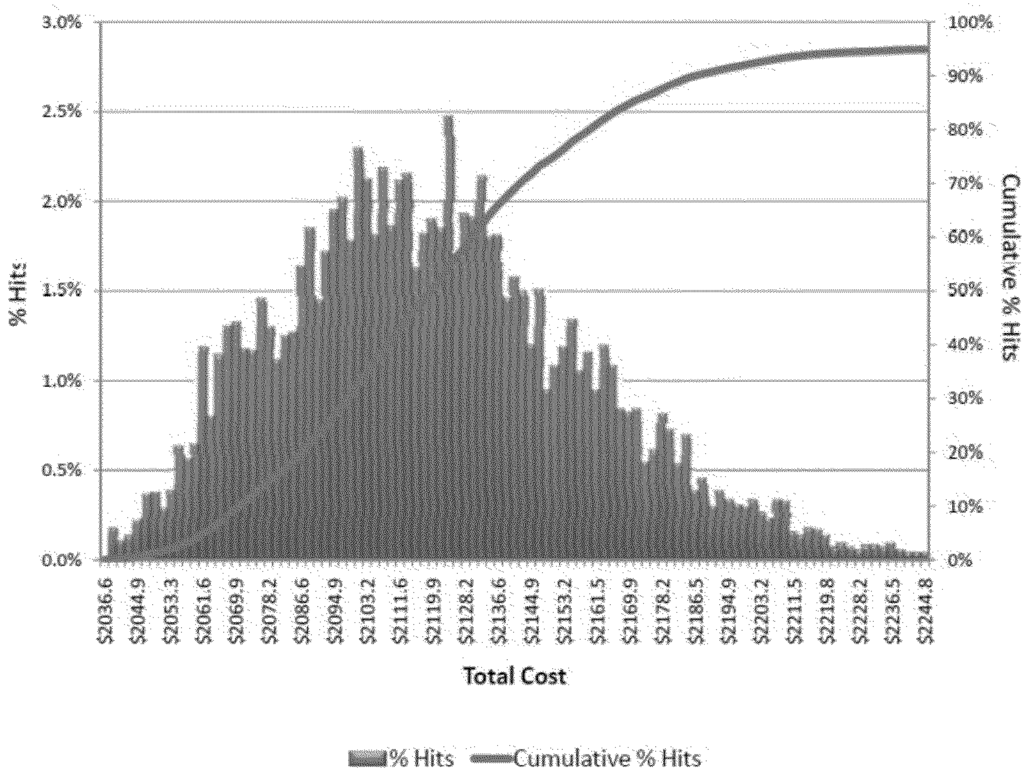
PG&E's QRA analysis is best summarized by the "Cumulative % Hits" versus "Total Cost" relationship shown on Figure 7-5 of PG&E's Testimony: [188]

[186] PG&E response to DRA data request DRA 44 Q3.

[187] See PG&E's response dated 1/24/2012 to DRA data request DRA 65 Q2. The P0 value plus baseline of $833.6 million is approximately $990.1 million, the lowest x-axis value in the "histogram for Part a." $156.5, the difference between these two numbers, is the contingency amount.

[188] Figure 7-5 in PG&E's Testimony is incorrect. See PG&E's response to DRA data request DRA_041-07. A corrected figure was provided in the January 20, 2012 Errata filing, p. 7-42.

Figure 13 – Results of PG&E QRA analysis for entire PSEP



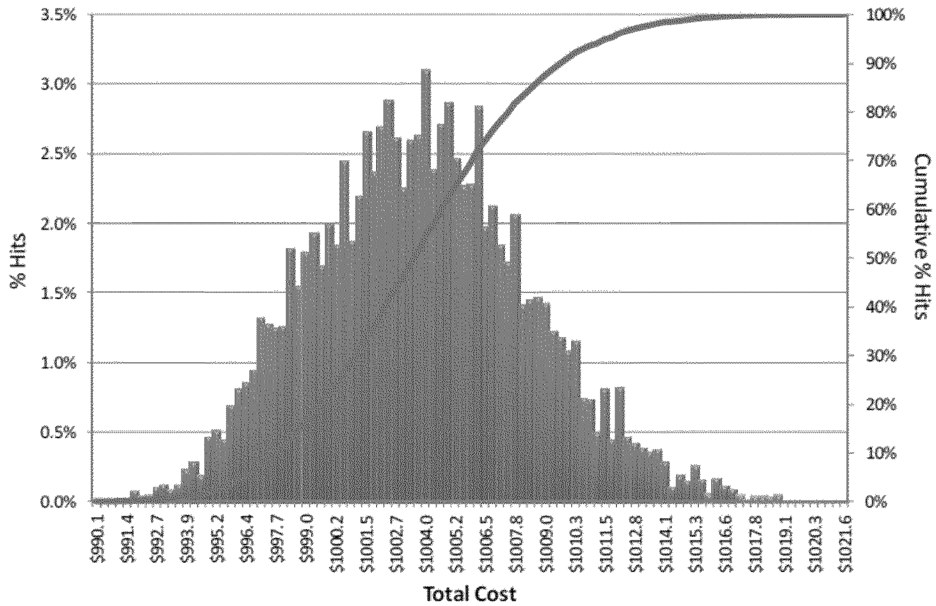
The X-axis numbers represent the probable project costs. The figure shows a 0% probability (P0) that actual costs will be less than $2,036.6 million, and that there is about a 97% (P97) probability that actual costs will not exceed than $2,244.8 million. PG&E proposes using the P90 contingency value of $2,183.9 million. PG&E's baseline estimate for the project is $1.803.4 million, which is less than the P0 value shown on this figure. The figure indicates that keeping the actual costs of the project under PG&E's baseline estimate ($1.803.4 million) is not achievable, and that keeping the actual costs below the zero probability (P0) value of $2,036.6 million is unlikely. This result is inconsistent with DRA's findings from Section 4.3 that PG&E's baseline costs are developed based on unit costs substantially higher than industry averages. DRA suspects that If PG&E had properly estimated baseline costs, and performed a proper QRA analysis using variability of outcomes over the entire "Range Applied" shown in Table 7-6, the

