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Commissioner	:	C. Peterman
ALJ	:	J. Wong
Witness	:	T. Roberts

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2015 Gas Transmission and Storage Rate Case

Chapter 4A
Hydrotest and
Vintage Pipe Replacement Programs

Corrected Version

San Francisco, California
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1 SCOPE OF TESTIMONY

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates (ORA) regarding Pacific Gas and Electric Company's (PG&E) "Hydrostatic Testing Program" (Hydrotest Program) and "Vintage Pipe Replacement Program" (VIPER Program) proposals associated with its Test Year (TY) 2015 Gas Transmission and Storage (GT&S) rate case. Specifically, this exhibit addresses PG&E's forecasts of operation and maintenance (O&M) expenses for 2015 and capital expenditures for 2013 through 2015 for these two programs. While this testimony relates primarily to Chapter 4A of PG&E's testimony (GT&S Testimony), it also relates to how capital expenditures for these two programs are used to calculate revenue requirement, as discussed in Chapter 16 of PG&E's testimony.

Expenses for PG&E's proposed Hydrotest Program are for work activities related to filling pipelines with water and pressurizing them to gather information related to establishing the appropriate Maximum Allowable Operating Pressure (MAOP) for a line.[1] PG&E also requests capital expenditures for this program which are not discussed in this testimony, or elsewhere in ORA exhibits.[2]

PG&E's proposed VIPER Program relates to the replacement of certain obsolete pipeline components (referred to as "features") that are located where PG&E perceives a risk of ground movement, except for pipes which cross a known earthquake fault line.[3] PG&E GT&S Testimony reflects that only capital expenditures are associated with this program. The discussion of the VIPER Program in this testimony discusses the relationship between VIPER and the related "Geo-Hazard Threat Identification and

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[1] PG&E also requests $2.55 million in 2015 expenses for Liquefied Natural Gas/Compressed Natural Gas (LNG/CNG) associated with the Hydrotest Program which are not addressed in this testimony, or elsewhere in ORA exhibits. See PG&E Prepared Testimony, Volume 1 (Barnes), Table 4A-8, p. 4A-32.

[2] This includes 2015 forecasted capital expenditures of $21.4 million to modify pipelines prior to hydrotesting and $2.92 million for LNG/CNG equipment to supply customers during hydrotests. See Ibid., Table 4A-9, page 4A-32.

[3] PG&E Response to ORA-DR-91 Q23. Pipelines that cross a known fault line are addressed in a separate program, the Earthquake Fault Crossings Program, discussed in PG&E Prepared Testimony, Volume 1 (Barnes) beginning at page 4A-43. This program is not addressed in this testimony, or elsewhere in ORA exhibits.

Mitigation" program (Geo-Hazard Program), but does not make specific recommendations regarding that program.

PG&E's activities and costs are grouped with similar types of work into Major Work Categories (MWCs). PG&E's forecasts for MWC expenses are expressed in SAP nominal dollars.[4] SAP dollars include certain labor-driven adders such as employee benefits and payroll taxes that are charged to separate Federal Energy Regulatory Commission (FERC) accounts. ORA's recommendations are made by MWC and in SAP nominal dollars which are then translated into the appropriate FERC accounts through the Results of Operations (RO) model.

2 SUMMARY OF RECOMMENDATIONS

This testimony results in three groups of recommendations: recommendations specific to the Hydrotest and VIPER Programs which impact those programs' scope and cost, and general recommendations applicable to both programs. The following summarizes ORA's recommendations specific to the Hydrotest Program:

- The Commission should adopt ORA's 2015 expense forecast of $91.7 million, which is based on the trend of actual Pipeline Safety Enhancement Plan (PSEP) costs, as compared to PG&E's forecast of $179.2 million, which is based on PG&E's PSEP cost forecast for a single year, 2013 which was escalated to 2015;
- Hydrotest costs for pipe installed after 1955 should be disallowed consistent with Decision (D.) 12-12-030,[5] and the Commission should adopt structural safeguards to ensure that hydrotests on these lines are performed in a timely and appropriate manner regardless of the cost consequences to PG&E. Among other things, PG&E should not be permitted to replace segments installed between 1955 and July 1, 1961 with segments from PG&E's "Flex List"; and
- PG&E should provide additional testimony to verify that its proposed rate of hydrotesting will not result in excessively high unit costs.

Table 4C-1 compares ORA's and PG&E's proposed TY2015 forecasts for hydrotesting program expenses, which are contained in MWC JT:

[4] SAP is PG&E's cost accounting system.

[5] See Exhibit ORA-03 for a full discussion of ORA's position on this issue.

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Table 4C-1 -Corrected
Hydrotesting Program Expenses for TY2015
(In Thousands of Dollars)

Description (a)	ORA Recommended (b)	PG&E Proposed[6] (c)	Amount PG&E>DRA (d=c-b)	Percentage PG&E>DRA (e=d/b)
Hydrostatic Testing Program, MWC JT	$91,702	$179,245	$87,543	95.5%
Total	$91,702	$179,245	$87,543	95.5%

The following summarizes ORA's recommendations specific to the VIPER Program:

- PG&E should phase in the VIPER Program in coordination with its proposed Geo-Hazard Program;
- The Commission should adopt ORA's 2015 capital expense forecast of $110.0 million, which is based on unit costs derived from PSEP actual costs of projects completed in 2012-2013, as compared to PG&E's forecast of $193.8 million, which is a forecast for 2013 capital expenses based on unit costs derived from a small set of nine anomalous PSEP projects.

Table 4C-2 compares ORA's and PG&E's proposed TY2015 forecasts for VIPER Program capital expenditures:

[6] PG&E Prepared Testimony, Volume 1 (Barnes), Table 4A-8, p. 4A-32.

Table 4C-2
VIPER Program Capital Expenditures for TY2015
(In Thousands of Dollars)

Description (a)	ORA Recommended (b)	PG&E Proposed[7] (c)	Amount PG&E>DRA (d=c-b)	Percentage PG&E>DRA (e=d/b)
VIPER, StanPac, MWC 44[8]	$1,701	$2,998	$1,296	76.2%
VIPER, MWC 75	$108,300	$190,825	$82,525	76.2%
Total	$110,002	$193,824	$83,821	76.2%

The following summarizes ORA's general recommendations applicable to both the Hydrotest and VIPER Programs:

- The scope of all work performed in 2015-2017 needs to be clearly defined for prioritization. To this end, the Commission should expressly identify deferred PSEP work and the GT&S decision trees associated with both programs – which establish the work priorities for those program - should be updated to include deferred PSEP pipe segments;
- The hydrotest and replacement costs for deferred PSEP work should be subject to the cost limitations established in D.12-12-030 and the Commission should confirm that PG&E has correctly applied the cost provisions of that decision. PG&E should not be allowed to bypass the PSEP cost caps by deferring work to this case;
- The cost limitations for pipe segments installed post-1955 adopted by D.12-12-030 should be applied for all PG&E hydrotest work, and for all pipe segment replacements initiated by a lack of records;
- If the Commission grants PG&E the flexibility it has requested to modify the scope of either program, the Commission must provide adequate oversight through structural safeguards to ensure that the highest priority work is

[7] PG&E Prepared Testimony, Volume 1 (Barnes), Table 4A-16, p. 4A-55 and PG&E Workpapers, Chapter 4A, p. WP 4A-478, lines 600 and 601.

[8] The Standard Pacific Gas Line Inc. (StanPac) is a joint ownership pipeline with Chevron Pipe Line Company. PG&E has a six-sevenths interest in StanPac, See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 2-2.

performed in an appropriate time frame, regardless of the cost consequences to PG&E;[9] and

- The Commission should order PG&E to collect cost data on both programs going forward to facilitate more accurate forecasts in the next rate case.

3 ANALYSIS AND DISCUSSION

3.1 Overview Related To PG&E's Hydrotest And VIPER Program Forecasts

In requesting $179.2 million for Hydrotest Program expenses and $193.8 million for VIPER Program capital expenditures for 2015, PG&E takes a new approach compared to its PSEP request in A.11-02-019, which was the precursor to the work PG&E now proposes for both programs. In PSEP, PG&E attempted to overwhelm parties and the Commission with thousands of pages of project descriptions, cost data, and maps to show how thorough it could be in the wake of San Bruno, even though it only had "approximately two months" to prepare its safety program and the rate estimates to support it.[10] In the current case, given many more months to prepare, PG&E provides a simplistic cost estimating model[11] and just 10 pages of workpapers to support its request for approximately $179 million in 2015 for Hydrotest Program expenses and $597 million in 2015-2017 for VIPER Program capital expenditures, which comprise the largest expense program (Hydrotest) and capital expense program (VIPER) in the entire GT&S application.[12] Even after extensive prompting via discovery by three parties, PG&E provided insufficient evidence to support these two requests.

[9] Because PG&E may have to test or replace lines subject to cost disallowances, PG&E has the incentive to avoid performing this work in favor of work which is subjec t to full cost recovery. The Commission will need to establish structural safeguards, including monitoring functions, to ensure work subject to disallowances is performed in a timely and appropriate manner no different than work subject to full cost recovery.

[10] PG&E PSEP Rebuttal Testimony in R.11-02-019, (Bottorff/Stavropoulos) p. 1-25.

[11] The cost model PG&E uses in this case has one unit cost for the Hydrotest Program and three unit costs for VIPER. In contrast, the cost model used by PG&E in PSEP had eight unit costs for hydrotest and 24 unit costs for pipe replacement projects. See Section 3.2.2 for additional discussion of the GT&S Hydrotest Program cost model, Section 3.3.4 for additional discussion of the GT&S VIPER Program cost model, and PSEP Exhibit 144, R.11-02-019, Amended Testimony of ORA Witness Roberts, pp. 60-76, for additional discussion of the PSEP cost models.

[12] Additional pages are provided in the workpapers for work planned outside of the rate case

Faced with limited data in the PG&E GT&S application, this testimony develops alternative forecasts for both programs which draw data from many sources and time frames, including primarily data gleaned from PG&E discovery responses and actual costs data from PG&E's PSEP Quarterly Compliance Reports (PSEP Reports) to the Commission. As the Commission considers this analysis and the recommendations in this testimony, it should be reminded that Public Utilities Code § 454 puts the burden of proof on PG&E to show that its requested rate increases are justified, not for ORA or other parties to prove that they are unreasonable. Despite this critical distinction, ORA's testimony not only demonstrates the unreasonableness of PG&E's request, but provides both reasonable forecasts for 2015 based on PG&E-generated data and other recommendations.

3.2 Hydrotest Program

3.2.1 Continuation of The Hydrotest Program Is Necessary To Comply With The Commission's Decision To Eliminate Reliance On the Grandfather Clause, However, It is Important For Both Cost And Safety Reasons To Establish The Appropriate Rate Of Testing For The 2015-2017 Program

3.2.1.1 Elimination of the Grandfather Clause

In the wake of the San Bruno explosion of September 9, 2010, the Commission issued D.11-06-017, ending the utility practice of relying upon the "Grandfather Clause" in the federal gas safety regulations (49 Code of Federal Regulations (CFR) § 192.619(c)) to operate vintage gas transmission pipelines at historical operating pressures without the need for a pressure test and full test records. Decision 11-06-017 stated that "historic exemptions [from pressure testing] must end,"[13] and ordered that all in-service natural gas transmission pipes in California be pressure tested or replaced. The Commission's elimination of reliance upon the Grandfather Clause, combined with PG&E's incomplete test records for significant portions of its system - even after completion of MAOP Validation[14] - necessitates an ongoing hydrotest program that

period, or that do not directly impact PG&E's calculated costs as defined above for these two programs.

[13] Decision 11-06-017, p. 18.

[14] PG&E Response to ORA-DR-72 Q1. PG&E's response to this data request shows that even

exceeds the hydrotest requirements already imposed on PG&E to meet federal regulations related to its Transmission Integrity Management Program (TIMP).[15]

PG&E has stated that following completion in 2014 of its PSEP work authorized in D.12-12-030 (the PSEP Decision), it will still have 1,500 miles of pipe operating over 20% SYMS without traceable, verifiable, and complete (TVC) records[16] of a modern pressure test.[17] Consequently, the question before the Commission is not whether a hydrotest program is needed, but instead the rate at which it should proceed given cost and safety concerns. ORA recommends that a sustainable long-term pace be established that:

1) Reflects an understanding of the full scope of PG&E's proposed GT&S Hydrotest Program;

2) Reflects that elimination of the Grandfather Clause for all of California's gas utilities will create an unprecedented demand for hydrotesting which may have a negative impact on the quality of the work performed, while driving up costs; and

3) Requires identification of the highest priority lines for testing based on Commission-approved criteria and decision trees, regardless of cost impacts to the utility.

after "completion" of its intensive records search, PG&E is still missing records for approximately 269 miles of its 5808 mile gas transmission line system.

[15] See, e.g., 49 CFR §§192.921(a)(2) and 939(a) and subparts regarding baseline assessment plan and periodic evaluation using hydrotesting and other methods.

[16] The requirement for a gas pipeline operator to retain traceable, verifiable and complete (TVC) records has existed for decades. Such records are required to responsibly operate a high pressure gas transmission system. However, in recognition of the dangers posed by PG&E's recordkeeping deficiencies that were discovered in the wake of the San Bruno incident, the NTSB issued an "urgent safety recommendation" within three months of the incident, reminding PG&E of this requirement and requiring that PG&E survey all of its gas transmission records to ensure that PG&E calculated maximum allowable operating pressure for a pipeline using only "traceable, verifiable, and complete" records. See the January 3, 2011, NTSB "Safety Recommendations" to the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). The Safety Recommendation to PHMSA, which summarizes all of the safety recommendations made that day, is attached to I.11-02-016 at Appendix B.

[17] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-33. PG&E states that the "flex list," provided in workpaper pages WP 4A-54 to WP 4A-60, is comprised of Class 1 and Class 2 pipe which will be added based on "Average Occupancy Count (AOC) numbers." See Ibid, page 4A-35.

3.2.1.2 *The Actual Scope Of PG&E's Proposed Hydrotest Program*

PG&E proposes an annual target of testing 170 miles a year, and the workpapers provide a list of estimated projects based on this target.[18] However, this is not a complete picture of the scope of PG&E's proposed Hydrotest Program. PG&E also states that it has 74 miles of pipe installed after 1961 which do not have TVC records, and for which it will not seek cost recovery.[19],[20] PG&E states that it "plans to hydrostatically test these [74] miles, but will further add mileage from the "flex list" in order to reach approximately 170 miles per year of *recoverable testing mileage* during the rate case period.[21] In other words, for 2015-2017 PG&E proposes to perform a total of approximately 195 miles of hydrotesting - 170 miles for which it will receive cost recovery, and approximately 25 miles a year for which it will not. PG&E appears to suggest that both sets of projects will be prioritized according to its hydrotest decision tree when it testifies that un-recoverable mileage will be tested as it is encountered, but the meaning and impacts of this testimony should be explicitly stated.

It is important for the Commission to establish that prioritization is not influenced based on whether or not hydrotest costs can be recovered. Projects should be prioritized by a decision tree regardless of cost recovery impacts on PG&E. ORA looks to the Commission's Safety and Enforcement Division (SED) to ensure that PG&E's proposed prioritization method via the new Hydrotest Program decision tree, including the use of Average Occupancy Count (AOC) to prioritize Class 1 and Class 2 segments

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[18] See PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-32 for the annual target. 2015-2017 proposed projects, listed in workpaper pages WP 4A-52 to WP 4A-53, have annual mileages of 171.0, 168.4, and 172.0 miles respectively.

[19] PG&E agrees that lines installed after adoption of GO-112 in 1961 should have TVC records, and that it will absorb the cost of hydrotesting post-1961 lines without TVC records. However, D.12-12-030 determined, based on PG&E representations to the Commission prior to adoption of GO 112 and representations made in the PSEP proceeding (A.11-02-019), that PG&E should be responsible for the costs of hydrotesting lines installed after 1955 lacking TVC records. This is further discussed in ORA Exhibit 3, Skinner, where ORA advocates that the disallowance of D.12-12-030 be applied in this case.

[20] With regard to the 1961 date, it appears that PG&E may not be including pipe segments installed between GO-112's effective date of July 1, 1961 and January 1, 1962.

[21] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-42, emphasis added.

added from the "flex list," appropriately prioritizes PG&E's work and provides the appropriate level of risk reduction.[22]

In addition, PG&E has deferred hydrotest work from PSEP and it appears that not all of this work is included in the list of proposed GT&S projects, such that the annual GT&S scope of approximately 195 miles may need to be expanded to accommodate completion of this work. As discussed in Section 3.4 below, there are two types of PSEP deferred work, which ORA refers to as Group 1 and Group 2 Deferrals. For hydrotesting, there are approximately 86 miles of Group 1 Deferrals that PG&E purposefully omitted from PSEP Phase 1. There are also approximately 25 miles of hydrotest Group 2 Deferrals which were not included in PSEP because PG&E did not evaluate the need for mitigation of all of its transmission pipe in its PSEP Update Application. The 25 miles of Group 2 Deferrals referred to here constitute the pipe segments that would have been identified for hydrotesting in PSEP if PG&E had run all of its pipe segments through the PSEP decision tree after completion of MAOP Validation

ORA is still performing analysis to determine the exact scope of PSEP deferrals, and whether or not they are included within the currently-proposed Hydrotest Project lists. If they are not, it is possible that these miles would need to be added to the 195 miles currently slated to be hydrotested annually. Until this analysis is complete and/or PG&E clarifies this issue, consideration must be given to the possible addition of the 111 total miles of deferred PSEP hydrotesting in 2015-2017, or the addition of up to 37 miles per year beyond the proposed 195 mile annual target contemplated in the Hydrotest Program.

