Exhibit No: ________________

Date: August 11, 2014

ALJ: John Wong

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015 – 2017 (U39G).	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

REDACTED

PREPARED DIRECT TESTIMONY OF

JONATHAN A. LESSER, PH.D.

ON BEHALF OF

THE INDICATED SHIPPERS

AUGUST 11, 2014

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I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, New Mexico, 87047.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. The Indicated Shippers, which for the purposes of this proceeding include Aera Energy LLC, Chevron U.S.A. Inc., Occidental Energy Marketing Inc., Phillips 66 Company, Shell Oil Products US and Tesoro Refining & Marketing Company LLC. Each of these companies transports natural gas on Pacific Gas and Electric Company's (PG&E or the Company) transmission system, as end-use customers and/or natural gas marketers.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have 30 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission (FERC), state legislative committees, Congress, and international venues. I have attached a copy of my curriculum vitae as Exhibit JAL-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony places PG&E's extraordinary revenue request in context from the perspective of a large industrial user of PG&E's natural gas transportation services. It assesses whether granting PG&E's application will result in "just and reasonable" rates considering the adequacy of support for PG&E's requested revenue requirement and capital expenditures. It observes generally that PG&E's management choices over the past decade likely have contributed to the "lumpiness" in proposed expense and capital spending evidenced by the Application. Finally, it proposes ratemaking tools the Commission can use to ensure "just and reasonable" rates in the face of this unprecedented request.

II. EXECUTIVE SUMMARY

Q. HOW WOULD YOU CHARACTERIZE PG&E'S SPENDING REQUEST?

A. If accepted, PG&E's proposals will result in unjust and unreasonable rates, creating rate shock without adequate assurances that the proposed expenditures will deliver the best safety value for ratepayer dollars.

PG&E has proposed to more than double the Company's 2014 revenue requirement by 2017. It forecasts a $1.6 billion Test Year (TY) 2015 increase in operating expenses and proposes additional capital spending of $2.6 billion in the three-year GT&S rate period to improve the safety of its pipeline transmission system. The proposal, if granted, would result in a tremendous rate shock for all customers on the PG&E system.

PG&E has not provided evidence that its risk management approach has created the right priorities for its spending. As the joint testimony with Prof. Feinstein (Joint Testimony) demonstrates, PG&E's approach fails to ground its assessment on sufficient asset condition information. In addition, PG&E's approach lacks fundamental components – budget and risk tolerance constraints -- for determining a set of programs that will provide ratepayers with the best value for their money. Finally, the programs and measures PG&E has proposed are based on a fundamentally flawed and ultimately opaque risk management decisionmaking process. These foundational concerns prevent the Commission from gaining confidence that the rates resulting from the Application will be just and reasonable.

Beyond the risk management concerns raised in the Joint Testimony, this testimony explains that PG&E has not adequately substantiated its proposed programs and costs. Some of the proposed programs are conceptual, at best, and lack project-specific detail. Other programs provide questionable cost forecasts. Still other programs raise concern that PG&E is trying to compress the costs of what should have been longer term projects into a three-year rate cycle. PG&E has failed to demonstrate that its proposals will lead to just and reasonable rates.

Q. HOW WOULD PG&E'S PROPOSAL AFFECT NONCORE CUSTOMERS?

A. If the CPUC approves all of PG&E's proposed \$4.2 billion capital and expense increases for the 2015-2017 period, noncore ratepayers will experience immediate rate shock. An overall 91% to 135% natural gas transportation rate increase, as PG&E has proposed for noncore customers by the end of this period, is surely a clear example of rate shock. The increase will flow directly to the bottom line of businesses that operate in a state, national and/or global market if they are unable to pass the cost increase on to their customers.

Q. HOW SHOULD THE MAGNITUDE OF POTENTIAL RATE IMPACT GUIDE THE COMMISSION'S REVIEW AND DECISIONMAKING?

A. PG&E's Pipeline Safety Enhancement Plan (PSEP) increase, adopted in D.12-12-030, resulted in a rate increase PG&E's industrial customers of approximately $0.30/Dth, less than one-third the proposed impact in this Application. Yet, in D.12-12-030, the Commission characterized the PSEP as a "massive capital and expense program" and observed "[t]o meet our constitutional and statutory duties, we must create powerful incentives for PG&E to manage this program efficiently and to aggressively identify and capture cost savings."[1] The Application warrants similar, if not greater, incentives for efficiency.