Figure 7-5 would show that there would be a probability of greater than zero (P0) that actual costs will be less than the 2,036.6 million PG&E shows in Figure 7-5. If PG&E were to use the AACE I Classification Range (-30% to +50%) shown in Table 7-6 for Class 4 estimate, it can be argued that the P0 values should be even *less* than the baseline cost of $1,803.4 million. Given that DRA's analysis shows PG&E's baseline cost estimate to be higher than industry averages, the QRA should show a significant probability that actual costs could be lower than the baseline estimate. The histogram shown in Figure 7.5 does not show distribution of outcomes for actual costs on either side of the base estimate as the AACEI range for a Class 4 estimate would indicate. At a minimum, the QRA should show a significant probability that actual costs could be less than PG&E's current 2,036.6 million estimate at P0. It appears as if PG&E tailored its assumptions for the QRA model to obtain a pre-determined level of contingency for the PSEP Pipeline Plan project, rather than using reasonable assumptions to let the QRA model suggest a proper level of contingency.

The following three figures illustrate the biased nature of PG&E's QRA analysis for contingency calculations of Pipeline Replacement capital projects. PG&E provided the following figure in response to a DRA request to provide the Monte Carlo results for pipeline capital projects:[189]

[189] PG&E response dated 1/24/2012 to data request DRA_65-2(a).

Figure 14 - Results of PG&E QRA analysis for the replacement portion PSEP Pipeline Plan pipeline replacement program



This graph makes it look as though there is a wide range of outcomes for actual costs. However, recall that the baseline estimate for pipeline capital project, primarily pipeline replacement, is $928.1 million. DRA first reformatted the above data to show the Monte Carlo results for pipeline capital projects the 20% contingency used by PG&E, and PG&E's P90 value:[190]

[190] Attachment 1 to PG&E response dated 1/24/2012 to data request DRA_65-2(a).

Figure 15 – PSEP Contingency request for pipeline replacement compared to PG&E QRA results[191]