ORA questions whether PG&E can safely hydrotest significantly more than roughly 195 miles of pipe per year, and whether such a rate makes sense as we move forward. The PSEP hydrotest and replacement program commenced in the aftermath of the San Bruno explosion should have attained the highest rates of work on the most vulnerable areas of PG&E's transmission system. From PSEP's inception to date, ORA

[22] SED issued a Preliminary Staff Report in this case on July 18, 2014. On page 27 of this report, SED acknowledges that PG&E intends to use AOC and total occupancy count (TOC) to prioritize work, and asks for "additional details including, any white papers, supporting the development of the AOC/TOC concept."

understands that PG&E has hydrotested approximately 566 miles of pipe.[23] The highest annual rate of hydrotesting attained was 198.8 miles in 2013,[24] providing the upper bounds of what PG&E should be expected to test in any given year. As discussed below, there are sound cost and safety reasons why the annual hydrotesting mileage target should be set somewhat lower going forward.

3.2.1.3 An Overly Aggressive Rate Of Hydrotesting Could Compromise Safety And Unnecessarily Increase Costs – Priorities Based On Objective Safety Criteria Must Be Established

ORA is concerned that the high rates of hydrotesting that could result from the combination of deferred PSEP work, post- July 1, 1961 work, and PG&E-proposed GT&S work will compromise the quality of hydrotest work and safety while concurrently driving up unit costs. This concern is exacerbated by the fact that the Commission's elimination of reliance on the Grandfather Clause extends to all California gas utilities, who are now beginning to compete with PG&E for a limited pool of contractors to perform an unprecedented amount of hydrotesting in the next seven to eight years.

ORA recommends that PG&E address whether and to what degree its proposed rate of testing, which could exceed any previous rate, combined with competition from other California gas utilities, could lead to supply constraints for contractors, excessive overtime, mistakes due to rushed work, and other factors that could drive up unit costs while simultaneously reducing the quality of work in the field, the quality of records and documentation, and PG&E's safety record for workers performing tests.

SED has expressed concern that PG&E is testing fewer miles of pipe missing TVC records, since annual mileage targets include tests performed for TIMP purposes.[25] This is a valid concern that must be balanced with the other issues raised here, and it emphasizes the need for the Commission to adopt objective safety criteria to prioritize PG&E's testing and replacement projects so that scarce resources are used in the most efficient manner possible. Consistent with this proposal, ORA recommends

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[23] PG&E July 30, 2014 PSEP Report, p. 3.

[24] Ibid, p. 50.

[25] SED Preliminary Staff Report on GT&S 2015-2017 Application 13-12-012, July 18, 2014, p.27.

in Section 3.4 below that deferred PSEP work – which would have been designated as high priority pursuant to PG&E's PSEP Decision Tree – be explicitly addressed in the GT&S Hydrotest Program decision tree and that SED confirm that the level of risk reduction is not less than that provided by the PSEP decision tree adopted in D.12-12-030. Alternatively, if SED confirms equivalency from a safety perspective, PG&E could commit to performing deferred PSEP project work as its first priority in GT&S.

3.2.2 PG&E's Hydrotest Program Forecast for 2015 Does Not Accurately Track Historic/Actual Costs And Fails To Account For Its Experience Of Declining Hydrotest Costs

3.2.2.1 PG&E Claims To Base Its Hydrotest Forecast On Historic PSEP Costs

PG&E's 2015 forecast for its Hydrotest Program, MAT JTC, is $179.245 million and is comprised primarily of a forecasted cost for strength tests.[26] Table 4C-3 below shows that this forecast is based on a 2013 average unit cost of $.97 million per mile, escalated to 2015 and then multiplied by the 170 miles of recoverable miles that PG&E represents it will hydrotest in 2015.

Table 4C-3
Derivation of PG&E's TY2015 Forecast For Hydrotest Program Expenses

2013 average unit costs ($ million/mile)	Escalation rate from 2013 to 2015	Estimated length (miles)	Total 2015 Test Forecast ($ million/mile)
$0.97	1.055	170[27]	$173.970

PG&E justifies its request for a unit cost of $0.97 million per mile by claiming that it is based on historical costs and that it is similar to its forecasted 2013 costs:

> PG&E proposes a unit cost of $0.97 million per mile for 2015 for the expense portion of the testing. This unit cost is similar to the forecasted 2013 cost per mile. PG&E believes that this cost per mile and resulting program expense cost is reasonable because it is based on historical costs.[28]

[26] PG&E 2015 GT&S Workpapers, Chapter 4A, p. WP 4A-51. This request also includes a request for $5.275 million for "uprates" which is not discussed in this testimony, or elsewhere in the ORA exhibits.

[27] This excludes non-recoverable mileage discussed above.

[28] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-41, emphasis added. The unit cost for 2015 including escalation is $1.02 million per mile.

As discussed in the following sections, PG&E's 2015 Hydrotest Program expense forecast is flawed for the following reasons:

1) PG&E claims that its Hydrotest Program forecast is based on PSEP actual cost data which is nearly twice the PSEP forecasted cost, yet PG&E cannot quantify why the PSEP actual costs are so much higher than the PSEP forecast;
2) PG&E's 2015 forecast does not take into account falling costs for hydrotesting, and the opportunities for further cost reductions;
3) PG&E's 2015 forecast is based on a forecast of 2013, which is not the same as a forecast based on historic costs;
4) Based on the evidence provided, PG&E's 2015 forecast appears to be methodologically flawed; and
5) PG&E improperly escalates 2013 forecasted costs to 2015 forecasted costs.

3.2.2.2 PG&E Does Not Quantify Why Its PSEP Actual Costs Are Twice The PSEP Forecasts

PG&E stated in its PSEP Application filed on August 26, 2011 in R.11-02-019 that its Phase 1 "strength test project unit cost [forecast] … varies from a low of $47 per foot to a high of $2,646 per foot, with an average unit cost for all pipes to be strength tested of $95 per foot."[29] This forecasted average cost for PSEP projects equated to $502,000 per mile, or approximately one half of the 2013 forecasted unit costs of $970,000 per mile that PG&E uses to forecast 2015 hydrotest expenses for GT&S.

It is important to recognize that PG&E's PSEP cost forecast model was created by an international expert, used construction costs provided by a local contractor, and was validated against PG&E historic data. The cost estimate was prepared by Gulf Interstate Engineering, an ISO 9001 quality certified company with a "core competency" in "construction management of pipelines" since it was founded in 1953.[30] Gulf's cost model utilized construction cost data from a local company, ARB, who has since performed 100 of the 255 PSEP hydrotests performed through March 31, 2014.[31]

[29] PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), pp. 3-41 to 3-42.

[30] See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3D-2 and 3D-7.

[31] See Attachment 1 to PG&E's Response to DR-ORA-89 Q2.

Finally, Gulf's cost model was validated "based on similar projects escalated to 2011 prices using information from PG&E's Unit Cost Database (UCDB.)"[32]

The PSEP forecast model was supported by PG&E and yielded an average unit cost of $502,000 per mile, excluding PG&E's requested contingency.[33] The Commission found that this cost per mile was at the high end of reasonable, disallowed the requested contingency, and reduced the requested escalation such that the unit cost implicitly adopted in D.12-12-030 was less than $502,000 per mile.[34]

Given this level of support for the PSEP unit cost estimates, which D.12-12-030 nevertheless found fell "in the high end of the range of reasonableness,"[35] ORA was understandably surprised that PG&E's 2015 unit cost forecast doubled those PSEP forecasts. It therefore sought to understand how PG&E's 2015 GT&S forecast could be so much higher than its previous PSEP forecast, which had such extensive support, and how PG&E's actual PSEP costs could be so much higher than what its PSEP forecasts had predicted.

ORA's analysis revealed that PG&E's Hydrotest Program forecast starts with a forecast of 2013 expenses, which the following discussion shows is higher than actual 2013 expenses. PG&E then relied upon a simplistic model to arrive at its 2015 forecast. As the discussion below shows, using a more robust data set of actual costs from 2011, 2012, and 2013 results in a 2015 forecast very similar to the original PSEP forecasts. In other words, it appears the PSEP cost forecast set a reasonable goal which PG&E should be able to attain over time.

[32] See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p.3-51.

[33] See PG&E PSEP Rebuttal Testimony in R.11-02-019, (Bottorff/Stavropoulos) p. 1-25: "We have used industry best practices to develop our estimates and contingency and stand behind them." Average unit cost from PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3-42. This value derived from the Total strength test cost of $393. 2 million from page 3-6 and the 783 miles of program scope from page 3-29.

[34] Approved cost tables in Appendix E to D.12-12-030 include disallowances for 2011, most of 2012, and certain pipe installed after 1955. These tables cannot therefore be used to calculate unit costs. In addition, the $0.5 million average unit cost in the PSEP estimate includes escalation from 2011 to 2014 at rate of 3.12%. D.12-12-030 found this rate was excessive. Using the approved escalation rate of 1.5%, the average unit cost of PSEP would be lower, and the $0.5 million per mile average is a generous extrapolation for use in 2015.

[35] D.12-12-030, p. 63.

In its testimony, PG&E attempted to explain that its actual PSEP hydrotest costs were much higher than forecasted and the reasons for these high costs:

> Based on actual costs experienced in 2011-2012, PG&E has found that the cost calculator developed by PG&E and adopted by Decision 12-12-030 typically under-estimates the cost of the project. Water management, including cleaning the pipeline, and managing taps and customer load has been more costly than the model predicts for *many* projects. Also, the cost calculator in *many* cases under-estimates the move-on and move-off costs of a project. The cost calculator assumes that a crew will move on to a pipeline and complete all the tests on that line with only a single move-on and move-off charge.[36]

However, this explanation includes a number of misleading statements which do not help to identify the real reasons why PSEP hydrotest costs might have been higher than forecast. First, PG&E's explanation mischaracterizes the PSEP cost calculator's treatment of move-on and move-off costs, which expressly provided for multiple move-on and move off charges.[37] Second, it provides no specific information supporting any of the reasons it cites for increased costs. PG&E's explanation identifies anomalies that occurred on "many" projects, but doesn't quantify how many projects experienced each of the identified issues, or the cost impact of each issue. ORA asked for analysis supporting the qualitative justifications listed above.[38] PG&E's response only provided project costs for a limited group of 58 of the 81 (72%) hydrotest projects it performed in 2013, and no data for projects performed in 2011 or 2012.[39] These 58 projects had actual costs that were 70% higher than forecasted in PSEP, rather than the 100% increase reflected in PG&E's 2013 forecast.[40] PG&E's response did not provide the

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[36] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-40, emphasis added.

[37] The PSEP model included two separate unit costs for moving equipment, a "mob -demob" charge of $500,000 applied only once for each project and a "move around" charge that was applied to each test section within a project. The move around charge varied from $200,000 to $500,000 depending on the pipe diameter and since many projects had multiple test sections, the forecasted move around cost was approximately $114 million for all projects, which was more than the total Mod/Demob cost. See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3E-17 and ORA workpapers.

[38] ORA-DR-106 Q3.

[39] Attachment 1 to PG&E Response to ORA-DR-106 Q3. PG&E completed 90 hydrotest projects in 2011, and 81 hydrotest projects each in 2012 and 2013. See Attachment 1 to PG&E Response to ORA-DR-89 Q2.

[40] Attachment 1 to PG&E's response to DR-ORA-106 Q3.

level of detail required to support PG&E's assertions regarding the specific cause of the cost difference between PSEP forecasts and actual costs.

ORA has asked PG&E to provide actual cost accounting data so that it can identify and quantify why or even whether PSEP actual costs appear to be, on average, twice the forecasted levels.[41] While this analysis is ongoing, ORA has thus far determined the following:

1) PG&E does not classify costs such that the costs of water management can be quantified; therefore, any PG&E assertions regarding the costs of water management cannot be supported;[42]

2) PG&E does not classify costs such that the costs to clean a pipeline can be determined; therefore, any PG&E assertions regarding the costs to clean a pipeline cannot be supported;[43]

3) PG&E does not classify costs such that the costs of providing LNG/CNG to customers can be determined; therefore, any PG&E assertions regarding the costs of providing LNG/CNG to customers cannot be supported;[44]

4) PG&E does not classify costs such that the costs to prepare a test section can be determined; therefore, any PG&E assertions regarding the costs to prepare a test section cannot be supported;[45]

5) Notwithstanding 3 years of extensive hydrotesting experience, PG&E has not performed detailed analyses to define hydrotest costs in terms of fixed, variable, and unpredictable components. Further, it has indicated it cannot provide this analysis.[46] This raises concerns about the value provided by the PSEP PMO, which has already overspent its authorized budget of $28.9 million;[47] and

[41] ORA-DR-59, ORA-DR-64, ORA-DR-92, ORA-DR-94, DR-ORA-103, and DR-ORA-106 include questions regarding PG&E cost accounting methods, PSEP costs, and 2015 GT&S forecasting methods relative to Hydrotest Program costs.

[42] PG&E Response to ORA-DR-59 Q2g through Q2n.

[43] PG&E Response to ORA-DR-59 Q2f.

[44] PG&E Response to ORA-DR-59 Q2o.

[45] PG&E Response to ORA-DR-59 Q2e.

[46] PG&E Response to ORA-DR-92 Q2 referring to Q1.

[47] Authorized budget from D.12-12-030 Table E-4. PG&E had spent $33.9 million in expenses and capital expenditures as of the end on June 2014. See Table 20-1 of the July 31, 2014 PSEP Report.

6) PG&E's explanation of the reason that PSEP actual costs exceed the PSEP cost forecasts does not take into account the decrease in actual costs that occurred between 2011 and 2013 should continue.

In sum, PG&E has not collected cost data in a manner that permits analysis of (a) actual hydrotest costs to identify cost drivers, (b) whether PG&E's actual costs, over time, significantly exceeded the PSEP cost forecast, and if so, why, or (c) how costs can be reduced going forward. That said, the ORA analysis presented below sheds some light on what is actually happening regarding PSEP costs, and what a more appropriate 2015 forecast should be.

3.2.2.3 ORA Analysis Shows That PG&E's Forecast For Hydrotest Costs Is Significantly Higher Than The Actual/Recorded Hydrotest Costs Contained In PG&E's Quarterly PSEP Reports To The Commission

Lacking specific information from PG&E to understand the significant difference between PG&E's forecasted PSEP hydrotest costs and the PSEP costs PG&E claimed it incurred, ORA compared actual cost data from PG&E's PSEP Quarterly Compliance Reports (PSEP Reports), which are filed pursuant to Commission Order,[48] to the cost data provided with PG&E's GT&S request. The PSEP Reports are submitted to the Commission in response to a direct order in D.12-12-030, and should contain the highest quality and most accurate data PG&E is able to produce. PG&E's SAP system is supposed to be the single source of all cost data.[49] Therefore, a comparison between the PSEP Report data and the GT&S data should yield similar data and similar results, but it did not.

ORA's comparison instead revealed that PG&E's 2011 and 2012 "actual costs" relied upon in the GT&S request were significantly higher than the actual costs PG&E reported in the PSEP Reports.[50]

ORA used a spreadsheet version of PG&E's PSEP Reports obtained through discovery as its source for the PSEP cost and mileage data.[51] Only recorded data was

[48] D.12-12-030, Ordering Paragraph 10 and Attachment D.

[49] PG&E Response to ORA-DR-64 Q3.

[50] ORA's analyses used "total" costs exclusively in calculating unit costs. This includes cost funded by both ratepayers and PG&E shareholders. It appears that PG&E also used total costs in its unit cost calculations.

used. The following Table 4C-4 compares the data compiled by ORA from PG&E's PSEP Reports and discovery responses to the data provided in PG&E's GT&S request:[52]

Table 4C-4
Comparison of Recorded Costs From PSEP Reports To Costs Represented By PG&E in GT&S

	Recorded Data from PSEP Reports					PG&E GT&S Request			
	Project Count	Total Footage	Total Mileage	Actual Cost ($million)	Unit Cost ($M/mile)	Miles Strength Tested	Cost ($million)	Unit Cost ($M/mile)	Unit Cost Variance (%)
2011	90	[illegible]	163.3	[illegible]	[illegible]	163	[illegible]	[illegible]	18%
2012	81	[illegible]	176.2	[illegible]	[illegible]	176	[illegible]	[illegible]	22%
2013	81	[illegible]	198.7	[illegible]	[illegible]	195	[illegible]	[illegible]	35%

This table shows that the mileage between the two data sets is the same, or nearly the same, for each year, 2011 through 2013.[53] This suggests that each data set addresses the same scope of work. However the unit costs contained in the GT&S request are 18% to 35% higher than unit costs based on the actual costs PG&E's discovery response related to the PSEP Report data represents were incurred in each year.[54]

ORA issued a data request to PG&E asking why the actual costs included in the PSEP Report data are lower than the costs used by PG&E in this case.[55] Lacking a response from PG&E at the time of this testimony, ORA continued its comparative review of both data sets.

The PSEP Report data provided through discovery includes project level recorded total costs for the 182 test projects completed between 2011 and 2013. The PSEP Reports provide a list of projects completed each year to date in response to Question 11 posed in Attachment D of D.12-12-030 which provides:

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[51] Attachment 1 to PG&E Response to ORA-DR-89 Q2.

[52] PG&E GT&S data from PG&E 2015 GT&S Workpapers, Chapter 4A, p. WP 4A-51.

[53] The GT&S request has a forecast for 2013 but the 2014 PSEP Reports have actual data for 2013, which includes 3.8 additional miles of work performed.

[54] Attachment 1 to PG&E Response to ORA-DR-89 Q2.

[55] DR-ORA-116 Q1.

On a project by-project basis, provide the amount budgeted for the project and an itemized list of the costs, including labor and material, incurred completing of the project. Identify the amount that a project was over or under-budget.[56]

The resulting tables 11-1 in PG&E's PSEP Reports, one per quarter, provide the "Total Cost" per project and a breakdown of this cost by labor, material, contract, and "other" costs. The inclusion of this "other" cost category, within the context of Question 11 above, strongly suggests that these project costs are all inclusive.

Question 23 of Attachment D to D.12-12-030 asked PG&E to document the mileage of testing completed year to date (YTD) as follows:

Provide a table showing the mileage of pipe PG&E forecast to hydrotest in R.11-02-019 and the mileage PG&E has tested year-to-date. Identify the location, Line #, milepost, Class of the pipe tested. Indicate whether the pipe is located in a High Consequence Area.