An extraordinary proposal requires an extraordinary exercise of the Commission's duty to ensure that ratepayers are not unduly harmed and that PG&E's proposed expenditures provide ratepayers with the greatest possible economic value. The Joint Testimony concludes, however, that PG&E's analytical methodology for prioritizing investments to improve safety and reliability suffers from fundamental flaws that make maximized ratepayer value impossible. Those conclusions are bolstered by the

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1 *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety* Engineering, Decision (D.) 12-12-030, December 20, 2012, p. 99.

conclusions in the Commission's Safety and Environmental Division's Preliminary Report of July 18, 2014.[2]

Q. HOW SHOULD THE COMMISSION EVALUATE THIS COMPLEX PROPOSAL YOU DESCRIBE IN THIS RATEMAKING TESTIMONY?

A. My testimony here illustrates that this rate case is particularly complex, involving not only traditional ratemaking principles, but a broad range of new considerations arising when risk management is integrated with the rate case process. To determine whether PG&E's proposals will result in "just and reasonable" rates, the Commission must first determine whether PG&E's approach to risk management will achieve an appropriate level of safety for the dollars spent. The Commission must ask:

1) What pipeline safety and reliability objectives will PG&E achieve through the proposed programs?
2) Does PG&E's analytical methodology to identify and mitigate risks produce consistent and reasonable results?
3) Does PG&E have sufficient information on the current conditions of its pipeline assets and how those conditions are likely to change over time, necessary to achieve the Company's objectives in the most cost-effective ways possible?
4) Has PG&E demonstrated the risk reduction and improved reliability that will result from its measures and the capability to achieve these gains in the most cost-effective manner possible?

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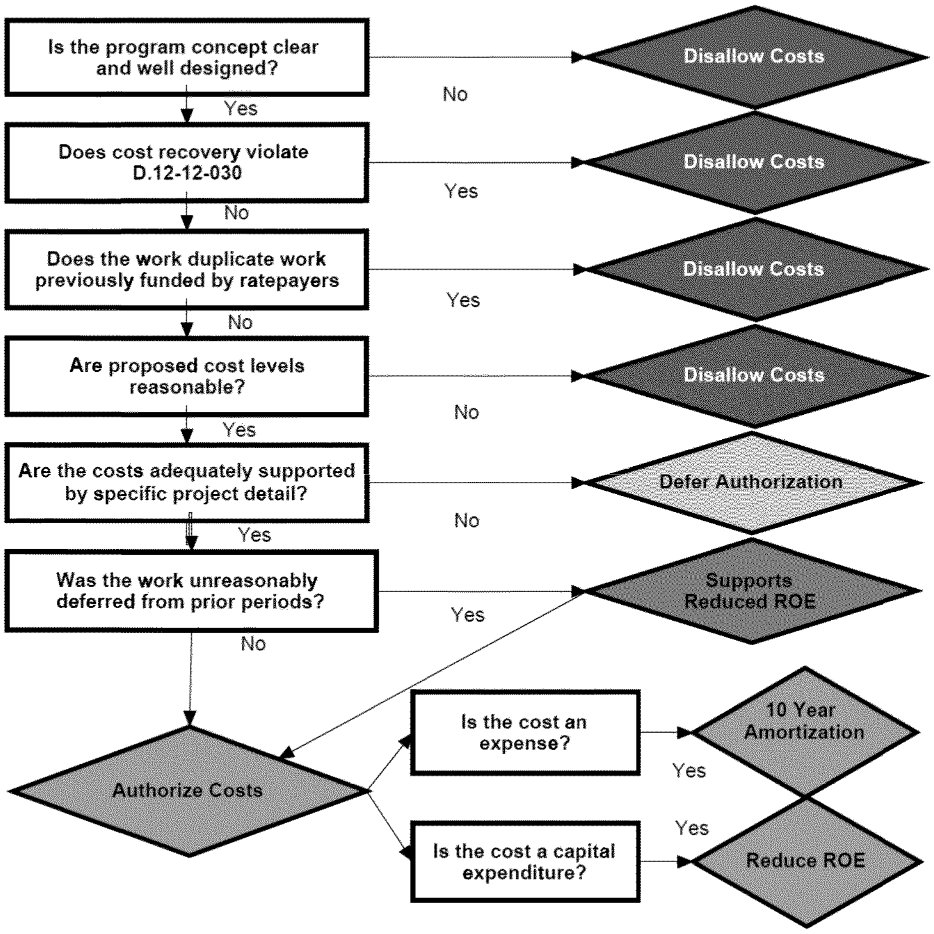
[2] Caroline Contreras, Steven Haine, and Suman Mathews, Pacific Gas & Electric Company Proposal for Cost of Service and Rates for Gas Transmission and Storage for 2015-2015 Application 13-12-012, "Preliminary Staff Report," July 18, 2014 (SED Report).