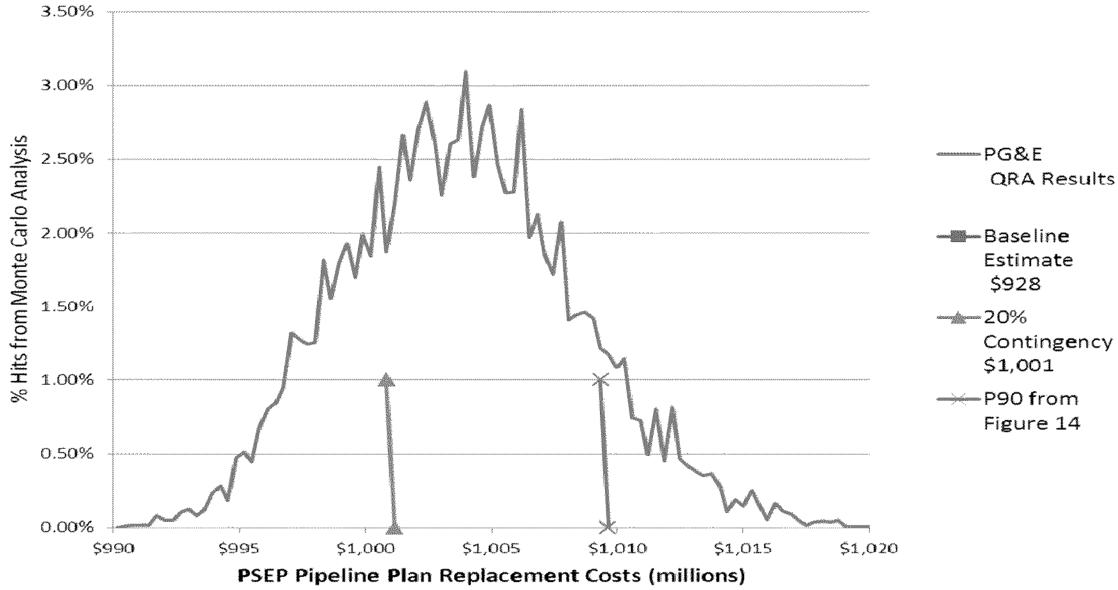
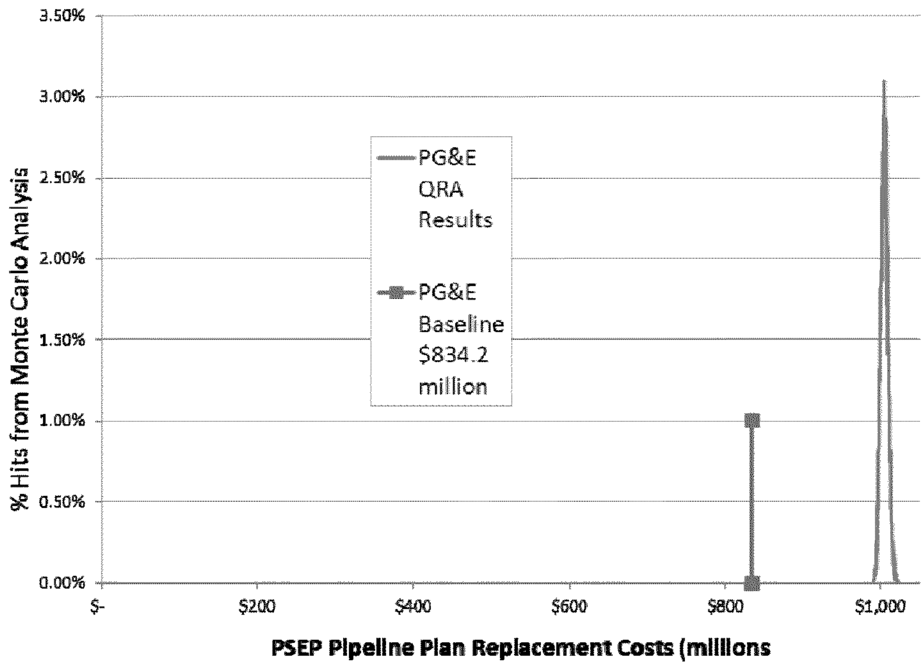


Figure 15 illustrates that PG&E's QRA provides outcomes roughly centered on the 20% value chosen by PG&E, but skewed to the right (greater probability of higher cost). This figure also illustrates the discrepancy mentioned in footnote XXX of this exhibit, since PG&E's 20% contingency is supposed to by a P90 value. It is clear from this figure that the 20% contingency is not a P90 value.

DRA also reformatted PG&E's QRA results to compare them to the baseline estimate of $834.6 million:

[191] Note that the magnitude of the 20% contingency and P90 bars have no meaning. They only indicate the size of these costs on the X-axis.

Figure 16 - PSEP baseline cost request for pipeline replacement compared to PG&E QRA results[192]



This graph shows that the QRA analysis yields a very narrow range of outcomes, all of which have a higher cost than the baseline.

7.6 Comparison of PG&E's PSEP Pipeline Plan Contingency request to other adopted contingency budgets

PG&E states, "the contingency amounts developed by PG&E are consistent with the contingency amounts previously approved by the Commission for work efforts with a similar risk profile and in line with industry guidelines," and provides PG&E's advanced metering infrastructure (AMI) application (A.05-06-028) and SmartMeterTM Upgrade application (A.07-12-009), which were adopted by the Commission in D.06-07-027 and D.09-03-026, as examples. [193] The Commission adopted an 8.0% contingency in PG&E's A.05-06-028 and an 11.7% in A.07-12-009. These amounts are far lower than the 21 percent

[192] See previous footnote 191.
[193] PG&E response to DRA data request DRA_041-11.

contingency PG&E requests in this application.[194] A review of all Commission authorized contingency amounts for all of the AMI-related applications indicate an average contingency rate of 8.1%:

Table 16 – CPUC approved baseline and contingency budgets for Smart Meters

Project	Cost Reqstd	Cost Adptd	Contingny Reqstd	Contingny Adopted	% Reqstd	% Adptd	Cite
PG&E Original		$ 1,739.4		$ 128.8		8.0%	D.09-03-026 in A.07-12-009, p.87.
SDG&E		$ 572.0		$ 33.8		6.3%	D.07-04-043 in A.05-03-015, p.38
		$ 490.0		$ 33.8		7.4%	p.38 also says 7.4%???
SCE		$ 1,634.0		$ 130.1		8.7%	D.08-09-039 in A.07-07-027; Dec. 5, 2007 errata Testimony, SCE-2, P.14 has contingencycosts
PG&E Upgrade	$ 572.4	$ 467.0	$ 65.5	$ 49.0	12.9%	11.7%	D.09-03-026 in A.07-12-009
SoCalGas	$ 1,080.0	$ 1,051.0	$ 98.0	$ 68.7	10.0%	7.0%	D.10-04-027 in A.08-09-023, pp. 2, 37,
All AMI		$ 5,463.4		$ 410.4		**8.1%**	**8.1% is the average for all AMI**