PG&E's PSEP Report data as provided through discovery comprise the cost and mileage data ORA compiled to create the table above.[57]

In comparison, the cost data in PG&E's workpapers in the GT&S application consisted primarily of a list of 268 line item costs that PG&E determined were related to hydrotesting for 2011 through 2017.[58] Some of these costs were then subtracted out because, as explained by PG&E, they should not be included in the unit cost calculations.[59] However, PG&E did not identify which lines items were subtracted to calculate its unit costs, even in response to repetitive discovery requests.[60] ORA reviewed data obtained through discovery to try and understand why this PG&E GT&S

[56] Table 11-1 in the PSEP Reports includes a column entitled ">10% Over Budget." A "yes" response is only provided if the total project cost exceeds the "Job Estimate" by more than 10%. A Job Estimate would have been created after project design was completed and the Job Estimates are generally significantly higher than the project costs estimated in the PSEP and PSEP Update applications.

[57] Attachment 1 to PG&E Response to DR-ORA-89 Q2.

[58] PG&E 2015 GT&S Workpapers, Chapter 4A, pp. WP 4A-4 to WP 4A-9.

[59] Ibid, p. WP 4A-50.

[60] PG&E's response to ORA-DR-59 Q13 provided costs that could be summed to provide the values in the third line of Table 1, page WP 4A-50, but they did not explain or demonstrate how data in line 1 of this table were derived. PG&E's response to ORA -DR-92 Q7 provided support for the data in line 1 of Table 1 as requested, but did not show how these costs could be derived using the data it provided in workpapers starting at page WP 4A-4, also as requested.

data differs from the PSEP Report data. A review of the 268 line items reveals that, as a general rule, the GT&S cost data PG&E relies upon for its 2013 and 2015 forecasts lacks the specificity of, and is not comparable to, the PSEP Report actual cost data, and much of the data provided is not even relevant to hydrotest costs. Among other things:

1) For 2011, while there are some line items for specific hydrotests, 63% of actual costs are attributed to a single line item with the general label "Strength Testing;"[61]

2) A significant amount of the actual costs included in PG&E's workpapers supporting its hydrotest unit cost forecast includes costs not related to hydrotesting. Specifically, 33% of 2011 actual costs, 40% of 2012 actual costs, and 13% of 2013 forecast costs are for two line items labeled "Data and MAOP Validation" and "MAOP Project Phase II." PG&E does not include these costs in unit cost calculations, so it is not clear why these costs are included in a data base that is supposed to be limited to supporting its hydrotest costs;[62]

3) 75% of the 2013 forecast was based on large single line item high level estimates, such as $83.1 million for "PSEP hydrotesting expense overrun" and $34.3 million for "PSEP Hydrotesting Disallowed Expenses;"[63]

4) There are no large costs or line items in the PG&E cost data that appear to have been excluded from the PSEP Report data and would therefore explain why the PG&E GT&S data shows much higher costs than the PSEP Report data.

In sum, PG&E's 268 lines of data to support its GT&S forecast lacks the resolution to determine what PG&E's unit cost estimate is based on, and why it differs from the PSEP Report data. Slight differences in cost data reported in different formats are understandable. However even the 18% cost difference for 2011 – which is the smallest cost annual difference between the GT&S forecast and the PSEP actual costs – is significant.

3.2.2.4 *PG&E's Forecast Does Not Address Declining Hydrotest Costs*

The PSEP Report data not only shows lower unit costs than PG&E has requested, based on actual PSEP costs, it also shows a clear downward trend in

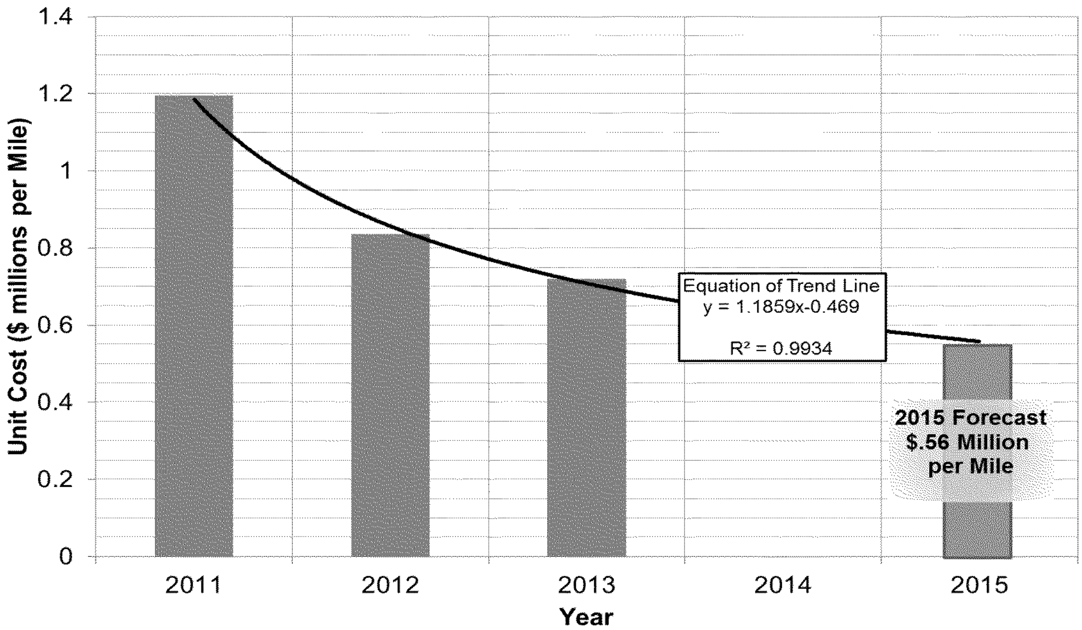
[61] PG&E 2015 GT&S Workpapers, Chapter 4A, p. WP 4A-5, line 194, shows $215.2 million for Strength Testing.

[62] Ibid, p. WP 4A-4, lines 154 and 155.

[63] Ibid, p. WP 4A-4, lines 159 and 160.

hydrotest costs between 2011 and 2013.[64] Such a trend is to be expected when a new program is commenced and the company experiences a learning curve. The following figure illustrates this trend, and extrapolates costs out two years to provide forecast costs for 2015 that take into account the likely continuation of the declining hydrotest cost trend:

Figure 4C-1
Declining Hydrotest Unit Costs Based on PSEP Reported Costs



This figure, using recorded 2011, 2012, and 2013 costs from PG&E discovery responses as shown in Table 4C-4, extrapolates a 2015 cost of approximately $0.56 million per mile using a trend line based on a power equation.[65] The power equation is a form of "experience curve" which describes how costs decline as experience

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[64] It was inappropriate to use 2014 data in this extrapolation for the following reasons:

- The 2014 data is based on crude and opaque cost estimates similar to PG&E's 2013 GT&S forecast;
- PG&E's GT&S forecast for 2013 did not accurately reflect recorded costs;
- Only the first quarter 2014 PSEP Report was available when this testimony was prepared;
- PG&E indicated that hydrotesting in 2014 was challenging and had higher unit costs. See PG&E Response to ORA-DR-92 Q12.

[65] The equation of the trend line is 1.11859X^-0.469 where x is equal to 1 for 2011. Using x=5 for 2017 yields $0.557 million per mile. The R^2 (R squared) value of 0.9934 indicates an excellent fit to the data. See the Exhibit 4C Workpapers.

increases. The ORA Exhibit 4C Workpapers show that this equation provides the best match to PG&E's reported cost data.[66] Also included in the ORA Exhibit 4C Workpapers is an alternative trend analysis using the recorded 2011 and 2012 expenses provided by PG&E in this case, and the recorded 2013 costs provided through discovery and adjusted using the same steps PG&E used for 2011 and 2012 recorded data.[67] This analysis was performed to compare results from the two data sets available to ORA. Extrapolating this data using the same power equation used to derive the trend line in Figure 4C-1 above results in a forecasted 2015 unit cost of $0.47 million per mile.[68]

Other information obtained through discovery or through my personal experience working on PG&E and Sempra utility pipeline programs since 2011 also support the conclusion that PG&E's hydrotesting costs should continue on a downward trend, including the following:

1) PG&E initiated the hydrotest program in 2011 in response the San Bruno explosion and the NTSB investigation that followed. It rightfully should have focused on safety, with less concern for the costs of the program. By 2015, PG&E should have progressed beyond "firefighting" mode and be positioned to make cost reduction more of a priority than previously.

2) PG&E implemented a hydrotest program cost reduction program in 2012, and there is no evidence that this program, or its successor, will fail to continue to produce cost reductions.[69]

3) 88% of the total hydrotest costs since the inception of PSEP were recorded by four "Alliance Construction contractors."[70] Pricing or cost containment was

[66] See http://en.wikipedia.org/wiki/Experience_curve_effects

[67] Section 3 of the ORA Exhibit 4C Workpapers describe how ORA used the process described on page WP 4A-50 to adjust data provided in Attachment 4 to PG&E Response to ORA-DR-59 Q11.

[68] ORA does not recommend using this $0.47 million per mile unit cost. While it results in a lower value, ORA is less certain of the quality of the data, the trend line is a less accurate fit to the data, and the results using different trend lines provides less confidence that the resulting unit cost is reasonable.

[69] See Redacted Attachment 1 to PG&E Response to ORA-DR-59 Q23.

[70] "The Alliance Construction contractor delivery model" and its progress is discussed in chapter 3 of each PSEP Report. In 2013, PG&E engaged in four contracts with "Alliance Construction contractors" and these contractors performed 218 of the 255 PSEP hydrotests performed from PSEP inception through March 31, 2014 2014, see Attachment 1 to PG&E Response to ORA-DR-89 Q2, and ORA Exhibit 4C Workpapers, Section 9.

not a major factor in the selection of these contractors,[71] cost control was not one of the primary objectives of the program,[72] and the "job estimate" for each project was determined by collaboration between PG&E and each Alliance contractor rather than through a project-level competitive solicitation.[73]

4) PG&E has multiple options going forward to utilize contracting methods with a greater focus on cost reduction, including adjusting the priorities with the current Alliance contractors model, re-negotiating those contracts, performing more work with PG&E construction crews, or utilizing the competitive solicitation process for more individual projects, or groups of projects.

5) Management of the large volume of water required for each hydrotest, which was the largest cost driver in Sempra's PSEP application (approximately 70%), provides a significant opportunity for cost reduction.[74] PG&E currently leaves water management to the construction contractors rather than treating water management as a significant cost driver and working with state agencies to find strategic ways to reduce both water supply and disposal costs.[75] Currently, PG&E does not collect data that allows it to quantify the actual cost of water management.[76] Consistent with ORA's recommendations in the Sempra PSEP case, PG&E should develop a water management plan focused on reducing water management costs, and seek CPUC assistance to work with other state water agencies to streamline permitting processes for the greater public good.[77]

6) A map of project locations provided by PG&E suggests that PG&E may not have considered the savings in mobilization/demobilization costs that could be achieved by performing tests in the same geographic area sequentially.[78]

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[71] See Redacted Attachments 1 and 2 to PG&E's response to ORA 109 Q2.

[72] April 30, 2014 PSEP Report, p. 11. The stated "primary objectives" of this program are "the establishment of best-in-class safety performance, a robust construction delivery model, and the maintenance of a qualified/skilled workforce to perform work planned."

[73] PG&E Response to DR-ORA-109 Q2b.

[74] ORA Exhibit 3, Revised Testimony of ORA Witness Roberts dated August 30, 2013 in the Sempra Utilities PSEP case, A.11-11-002, p.III-11.

[75] PG&E Redacted Response to DR-ORA-59 Q19.

[76] PG&E Response to DR-ORA-59 Q2g and Q2n.

[77] ORA Exhibit 3, RevisedTestimony of ORA Witness Roberts dated August 30, 2013 in the Sempra Utilities PSEP case, A.11-11-002, pp. V-28 to V-29. Sempra requested CPUC assistance in its PSEP application and ORA supported this request. PG&E has hydrotest waste management procedures, provided asRedacted Attachments 1 and 2 to PG&E Response to ORA 59 Q17, but these are project level procedures rather than a program-wide plan to strategically reduce water management costs including water supply, transportation, on-site storage, on-site treatment, and disposal. PG&E has also not sought CPUC assistance in this statewide issue. See PG&E Response to ORA-DR-59 Q19e.

[78] Attachment 1 to PG&E's Response to DR-ORA-93 Q10.

> For example the map shows five tests in the Redding area, two in 2015, one in 2016, and two in 2017.[79] A review of PSEP hydrotest data indicates that most projects, even the longest tests, were completed in one to two months. Thus, it is unlikely that these five tests will require test equipment in one area for three years. Consideration of mobilization/demobilization costs in the scheduling of projects, which were estimated to be $500,000 per test in PSEP and claimed to be higher in the current application,[80] could result in considerable cost savings.[81]

Based on these findings, it is reasonable to assume that the cost reductions in hydrotest unit costs that PG&E has achieved to date can and should continue into the future.

3.2.2.5 The 2015 Hydrotest Program Forecast Is Based On A Forecast Of 2013, Which Is Not The Same As A Forecast Based On Historic Costs

As discussed above, PG&E's proposed 2015 hydrotest unit cost of $1.02 million per mile is based on a forecast for a single year, 2013. 2013 recorded costs were available through discovery, but had to be adjusted to be comparable to the recorded unit cost provided by PG&E in workpapers. As shown in Section 3 of the Exhibit 4C Workpapers, application of the same methodology PG&E used in calculating 2011 and 2012 unit costs yields a recorded 2013 unit cost of $0.63 million per mile.

3.2.2.6 PG&E's 2015 Hydrotest Program Forecast Is Based On A Significant Methodological Flaw

With regard to its 2015 expense forecast methodology, PG&E states:

> PG&E proposes a unit cost of $0.97 million per mile for 2015 for the expense portion of the testing. This unit cost is similar to the forecasted 2013 cost per mile. PG&E believes that this cost per mile and resulting program expense cost is reasonable because it is based on historical costs.[82]

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[79] Refer to Table 11-1 in any of the PSEP Reports and compare the mobilization date, the starting data, to the tie-in date, the completed date.

[80] See discussion in Section 3.2.2.2 above regarding PG&E's claims that increased mobilization/demobilization costs led to hydrotest costs higher than forecasted

[81] See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3E-15, and PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-40.

[82] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-41. PG&E's proposed 2015 unit cost is more accurately $1.02 million per mile, including escalation.

Thus, PG&E suggests that it is appropriate for it to use its forecasted 2013 unit costs to forecast its 2015 unit costs because the work in both years must be similar. In this manner, PG&E's uses a single data point – its 2013 forecast – and derives its 2015 forecast based upon a qualitative assumption that the work in both years are similar so that their cost estimates should be similar.

However, PG&E provides no support in testimony or workpapers to support *any finding* that the work in those years will be similar, or in any other way comparable, to justify its reliance on the 2013 forecast to derive its 2015 forecast. For example, PG&E could have provided comparative data on the proportion of pipe diameters, project lengths, and project locations for each program. However, PG&E did not provide such evidence.

More significantly, given the amount of data available regarding actual hydrotest costs for 2011, 2012, and 2013,[83] PG&E's reliance upon a 2013 forecast to derive its 2015 forecast based on unidentified qualitative factors, is even less justifiable. Reliance upon a single data point when other data is available is methodologically inappropriate.[84] Among other things, a single data point can be used to generate an infinite number of forecast values and is therefore unreliable. Given the availability of actual data, which ORA has used to analyze PG&E's forecast and to derive alternative forecasts, PG&E's derivation of its 2015 forecast should be rejected as methodologically flawed and the Commission should articulate expectations for a higher standard of analysis in future rate cases.

3.2.2.7 PG&E Improperly Escalates The 2013 Forecast Costs To Derive 2015 Forecast Costs.

PG&E escalates its 2013 forecasted unit cost of $0.97 by 5.5% to obtain the unit cost used to support its 2015 request for $173.97 million for hydrotest expenses, not including uprates and other expenses. PG&E's response to a TURN data request

[83] PG&E would not have had a full year of 2013 recorded data when this application was filed in December 2013, but it had three quarters of data, as provided to the Commission in the October 29, 2013 PSEP Report.

[84] Qualitative forecasting techniques, which are subjective estimations based on the opinion and judgment of consumers or experts could be used, but they are only appropriate when past data are not available. See http://en.wikipedia.org/wiki/Forecasting.

shows that PG&E's proposed 5.5% escalation is based on forecasting expenses from 2012 to 2015.[85] However, PG&E bases its 2015 forecast on a forecast of 2013 PSEP expenses, rather than 2012 actual costs. If the Commission determines that escalation is appropriate, the correct escalation rate is 4.07%.[86]

3.2.3 Hydrotest Costs For Post-1955 Lines Should Be Disallowed Consistent with D.12-12-030, But Segments Installed Between 1955 And June 30, 1961 Should Not Be Replaced From PG&E's "Flex List"

Subject to a successful showing that PG&E can perform approximately 195 miles of hydrotesting on a long term basis without the adverse impacts identified in Section 3.2.1.3 above, ORA supports PG&E's proposal that its shareholders pay the hydrotest costs for pipes installed after 1961 and lacking TVC hydrotest records, but clarifies that the disallowance apply to pipes installed after June 30, 1961, which is the effective date of GO-112.[87] In addition, the testimony of ORA Witness Skinner in Exhibit ORA-03 explains why this disallowance should be extended to pipes installed after December 31, 1955 that are lacking TVC hydrotest records.[88]

PG&E testifies that the 510 miles it plans to test between 2015 and 2017 (170 miles per year) includes 47 miles of pipe installed between 1955 and 1961.[89] If the Commission does not change its current policy, and finds that the cost of hydrotesting of these 47 miles should be borne by PG&E shareholders, these projects should remain in the 170 mile per year program. PG&E should not be permitted to augment its annual hydrotest program with additional miles from its "Flex List" to make up for the lost revenues. Permitting PG&E to supplement its testing with more pipe segments would add 15.6 miles per year to its current proposal to test 194.7 miles per year (170 miles + 24.7 miles of post-1961 lines), for a total 210.3 miles per year. This level of annual hydrotesting would be truly "unprecedented" – and fails to take into account the

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[85] PG&E Response to DR-TURN-11 Q17, Attachment 1.