Based on PG&E's testimony and supporting materials, it will be difficult, if not impossible, for the Commission to conclude that PG&E has met its burden of proof on the reasonableness of its approach to risk management.

If the Commission moves beyond the inadequacy of PG&E's risk management foundation, it must determine whether PG&E has otherwise adequately supported its proposal. Conclusions that the programs are not substantiated may suggest a range of remedies, including traditional disallowance, cost recovery deferral, long-term expense amortization or reduction in PG&E's return on equity for capital invested during this rate period. Figure 1 depicts a framework the Commission can use to determine the reasonableness of PG&E's proposed spending.

Figure 1: Recommended Evaluation Framework



Q. BEYOND THE SUFFICIENCY OF PG&E'S SHOWING, ARE THERE OTHER FACTORS THE COMMISSION SHOULD HAVE IN MIND AS IT ASSESSES PG&E'S PROPOSAL?

A. Yes. The Commission should examine other factors when assessing the impacts on ratepayers. Fundamentally, it is important that PG&E be required to demonstrate the need for the expenditures in the proposed time frame while also demonstrating that the expenditures produce a reduction in overall risk compatible with its goals and objectives. On its face, the proposal appears to be an effort to "catch up" with deferred maintenance as part of a broader system upgrade that began with the PSEP and is forecast to carry into the next decade. Under these conditions, burdening ratepayers with all of these costs in three years, and more than doubling many noncore customer rates, is not just and reasonable. To mitigate the rate impacts requires implementation of atypical ratemaking tools and shareholder participation in solutions.

Q. HOW DO YOU PROPOSE TO ADDRESS THE ISSUES YOU HAVE IDENTIFIED?

A. The Commission should exercise its obligation to ensure just and reasonable rates through the following discrete actions:

1. **Improved Risk Management Methodology**. Direct PG&E to modify its approach to risk management to correct the flaws identified in the Joint Testimony.
2. **Transparent Risk Tolerance Constraints**. Ensure that PG&E, whether through its own decisionmaking process or at the Commission's direction, creates clear safety objectives and risk tolerance levels to guide its planning.
3. **Transparent Budget Constraints.** Ensure that PG&E, whether through its own decisionmaking process or at the Commission's direction, develops a guiding budget that avoids rate shock and ensures the affordability of its natural gas transportation services.

4. **Cost Recovery Deferral.** Defer cost recovery for programs and activities for which PG&E has not obtained the system information necessary to determine an optimal program of safety measures, not developed analytically correct methodologies necessary to identify and implement such program, not identified the specific activities on which the requested revenues will be spent, or adequately explained the risk reduction benefits of the program.

5. **Disallowance.** Disallow costs proposed by PG&E where cost recovery would run contrary to D.12-12-030.

6. **Long-Term Expense Amortization.** Amortize recovery of certain expenses over a ten-year period to reduce rate shock, recognizing that PG&E is playing "catch-up" and that the investments are of a long-term nature.