In comparing contingencies for PSEP Pipeline Plan and AMI projects, the status of technology and project scope must be considered. PG&E has ample experience with Pipeline replacement and Hydrotesting projects, as PG&E has been doing such work on a large scale routinely for decades. The technology for PSEP Pipeline Plan projects proposed in this application is mature and PG&E should be very experienced estimating, designing, and implementing these pipeline projects. In contrast, California led the nation in implementing new metering technology on a wide scale, and PG&E was the first California utility to implement an AMI plan. Also, AMI deployment was similar in scope to the PSEP Pipeline Plan, since PG&E has requested nearly $2.2 billion for PSEP Pipeline Plan, a request similar in size to PG&E's $2,186 million cost request for AMI.[195] And yet, PSEP contingency rate is much higher than PG&E's AMI contingency rate.

[194] PG&E Testimony, Chapter 7, p.7-46.

[195] Citations are provided in Table 16.

7.7 Contingency Cost Adjustments

As discussed elsewhere in this testimony, DRA finds that PG&E's Pipeline Modernization Plan is not mature enough to form a proper baseline estimate for risk analysis. DRA also finds PG&E's QRA analysis to be deficient and biased towards achieving a certain level of contingency. Based on the review of Commission's previous decisions for similar projects, the 21% contingency PG&E is requesting is excessive. Table 16 above shows that for the statewide Smart Meter projects, the Commission adopted an average contingency of only 8.1%.

Considering the relative maturity of Pipeline Replacement and Hydrotesting projects compared to the Smart Meter technology, the risks of cost overruns should be much lower for the former. Because, as discussed in Section 7.2 above, PG&E has not performed a proper QRA using the "best practices checklist" for sensitivity analysis, DRA does not recommend a specific contingency percentage at this time. A proper QRA would yield a contingency rate substantially lower than the 21% proposed by PG&E. For illustrative purposes, DRA uses a contingency rate of 8% in its cost adjustments in Exhibit DRA-09.

DRA's Specific Recommendations on Contingency

1) Update Baseline cost estimates as a first step - DRA recommends the Commission only approve the contingency amounts based on an <u>updated</u> baseline estimate done close to the timeline when the Final Implementation Plan is available. An updated contingency estimate would not delay or in any way harm the progress of PSEP Pipeline Plan as contingency amounts are drawn down only when the authorized budget based on the base estimate has been exhausted first. As PG&E's PSEP Pipeline Plan project becomes more defined i.e., moves from the current Class 4 to a lower, more defined class, the contingency for estimating allowances/uncertainty should

narrow further than the "Range Applied" amounts shown in Table 7-6. It would also provide an opportunity to check if the original base estimate for the project needs to be modified as well.

2) Update Contingency analysis
   - Follow GAO best practices from PG&E Figure 7-4,
   - Require PG&E run its Monte Carlo model without any "Risk Allowance" adders. These project execution risks should balance out in aggregate and adders are not necessary because PG&E does not consider any outcomes where actual costs of the project could be lower than the base estimate for this phase of the project.
   - Run the Monte Carlo model through the entire spectrum of "Range Applied" amounts and not limit to just point values as PG&E has done.
   - Use P80 or lower probability.

3) Use a contingency value of 8% for illustrative planning purposes until PG&E provides an updated estimate done close to the timeline when the Final Implementation Plan is available.

4) DRA recommends the Commission approve contingency amounts in silos of cost categories. DRA is concerned that if the entire contingency budget PG&E is requesting ($380.5 million, see Table 7-10) is provided as a lump sum, the Commission cannot properly ensure that contingency funds are used only for the demonstrated uncertainties and risks not captured in the adopted base estimate. The cost categories in Table 7-7 show that they vary from a relatively small $0.1 million (capital item 44A at line 3) to as high as $167.7 (capital item 2H1at line 2). Otherwise, it would be easy and

tempting to use the contingency budgets from the larger and/or unused categories to cover improper or inefficient spending in smaller categories.

Fund shifting between various items within a silo could be allowed without prior Commission approval. The Commission may, under certain conditions, allow PG&E to request via an advice letter fund shift between the silos. DRA recommends the following fund shifting guidelines:

- Require separation of contingency amounts for "capital" and "expense" items.
- If having a contingency silo for each item shown in Table 7-6 of PG&E's Testimony is not practical, silo the contingencies for a group of items in a way that makes sense. e.g., all "Valve" items could be grouped together to have their own contingency amount.
- Require a Tier 2 Advice Letter for moving contingency funds between any two silos.

8 Cost issues not included in DRA's cost adjustments

8.1 Issues analyzed but not included in DRA's cost adjustments

Three additional cost drivers were reviewed to support this testimony: escalation, customer outreach, and test heads. These analyses were performed as secondary priorities and the results were not incorporated into DRA's recommended cost adjustments. Additional analysis should be performed on each of these issues, and results of these analyses should be included in subsequent iterations of the PSEP.