[86] Ibid, 4.07% obtained using 2.1% from line 70 and 1.93% from line 71.

[87] See D.12-12-030, p. 11, footnote 9.

[88] See D.12-12-030, p. 117, Findings of Fact 16 through 18, and p. 122, Conclusions of Law 15 and 16 for the findings and conclusions forming the basis for this date.

[89] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), Table 4A-12, p. 4A-43.

possibility that up to 111 miles of deferred PSEP hydrotesting may need to be performed as well, as discussed in Section 3.4 below.[90]

As described in Section 3.2.1.3 above, ORA proposes that the Commission set a realistic annual hydrotesting goal that strikes an appropriate balance among cost and safety factors. A testing rate that is too high will put upward pressure on unit costs due to supply constraints, and could result in poor quality and on-the-job safety issues.

3.2.4 ORA Recommends An $87.5 Million Reduction To PG&E's $179.2 Million 2015 Hydrotest Program Expense Request

Based on the above discussions regarding the proper scope of PG&E's Hydrotest Program, unit costs based on actual PSEP costs reflected in the PSEP Report data, falling hydrotest costs, and disallowances for pipes installed post-1955, ORA recommends an $87.5 million adjustment to PG&E's 2015 hydrotest expense forecast of $179.2 million, to $91.72 million.

Specifically, ORA recommends the use of the $0.56 million per mile unit cost obtained by extrapolating 3 years of <u>recorded</u> costs as discussed in Section 3.2.2.4.[91] This unit cost is roughly consistent with the average unit cost of the $0.50 million per mile that PG&E forecast for PSEP in 2011. Using this forecast reduces PG&E's requested forecast by $78.8 million, and is consistent with ORA's analysis that shows that PG&E's hydrotest costs are falling, not increasing. ORA also recommends disallowance of expenses for pipe installed after 1955 where PG&E does not have TVC hydrotest records. Based on ORA's proposed unit cost of $0.56 million per mile and PG&E's estimate that 47 miles were installed between 1955 and 1961, this results in a

[90] As discussed in Section 3.4.2, there are 86 miles of Group 1 hydrotest deferrals and 24.6 miles of Group 2 hydrotest deferrals, or approximately 111 miles total. PG&E has committed to performing Group 2 Deferrals in 2015-2017 but it is not clear how much of the Group 1 deferrals are already included in the proposed 2015-2017 scope.

[91] ORA does not recommend using the $0.47 million per mile unit cost derived from the alternative trending analysis discussed in Section 3.2.2.4 above and in Section 3 of the Exhibit 4C Workpapers. While it results in a lower value, ORA is less certain of the quality of the data, the trend line is a less accurate fit to the data, and the results using different trend lines provides less confidence that the resulting unit cost is reasonable.

$8.8 million disallowance.[92] Under PG&E's proposed unit cost, this disallowance would be $16.0 million.

UCC codes for each of the proposed hydrotest projects, which are required to group them into the line items below for use elsewhere in the workpapers and in the input to the RO model, were not provided in PG&E's filing. Therefore the $87.5 million reduction for 2015 was spread across the 14 line items related to the 2015 hydrotest forecast in proportion the PG&E's forecasted costs, as set forth in Table 4C-5 below:

Table 4C-5 - Corrected
ORA-Proposed Adjustments To The Hydrotest Program Forecast

PG&E WP Line No	Planning Order Number	Order Description	MAT	PG&E 2015 Forecast	Adjustment for $0.56 M/mile unit cost	Adjustment for 1955-1961 Pipe using $0.56 unit cost	Line Item Adjustment in RO model	ORA 2015 Forecast
JH8	1B2H88	5 -$- -B A	JC	928 22J	[illegible]	[illegible]	[illegible]	[illegible]
JHB	1B2H8B	5 -$- - N	JC	881 BH1H	[illegible]	[illegible]	[illegible]	[illegible]
JHJ	1B2H8H	5 -$- -N H	JC	B H 8	[illegible]	[illegible]	[illegible]	[illegible]
JHH	1B2H8J	5 -$- -N H B	JC	21H9HH	[illegible]	[illegible]	[illegible]	[illegible]
JH1	1B2H81	5 -$- -NS H	JC	8B 21 B9	[illegible]	[illegible]	[illegible]	[illegible]
JH2	1B2H82	5 -$- -S H	JC	B1 I 9 11	[illegible]	[illegible]	[illegible]	[illegible]
JH	1B2H8	5 -$- -S A	JC	28 H 8	[illegible]	[illegible]	[illegible]	[illegible]
J9J	1B2H9B	3 5 6 -$- -B A	JC	H98 B I	[illegible]	[illegible]	[illegible]	[illegible]
J9H	1B2H9J	3 5 6 -$- - N	JC	8I J 98	[illegible]	[illegible]	[illegible]	[illegible]
J91	1B2H91	3 5 6 -$- -N H	JC	8JJ J2	[illegible]	[illegible]	[illegible]	[illegible]
J92	1B2H9H	3 5 6 -$- -N H B	JC	H 9JH	[illegible]	[illegible]	[illegible]	[illegible]
J9	1B2H92	3 5 6 -$- -NS H	JC	1 B 9	[illegible]	[illegible]	[illegible]	[illegible]
J9I	1B2H9	3 5 6 -$- -S H	JC	8 282 I 9J	[illegible]	[illegible]	[illegible]	[illegible]
H	1B2H9I	3 5 6 -$- -S A	JC	8 BJH	[illegible]	[illegible]	[illegible]	[illegible]
H 8	1B2H8I	5 6 Hy -, _U -	JC	1 B 1		[illegible]	[illegible]	[illegible]
		Total		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Hydrotesting Program expenses for 2016 and 2017 are addressed in the attrition year testimony of ORA Witness Tang, Exhibit 18.

3.3 Vintage Pipe Replacement Program (VIPER)

PG&E estimates that there are 370 miles of pipe with "vintage features" in locations where there is a threat of land movement, and that these pipes represent "one of the top risks facing the transmission pipe asset."[93] PG&E proposes to replace 20 miles of this pipe that are "<u>in proximity to population</u>" during each year of the rate case

[92] This disallowance will change if ORA subsequently determines that more than 47 miles are subject to this disallowance, or if the Commission ultimately adopts a different unit cost.

[93] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-52 and 4A-55.

period through this program.[94] PG&E forecasts $193.8 million in capital costs associated with the VIPER Program in 2015.

As set forth in detail below, ORA has a number of concerns regarding PG&E's proposed VIPER program, including the following:

1) The VIPER Decision Tree does not consider the full range of line segments that should be considered for replacement between 2015 and 2017;

2) PG&E previously eschewed the need for VIPER-type replacements within PSEP, such that work that could have been initiated under PSEP was delayed until now;

3) If VIPER proceeds now, it should be done in coordination with PG&E's proposed Geo-Hazard Program which will inform priorities for VIPER work;

4) Coordination with PG&E's proposed Geo-Hazard Program is also desirable because it will provide for a slower phase-in for VIPER than PG&E has proposed, allowing time for delayed PSEP work to be done in the earlier years; and

5) PG&E's VIPER Program forecasts are too high and cannot be supported, therefore, they should be reduced.

As a result of these issues, ORA's 2015 forecast for VIPER capital expenditures is $110.0 million, as compared with PG&E's forecast of $193.8 million, as set forth in Table 4C-2 in Section 2 above.

3.3.1 PG&E's Proposed VIPER Decision Tree Should Be Updated To Evaluate All Pipeline To Be Considered For Replacement Between 2015 and 2017

PG&E proposes to evaluate pipeline segments for replacement in the VIPER Program using the VIPER decision tree, which is provided as Figure 4C-4 in Section 3.4.1 below. However, use of the VIPER decision tree is not optimal because PG&E's VIPER decision tree improperly narrows the types of pipe which should be considered for replacement beginning in 2015 to only those with vintage fabrication or construction in locations susceptible to land movement. As discussed in Section 3.4.2 below, there are a number of pipe segments posing other types of threats which would have been identified for testing or replacement under the PSEP decision tree which would not

[94] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-54.

necessarily be mitigated under the VIPER decision tree. While PG&E has proposed to include some of the deferred PSEP pipe segments in VIPER, this is not sufficient because it is not clear that VIPER would identify those pipe segments for mitigation. Consequently, PG&E should be required to explain how the VIPER decision tree should be modified to address the deferred PSEP pipe segments and how mitigation for those pipe segments will be prioritized.[95]

While PG&E may argue that the threats mitigated by the VIPER decision tree should take priority over deferred PSEP work, this argument would be disingenuous because PG&E has previously argued that PSEP work should take priority over the types of threats now proposed to be mitigated in the VIPER Program.

The threat regarding vintage pipe features in unstable locations was raised in the original PSEP application in a report provided by PG&E's consultant Kiefner and Associates. Referring to the PSEP decision tree, the Kiefner Report explained that certain obsolete pipe features would undergo an engineering condition assessment (ECA) and presumed that they would be replaced if they were located in areas where the effects of seismic activity could be expected, such as fault crossings or potentially unstable slopes.[96]

Many of the pipe features proposed for replacement in VIPER were listed in the PSEP decision tree, including wrinkle bends, and couplings. However, as the Kiefner Report observed, PG&E did not have an ECA protocol in place in 2011, and so no pipe segments were proposed for replacement.[97] PG&E described an ECA as a process "used to decide and schedule replacement of these pipe attributes relative to industry best practices and the likelihood that the area could experience excessive ground movement that could damage, fracture, or rupture a gas pipeline."[98] The PSEP Update

[95] SED had a related issue regarding prioritization of VIPER projects. See SED Preliminary Staff Report on GT&S 2015-2017 Application 13-12-012, July 18, 2014, pp. 36 to 37.

[96] See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3C-13 for review by Kiefner and Associates. PSEP Decision Tree provided as Attachment 3A in the same filing.

[97] PG&E PSEP Rebuttal Testimony in R.11-02-019, (Hogenson) p. 3-6.

[98] PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3-15. The GT&S application also includes an "ECA" program, but this is for "engineering critical assessment" (as opposed to an "engineering condition assessment") which is not applied to the "transmission" asset family that includes the VIPER program. PG&E 2015 GT&S Prepared Testimony, Volume

Application filed October 29, 2013 as A.13-10-017 also did not include projects to replace construction threats based on an ECA.[99]

The Kiefner Report addressed other pipe construction features included in the PSEP decision tree at decision point 2E, which are also slated for mitigation in VIPER, including certain types of girth welds and chill rings.[100] The Kiefner Report highlighted that the threat posed by these obsolete pipe features cannot be mitigated through hydrotesting. However both the Kiefner Report and PG&E's testimony failed to address the fact that the PSEP decision tree routed pipe segments with these features <u>away from</u> replacement if a hydrotest had been performed.[101] Consultants for TURN and ORA agreed with the Kiefner Report that hydrotesting did not address these concerns, and concluded that the decision tree needed to be modified to require replacement of these segments as a high priority for mitigation even though this mitigation was ten times more expensive than PG&E's preferred option.[102, 103] PG&E argued against replacing these segments as part of PSEP, in part because this would preclude mitigation of other pipe threats.[104] D.12-12-030 adopted PG&E's proposed decision tree as filed and did not address the engineering concerns raised by TURN and ORA.

Now, PG&E seems to have reversed its previous position by providing testimony that lines with vintage features located in areas of seismic activity are "one of the top risks" facing the pipeline asset family, and that the VIPER program is required to resolve

1 (White), p. 6-2.

99 ORA reviewed the PSEP Update database that defines PSEP mitigation, file "PSEP Updated Pipe Segment Database 10.24.13.xls," and found that no pipe segments had a DT outcome of "F1," which indicates a need for Phase 1 replacement following an ECA.

100 PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3C-14.

101 PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), Attachment 3A, decision point 2F.

102 PSEP Exhibit 131, January 31, 2012 Prepared Testimony of TURN Witness Kuprewicz, pp. 22-23, and PSEP Exhibit 145, January 31, 2012 Prepared Testimony of ORA Witness Rondinone, p.12.

103 The forecasted PSEP average cost per foot was $95 for hydrotest and $855 for replacement. See PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), pp. 3-40 and 3-42 respectively

104 PG&E PSEP Rebuttal Testimony in R.11-02-019 (Hogenson), p. 3-7.

this threat.[105] One possible rationale for PG&E's change in position is that vintage features located in areas of seismic activity are the highest threat once other threats identified though the PSEP decision tree have been removed. However, even if this is the case, as discussed in Section 3.4 below, PSEP-identified work has been deferred, and the VIPER decision tree needs to be revised to show how this deferred PSEP work is prioritized, and an explanation provided if PG&E proposes that deferred PSEP work not be the highest priority for work beginning in 2015.

3.3.2 It Is Unclear Why, If VIPER Threats Were So Pressing, PG&E Did Not Perform The Work as "Higher Priority" Work When Other PSEP Projects Were Cancelled

In the PSEP Update Application, PG&E indicated that MAOP validation resulted in reducing the original scope of pipe replacement by 23%, from 186 miles to 143 miles.[106] D.12-12-030 allowed PG&E to replace this scope with "higher priority" project[s]" and adjust the cost cap accordingly. The adopted PSEP decision tree also gave considerable leeway for PG&E to perform mitigation based on engineering judgment.[107] Thus, to the extent that VIPER work was high priority, PG&E had the opportunity to begin performing VIPER work in 2013 or 2014, but it did not capitalize on this opportunity. Therefore, while ORA continues to support the need for a program to replace obsolete or vintage pipe features, the case history supports one of two approaches to the VIPER program: 1) if the threats identified for resolution in the VIPER program truly represent some of the highest risks to PG&E's system, it was inappropriate for PG&E to exclude these lines from PSEP, and any work performed under VIPER should be subject to the PSEP cost recovery rules of D.12-12-030,[108] or 2)

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[105] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-55.

[106] PSEP Update Testimony, Table 2-5, page 2-26.

[107] In the PSEP hearings, PG&E emphasized that the decision tree includes the proviso that "Decision Trees Do Not Imply Final Decisions. Should Always be Combined with Practical Judgment" to support mitigations they felt were necessary. R.11-02-019, 11 RT 1401, lines15-20 (PG&E/ Hogenson).

[108] PG&E Response to ORA-DR-007 Q05a: "The risks identified and for which PG&E is proposing mitigation programs in this rate case period are not new. What is new is the process by which PG&E evaluates the risks and prioritizes the mitigation programs to address those risks. Inherent in this risk management process is the reliance on asset data."

the risk from the threats is not so great that PG&E should rush into the VIPER program prematurely, without a phase in period as described in Section 3.3.3 below that can be coordinated with PG&E's related Geo-Hazard Program.

3.3.3 If VIPER Proceeds, Its Phase-In Should Be Coordinated With PG&E's Proposed Geo-Hazard Program

Regardless of whether or not PG&E was justified in not replacing vintage pipe features as part of PSEP, the timing of the VIPER Program PG&E now proposes must be considered. While not addressed in PG&E's testimony, ORA analysis of PG&E data, which is summarized in Table 4C-6 below, shows that PG&E plans to start the program with more than the target of 20 miles a year, and then slow the pace of the program to 16.61 miles in 2017.[109]

Table 4C-6
VIPER Program Replacement Schedule

Pipe Size	2015 Mileage	2016 Mileage	2016 Mileage	Total
<12"	[illegible]	[illegible]	[illegible]	[illegible]
12-24"	[illegible]	[illegible]	[illegible]	[illegible]
24"+	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]
% of 2015 Mileage	100%	96%	77%	NA

At first glance, it seems strange that the scope of a new program would decrease over the years, instead of starting small and ramping up. This curiosity is magnified when considered together with the fact that PG&E is requesting approximately $8 million per year during the rate case period, a total of $24.6 million, for a "Geo-Hazard threat identification and mitigation program" to "refine data about land movement that will help it more effectively address the interactive threats created by land movement."[110] If PG&E feels that data about land movement needs to be refined, and since it was willing to delay mitigation of obsolete pipe features until after PSEP, the correct trajectory for the VIPER program should be to commence once the Geo-Hazard

[109] From PG&E 2015 GT&S Workpapers, Chapter 4A, pp. WP 4A-711 to WP 4A-712. Annual Total mileage as summed by ORA.

[110] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-59.

Program has produced results, and should ramp up as the flow of data from the Geo-Hazard Program increases at a stable level.

PG&E should establish a plan that integrates the VIPER and Geo-Hazard Programs and defines how and when data from the Geo-Hazard Program will be available for use in the VIPER Program. Focusing on PSEP deferred work first should provide adequate time for PG&E to implement a more effective VIPER Program in 2016 or 2017.

3.3.4 PG&E's Proposed VIPER Program Costs Are Too High And Cannot Be Supported

3.3.4.1 PG&E's Cost Estimate Methodology

The only discussion of PG&E's cost estimate methodology for VIPER in PG&E's testimony is: "the costs [for VIPER]…are based on unit costs for varying diameters of pipe and historical costs for those various diameters of pipe during PSEP." This explanation is supplemented with one page in PG&E's workpapers which only contains the following "Summary Unit Cost Table."[111]

Table 4C-7
PG&E-Proposed GT&S VIPER Unit Costs

Years	Units	$/foot based on PSEP actuals & forecast 2012 & 2013 (x $1,000)
24'-30" Highly congested SF Peninsula/San Jose		
	$ per foot	$2,500
	$/mile	$13,200
16-12" Congested Sacramento		
	$ per foot	$1,100
	$/mile	$5,808
< 12" Congested		
	$ per foot	$1,000
	$/mile	$5,280

This table shows that PG&E proposes to use three unit costs: $5.38 million, $5.8 million, and $13.2 million per mile of small, medium, and large diameter pipes

[111] PG&E 2015 GT&S Workpapers, Chapter 4A, p. WP 4A-722. In addition, page WP 4A-710 has a section titled "COST ASSUMPTIONS," but this only says "See Cost Calculator for details." There is no workpaper with this title or label. It appears that the reference is to page WP 4A-722.

respectively.[112] The balance of workpapers for this program (12 pages in total) multiply these unit costs by estimated project lengths to derive project costs, which in turn are summed to arrive at program costs.[113] 81 proposed GTS projects for 2015 through 2017 are listed on the first two pages of these workpapers, and the remaining ten pages list projects as "Post Rate Case."[114] Even with the wide range of unit costs seen above, and a stated prioritization based on "% TOC,"[115] the estimated cost of for each of the first three years of the program is exactly the same before escalation: $181.444 million. The final step in PG&E's 2015 cost estimate is to apply a 7% escalation, which increases the 2015 request to $193.824 million.[116]

As a result of the paucity of PG&E's showing to support the VIPER program, ORA engaged in extensive discovery to understand the basis for PG&E's cost estimates. This discovery revealed the following:

- PG&E applied a 3 year escalation rate to all projects, even though its unit costs are based on 2012 and 2013 data as shown in the table above, which means that PG&E should have used a lower escalation rate;[117]
- PG&E's unit costs are based on a limited sample of nine PSEP projects: seven completed projects, and the forecasted costs of two others (discussed in detail below);
- PG&E has performed no other analyses to support the reasonableness of its proposed unit costs;[118]

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[112] The descriptions also mention congestion level, but as discussed in Section 3.3.4.6 below, PG&E has assumed that all projects in the 2015-2017 time period will be in congested areas.