7. **Reduced ROE.** Reduce, for a ten-year period, the return on equity for capital invested in this rate period to 9.4%, the low end of the range of reasonableness approved in the Cost of Capital D.12-12-034 for a natural gas distribution utility.

With these changes, the Commission can have a sufficient level of assurance that the plan PG&E implements will result in just and reasonable rates.

Q. HAVE YOU SUMMARIZED THE GENERAL IMPACT OF YOUR RECOMMENDATIONS ON PG&E'S PROPOSED REVENUE REQUIREMENT AND CAPITAL EXPENDITURES?

A. Yes. Exhibit JAL-2 summarizes the impact of my proposals on PG&E's proposed operating expenses, and Exhibit JAL-3 summarizes the impact on the proposed capital expenditures.

III. THE APPLICATION REQUIRES CAREFUL SCRUTINY

Q. DOES PG&E'S PROPOSAL STRIKE YOU AS A "BUSINESS AS USUAL" RATE CASE FILING?

A. No. The sheer magnitude of the request sets it apart from any other rate case previously filed by PG&E for its natural gas system and from any other rate case with which I am familiar. The request is even greater than PG&E's more urgent request in the PSEP. As such, the nature of the work and the magnitude of spending require greater scrutiny.

Q. WHAT HAS LED YOU TO THE CONCLUSION THAT PG&E IS CATCHING UP WITH PAST WORK DEFERRAL?

A. Although my testimony does not attempt to evaluate PG&E's level of compliance with federal or state safety regulations, it does not take an expert to conclude that this case, like the PSEP, is a case of "catch up." Regulations addressing pipeline safety have been around for decades, with the most prominent regulations placed under the administration of the Pipeline and Hazardous Materials Safety Administration (PHMSA) a decade ago. Important programs on PG&E's system, however, such as corrosion control, appear to have languished until the San Bruno incident. Even apart from compliance with explicit regulations, PG&E's diligence in knowing the condition of its system assets and prudency in pursuing system maintenance appears to be at odds with *Good Utility Practice*.

Q. DOES THE ABSENCE OF SPECIFIC REGULATORY REQUIREMENTS MEAN THAT A REGULATED UTILITY'S MANAGEMENT CAN OPERATE WITH IMPUNITY?

A. No. As part of *Good Utility Practice*, regulated utilities are required to follow a basic set of standards and practices, and charge just and reasonable rates.

Q. CAN YOU PROVIDE A DEFINITION OF GOLD UTILITY PRACTICE?

A. Yes. The Federal Energy Regulatory Commission (FERC), defines *Good Utility Practice* as:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of *reasonable* judgment in light of the facts known *at the time the decision was made,* could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.[3]

A utility engaging in Good Utility Practice equates to what the Commission referred to as a "prudent gas transmission systems operator" in D.12-12-030. For example, knowing that corrosion presented a risk to pipeline integrity, it would be reasonable for a regulated pipeline operator to implement accepted practices to detect and control corrosion, even in the absence of specific laws mandating such control, but it would not be reasonable for a pipeline operator to ignore corrosion control completely. Maintaining adequate records is

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[3] FERC, *Pro Forma Open Access Transmission Tariff* (OATT), Appendix C (emphasis added), 72 Fed. Reg. 12,266–12,531 (March 15, 2007).

Good Utility Practice, regardless of whether federal regulations or Commission orders may compel certain recordkeeping practices.

Q. WHY IS IT RELEVANT WHETHER THIS IS A CASE OF CATCH UP, RATHER THAN BUSINESS AS USUAL?

A. Attempting to condense long-term system maintenance expenses and material capital spending into this three year period will result in rate shock. Moreover, it appears that many of the identified expenses and investments are part of a longer term program, accelerated into the early years. The lumpiness of spending requires the use of atypical ratemaking tools, such as long-term expense amortization, to smooth the effects of PG&E's catching up with existing regulations and practices. PG&E's management's role in this catch up also suggests an important role for shareholders, in helping mitigate the resulting rate shock.