Exhibit DRA-6 includes analysis of escalation and customer outreach costs, which, after "all-in" costs and mobs and moves, were the next highest, cost drivers for both replacement and hydro projects (See Figure 7 and 8 of this testimony).

8.1.1 Escalation

Escalation charges are applied for all PSEP Pipeline Plan costs incurred after 2011 at an annual rate of 3.12%. This adds approximately $70 million to the overall cost of the PSEP Pipeline Plan, as shown in Figures 7 and 8 of this exhibit. In Exhibit DRA-6, BEAR finds that PG&E's escalation costs are excessive because:

- PG&E's annual escalation rate of 3.12% is too high given the current state of the United States economy and volatility of steel prices
- Escalation rates are inappropriately applied using the completion date of a project, rather than when engineering and procurement establish actual costs

BEAR recommends using the date when engineering and procurement establish actual costs to apply an escalation rate of approximately 1.1% to 1.5% through Phase 1 of the PSEP.

8.1.2 Customer Outreach

PG&E applies a 2.9% adder for customer outreach costs add over $31 million to replacement and hydrotest project costs.[196] BEAR reviewed information provided by PG&E in response to DRA written data requests and found that customer outreach includes:

- Approximately $5 million for new databases
- Approximately $3 million for government relations

[196] $31 million was calculated by DRA by summing the customer outreach cost included in each replacement and hydrotest project. BEAR found that PG&E reported the total budget for customer outreach to be $28.5 million.

BEAR notes that the budgets for both of these items varied significantly between two PG&E responses to DRA data requests. BEAR appropriately questions the need for government relation as a component of customer outreach, and for customer outreach generally for an issue with so much public interest and media attention.

8.1.3 AFUDC for hydrotests

PG&E's Resource Guide defines AFUDC as "[t]he allowance for funds used during construction (AFUDC) is an accounting procedure used by utilities to *capitalize* the costs of financing the construction of facilities."[197] In Exhibit DRA-6, Table 13, BEAR notes that PG&E included 5.24% for AFUDC for hydrotest projects. Since the costs of hydrotests are expensed, not capitalized, AFUDC should not be included for these projects.

8.1.4 Test heads for hydrotests

A pair of test heads is required for each hydrotest, to isolate the test section and pressuring it. PG&E requests funds for test heads in two parts of the PSEP Pipeline Plan, even though they currently have approximately 50 pairs of test heads in inventory, ranging in size from 3" to 36". [198] First, PG&E requests $6.7 million for test heads as part of "Strength Test Capital Valves and Testheads." [199] DRA inquired about this cost in one of its first data requests: [200]

> "Please describe a "testhead" and its use, discuss whether it is removed or left in place after testing, provide unit cost data as a function of pipe diameter and other relevant installation features, and provide supporting documentation for unit cost data."

[197] PG&E "Resource, an encyclopedia of energy utility terms", Second Edition, p.15.
[198] PG&E response dated 12/21/2011 to data request DRA 25 Q19, attachment 1.
[199] PG&E Workpapers at WP 3-558.
[200] Data request DRA 8 Q19(a), emphasis added.

PG&E did not adequately address the cost portion of this question in their response:

> "PG&E plans to build 12 pairs of test heads (various pipe diameters) to support the strength testing requirements for the Phase 1 work scope. The cost estimate was based on the price of materials (pipe, end caps, Mueller taps, flanges, and miscellaneous fittings) and fabrication costs for other similar welded assemblies PG&E has built in the past." [201]

A follow up data request also failed to yield a useful response:

> "The cost to fabricate a test head will vary depending on size, pipe diameter and maximum working pressure. PG&E did not create unit costs estimates for test head fabrication and construction in preparation of this filing. Each hydrostatic test head is composed of several components, pipe body, end cap, isolation valves, valves for moving product in and out, gauge taps, support skids, etc. The table below contains a material list and unit cost for line pipe and end caps, two components of a test head, purchased in 2011 in support of the hydrotesting program." [202]

In addition to the $6.7 million request, PG&E also requests funds for a new set of temporary test heads for each and every hydrotest, even where multiple tests are included in the same project. In essence, PG&E is requesting $15,000 to $40,000 per test for disposable test heads. [203] DRA asked: [204]

"PG&E appears to be requesting $15,000 - $40,000 for temporary test heads for each pressure test performed, and then disposing of them. Explain if DRA's interpretation is correct, and why PG&E is not using existing permanent test heads, or building additional permanent test heads?"

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[201] PG&E response dated October 6, 2011 to data request DRA 8 Q19(a).

[202] PG&E response dated 10/19/21011 to data request DRA 11 Q2(a). PG&E included a table of material costs per foot which was insufficient to allow DRA to analyze how PG&E calculated a specific cost request of $6.7 million.

[203] PG&E Testimony, WP 3E-17.

[204] Data request DRA 26 Q3.

PG&E's response did not answer this question.[205] Based on PG&E's failure to answer DRA questions, we were unable to address the reasonableness of PG&E's cost requests for test heads.