[113] Project costs for replacement of StanPac jointly owned pipe are multiplied by "6/7" presumably because this corresponds to PG&E's percentage of ownership.

[114] PG&E 2015 GT&S Workpapers, Chapter 4A, pp. WP 4A-712 to WP 4A-721.

[115] "TOC" is "Total Occupancy Count." Please see footnote 153 below for a discussion of the meaning and application of % TOC.

[116] PG&E 2015 GT&S Workpapers, Chapter 4A. See the first table on page WP 4A-711. ORA confirmed the annual value is correct by summing by year the projects costs in the larger table beginning on the same page.

[117] PG&E Response to ORA-DR-56 Q15b. PG&E's response states that 2012 actual costs are escalated, and refers to Attachment 1 to PG&E's Response to DR-TURN-11 Q17, which indicates that rates of 1.92%, 2.51%, and 2.39% were used for y ears 2012-2014 respectively. These rates were multiplied to yield the 7.0% escalation rate PG&E used for to extrapolate its proposed unit costs on page WP 4A-722 to 2015. A lower rate of 4.95% should be used where a 2013 forecasted project cost was used, and 2.39% where a 2014 forecast was used.

[118] See PG&E's responses to ORA-DR-56 Q4 and ORA-DR-64 Q7.

- PG&E asserts that its unit costs should be high because the "Vintage Pipe Replacement Program is targeted on very short segments of pipe that are in congested locations," but provides no support for this assertion;[119]

The only support PG&E has provided for the requested unit costs is the following Table 4C-8 which PG&E provided pursuant to an ORA data request, and which provides limited information regarding the nine PSEP projects PG&E relied upon to derive its unit costs.[120]

Table 4C-8
PG&E-Provided Support for VIPER Unit Costs

PSEP Project #	Route	Diameter Range	Estimate at Completion (Includes Actuals & Forecasts)	Miles	Cost ($/Ft)
R-004	142S	< 12"	$ 5,414,078	1.04	$ 986
				Ave Cost/Ft	$ 986
R-006	111A	12" - 24"	$ 33,382,484	9.45	$ 669
R-037	172A	12" - 24"	$ 18,331,009	3.19	$ 1,088
R-061	196A	12" - 24"	$ 35,432,204	2.06	$ 3,258
R-066	119B	12" - 24"	$ 8,083,158	2.00	$ 765
				Ave Cost/Ft	$ 1,080
R-022	109	24"+	$ 46,132,492	3.26	$ 2,680
R-030	109	24"+	$ 20,851,345	1.61	$ 2,453
R-047	109	24"+	$ 4,885,313	0.47	$ 1,969
R-049	109	24"+	$ 6,714,142	0.67	$ 1,898
				Ave Cost/Ft	$ 2,476

*** Data as of 3/20/2013 ***

119 PG&E Response to ORA-DR-56 Q4a.

120 PG&E Response to ORA-DR-56 Q3. The response also states "Please note that the data that was used to develop the cost estimates was as of 3/20/2013. Average costs per foot were rounded to the nearest hundred dollars, yielding the unit costs that are found in the workpapers on page WP 4A-722." PG&E thus rounds up the unit costs, and uses the higher unit costs in Table 4C-7 and in its 2015 request.

The limitations of PG&E's cost forecast based on these findings are discussed in the following sections. The discussion demonstrates that PG&E has insufficient support for its cost forecast and that ORA's alternative forecast for 2015 VIPER Program capital expenditures is reasonable and should be adopted.

3.3.4.2 Comparison to PSEP Actual Replacement Unit Costs

ORA's analysis began with an attempt to confirm PG&E's unit calculations using available data regarding the nine PSEP projects PG&E used to derive its proposed unit costs. Except as noted, ORA prepared the following Table 4C-9 using data from PG&E's PSEP Reports to validate information on each of the nine PSEP projects PG&E relied upon to develop the VIPER unit cost estimates. Information discussed in detail below is highlighted in the table for convenience.

Table 4C-9
PSEP Report Data On PG&E's 9 Projects Used To Develop VIPER Unit Costs

New PSRS	Project Description	OD (inch)	Tie-in Date	Length (miles)	Est. Cost	Actual Cost	Est. $M/mile	Actual $M/mile
23816	R-004 L-142S REPL 1.04mi	10	9/29/12	1.04	$ 5.82	$ 5.40	$ 5.6	$ 5.2
	Total for <12"			1.04	$ 5.82	$ 5.40	$ 5.6	**$ 5.2**
26029	R-006 L-111A REPL 9.78MI	24	2/28/13	8.80	$ 35.52	$ 35.35	$ 4.0	$ 4.0
29247	R-037 L-172A REPL 3.06MI	16	1/31/14	3.07	$ 40.60	$ 38.57	$ 13.2	$ 12.6
27951	R-061 L-196A 2.00 MI	NA	NA	NA	NA	NA	NA	NA
31693	R-066 L-119B 1.12 mi	12.75	6/5/14	*1.18*	$ 7.34	$ 7.26	$ 6.2	$ 6.2
	Total for 12"-16"			13.05	$ 83.46	$ 81.18	$ 6.4	**$ 6.2**
26019	R-030 L-109_3A REPL 1.61mi	24	12/16/12	1.61	$ 19.61	$ 19.76	$ 12.2	$ 12.3
25727	R-022 L-109_2A REPL 3.50MI	24	6/19/13	3.50	$ 55.80	$ 42.57	$ 15.9	$ 12.2
26024	R-047 L-109_4B REPL 0.47 MI	24	12/8/12	0.47	$ 4.71	$ 4.93	$ 10.0	$ 10.5
26026	R-049 L-109_4D REPL 0.67MI	30	12/8/12	0.67	$ 6.68	$ 6.68	$ 10.0	$ 10.0
	Total for 24"-30"			6.25	$ 86.80	$ 73.95	$ 13.9	**$ 11.8**

This table summarizing the PSEP Report data highlights a number of anomalies in PG&E's representations regarding the nine PSEP projects and PG&E's calculation of unit costs:[121]

[121] Deviations in the PSEP Report data related to Project R-066, discussed in the text, are from the July 30, 2014 PSEP Report, Table 11-1, line 61, except the diameter, which is from PSEP Update workpapers page WP 2-1003, and the project length is as given in PG&E's response to ORA 56 Q3. This project length was used because the job estimate is more than twice the PSEP Update estimate of $3.248 million, which was for 5,934 ft. But Table 23-1 in this PSEP

1) PG&E's unit costs are not consistent with the unit costs calculated by ORA. ORA's unit cost calculations in Table 4C-9 are based on the same nine projects PG&E relied upon. However, PG&E combines actual and forecasted data from March 20, 2013, whereas ORA calculates actual and estimated unit costs separately, and uses data from more recent PSEP Reports;

2) PG&E's Table 4C-7 summarizing its unit costs is not consistent with PG&E's Table 4C-8, grouping the nine projects for calculation of the same unit costs. Table 4C-7 calculates three separate unit costs for lines below 12" in diameter, 12"-16" in diameter, and 24"-30" in diameter (and rounds those unit costs upward) while Table 4C-8 reaches the same unit calculations based on different diameter groupings – below 12", between 12" and 24" and 24" and above.

3) These inconsistencies in PG&E's two unit cost tables create confusion. For example, the PSEP Report data shows that PSEP project R-006, the second project listed on Table 4C-9, is a 24" project. It appears to have been included in the Table 4C-8 calculation for lines between 12" and 16", but in Table 4C-7 appears to be grouped with lines 12"-24" in diameter. In either event, it should be in the unit cost calculation for lines 24" in diameter and above;

4) For PSEP project R-037, the third project listed on Table 4C-9, the estimated and actual costs in the PSEP Report of $40.6 and $38.57 are more than double the estimate of $18.33 million used by PG&E in Table 4C-8. It may be because this project caused damage to an adjacent line, L-116, and the cost of repairing that line may have been included in the total;[122]

5) PSEP Project R-061, the fourth project on Table 4C-9, is scheduled to begin August 16, 2014, but the latest PSEP Report does not provide a "job estimate amount," though PG&E appears to have one, since a forecasted cost is provided in Table 4C-8. The PSEP Report reflects that this project will be a "partial retirement" and so it does not appear to be a typical replacement project.[123]

6) For PSEP project R-066, the fifth project listed on Table 4C-8, the 2.0 mile project length used by PG&E contradicts data in the PSEP Report, which shows that the project is 1.18 miles, Table 4C-9. However, since the cost estimate is nearly double the PSEP Update cost estimate, this mileage may be correct.[124]

Report shows a 1.18 mile length. See notes in Table 19-1 of the July 30, 2014 PSEP Report regarding a $0.5 million cost increase.

[122] See July 30, 2014 PSEP Report, p. 14.

[123] See July 30, 2014 PSEP Report, Table 13-1, line 36.

[124] For cost, see PG&E PSEP Update Workpapers (A.13-10-017), Chapter 4A, p. WP 2-4, line 236, which shows a Total Cost of $3.248 million. For mileage, see July 30, 2014 PSEP Report, Table 22-2, line 11.

With these anomalies in mind, ORA reaches the following conclusions regarding PG&E's proposed unit costs for the VIPER Program:

1) The estimated unit costs for the smallest pipes – those less than 12" in diameter -are based on one project;

2) All four projects PG&E relied upon to develop the estimated unit costs for "medium sized pipes" between 12" and 16" in diameter have data inconsistencies between the PG&E-provided data and the PSEP Report data, or involve circumstances that do not lend themselves to being used as "samples" for a limited data set. Specifically, PG&E includes a 24" diameter pipe (PSEP project R-006) to calculate unit costs for pipes between 12" and 16", PG&E uses another project with no cost estimate in the PSEP Report and indicates that part of the line will be retired (PSEP project R-061) – thus putting into question PG&E's choice to use this project in a small sample. PG&E uses another project with implementation challenges, requiring possible adjustments to the final costs (PSEP project R-037), and another (PSEP project 066) which has conflicting mileage data between the PSEP Report and PG&E's chart.

3) Using PSEP Report data, the estimated unit cost for large pipes (24" - 30") is significantly lower using actual project costs rather than forecasted costs ($11.8 million compared to $13.9 million per miles from Table 4A-9 above) and is also lower than PG&E's proposed unit cost of $13.2 million per mile from Table 4A-7 above.

4) The estimated unit cost for large pipes would be even lower - $7.2 million per mile - if data for PSEP project R-006 – a 24" pipe - was correctly included in this unit cost calculation instead of in the calculation for the one for "medium sized pipes" between 12" and 16".

PG&E's filings and discovery responses do not explain why only these specific projects were used in its unit cost calculations, or why these projects provide a reasonable basis for forecasting costs for the VIPER Program.

Given PG&E's reliance on such a small data set of projects to set VIPER unit costs and the anomalous nature of many of those projects, ORA decided to analyze all of the PSEP actual cost data to determine if PG&E's use of data from the 9 PSEP projects was generally representative of the available PSEP data.[125]

[125] Attachment 1 of PG&E's response to ORA 64Q13 provided a list of completed projects in a format similar to the Table 11-1 of the PSEP Quarterly Compliance Reports, added the project diameter, but it omitted cost data. Attachment 1 to PG&E's response to ORA 89 Q2 provided all Table 11-1 data plus other data fields requested by ORA. ORA merged data from these two attachments and manually added data from other sources where it was missing.

Table 4C-10 below uses data from electronic versions of the PSEP Reports provided by PG&E, and organizes it to calculate unit costs similar to how they were calculated for the purposes of the PG&E-generated Table 4C-7 above.[126] Table 4C-10 below differs from summary tables in the published PSEP Reports in that only projects with a tie-in date in the given year were included, and only completed replacement projects were included.[127]

Table 4C-10
ORA Calculation Of Unit Costs Using PSEP Report Data On Completed Replacement Projects

	2012				2013				2012-2013			
Pipe Size (inch)	Projects	Miles Completed	Total Cost ($millions)	Unit Cost ($millions/ mile)	Projects	Miles Completed	Total Cost ($millions)	Unit Cost ($millions /mile)	Projects	Miles Completed	Total Cost ($millions)	Unit Cost ($millions /mile)
<12	3	3.5	$11.043	$3.1	10	2.3	$11.561	$5.1	13	5.8	$22.604	$3.9
12,16	6	3.8	$18.051	$4.7	4	19.7	$74.538	$3.8	10	23.5	$92.589	$3.9
24+	9	6.9	$72.459	$10.6	10	37.1	$243.200	$6.6	19	43.9	$315.659	$7.2
All	18	14.2	$101.553	$7.2	24	59	$329.299	$5.6	42	73.2	$430.852	$5.9

Table 4C-10 shows the following:

1) There were no replacement projects completed in 2011, so only 2 full years of recorded data are available – for 2012 and 2013;
2) There were at least 3 projects completed for each size range in 2012 and 2013, which is three times larger than the sample of one that PG&E used for its unit cost for small pipes (under 12" in diameter);
3) PG&E replaced 59 miles of pipe in 2013, which is significantly more than the annual rate it proposes for VIPER;
4) Unit costs for the smaller two groups of pipes are the same (under 12" and between 12" and 16"), and are 26% to 33% lower than PG&E's proposed unit costs;
5) The unit cost for large pipe (24" +) is 45% lower than PG&E's proposed unit cost.

[126] Attachment 1 to PG&E Response to ORA-DR-89 Q2.

[127] In some PSEP Quarterly Compliance Reports and some discovery responses PG&E included retirements, downrate s, and transfers within the results for pipe replacement. Language in the proposed settlement for the PSEP Update Application aims to correct this. Projects with retirements, downrates, and transfers are not included in the table above, leading to lower mileage and total cost figures.

Table 4C-10 shows that for every pipe size range, and each year, unit costs calculated based exclusively on completed PSEP projects are lower than unit costs based on PG&E's use of recorded and forecasted data for a subset of nine PSEP projects.

This data also shows costs decreasing from 2012 to 2013 for all pipe ranges except the smallest pipes. While ORA proposed a unit cost based on the extrapolation of three years of data for hydrotest costs,[128] it does not attempt to do so in this case since the data set is much smaller in terms of projects per size per year, and because there are only two years of data available for extrapolation.

3.3.4.3 *Comparison To PSEP Adopted Unit Costs*

PG&E's PSEP testimony in R.11-02-019 estimated an average replacement cost of $855 per foot, which equates to $4.51 million per mile. This is supported in the table below, which includes ORA-calculated values for each of the 4 pipe size ranges PG&E proposed in the PSEP proceeding:[129]

Table 4C-11
PG&E PSEP Pipeline Replacement Unit Cost Forecast

Pipe Size	Project Count	Miles	Total Cost ($ millions)	Unit Cost ($ millions/mile)
All	168	185.5	$843.9	$4.5
12" and under	120	83.5	$334.7	$4.0
14" to 20" all	17	36.8	$142.3	$3.9
22" to 28"	23	62	$347.2	$5.6
30" to 40" all	8	3	$19.7	$6.6

Even though PG&E switched to a different set of size groupings between PSEP and GT&S, the following comparisons of PSEP actual costs and PG&E's proposed unit cost for GT&S can be made:

[128] See the discussion in Section 3.2.2.4 above.

[129] PSEP projects often included more than one size of pipe. PG&E was only able to provide the primary OD for each project (see PG&E Response to ORA-DR-64 Q13j). To compile the table above, ORA assigned each project to a size range based on the predominant size of pipe in the project based on a review of the footage per size for each project. See Exhibit 4C Workpapers, Section 7.

1) Actual unit costs for PSEP pipes less than 20” diameter ($3.9 million per mile – see Table 4C-10) are nearly identical to PG&E’s PSEP forecasted unit cost ($3.9 - $4.0 million per mile – see Table 4C-11);

2) Actual unit costs for PSEP pipes larger than 20” diameter ($7.2 million per mile – see Table 4C-10) are 9% to 28% higher than PG&E’s PSEP forecasted unit costs ($5.6-$6.6 million per mile – see Table 4C-11);[130]

3) PG&E’s proposed unit costs for GT&S line replacements are meaningfully higher than those it forecasted for PSEP pipeline replacements, as shown in Table 4-12 below.

Table 4C-12
Comparison of PG&E PSEP Forecast, PSEP Actual, And VIPER Unit Costs For Pipe Replacement
(In Millions Per Mile)

OD	PG&E PSEP Forecast	PSEP Actuals	PG&E GT&S 2015 Forecast
<20”	$3.9 - $4.0	$3.9	$5.28 - $5.8
>20”	$5.6 - $6.6	$7.2	$13.2
All	$4.5	$5.9	$9.0 - 9.7[131]

This table shows that while actual PSEP costs for 2012 and -2013 were higher than forecast for by approximately 30%, PG&E is requesting more than double the PSEP forecast, and 52% to 64% more than PSEP actuals in its 2015 GT&S forecast.