Q. ARE THERE OTHER CONSIDERATIONS THE COMMISSION SHOULD KEEP IN MIND IN EVALUATING YOUR RECOMMENDATIONS?

A. Yes. The Commission should be cautious not to be drawn by the "safety hue" of PG&E's Application to approve proposals without specific project level detail. This proceeding is a rate proceeding to determine what are just and reasonable rates for ratepayers. The desire to approve more conceptual project level budgets in the PSEP may have been compelled by urgency following the San Bruno incident. PG&E's proposal in this case, however, is not an urgent response. Moreover, the level of rate increase PG&E has proposed is staggering, commanding a higher level of scrutiny to warrant up-front approval of project costs.

The Commission should focus closely on ensuring that the proposed costs are "known and measurable," a ratemaking standard long used by FERC and state agencies, alike. In my textbook, *Fundamentals of Energy Regulation*, I explain:

> The *known and measurable* standard means that, regardless of whether the regulated firm has control over a particular cost or not, to be included as part of the firm's revenue requirement, costs must have a realistic basis. For example, suppose a firm's [cost of service] study includes an additional $10 million in costs of wages and salaries in the rate year. To be accepted as known and measurable, that salary increase must have a realistic basis. Justifying an increase by telling regulators, "We think we will hire 30 or 40 new employees next year," will likely not meet the known and measurable standard. We say "likely" because there is no single definition of "known and measurable," and different regulators apply the standard with different levels of rigor.[4]

This Application warrants a high level of rigor.

IV. AUTHORIZING PG&E'S SPENDING REQUEST WOULD CAUSE UNPRECEDENTED RATE SHOCK

Q. HOW WILL PG&E'S REQUEST AFFECT NONCORE INDUSTRIAL CUSTOMERS?

A. PG&E's revenue request will result in unprecedented rate shock. As shown in Table 1 below, by 2017, a high load factor noncore industrial customer connected to PG&E's system at the transmission level and transporting on PG&E's Redwood backbone transmission path will experience an increase of 91%. Using those same assumptions, an electric generator will see a 135% increase. Industrial customers who

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[4] Jonathan Lesser and Leonardo Giacchino, *Fundamentals of Energy Regulation* (2013), p. 109.

use on-site electricity generation to meet their electrical requirements will experience the effects of both backbone and end-use transportation rate increases.

Table 1: Rate Increases Proposed by PG&E

	Present Rates ($/Dth)	2015 Rates ($/Dth)	2014 - 2015 Change	2017 Rates ($/Dth)	2014 - 2017 Change
End-Use Transportation (G-NT)					
Noncore Industrial (Trans.)	$0.8680	$1.3710	58%	$1.5530	79%
Noncore EG (Trans.)	$0.4960	$1.0030	102%	$1.1850	139%
Backbone Transmission (G-AFT)					
Silverado	$0.1538	$0.3234	110%	$0.3860	151%
Redwood	$0.2663	$0.5124	92%	$0.6079	128%
Baja	$0.3063	$0.5124	67%	$0.6079	98%
Illustrative Industrial Total	**$1.1343**	**$1.8834**	**66%**	**$2.1609**	**91%**
EG Illustrative Total (noncore + Redwood)	**$0.7623**	**$1.5154**	**99%**	**$1.7929**	**135%**

* Backbone Rates are Annual Rates (AFT) with SFV Rate Design using 100% load factor.
** Total is illustrated assuming deliveries on the Redwood Path.

Q. HOW DO THESE INCREASES COMPARE WITH INCREASES RESULTING FROM IMPLEMENTATION OF PSEP PHASE 1?

A. Table 2 compares the Pre-PSEP noncore industrial and noncore electric generation rates with the Post-PSEP rates at implementation. The PSEP increased rates by $0.1543/Dth for transmission-level noncore customers, compared to the GT&S proposed increase of $1.03/Dth.