8.2 Issues neither analyzed nor included in cost adjustments

As mentioned previously, the first step of DRA's analysis of the PSEP Pipeline Plan was to determine the main cost drivers and then to focus on them. Based on this review, as illustrated in Figures 1, 7, and 8, DRA did not analyze the following components of the PSEP Pipeline Plan:

- Pipeline to repair hydrotest failures ($37.5 million, Capex)
- Pipeline Upgrades for ILI ($30.3 million, Capex)
- Isolation Valves for hydrotest ($11.1 million, Capex)
- Pipeline to replace short sections ($8 million, Capex)
- Pipeline ILI ($9.6 million, expense)
- Other Pipeline Expenses ($4.9 million)[206]
- Program Management ($27 million total; $18 million Capex, $9 million expense)

DRA has suggested significant costs adjustments to the PSEP Pipeline Plan, such that the proportion of these "other costs" has increased from under 7% to over 20% of the total costs (See Section 2.2 and Table 17 of this exhibit).

9. Summary of Recommended Cost Adjustments

[205] PG&E response dated 12/5/21011 to data request DRA 26 Q3.
[206] See page 3-6 of PG&E Testimony. These total $108.4 million, out of a total request of $1,606.5 billion, which includes contingency, or 6.7% of the pipeline costs.

Based on the analysis in the sections above, DRA has quantified a number of cost adjustments, which are used in Exhibit DRA-9 for revenue requirement and rate calculations. The impact of all adjustments to baseline costs is shown in Table 17:

Table 17 – DRA Cost Adjustment for PSEP Pipeline Plan pipeline modernization

	Ratepayers				PG&E			Total						
Source	REPL	Hydro	Other*	Total	REPL	Hydro	Total	REPL	Hydro	Other*	Total	% Paid by Ratepayers	Ratepayer Adjustment	% Adjst.
	Million	Million	Million	Million										
PG&E Testimony	$834.2	$393.2	$108.4	$1,335.8	$ 9.7	$11.8	$21.5	$843.9	$404.9	$108.4	$1,357.3	90.4%	$ -	0.0%
PG&E per DRA model	$805.0	$399.3	$108.4	$1,312.7	$ 9.5	$11.8	$21.3	$814.4	$411.1	$108.4	$1,334.0	90.3%	$ (23.0)	-1.7%
DRA Testimony	$355.5	$ 20.6	$108.4	$ 484.5	$18.9	$59.6	$78.5	$374.4	$ 80.3	$108.4	$ 563.1	66.8%	$ (851.2)	-63.7%

All dollar values in millions.
* Other includes Line 4, 5, 10, and 11 from PG&E Testimony, Table 3-1.

Costs for alternative scenarios can be calculated using the DRA models described in Section 2.4.1

PG&E's contingency is also adjusted in two ways. First, PG&E's contingency request for the PSEP Pipeline Plan of $270.7 is essentially obtained by applying fixed contingency rates to the baseline estimate. The adjustments in Table 17 reduce the baseline estimate to 41.3% of the PG&E's total request for $1,357.3 million, so contingency will be reduced proportional. Second, in Section 7.6 of this exhibit, DRA showed why it believes an 8% contingency is more appropriate than the 20% or 21% used by PG&E. Applying DRA's 8% figure to the DRA's adjusted total cost above yields a contingency amount of $45 million.

To be clear, these adjustments are provided for illustrative purposes only, to show quantitatively the impact of adjustments to the PSEP Pipeline Plan recommended by DRA's consultants, BEAR and Delfino Engineering, and this witness. DRA is not recommending that these specific cost adjustments be the basis for authorizing any cost recovery at this time. Shortcomings discussed throughout this testimony lead DRA to make more general recommendations, including rejecting the current PSEP Pipeline Plan, as fully discussed below in Section 10.

Also note that Table 17 and DRA's analysis includes costs for all four years for which PG&E included costs in the PSEP Pipeline Plan, 2011-2014, even though PG&E has stated that its ratepayers will absorb costs incurred in 2011 (see Section 6.2)

10. DRA Recommendations for alternative to current PSEP Pipeline Plan

10.1Reject the current pipeline modernization plan

Section 4 of this testimony details many failings of the proposed PSEP Pipeline Plan Pipeline Plan, particularly as the basis of a request for ratepayer funding. The current plan should be rejected for the following reasons:

1. The PSEP Pipeline Plan includes a "conceptual" AACE Class 4 cost estimate, not the type of detailed cost estimate required for cost-recovery of a multi-billion dollar project[207]
2. The PSEP Pipeline Plan is based on out-of-date and incomplete MAOP and HCA data
3. PG&E's DT is flawed, resulting in excessive replacement, and excessive Phase 1 testing
4. PG&E's DT is poorly reflected in the PSEP Pipeline Implementation Plan , leading to increased costs and safety risks
5. Numerous errors or unjustified deviations from the PG&E's Testimony were identified
6. Unit costs are excessive

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[207] PG&E Testimony, p. 7-23.