3.3.4.4 Comparison To Water Main Pipe Replacement Program Unit Costs

In order to provide context for ORA’s proposed unit costs for the Viper Program, ORA analyzed the costs of water main replacement programs. ORA acknowledges that comparison of data between industries can be difficult, but they are often required and/or useful. PG&E has used comparisons to the airline, railway, automotive, and

[130] A higher percentage of 22” to 28” pipe was completed (71% = (43.9-0.7 miles)/62 miles) than 30” to 40” (23% = .7 miles/3 miles). Therefore, the 28% figure is more indicative of the difference between forecasted and actual costs for these pipes..

[131] Based on PG&E’s request for $193.8 million in 2015. The lower unit cost of $9.0 million per mile is based on the approximate length of projects proposed for 2015, 21.6 miles, and the higher value is based on the target length of 20 miles.

other industries in this application regarding benchmarking.[132] And while there are many details about the specifics of each project that are not known, water main replacement has many similarities to gas pipeline replacement. There is no apparent reason why replacing the same length and diameter of pipe in the same location should have significantly different planning, permitting, design, customer outreach, project management, construction management, provision for customer outages, trenching, shoring, material transportation, mitigation of conflicts with other utility pipes, traffic management, work hour restriction costs, or remediation costs. Water mains also undergo hydrotesting as part of the installation process.[133] In addition, independent construction companies performed the actual pipe replacement for all of the water projects discussed herein, and the majority of PG&E's projects were also performed by construction contractors.

In this situation, while other comparisons may have been possible, ORA felt that the comparison to water mains was the most appropriate. ORA provided expert testimony in the original PSEP application proceeding, R.11-02-019, regarding pipe replacement costs based on national surveys of gas pipelines.[134] PG&E argued that this data was not directly comparable because a larger proportion of gas transportation pipeline discussed in the surveys was in rural areas.[135] While PG&E's criticism was largely misplaced,[136] in the current proceeding ORA sought data on the replacement of comparable underground utilities in urban areas to provide a different perspective on the same issue. ORA considered a wide range of alternatives, including analysis of gas pipelines in other urban areas, petroleum pipelines, underground electrical lines, and water transmission lines. Given that PG&E has indicated that its costs are highly dependent on local congestion levels and permit conditions, alternatives outside of

[132] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Stavropoulos), p. 1-17.

[133] EBMUD "Standard Drawings for Installation of Water Mains 20" and Smaller," p.7., available at: http://ebmud.com/sites/default/files/pdfs/StdDwg20andSmaller07-08-R2-web.pdf.

[134] PSEP Exhibit 147, Prepared Testimony of ORA Witness Scholz, pp. 3-9.

[135] PG&E PSEP Rebuttal Testimony in R.11-02-019 (Hogenson), pp. 3-37 to 3-38.

[136] ORA's analysis accounted forthe locations of pipe in the surveys, provided conservative adjustments as needed, and rebutted PG&E's claims. See ORA Opening Brief for PSEP in R.11-02-019, pp.97-98.

PG&E's service territory were eliminated. Alternatives where the utility differs significantly from gas pipelines were also eliminated. Ultimately, water main replacement costs were selected as the best set of comparable data for the following reasons:

- Water mains use some of the same pipe diameters as gas lines;
- Water mains and gas pipelines often share the same right of way;
- Water and gas line networks are comparable in terms of having transmission, distribution and customer service lines of decreasing diameter;
- For water mains made of welded steel, the project life cycle from planning through tie-in is essentially identical to that of gas transmission lines; and
- Water utility data in PG&E's most dense population centers was publicly available.

ORA compiled and analyzed data for water mainline replacement projects performed for the San Francisco Public Utilities Commission (SFPUC) and East Bay Municipal Utility District (EBMUD) which is included in the ORA Exhibit 4C Workpapers.

The following Table 4C-13 compares the results of this analysis for steel and ductile iron water main replacement projects to PG&E's forecasted unit costs for the VIPER Program:[137]

Table 4C-13
Comparison Of SFPUC, EBMUD, PSEP, and GT&S Pipe Replacement Unit Costs (In Millions Per Mile)

Pipe OD	SFPUC Actuals	EBMUD Actuals, Excluding Projects with RR Crossings[138]	PSEP Forecast	PSEP Actuals	PG&E GT&S 2015 Forecast
<20"	$1.6-$1.79	$1.43 -$2.21	$3.9 - $4.0	$3.9	$5.28 - $5.8

[137] Data for SFPUC and EBMUD shows the range of individual project unit costs, subject to the footnotes provided. PG&E data are average unit cost for each group of data.

[138] EBMUD data included a project with 270 feet 12" pipe that had a unit cost of $11.69 million per mile, and a project with 290 feet of 30" that had a unit cost of $9.68 million per mile. Unit costs for these projects were excluded from this table because they involved railroad track crossings. However, even these short projects with special circumstances were less expensive per foot than the average unit cost forecasted by PG&E for large pipes.

>20"	$2.95[139]	$4.81 -$6.41	$5.6 - $6.6	$7.2	$13.2
All	NA	NA	$4.5	$5.9	$9.0 - 9.7[140]

This data indicates that the *average* unit costs for PG&E gas pipeline replacement across its entire service area are significantly more expensive than the unit costs for water main replacement in two of the most populated areas within that service territory. More importantly, this data does not support the ratio of PG&E's unit costs between large and small pipes. This is particularly important since, as shown in Table 4C-14 below, the percentage of large pipe replacement in VIPER nearly doubles over the rate case period, from 37% to 70%:

Table 4C-14
PG&E's Estimated Rate of Replacement of Each Size of Pipe over the Rate Case Period

Pipe Size	2015 Mileage	2015%	2016 Mileage	2016%	2016 Mileage	2017%
<12"	[illegible]	19%	[illegible]	32%	[illegible]	9%
12-24"	[illegible]	44%	[illegible]	25%	[illegible]	21%
24"+	[illegible]	37%	[illegible]	43%	[illegible]	70%
Total	[illegible]	100%	[illegible]	100%	[illegible]	100%

While a comparison to the cost to replace water mains may not provide an "apples to apples" comparison, the data compiled by ORA should prompt the Commission to ask "why does it cost so much more to grow an apple than an orange and deliver it to the same customer?" PG&E has the best data to answer that question, and the Commission should either accept ORA's proposed reductions to the VIPER Program forecasts, or require PG&E to gather and provide evidence that its higher costs are reasonable.

[139] Data was only available for one project with pipe larger than 20" OD, but this project had 7,135 feet of 24" pipe and 6,050 feet of 4", 6", and 8" pipe. The project cost provided is for all pipe, and would likely be higher if the entire project was for 24" pipe.

[140] Both values are based on PG&E's request for $193.8 million in 2015. The lower unit cost of $9.0 million per mile is based on the approximate length of projects proposed for 2015, 21.6 miles, and the higher value is based on the target length of 20 miles.

3.3.4.5 Factors Supporting Declining Replacement Unit Costs

Previous sections of this testimony have identified factors supporting the concept that replacement unit costs should be trending downward. For example, similar to the points made in Section 3.2.2.4 regarding declining hydrotest costs, PG&E should experience increased efficiencies as it continues to gain experience with large scale pipeline replacement work, and it should be able to adjust its contracting processes to include a greater emphasis on project costs.[141] PG&E also embarked on a cost savings program in 2013, similar to the program for hydrotesting, but initiated at a later time.[142] While pipe replacement appears to be a more mature and established part of PG&E's operation, and there may be fewer opportunities for unit cost reductions, there is no reason that costs should not continue to decline as PG&E narrows its replacement focus on the VIPER Program.

There are three additional factors specific to VIPER that should be considered relative to cost trends. First, the VIPER Program proposes a moderate rate of work compared to the pace of PSEP. Any inefficient processes or contractors that were required to meet the higher PSEP pace can be corrected or eliminated. This should lead to lower costs. Second, VIPER promises high value construction work performed at a moderate rate of installation over 11 years. This program will provide a steady income stream for construction contractors and PG&E should be able to leverage the desirability of this fact to negotiate lower prices and less risk. Third, by prioritizing projects based on the % TOC metric PG&E proposes, replacement should occur in progressively less congested locations over the life of the program. This is discussed in more detail in Section 3.3.4.6, but it is noted here as a trend that should lead to lower costs over time.

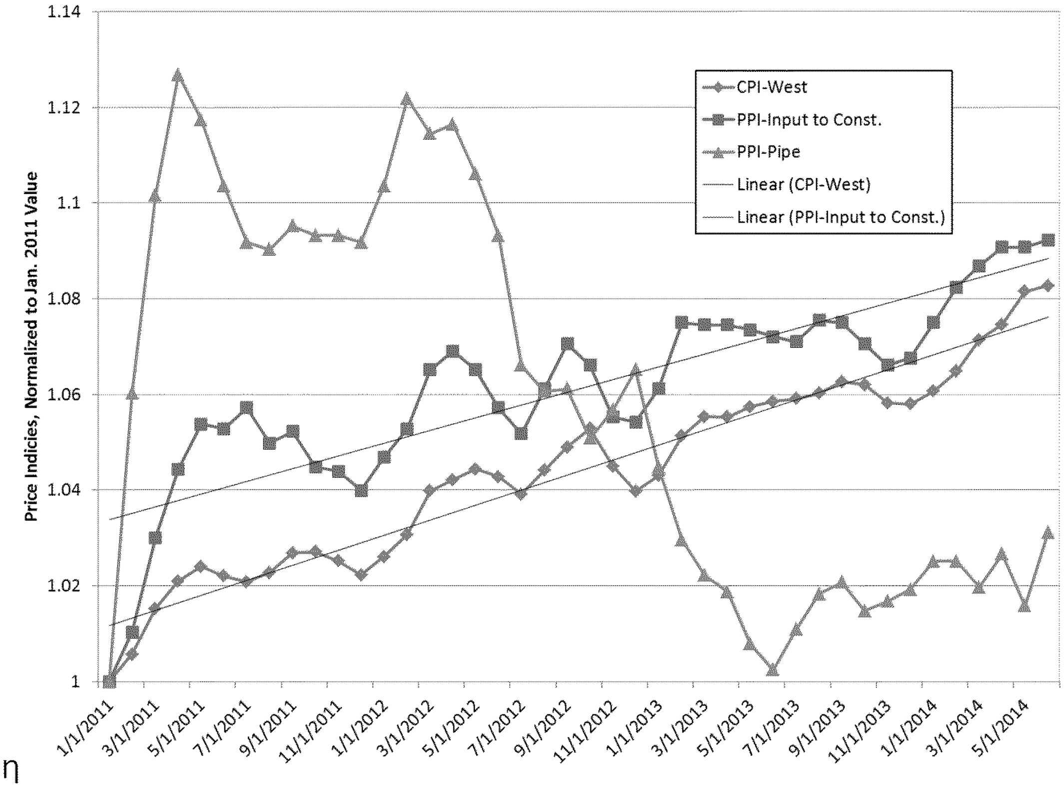
[141] In PSEP, contractor costs for pipe replacement were a smaller percentage of total costs compared to hydrotesting, 68% vs. 84% respectively. This is primarily because PG&E's internal construction group, GT/GC, performed more than half of the projects, and incurred 15% of the total costs vs. the 1.3% of hydrotest costs it incurred. Refer to Exhibit ORA-4C Workpapers, Section 9.

[142] PG&E Response to ORA-DR-104 Q1 states that "in 2013 PGE did embark on cost savings initiatives comparable to those i n the response to GTS-RateCase2015_DR_ORA_059-Q23 [hydrotest]."

ORA recognizes that these trends toward lower costs must be weighed against increases in labor and material costs due to inflation between the date of the actual PSEP cost data in the replacement unit cost forecast and 2015. Figure 4C-2 below shows various price indices from the beginning of 2011 through June 2014:[143]

[143] U.S. Department of Labor, Bureau of Labor Statistics data for 1) Consumer Price Index, Western region urban, Series Id.CUUR0400SA0; 2) Producer Price Index, Inputs to Construction, Series Id. PCUBCON—BCON; 3)) Producer Price Index, Iron & steel pipe and tube mfg. from purchased steel, Series Id. PCU33121-33121. See http://www.bls.gov/.

Figure 4C-2
Comparison of Various Price Indices Between January 2011 and June 2014



This data shows overall prices rising on average approximately 1.6% to 1.9% annually through this time period.[144] These rates are lower than the escalation rates PG&E used in its forecast of 2015 capital costs of 1.92%, 2.51%, and 2.39% for 2012, 2013, and 2014 respectively.[145] In addition, Figure 4C-2 shows that the price index for steel pipe does not increase at a linear rate and has risen less than 2% over the entire 3.5 year period. ORA testimony in the PSEP proceeding indicated that pipe material, all of which are steel, represented 27% of the variable cost for 10" pipe replacement and 48% for 36" pipes, and is thus a significant driver of replacement cost.[146] PG&E

[144] The slope for the PPI-input to construction is 1.6% annually and f or the CPI data is 1.9% annually. See Exhibit 4C Workpapers, Section 10.

[145] Attachment 1 to PG&E Response to DR-TURN-11 Q17.

[146] PSEP Exhibit 146, Prepared Testimony of ORA Witness Delfino, p. 1-13. PG&E's PSEP forecast showed lower percentages of 9% and 26% respectively based on pipe material estimates from 3E-6 and "All-in Model Costs" for non -congested pipe, page 3E-12 for 10" and 36" pipe respectively. Pipe material is a smaller percentage of costs as the level of congestion increases. See Exhibit ORA -2C Workpapers.

calculated escalation rates the same for all G&TS capital expenditures, most of which do not rely on steel pipe as a significant price component. This data shows that if PG&E were appropriately escalating unit costs from 2012 and 2013 to 2015, the escalation rate used should be lower than forecasted by PG&E, which assumed all costs used in the forecast were incurred in 2012.[147]

In sum, PG&E had many opportunities to reduce pipe replacement costs when it was performing its PSEP replacement work, and these opportunities still exist. When considering if these opportunities are offset by inflationary forces, unique cost elements such as the cost of steel pipe mean that the general measures of inflation are not wholly applicable. And if escalation is used to inflate costs from prior years, it must only be applied based on the actual year data used in the forecast was recorded.

3.3.4.6 Contrary To PG&E Assertions, The Length and Location of VIPER Projects Does Not Appear To Impact The Unit Cost Of Replacement

PG&E asserts that its replacement unit costs should be high because the "Vintage Pipe Replacement Program is targeted on very short segments of pipe that are in congested locations."[148] However, PG&E provides no support for this assertion. Further, ORA has determined that neither of these claims are supported by the available data.

First, PG&E asserts that VIPER Program unit costs are high because the projects are short. While this is a reasonable assertion if replacement projects have significant fixed costs, PG&E has provided no evidence that replacement projects do have significant fixed costs. Further, PG&E chose to employ a simplistic cost model to forecast VIPER unit costs that only has variable costs. In response to discovery, PG&E indicated it has not performed any analysis to determine if there are fixed costs for replacement projects,[149] and that "PG&E does not have the ability to analyze PSEP cost data and classify PSEP Pipe Replacement costs" in terms of fixed, variable, and

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[147] When looking at all PSEPreplacement work in 2012-2013, more than three times the costs were incurred in 2013 as were in 2012 (see Table 4C-10). Attachment 1 to PG&E's Response to TURN 11 Q17 indicates that capital expenditures from 2013 should be escalated by 5.0%, not 7% which is only applicable to expenditures in 2012 per PG&E's response.

[148] PG&E Response to ORA-DR-056 Q4a.

[149] PG&E Response to ORA-DR-090 Q4.

unpredictable costs.[150] In addition, PG&E's PSEP testimony indicated that unit costs for replacement projects are relatively indifferent to project length by stating that "unit costs in Phase 1 vary from a low of $780 per foot to a high of $981 per foot."[151] Because forecasted PSEP replacement project lengths varied significantly as shown in Section 11 of Exhibit 4C Workpapers, this small range of variation in per foot unit costs indicates that fixed costs are small in comparison to costs that vary with project length.

Even though project length does not appear to be a major cost driver for pipe replacement, ORA compared PSEP project lengths with those proposed for the VIPER Program. The data and analysis provided in the Exhibit 4C Workpapers, which is summarized in Table 4C-15 below, shows that the median length of proposed VIPER projects is approximately the same as the median length of completed PSEP projects.

Table 4C-15
Comparison of the Median Length of Various Pipe Replacement Projects

Program	# of Projects	Median Length (ft)
Proposed VIPER Projects	81	2,640
Proposed PSEP Projects	168	509
Completed PSEP Projects[152]	58	2,587

This data does not support PG&E's claim that the proposed GT&S projects are shorter in length.

Second, PG&E asserts that VIPER projects will be in heavily populated areas initially because of the % TOC method it uses to prioritize work.[153] It therefore only

[150] PG&E Response to ORA-DR-090 Q5.