Table 2: Change in Noncore Rates – Pre and Post PSEP

	Pre-PSEP Rates ($/Dth)	Post-PSEP Rates ($/Dth)	Change	
Transmission Level				
End-Use (G-NT)	$0.3555	$0.5098	$0.1543	43.4%
Electric Generation (G-EG)	$0.2902	$0.4445	$0.1543	42.0%
Backbone Transmission (G-AFT at SFV full capacity)				
Redwood to On-System	$0.2676	$0.2676	--	--
Baja to On-System	$0.3030	$0.3030	--	--

Silverado to On-System	$0.1529	$0.1529	--	--
Illustrative Industrial NC (G-NT + Redwood)	$0.6231	$0.7774	$0.1543	24.8%
Illustrative EG (G-EG + Redwood)	$0.5578	$0.7121	$0.1543	27.7%

Q. HOW DO THESE INCREASES COMPARE TO PRIOR REVENUE LEVELS?

A. As shown in Table 3, PG&E's proposed revenue requirement in 2017 is over $1.5 billion, triple the Company's 2011 revenue requirement. This is an unprecedented increase and is likely to have significant adverse economic impacts on noncore customers.

Table 3: Proposed Change in PG&E Revenue Requirement

Year	Request (Millions)	Change (Millions)	% Change
2011	$514	N/A	N/A
2014	$731	$217	42.22%
2015	$1,286	$555	75.92%
2016	$1,357	$71	5.52%
2017	$1,515	$158	11.64%
Total		**$1,001**	**195%**

From the perspective of a noncore industrial customer, the increase by 2017 of $1.03/Dth is more than three times the approximately $0.30/Dth increase following PSEP implementation.

Q. DOES SETTING THE IMPACT IN THE CONTEXT OF THE TOTAL DELIVERED COST OF NATURAL GAS, RATHER THAN NATURAL GAS TRANSPORTATION SERVICES, SUGGEST A LOWER RATE IMPACT?

A. No. Of course, mathematically, the percentage impact will be lower. For example, assuming an illustrative $5.00/Dth gas commodity price at the PG&E Citygate, the 2017 increase still represents a 16.7% rate increase. Using the same assumptions for electric generators yields a 17.9% increase. Such rate increases, by any stretch of the imagination, are still significant.

Moreover, "pennies per day" arguments that attempt to minimize the economic impacts of these rate increases ignore both their cumulative magnitude and the ability of noncore industrial customers to absorb such increases while remaining competitive. In my opinion, the Commission's framework for assessing whether rate impacts are just and reasonable for noncore customers belongs within the scope of its jurisdiction for those services. Just as the Commission should not evaluate the reasonableness of a proposed rate increase by comparing it to average household income or California gross domestic product per individual, it should not evaluate the reasonableness of the proposed rate increases on noncore customers through any sort of aggregate natural gas expenditure analysis.

Q. ARE THERE OTHER RATE IMPACTS THE COMMISSION SHOULD BEAR IN MIND AS IT CONSIDERS THIS APPLICATION?

A. Yes. Higher gas transportation rates will lead to higher electricity prices, which will increase by more than simply the increase in gas transportation costs. The cause of this "multiplier effect" is the integrated California wholesale electric market. In this market, the marginal generator determines the market price for every hour. Therefore, higher costs paid by electric generators transporting gas on PG&E's system will affect the entire California market, including sales that do not take place in the California ISO market. In 2013, in-state gas generation was 120.9 terawatt-hours (TWh), approximately 41% of total generation and net imports, a percentage that continues to increase.

Q. HOW CAN THIS MULTIPLIER EFFECT BE ESTIMATED?

A. A detailed calculation of the multiplier effect would require simulating the entire California electric system on an hourly basis, including the effects of the price of imported electricity, to determine the marginal generator in every hour and the effect of the entire generation stack on market prices. In some off-peak hours, for example, where the marginal generator is wind or hydroelectric, natural gas units would not be operating and thus higher natural gas transportation rates would not affect the wholesale market price. During peak hours, the least efficient natural gas units would set the market price. The less efficient the marginal generator, the larger will be the impact on the wholesale market price, because less efficient generators must transport more gas for each megawatt-hour of electricity generated.

Q. IS IT POSSIBLE TO DEVELOP AN APPROXIMATION OF THE IMPACT?

A Yes. I have prepared a simple approximation that estimates the overall impacts based on total gas-fired generation in the state in 2013, PG&E's proposed increases in the EG transmission rate shown in Table 1, the total amount EG natural gas PG&E forecasts it will transport during the three-year GT&S period, and the forward market heat rate PG&E uses to estimate short-run avoided cost (SRAC) that it pays to certain qualifying facility (QF) generators. The calculation is based on a three-step process.