7. PG&E's quantitative risk analysis (QRA) does not quantify real risks; the resulting contingency request is basically an educated guess, and inflates overall program costs

10.2 Use DRA's recommendations and adjustments for future revisions of the PSEP Pipeline Plan

DRA provides a critique of many aspects of PG&E's PSEP Pipeline Plan in this exhibit, and offers alternatives. The CPUC should require PG&E to correct these deficiencies as recommended by DRA, and to provide a sounder plan in the future.

The CPUC and PG&E should use DRA's alternative recommendations and cost adjustments, contained in this exhibit when PG&E delivers a revised PSEP Pipeline Plan.

10.3 Expedite a revised and fully vetted test plan for 2012

PG&E initiated hydrotesting and replacement in 2011 and "[a]s of December 30, 2011, about 144.5 of the 152 Priority 1 transmission pipeline miles have been hydrostatically tested and tied in, replaced, or have had strength test pressure records verified."[208] The current PSEP Pipeline Plan includes $198 million in 2012 for pipeline replacement and $93.7 million for hydrotesting.[209] "PG&E has delayed eight tests representing 5.7 Priority 1 miles into 2012 until after the winter cold season or permits are obtained. Seven of these tests were delayed because they could not be completed before November 15 and would have risked PG&E's ability to serve core customers. One test, T-57 on Line 300A, has been delayed because of an environmental permit, which we hope to obtain by early January to allow testing early in 2012."[210]

[208] PG&E Hydrotest status report dated 12/30/2011 in R.11-02-019, p.6.
[209] PG&E Testimony, p. 3-6, Table 3-1. This is in addition to projects planned for 2011, but which were delayed.
[210] PG&E Hydrotest status report dated 12/30/2011 in R.11-02-019, p.5.

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PG&E should initiate priority mitigation measures as soon as winter gas demands allow, but only if priority and need are accurately determined. DRA recommends the following steps to reliably determine priorities quickly and accurately for the highest-priority segments remaining:

1. **Review hydrotests that were delayed from 2011 to ensure they are consistent with CPUC safety objectives.** The Commission's CPSD division should review the December, 30, 2011 hydrotest report and issue an evaluation and recommended changes.[211] Since PG&E has stated that its shareholders will absorb the costs of 2011 hydrotesting, even if they are delayed, the CPUC need not review the reasonableness of these costs in advance.[212] The CPSD report should be issued by March 1, 2012.

2. **Re-evaluate the mitigation outcomes for pipeline segments in HCA areas using better data and criteria.** PG&E's June 30, 2011 class location study report provided revisions to its HCA classifications which were not used in creating the PSEP Pipeline Plan.[213] Since HCA classification is a key factor in prioritizing projects in both PG&E and DRA's DT, this new and existing information should be used.[214] DRA recommends that non HCA Class 2 segments not be considered as HCA for this task, since PG&E's inclusion of Class 2 as HCA is not consistent with the Commission's directions.[215] In addition, PG&E's October 14,2011 MAOP validation report stated that the verification process will be completed for 1,805 miles of high priority segments as of January 31,

[211] PG&E Hydrotest status report dated 12/30/2011 in R.11-02-019.
[212] As discussed in Section 6.2 of this exhibit.
[213] As discussed in Section 3.3 of this exhibit.
[214] Ongoing findings, orders, and decisions in OII I.11.11.009 should also be incorporated.
[215] D.11-06-017 in R.11-02-019,Ordering Paragraph 4, p.31.

2012[216] As with HCA classification, the status of test records is a key factor in determining project priority for both PG&E and DRA. For this evaluation, DRA recommends using "then current" test requirements to establish priority. Alternatively PG&E's criteria of using only Sub-part J tests can be used.[217] DRA generally recommends that its DT be used for this assessment. If PG&E does not use the DT recommended by DRA, we recommend including only segments with DT outcomes F1, F2, and C2, where PG&E and DRA concur on the required action.

3. **Develop a new PSEP Pipeline Implementation Plan for priority HCA segments that require early 2012 action.** PG&E should Identify projects which do not rely on incomplete MAOP validation, and where parties concur that priority action is required, as priorities for 2Q 2012. Only hydrotests should be considered for inclusion, unless PG&E can provide compelling evidence that specific replacement projects have more urgent need for mitigation. PG&E should identify and provide justification for any and all of the following: inclusion of lower priority segments which are adjacent to the high priority segments; OD increases; line re-routing; and anticipated cost variances from their cost models. The PSEP Pipeline Implementation Plan should be reviewed by CPSD and DRA, and modified by PG&E until both divisions are satisfied that the plan is reasonable.

4. **Direct the MAOP validation team to prioritize evaluation of segments included in the 2012 PSEP Pipeline Implementation Plan**. The PSEP Pipeline Implementation Plan may include segments which are not in HCA areas (included due to proximity to HCA segments) and which might not have completed MAOP validation. The MAOP validation team should be

[216] October 14, 2011 MAOP report filed in R.11-02-019, p.2.
[217] The industry, state, and federal requirements at the time of installation or re-testing.

directed to prioritized its assessment of these segments to ensure their inclusion is based on the complete and final assessment of their records.