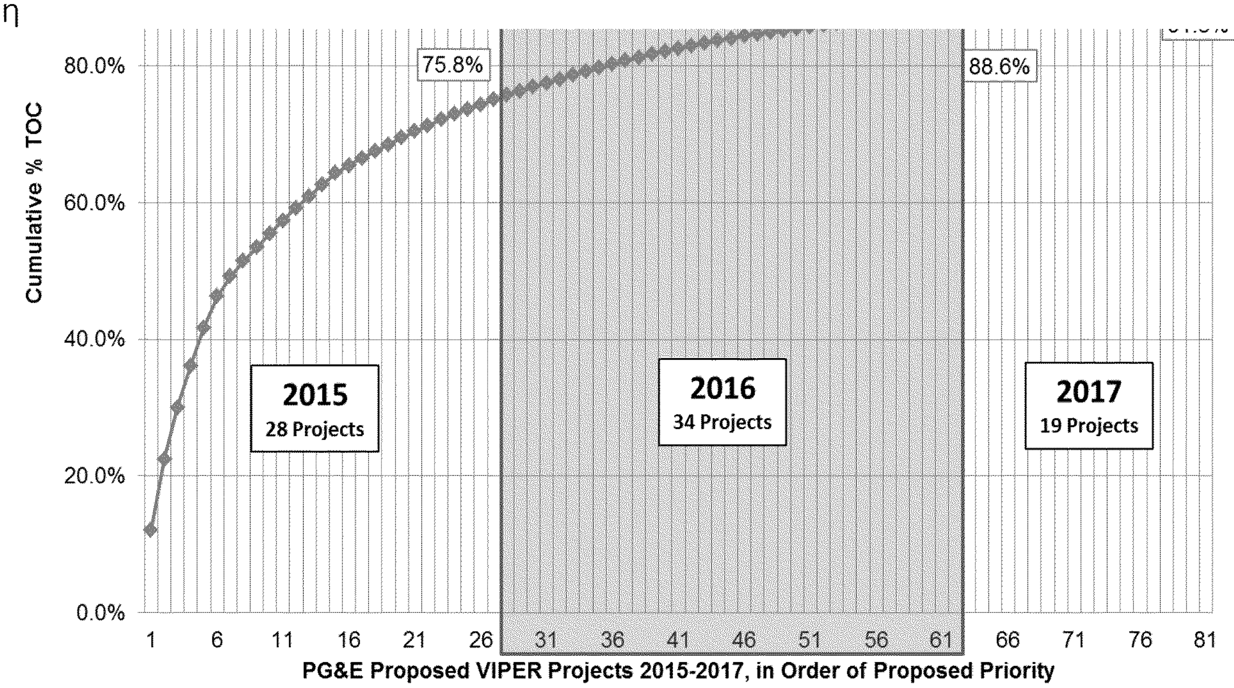
[151] PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), p. 3-40. The highest per mile cost, $5.17 millon per mile, is 26% higher than the lowest cost per mile, $4.12 million.

[152] ORA Exhibit 4C Workpapers, Section 11.

[153] Total Occupancy Count (TOC) is a measure of how many people are within the potential impact radius (PIR) of a pipeline. PG&E determines the OC for each section of pipe it will replace, which establishes what percentage of the TOC will be impacted by replacing the

provided and proposed unit costs for congested areas.[154] However, PG&E separately acknowledged that this will change over time.[155] Figure 4C-3 below confirms that this change will likely occur within the timespan of the current case:[156]

Figure 4C-3
Cumulative %TOC for PG&E Proposed 2015-2017 VIPER Projects



This chart shows that 75.8% of TOC is reached by the end of 2015. 12.8% is incrementally reached in 2016, and only 2.7% of additional TOC is addressed in 2017, bringing the total TOC addressed by the end of 2017 to 91.3 with significantly diminishing returns post-2015. Since the scope of replacement is relatively constant at 20 miles per year, the reduction in annual % TOC impact can only be due to a lower population within the potential impact radius (PIR) of each project. This indicates that work is performed in progressively less dense or congested areas. This chart shows

particular section of pipe. This is the % TOC. See PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-54.

[154] PG&E 2015 GT&S Workpapers, Chapter 4A, p. WP 4A-722.

[155] PG&E Response to ORA-DR-91 Q20.

[156] This chart was prepared by ORA using the % TOC data from PG&E's list of 81 projects in the 2015-2017 time-frame provided on pages WP 4A-711 to WP 4A-712. See PG&E Response to ORA-DR-88 Q4 for an explanation of the anomalous spike at the start of 2017.

that while it may be reasonable to assume that the first 10 or even 20 projects are in areas of high congestion, it is not reasonable to assume that the balance of projects in 2015, and all projects in 2016 and 2017 are in high congestion areas. This is further supported by a map provided by PG&E in response to discovery which shows 2015 projects in urban areas like San Francisco, the East Bay, and San Jose, but 2016 and 2017 projects generally in less densely populated locations.[157] While this case focuses on the 2015 test year, a reasonable forecast of pipe replacement costs must account for how costs will decrease throughout the entire test period, and PG&E's proposed unit costs fail to do this.

3.3.5 The Commission Should Adopt ORA's Forecast Of $110.0 Million, as Compared to PG&E's Forecast of $193.8

PG&E makes the current capital request for the VIPER Program based on unit costs derived from a limited number of projects, a combination of recorded and forecasted costs, and no testimony discussing why these specific projects are more representative of the proposed scope of VIPER than actual PSEP costs for the same type of work. There are problems with the data PG&E used, and when PG&E's forecasts are replaced with actual data from PG&E's PSEP Reports to the Commission, the calculated unit costs decrease. PG&E has made qualitative claims about the length and location of VIPER projects relative to PSEP projects as causes of higher unit costs in response to discovery, but only qualitatively. ORA's analysis does not indicate that VIPER projects are longer or in more congested locations. In sum, there is insufficient justification for PG&E's 2015 VIPER forecast, which is approximately 65% higher than PSEP actual costs, and approximately double the PSEP forecast PG&E provided to the Commission in 2011.[158]

As ORA has demonstrated here, a more reasonable forecast is obtained by averaging the data for all PSEP projects completed in 2012 and 2013. This is confirmed by comparison to the estimates PG&E provided to justify its PSEP request,

[157] Attachment 1 to PG&E Response to ORA-DR-091 Q15.

[158] Refer to Table 4C-12. Percentages based on the following for all pipe sizes: PSEP Forecast, $4.5 million; PSEP Actual, $5.9 million, PG&E GT&S Forecast $9.7 million unit cost. PG&E GT&S Forecast is based on the targetannual length of 20 miles.

and by comparison to the cost to replace water mains in San Francisco and the East Bay. The following Table 4C-16 uses the unit costs derived in Table 4C-10 above to calculate the costs of VIPER for 2015 through 2017:

Table 4C-16
Calculation of VIPER Total Costs for Rate Case Period Based on Actual Unit Costs from PSEP Projects

		2015		2016		2017	
Pipe Size	Unit ($M/mile)	Scope (miles)	Cost ($ mi	Scope (miles)	Cost ($ mi	Scope (miles)	Cost ($ mi
<12"	3.9	4.10	16.00	6.70	26.13	1.43	5.58
12-24"	3.9	9.60	37.45	5.13	20.01	3.55	13.84
24"+	7.2	7.90	56.87	8.82	63.51	11.68	84.1
Total		21.60	$ 110.32	20.65	$ 109.67	16.61	$ 103.13
Annual $M/m			$ 5.1		$ 5.3		$ 5.2

ORA calculated the total adjusted value of $110 million[159] for the 2015 forecast by replacing PG&E's proposed 2015 unit costs with ORA unit costs. The scope of PG&E's proposed 2015 projects were not adjusted.[160] Escalation of 2013 and 2012 PSEP costs is not included in this recommendation because ORA believes PG&E improvements in efficiency should, at a minimum, offset any increases in material or labor costs, as discussed previously in Section 3.2.2.4 regarding the Hydrotest Program. If, however, the Commission believes that 2012 and 2013 PSEP costs should be escalated to 2015, a lower rate than the 7% proposed by PG&E should be used.[161]

As previously discussed, ORA's unit cost adjustments result in different costs for 2015, 2016, and 2017, even though it did not change the proposed scope for any year. This highlights a limitation of the simplistic model PG&E used in this application, and how annual costs will depend on the mix of projects PG&E actually performs. This testimony only addresses the 2015 test year, as attrition year methodology is used for the remaining years as discussed in Exhibit ORA-18,

[159] $110.32 million shown in Table 4C-16 includes a rounding error. The actual value of $110,002,350 is provided in Table 4C-17 below.

[160] PG&E 2015 GT&S Workpapers, Chapter 4A, p. WP 4A-711.

[161] See footnote 147 above.

Witness C. Tang. However, it is worth noting three factors that will act to stabilize or reduce annual VIPER Program costs. First, the unit costs proposed by ORA are much more consistent across pipe sizes, with a 1.8 ratio of highest to lowest unit cost compared to the 2.5 ratio in PG&E's proposal. These ratio changes result in less cost variance if a higher proportion of large pipes are replaced in a given year. Second, PG&E is replacing pipes in the most congested locations first. As the VIPER Program matures and reaches into less congested areas, unit costs for all size pipes should decrease. Third, since the same unit cost is used for all pipes 16" and smaller, the proportion of pipe larger than 12" vs. those smaller than 12" will not impact annual program costs.

Based on the preceding analysis, the following adjustments were provided to ORA's RO witness and used for subsequent revenue requirement calculations:

Table 4C-17
Adjustments to the VIPER Program Forecasts for Calculation of Revenue Requirements

PG&E WO Line No.	Planning Order Number	Order Desciption	UCC	MAT	PG&E 2015 Forecast	Line Item Adjustment in RO model	ORA 2015 Forecast
600	5902381	Vintage Pipe Repl 2015 - STN	B21B	44A	$ 1,499,069	$ 648,292	$ 850,777
601	5902382	Vintage Pipe Repl 2015 - STN	B22B	44A	$ 1,499,069	$ 648,292	$ 850,777
701	5753205	Vintage Pipe Repl 2015 - LT[illegible]N1	B20	75E	$ 62,960,888	$ 27,228,243	$ 35,732,645
703	5753207	Vintage Pipe Repl 2015 - LT[illegible]N2	B20	75E	$ 62,960,888	$ 27,228,243	$ 35,732,645
704	5753210	Vintage Pipe Repl 2015 - SS[illegible]TH1	B25	75E	$ 27,302,484	$ 11,807,309	$ 15,495,175
705	5753211	Vintage Pipe Repl 2015 - SS[illegible]TH2	B25	75E	$ 27,302,484	$ 11,807,309	$ 15,495,175
706	5753212	Vintage Pipe Repl 2015 - SP[illegible]H1	B24	75E	$ 5,149,579	$ 2,227,001	$ 2,922,578
707	5753213	Vintage Pipe Repl 2015 - SP[illegible]H2	B24	75E	$ 5,149,579	$ 2,227,001	$ 2,922,578
		Total			$ 193,824,040	$ 83,821,690	$ 110,002,350

UCC codes for each of these projects, which are required to group them into the nine line items above for use elsewhere in the workpapers and in the input to the RO model, were not provided in PG&E's filing. PG&E provided these codes in response to an ORA data request, but there was a discrepancy compared to the workpapers, so the table above spreads the adjustments across UCCs in the same proportion as PG&E's request.[162]

[162] See Section 12 of the ORA Exhibit 2C Workpapers for details.

3.4 PG&E's GT&S Decision Trees Should Be Updated To Address PSEP Deferred Work And PSEP Deferred Work Should Be Subject To The Cost Limitations of D.12-12-030

3.4.1 Overview

In D.12-12-030, the Commission adopted PG&E's proposed PSEP decision tree which established a methodology to prioritize PSEP work so that the pipe segments posing the most threat to PG&E's system were mitigated first, either through hydrotesting or replacement. Decision 12-12-030 also established cost caps for "Phase 1" PSEP work to be performed prior to 2015.[163], [164]

PG&E's PSEP Update Application, A.13-10-017, revealed that PG&E has deferred a significant amount of PSEP work, described in detail in Section 3.4.2 below. This deferred work is not directly addressed in the GT&S testimony, in part because PG&E "is no longer forecasting PSEP work as part of a separate work stream" and "PSEP MWCs are no longer applicable and will be eliminated after the end of 2014."[165] In addition, the decision trees PG&E uses to prioritize GT&S Hydrotest and VIPER projects have no provisions to address this deferred work which was, or should have been, classified as high-priority Phase 1 PSEP work. PG&E effectively seeks to unilaterally change the prioritization method not only for "Phase 2" PSEP work, but also for high-priority Phase 1 PSEP work not completed before 2015 as contemplated in D.12-12-030.[166]

PG&E's lack of transparency regarding deferred PSEP work is most clearly illustrated by the proposed GT&S VIPER decision tree, in which the first decision point fails to account for work that was planned and prioritized for replacement during PSEP,

[163] D.12-12-030 approved PSEP Phase 1. It was anticipated that the next round of hydrotesting and replacement would be PSEP "Phase 2." PG&E has abandoned the concept of Phase 2 PSEP work and now proposes the Hydrotest and VIPER Programs to replace PSEP Phase 2.

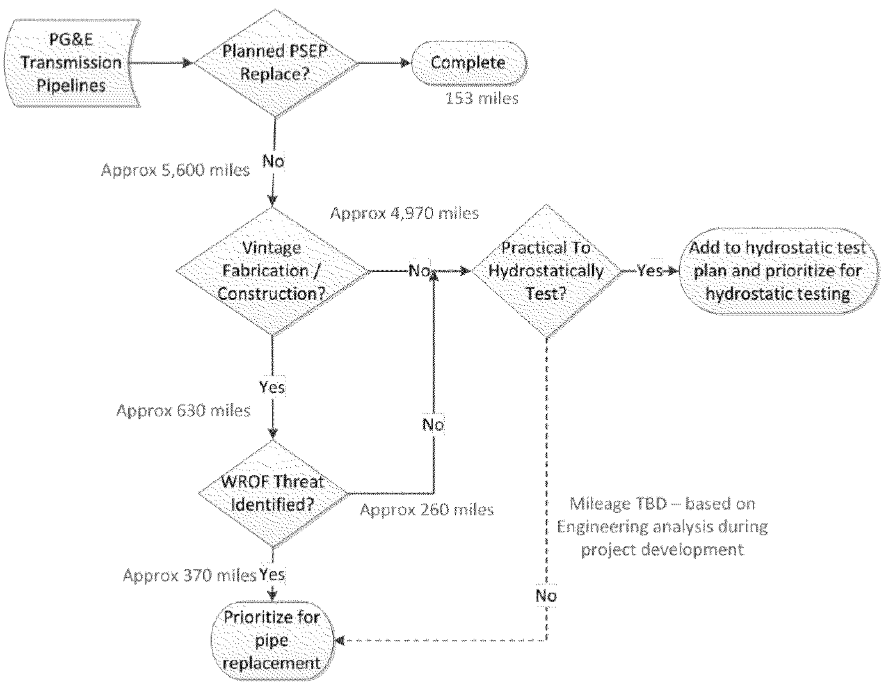
[164] As described in this Section, PG&E has abandoned the concept of Phase 2 PSEP work and now proposes the Hydrotest and VIPER Programs to replace PSEP Phase 2.

[165] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Krannich), p. 3-4.

[166] The Preliminary Report of the Safety and Enforcement Division, issued July 18, 2014 in this proceeding, raised similar concerns starting on p. 26.

but that was not completed. The following figure depicts the flow of projects through the VIPER decision tree:[167]

Figure 4C-4
PG&E VIPER Program Decision Tree



As the first two diamonds at the top of the VIPER decision tree reveal, a pipe segment with a manufacturing threat designated for replacement (or which should have been designated for replacement) by the PSEP decision tree, but not replaced during PSEP, has no immediate path to replacement in the VIPER Program since the VIPER Program pertains only to certain fabrication and construction threats. Thus, a line that should have been replaced in PSEP Phase 1, will not be replaced unless it otherwise qualifies for replacement under the VIPER decision tree criteria.

This problem is less obvious for the Hydrotest Program since many decision points in the GT&S decision tree are the same, or very similar to, those in the PSEP decision tree.[168] However, it is clear that the GT&S Hydrotest decision tree starts the

[167] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-58.

[168] See PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), p. 4A-34.

analysis "from scratch" and there is no on-ramp for pipe segments that would have been prioritized for testing or replacement under the PSEP decision tree, but which were not tested or replaced.

Correctly prioritizing deferred mileage has obvious safety implications because the GT&S Hydrotest and VIPER decision trees define the scope and timing of PG&E's testing and replacement work going forward. It also has significant cost implications since PG&E's proposed unit costs for the GT&S Hydrotest Program are higher than the costs allowed in PSEP,[169] and because PG&E seeks to only have hydrotests for post-1961 lines disallowed due to missing or incomplete records, compared to the level adopted by the Commission in D.12-12-030, which applied disallowances to post-1955 lines.

PG&E has known since early in 2011 that it was likely to incur disallowances against its actual PSEP costs.[170] These PSEP disallowances have created a strong financial incentive for PG&E to defer work to the GT&S case where it could seek higher unit costs and potentially see an end to these disallowances. PG&E testifies that its GT&S decision trees are intended to move it "towards a more holistic approach to prioritizing the management of risk arising from the threats to its Transmission Pipe assets."[171] ORA is not opposed to this concept, but it cannot support new decision trees that fail to address deferred PSEP work, thereby reducing the safety of PG&E's system. Further, PG&E's failure to directly address the issue of deferred PSEP work – lines that should have been hydrotested or replaced under the PSEP decision tree but which were not – appears to be a calculated attempt to bypass the cost caps and disallowances implemented by D.12-12-030. As such, PG&E should not be rewarded for deferring this important work.

3.4.2 Scope of deferred PSEP work

There are two groups of pipe segments and projects deferred from PSEP: (1) those PG&E deferred explicitly in the PSEP Update Application and (2) those it deferred

[169] See Section 3.2.2 of this testimony.

[170] PG&E PSEP Rebuttal Testimony in R.11-02-019, (Campbell), p. 4-2.

[171] PG&E 2015 GT&S Prepared Testimony, Volume 1 (Singh), p. 4-13.

by omitting them from consideration in the PSEP Update. These will be referred to as "Group 1 Deferrals" and "Group 2 Deferrals," respectively.

PG&E's PSEP Update Testimony reflects that for Group 1 Deferrals, 18% of the pipe replacement scope, and 11% of the hydrotest scope was deferred.[172] These represent a combined total of 119 miles of deferred PSEP work in Group 1. PG&E assigned "deviation codes" to pipe segments where it determined that there was a reason not to perform the mitigation determined by the PSEP decision tree, including deferring mitigation beyond PSEP.[173] SED performed an audit of the PSEP Update Application (SED Report) which focused on PG&E's deferred work and concluded that "the workpapers supporting the PSEP Update Application are not error-free and that the scope update is not entirely consistent with SED's expectations."[174] Notwithstanding these findings the SED Report determined that "no imminent safety concerns arose from SED's review."[175] The SED Report does not, however, address the safety issue posed by performing less mitigation work than PSEP originally proposed, especially in light of the fact that the PSEP decision tree was intended to identify the highest priority projects requiring testing or replacement. Even if SED were to determine that these deferrals, as a whole, were not a concern from a safety perspective, they are a concern for ORA from a cost perspective since mitigation costs could double as a result of PG&E deferring this work if PG&E's GT&S cost forecasts are adopted by the Commission.[176]

[172] See PG&E PSEP Update Prepared Testimony in A.13-10-017, (Hogenson/Campbell). Table 2-5 on page 2-26 indicates that 33.0 miles were deferred of the 185.7 miles originally proposed pipe replacement. Table 2-10 on page 2-29 indicates that 86.0 miles were deferred of the 783 miles originally proposed for hydrotest.