(1) Estimate the total increase in EG-related natural gas transportation costs per year under the proposed PG&E rate increases;

(2) Estimate the increase in the market price of electricity, based on the average forward market heat rate; and

(3) Estimate the total increase in electric generation costs, assuming that the average increase in electric prices would reflect the price calculated in (2), based on the 2013 level of gas-fired generation, excluding any price increases on imported electricity and excluding the resulting increases in payments to QF generators who qualify for the SRAC rate.

Q. USING THIS APPROXIMATION, WHAT MULTIPLIER IMPACT DO YOU ESTIMATE?

A. I estimate an overall increase in electric costs of $2.3 billion over the 2015 – 2017 GT&S period because of a $377.6 million increase in total natural gas transmission costs. The resulting overall multiplier is therefore 6.12.

Q. COULD THE IMPACT BE GREATER?

A. Yes. As shown in Table 14-2 of PG&E's testimony, actual transported natural gas in 2012 averaged 676 MDth/day, over 40% greater than PG&E's forecast for 2015, because, as the testimony notes, 2012 was a dry year in Northern California.[5] Of course, the drought is now in its third year and, given the drop in reservoir levels, is likely to continue to restrict generation from hydroelectric facilities in California. Data compiled by the California Energy Commission (CEC) shows that total hydroelectric generation was 42,731 GWh in 2011, then decreased to 27,459 GWh in 2012, and further decreased to 24,098 GWh in 2013.[6]

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5 PG&E Direct Testimony, Vol. 2, Ch. 14, p. 14-11, lines 19-21.

6 California Energy Commission Energy Almanac. http://energyalmanac.ca.gov/electricity/electricity_generation.html.

Q. ARE THERE ANY OTHER PERSPECTIVES THAT CAN ASSIST THE COMMISSION IN UNDERSTANDING THE PROPOSED IMPACTS?

A. Yes. The Application could have a greater impact on Emissions Intensive, Trade Exposed (EITE) entities, as designated by the Air Resources Board (ARB), than under California's Cap-and-Trade program.[7] ARB's Cap-and-Trade program design included an analysis of certain California industrial sectors that are exposed to both domestic and international competition. ARB recognized that sector competitors in most other markets would not face these costs, since California is one of the very few carbon-regulated markets. For entities it concluded were "emissions intensive, trade exposed," it set up a system to allocate free allowances for direct (e.g., combustion) emissions to mitigate the compliance cost under its program for a transition period.[8] Recognizing that most other markets outside of California did not bear similar costs, the goal was to avoid the shift of production in these sectors to entities outside of California, with the ultimate goal of mitigating the threat of economic emissions "leakage" outside of California.[9] This Commission is currently implementing EITE mitigation for indirect (e.g., purchased electricity) GHG emissions costs imposed on EITE sectors in a pending rulemaking, R.11-03-012.

PG&E's application should raise the same concerns. The increase PG&E has proposed will have a material impact, in fact a greater impact, on the same EITE sectors

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[7] Cal. Code Regs. Title 17 §§95800 to 96023.

[8] *See id.* §§95870, 95890 and 95891; *see also* Initial Statement of Reasons, Appendix K, Leakage Analysis (Appendix K), at http://www.arb.ca.gov/regact/2010/capandtrade10/capv4appk.pdf.

[9] *See generally id.,* Appendix K.

identified by ARB for transition assistance. Like the Cap-and-Trade compliance costs, these sectors will bear costs that are not borne by competitors in other domestic or international markets. In fact, while the statewide Cap-and-Trade program generally put all in-state competitors on equal footing, the proposed rate increase will be unique to customers in PG&E's service territory, thus even affecting in-state competition.