5. **Provide a final 2012 PSEP Pipeline Implementation Plan, using final MAOP and HCA data, by June 30, 2012.** This plan should also be reviewed by CPSD and DRA, and modified by PG&E until both divisions are satisfied that the plan is reasonable.

10.4Initiate ground work early in 2012 required to support a long-term PSEP Pipeline Plan

In parallel with the activities above, PG&E, parties, and the CPUC need to lay the groundwork required to develop an accurate, safe, and cost-effective plan to evaluate all transmission line segments. DRA recommends that three tasks in particular be completed by September 2012:

1. **Continue the OIR process to resolve contentious** issues – This testimony has revealed many issues where DRA disagrees with key elements of PG&E's PSEP Pipeline Plan. Other parties will likely find other issues, and may disagree with DRA's findings. DRA recommends that the current OIR schedule, including hearings in March 2012, continue to enable the CPUC to rule on contentious issues before PG&E performs a second iteration of the PSEP Pipeline Plan. The Assigned Commisioner and Assigned ALJ should also establish a process to vet PG&E's revised PSEP Pipeline Plan on an expedited basis.

2. **Complete MAOP validation for all transmission segments** – The current PSEP Pipeline Plan includes many segments in Phase 1 based on incomplete results from the MAOP validation process. Many of these segments are not classified as HCAs. MAOP validation will be completed

for 1,805 miles of high priority segments as of January 31, 2012[218] The Commission should direct PG&E to complete the MAOP validation for all segments to be included in the PSEP Pipeline Plan, accounting for HCA classification changes, by September 31, 2012.

3. **Coordinate with the HCA OII 11-11-009** – As noted above, HCA classification is an important criteria in determining the correct threat mitigation measure. A CPUC press release regarding its investigation into PG&E's classification of pipelines, I.11-11-009, stated: "The CPUC will review and determine whether PG&E has failed to classify its pipelines correctly and whether PG&E failed to comply with federal standards requiring that it regularly study, patrol, and survey these locations for increased population density."[219] While DRA recommends using PG&E's revised HCA classifications from the June 30, 2011 class location study report, we also recommend monitoring and coordinating the PSEP Pipeline Plan development with the record developed in the HCA OII.[220]

4. **Perform a more detailed review of a sample of PG&E's project groupings, and determine criteria for including non-priority segments in Phase 1 projects**.

5. **Survey hydrotest costs** – per BEAR recommendations in Exhibit DRA-6
6. **Determine the cost and time required to prepare a AACE Class 1, 2, or 3 cost estimate for all required pipeline mitigation work** – Since PG&E is requesting over $270 million in contingency based primarily on the

[218] October 14, 2011 MAOP report filed in R.11-02-019, p.2.
[219] CPUC press release dated November 10, 2011, available at http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/151457.htm.
[220] DRA disagrees with PG&E's default treatment of Class 2 segments as high priority segments requiring Phase 1 treatment, and discussed in Exhibit DRA-4.

AACE Class 4 cost estimate prepared by Gulf, the cost and feasibility of a more detailed estimate should be considered.

10.5Redo DT assessment and define a new PSEP Pipeline Implementation Plan for all transmission segments

DRA recommends that PG&E revise and re-file the PSEP Pipeline Plan and incorporate the following:

- Final MAOP validation results
- CPUC approved HCA classification[221]
- CPUC approved DT,
- CPUC approved data source for test records used by the DT and for use in cost allocation,
- CPUC approved criteria for grouping segments into projects
- CPUC approved unit costs and cost models
- CPUC approved shareholder/ratepayer allocation criteria
- A QRA analysis that actually quantifies risks in each PSEP Pipeline Plan program element, and establishes a contingency accordingly
- Findings and lessons learned from 2011 hydrotest program
- One schedule/plan which shows *how* all PSEP Pipeline Plan elements (ILI, valve replacement, etc.) will be integrated
- One schedule/plan which shows *how* PSEP Pipeline Plan tasks will be integrated with TIMP activities
- A method of highlighting and justifying capacity upgrades and line relocation.

DRA further recommends that PG&E include details on the Phase 2 schedule and costs, which should result in a plan for all transmission segments. This plan should be filed by October 2012 to allow review prior to 2013 implementation.[222]

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[221] Including CPUC direction on the treatment of Class 2 locations,

[222] Cost recovery based on this plan is addressed in Exhibit DRA-2.

1. CONCLUSION

This testimony presents the results of a detailed analysis of PG&E's proposed PSEP Pipeline Plan, and incorporates the analysis of DRA's consultants. Based on shortcomings described herein, the Commission should reject the current proposal and order PG&E to issue a revised proposal per DRA's recommendations. Interim measures per DRA recommendations should be implemented while this revised plan in is being generated and vetted. DRA is not recommending that the specific costs adjustments provided in this testimony be implemented, but rather used to highlight flaws in PG&E's PSEP Pipeline Implementation Plan, and to illustrate the benefits provided by DRA's recommendations.