[173] See PG&E PSEP Update Prepared Testimony in A.13-10-017, (Hogenson/Campbell), Table 2-1, pp. 2-14 to 2-16.

[174] Safety Review Report of PG&E's PSEP Update Application by the California Public Utilities Commission's Safety and Enforcement Division, April 25, 2014, served on the parties in A.13-10-017 (SED PSEP Report), page 2. ORA questioned how SED could reach a conclusion of "no imminent safety concerns" given the limited sample of projects it reviewed, and its lack of definition of "imminent safety concerns." ORA also requested SED to identify those pipe segments that should have been mitigated in PSEP Phase 1, but were not. See June 4 letter from ORA.

[175] SED PSEP Report, p. 2.

[176] See page 65 below for a discussion of how data provided by PG&E shows an 80% increase

Group 2 Deferrals are pipe segments that would have been replaced in PSEP if PG&E had applied the adopted PSEP decision tree to all transmission pipe segments. This group of deferrals was not mentioned or quantified in PG&E's testimony in the PSEP Update Application or in the GT&S Testimony, but was first brought to light in the SED Report, which found that "with limited exceptions, the MAOP Validation results were evaluated and incorporated into the PSEP program only for pipeline segments that were part of the original PSEP proposal."[177] In other words, once the MAOP Validation was complete, PG&E did not re-run its entire transmission system through the PSEP decision tree to determine if any new segments were designated as "higher priority." The SED report included a discussion of a "preliminary query of the MAOP validation results which indicate that the following [62.1] miles of pipeline potentially do not have valid test records and are not currently in the Updated PSEP Application."[178] Subsequent discovery revealed that this number is actually 45 miles, 20.2 miles of replacement and 24.8 miles of hydrotest.[179] This mileage is a minimum figure since it only includes pipe segments requiring mitigation. PSEP project mileage was increased to improve project efficiency, and PG&E has indicated it plans to continue this practice: "PG&E plans to build optimal project scopes whereby we may also test adjacent untested class 1 and 2 Non-HCA segments for project and program cost efficiency resulting in many more segment miles being addressed above and beyond these 45 feature miles."[180] Project engineering in PSEP resulted in a 43% increase in the scope

in average cost per mile for 34 test and replacement projects under GT&S, and how this, coupled with an increase in scope, resulted in costs for these projects nearly quadrupling. In addition, PG&E's requested hydrotest unit cost of $1.02 million per mile, including escalation, is more than double the PSEP average forecasted value of $0.5 million per mile, and its average forecasted 2015 unit cost for replacement of $9.0 million per mile is twice the PSEP forecast of $4.5 per mile.

[177] SED PSEP Report, p. 28.

[178] SED PSEP Report, p. 29.

[179] PG&E Supplemental Response dated July 23, 2014 to DR-ORA-89 Q1c. The replacement mileage is for segments with M2 or F2 PSEP decision tree outcomes that require Phase 1 replacement, and hydrotest mileage is for outcomes M4 and C2 that require Phase 1 hydrotesting. These are segment miles requiring high-priority mitigation per the adopted PSEP decision tree.

[180] PG&E Supplemental Response dated July 23, 2014 to DR-ORA-89 Q1h.

of hydrotest projects proposed in the original PSEP.[181] If GT&S project engineering results in similar growth, the 45 miles deferred would result in approximately 65 miles of additional testing and replacement in 2015-2017, or approximately 21.5 miles each year.

PG&E has stated that it plans to mitigate all 45 miles identified as Group 2 Deferrals mileage "during the 2015 GT&S Rate case."[182] However, it is unclear if and how this scope of work is included in GT&S. Based on the VIPER Program description and decision tree, it does not appear that the 20.2+ replacement miles of Group 2 Deferrals are included in the list of proposed replacement projects. Most of the 24.8+ hydrotest miles in Group 2 should be included in the GT&S list of proposed hydrotests, since all transmission segments were supposed to have been evaluated using the GT&S decision tree which is similar to the PSEP decision tree in this regard. However, the GT&S Application does not track the status of this mileage.[183] PG&E also indicated that "no further prioritization has been given to these features within the 2015 GT&S rate case."[184]

In order to better understand where the deferred projects are going to be addressed in GT&S, ORA issued a data request to PG&E asking for cost information on any projects that "dropped out of a program category pursuant to the PG&E Update Application in A.13-10-017 and are now included in GT&S."[185] This question did not

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[181] 237 miles of the 783 hydrotesting miles originally proposed in PSEP were included "by determination of efficient ending points per project as opposed to the exact start and stop of every pipe segment without a pressure test," PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson), pp. 3-29 to 3-30. In other words, PG&E only needed to replace 546 miles (783 – 237) based on the PSEP decision tree, but added 237 extra miles, or 43% more than the 546 miles required, to build longer tests that ended in locations where test equipment could be set up. PSEP replacement projects also were expanded to include segments for "project efficiency." See PG&E PSEP Update Prepared Testimony in A.13-10-017, (Hogenson/Campbell), p. 2-14, description of Deviation Number 3, "Constructability."

[182] PG&E Supplemental Response dated July 23, 2014 to DR-ORA-89 Q1h. This response also states that "PG&E has not developed specific project scopes to address these features," which indicates the scope of adjacent miles included in these projects is not yet known.

[183] Class 2 segments, which were prioritized with Class 3 and 4 in the PSEP decision tree, have less priority in the GT&S hydrotest decision tree. Class 2 pipe segments within the Group 2 Deferrals may not be prioritized for 2015-2017 testing depending on their calculated AOC.

[184] PG&E Response to DR-ORA -112 Q1a.

[185] ORA-DR-9 Q2.

differentiate between Group 1 or Group 2 Deferrals because ORA was not aware of the Group 2 Deferrals at the time of the request and ORA assumes that PG&E's response only provided data relevant to the Group 1 Deferrals. ORA analysis of the data provided in PG&E's response revealed two things. First, PG&E provided data for 34 hydrotest and replacement projects with a total of 189 miles deferred.[186] While each of these projects has footage in GT&S, their total length in GT&S is only 35.6 miles.[187] Neither of these values corresponds to the amount of Group 1 Deferrals quantified in PG&E's PSEP Update Application, which was 119 miles.[188] It therefore appears that not all Group 1 Deferrals are currently scheduled for mitigation in GT&S.

The second finding is that the average cost for these 34 projects would have been $0.66 million per mile based on the PSEP cost model, but in GT&S they are forecasted to cost $1.18 million per mile – nearly twice the PSEP cost.[189] These figures include both replacement and hydrotest so they should not be used directly for comparison to other unit costs in this testimony, but they do illustrate how PSEP projects deferred to GT&S will result in higher costs to ratepayers if PG&E's implied proposal to roll these projects into GT&S is adopted.[190]

In the PSEP proceeding PG&E requested a specific scope for PSEP prior to completion of its MAOP Validation process and D.12-12-030 approved a budget for this scope, but included provisions to modify the scope and cost caps once MAOP validation was completed. Decision 12-12-030 explicitly provided for the addition of new high-priority work to offset any reductions in scope due to found records, such that PG&E should have mitigated pipe segment threats at the rate it originally proposed. But the

[186] PG&E Supplemental Response dated March 26, 2014 to DR-ORA-9 Q2, Attachment 1, total for column "L."

[187] Ibid, total for column "N."

[188] See footnote 172 and accompanying text.

[189] PG&E Supplemental Response dated March 26, 2014 to DR-ORA-9 Q2, Attachment 1. The $0.66 value is the sum of column "P" costs divided by the sum of column "N" miles; the $1.18 value is the sum of column "G" costs divided by the sum of column "F" miles.

[190] In addition to the increase in unit costs, total costs also increase. Data in Attachment 1 to PG&E Supplemental Response to ORA-DR-9 Q2 shows that the PSEP cost for these 34 projects would be $23.4 million for 36.6 miles, but a GT&S cost of $91.7 million for 77.7 miles.

PSEP Update Application showed that PG&E instead significantly reduced the scope of PSEP. In other words, PG&E did not replace all cancelled projects with higher priority projects. Instead, there was a 23% reduction in planned replacements and 16% reduction in planned hydrotests.[191] This was in part because while PG&E used the result of the MAOP Validation to eliminate unnecessary projects, it did not run its entire database through the PSEP decision tree to see if any new projects were identified for testing or replacement.[192] PG&E evidently chose not to complete the amount of work it originally proposed. Given this context, ORA has three recommendations, as described below.

3.4.3 ORA Recommendations

First, PG&E should define the full scope of both the Group 1 and Group 2 Deferrals, including extra pipe segments added for project efficiency. PG&E should distinguish hydrotesting from replacement mileage, and provide cost driver data required by the PSEP cost model for these projects, including project location, pipe diameter(s), installation dates, and any other data required to calculate PSEP costs and disallowances. The status of deferred PSEP work should be tracked separately in reports to the Commission. Second, PG&E should modify both its Hydrotest and VIPER Program decision trees to provide an on-ramp for deferred PSEP work, and decision points to prioritize these pipe segments. Alternatively, PG&E should be required to attest that all deferred PSEP work will be completed in the 2015-2017 timeframe and provide a detailed description of how this work will be prioritized relative to projects already proposed for GT&S. In either case, proposed project lists in the workpapers,

[191] (185.7-143.3)/185.7 miles for replacement, per Table 2-5 PG&E PSEP Update Prepared Testimony in A.13-10-017, (Hogenson/Campbell), p. 2-26; (783-658)/753 miles for hydrotest, Table 2-10, Ibid, p.2-29. These values are higher than those on page 60 above because they show the total reduction in scope which includes Group 1 Deferrals, cancelled projects, and added scope.

[192] See PG&E PSEP Update Prepared Testimony in A.13-10-017, (Hogenson/Campbell), p. 2-16 where PG&E explains the method by which it evaluated pipe segments not in the original PSEP scope which resulted in new scope in the PSEP Update. Further clarification is provided in PG&E's Response to DR -ORA-8 Q6 issued in the PSEP Update Application, A.13-10-017, which states that "there was no specific criteria used to determine how far upstream and downstream the data validator should look. Each project was looked at on a case-by-case basis."

annual targets, and all references to the scope of the GT&S Hydrotest and VIPER Programs should be updated to expressly identify and include the PSEP deferrals.

Third, the scope determined consistent with the first recommendation should be valued based on the PSEP cost model as adopted in D.12-12-030, including the disallowance provisions. PG&E planned, or should have planned, to perform this work in PSEP. It found records through the MAOP Validation that provided the opportunity to cancel unnecessary projects and add new higher priority projects to PSEP Phase 1, consistent with what was contemplated in D.12-12-030. If the Commission adopts GT&S cost forecasts that produce program costs that are comparable with the costs established in D.12-12-030, such as the forecasts provided in Sections 3.2.4 and 3.3.5 of this testimony, it may be possible to use one cost methodology for all projects subject to PG&E demonstrating that program costs are the same, and possibly applying an adjustment that accounts for any cost differences and/or the hydrotest disallowance. Regardless, the intent should be to prevent PG&E from bypassing the PSEP cost caps established in D.12-12-030, and to ensure the burden of proof is on PG&E to show they have not done so.

3.5 The Commission Should Confirm That PG&E Has Correctly Applied The PSEP Cost Caps And Is Only Collecting Revenue Requirement On PSEP-Authorized Capital Expenditures

Decision 12-12-030 authorized PG&E's PSEP program and set both unit cost caps on PSEP projects, as well as a total cost cap on PSEP expenditures. These caps were intended to disallow certain capital expenditures for the life of the project so that revenue requirement would only be collected on the capped amounts. PG&E, ORA, and TURN recently proposed a settlement agreement to the Commission that further reduced the total cost caps set in D.12-12-030 to reflect that PG&E reduced the scope of work that it performed under PSEP.

An issue of concern to ORA is confirming that the cost caps set in D.12-12-030 continue to flow through into GT&S so that PG&E only collects revenue requirement on the capped amount for PSEP capital projects.

PG&E testimony indicates that PSEP costs are included in the GT&S revenue requirement: "PG&E's GT&S cost of service, as expressed in revenue requirement, is

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calculated based on: (1) PG&E's planned capital and expense expenditures; …(3) the Pipeline Safety Enhancement Plan (PSEP) approved by the CPUC in Decision 12-12-030."[193] PG&E further explains that it "has combined the proposed GT&S forecast with PSEP ongoing authorized capital recovery … by adding in the results of a separate model."[194] This is demonstrated in the workpapers in that the total base revenue requirement (BRR) of $1,286.3 million provided in testimony is the sum of the GT&S 2015 BRR of $1,187.4 and the PSEP BRR of $99.0 million.[195] However, Table 16-4 of PG&E's GT&S testimony provides the same total BRR of $1,286.3, but does not include the UCC for PSEP, which is 560. This seems to conflict with the workpapers.

In response to discovery, PG&E identified the MS Excel file where the PSEP BRR is calculated and the "RO_Gas" model where the PSEP BRR is combined with the GT&S BRR to obtain the total BRR.[196] It appears that in the separate PSEP file, PG&E uses capped PSEP capital expenditure values, which should then flow into the RO_Gas model automatically. However, the RO_Gas model also has an input screen that ORA was instructed to use to input capital adjustments. This screen includes the un-capped PSEP values for 2013 and 2014.[197] ORA reduced the PSEP capital expenditures for 2013 and 2014 in this input screen, and the base revenue requirement calculated by the model was reduced.[198] It therefore seems as though uncapped PSEP pipeline modernization costs values may be entering the BRR, and/or there may be some duplication of PSEP costs entering the total GT&S BRR calculation.

[193] PG&E 2015 GT&S Prepared Testimony, Volume 2 (Jones), p. 16-1. Additional details of how this will be performed in concert with the concurrent PSEP Update application A-13-10-017 are provided on page 16-7.

[194] Ibid, page 16-6.

[195] GT&S BRR is provided in PG&E 2015 GT&S Workpapers, Chapter 16, p. WP 16-1 line 1 and PSEP BRR provided on page WP 16-330 line 1. The $0.1 million difference is due to rounding.

[196] Per PG&E's responses to DR-ORA-105 questions 1 and 3, these files are "Life_PD_PSEP_TOTAL_Revised_ROE_100413.xlsx" and "RO_Gas.xlsm" respectively.

[197] File "CapitalModel," "Adjustments" tab, line 2193. This line includes the exact value for 2013, $329.3 million, but a lower value for 2014, $333.4 million. ORA does not know at this time why the 2014 values do not match.

[198] The values for 2013 and 2014 in line 2193 listed in the previous footnote were reduced to zero. The 2015 base revenue requirement of $1,286 million from Table 16-1 was reduced to $1,196 million.

ORA has issued discovery on this issue, met with PG&E to discuss this inconsistency, and continues its analysis of this issue. During discovery, ORA asked "*Is PG&E proposing that PSEP actual costs, rather than capped costs adopted by D.12-12-030 or subsequent decisions regarding A.13-10-017, be included as plant and ratebase for the purposes of determining rates in the current proceeding?*" PG&E's response was a clear "No."[199] However, this issue was not resolved to ORA's satisfaction prior to preparing this testimony.[200] Given the magnitude of this discrepancy, PG&E should make a transparent showing in rebuttal that can be used to verify that capped PSEP costs are appropriately included in the GT&S base revenue requirement request for the 2015 test year.

3.6 Commission Oversight Is Required To Ensure PG&E Performs The Highest Priority Work First, Regardless Of Cost Recovery Concerns

PG&E has, at various points in its G&TS Application, sought authority from the Commission to modify the scope of both the Hydrotest and VIPER Programs.[201] As described in Section 3.4.1 above, because PG&E may have to test or replace lines subject to cost disallowances, PG&E has the incentive to avoid performing this work in favor of work which is subject to full cost recovery. Consequently, if the Commission grants PG&E flexibility to modify the scope of Hydrotest and VIPER Programs, the Commission will need to establish structural safeguards, including monitoring functions, to ensure work subject to disallowances is performed in a timely and appropriate manner no different than work subject to full cost recovery.

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199 DR-ORA-105 Q2 and PG&E Response to DR-ORA-105 Q2.

200 The "RO_Gas" file is very large and can only be run on a computer loaned to ORA by PG&E. This computer was needed to input ORA costs adjustments from all ORA witnesses and to support ORA testimony on Chapter 16 and 17, and was not available to help resolve this issue prior to testimony.

201 See, for example, PG&E 2015 GT&S Prepared Testimony, Volume 1 (Barnes), pp. 4A-35 and 4A-59.

3.7 Going Forward Collection and Retention Of Data

As demonstrated throughout this testimony, PG&E's showing in this proceeding has not been substantiated by quality data, and when asked, PG&E was unable to provide data supporting its forecasts. To develop its proposed forecasts, ORA relied upon the extensive data available in PG&E's PSEP Reports – reports which this Commission ordered and specifically identified what they should contain.[202] Without this readily available data, the Commission would not be able to have any picture of what is happening in PG&E's hydrotesting and replacement programs, other than the limited picture PG&E presented in this case.

To continue the collection and organization of the valuable information provided by the PSEP Reports, this Commission should order PG&E to continue to produce a form of report similar to the PSEP Reports for its ongoing Hydrotest and Replacement Programs.[203] The transparency provided by the PSEP Reports has been invaluable to ORA's work in a number of proceedings, including this one, and should continue until PG&E's reconstruction of its pipeline system is concluded. Among other things, requiring PG&E to prepare and distribute such reports will facilitate the development of more accurate forecasts in the next rate case.

[202] See D.12-12-030, Ordering Paragraph 10 and Attachment D.

[203] ORA will propose possible revisions to the PSEP Reports for going forward purposes at some stage in this proceeding.