Importantly, the impact of the proposed increase will be *greater* than the current cap-and-trade impact on natural gas combustion by industrial customers. In the May 16, 2014 ARB auction, the market price of greenhouse gas (GHG) compliance instruments cleared at $11.50 per metric ton for 2014 vintage allowances. Since combustion of each dekatherm of natural gas produces approximately 0.05306 metric tons of GHG emissions, this means that the impact of an entity's carbon compliance obligation for GHG emissions would be approximately $0.61/Dth. In comparison, the per-Dth impact of the Application on industrial noncore natural gas consumers will be approximately $1.03/Dth by 2017. If ARB was concerned about the impact $0.61/Dth would have on emissions leakage and the competitiveness of California's EITE industrial sectors, California should be doubly concerned about PG&E's proposed rate increase. Northern and Central California business and industry will be hit with material cost increases that will not be experienced by their out-of-state competitors. The Commission cannot ignore the extraordinary effects of this rate increase on PG&E noncore customers and the economy.

Q. HOW SHOULD THE COMMISSION ADDRESS THE RATE SHOCK POTENTIAL?

A. Extraordinary impacts require extraordinary mitigation tools and "powerful incentives" such as those offered in my testimony. My recommendations and those in the

Joint Testimony will improve the value of PG&E's program to ratepayers and reduce rate shock.

Q. CAN YOU APPROXIMATE THE REDUCTION THAT WILL OCCUR AS A RESULT OF YOUR PROPOSALS?

A. Not entirely. The proposals offered in the Joint Testimony could lead to modifications to PG&E's proposed mitigation measures; there is no way to anticipate the effects of these modifications.

V. ATYPICAL RATEMAKING TOOLS ARE REQUIRED TO MITIGATE RATE SHOCK

Q. ARE "BUSINESS AS USUAL" RATEMAKING TOOLS SUFFICIENT TO ADDRESS THE ENORMOUS RATE IMPACT THAT WOULD RESULT FROM THIS PROPOSAL?

A. No, as discussed above, extraordinary impacts require extraordinary measures. And, as the Commission observed in D.12-12-030, "[t]o meet our constitutional and statutory duties, we must create powerful incentives for PG&E to manage this program efficiently and to aggressively identify and capture cost savings." Ratemaking "business as usual" is not an option.

Q. WHAT "EXTRAORDINARY" TOOLS ARE YOU PROPOSING?

A. In addition to (1) traditional disallowances, I am proposing three atypical ratemaking measures:

(2) Deferral of cost recovery using memorandum accounts and subsequent reasonableness review.

(3) 10-year amortization of operating expenses.

(4) A 10-year, 110 basis-point reduction of ROE on the capital expenditures made in this rate period.

A. Cost Recovery Deferral

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "COST RECOVERY DEFERRAL."

A. The Commission already has provided a general outline of this approach in its decision on the Southern California Gas Company and San Diego Gas & Electric Company (together, Sempra) PSEPs. In D.14-06-007, the Commission found that Sempra had "presented a reasonable, albeit conceptual plan to enhance the safety of their natural gas pipeline system…."[10] Based on the Commission's observation that Sempra had failed to provide sufficient specificity in its request, it concluded:

> Therefore, we adopt the concepts embodied in the Decision Tree and authorize a Safety Enhancement Capital Cost Balancing Account and a Safety Enhancement Expense Balancing Account for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to record the costs incurred, subject to refund, after a reasonableness review.[11]

This mechanism is similar, if not the same, as the deferral mechanism proposed in this testimony.

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[10] *In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding,* D.14-06-007, June 12, 2014, p. 3.

[11] *Id.* at 2.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD DEFER COST RECOVERY.

A. The lack of specificity in many of PG&E's programs render them merely conceptual and speculative. Not only is it unreasonable to force ratepayers to pay for speculative programs whose costs fail the "known and measurable" standard, it is especially egregious in the face of enormous rate increases.

Preventing rate recovery for speculative costs is vital to the integrity of the ratemaking process. If the Commission approves a conceptual program in a rate case, without delineating specific pipelines, pipeline segments, capital and expense activities, and the attendant safety risk reduction it will be unable in the next rate case to reasonably determine whether the proposed revenue requirement duplicates costs for which recovery was authorized in the first rate case. Ratepayers should never be forced to pay the same costs twice, or more, nor should they be forced to pay for costs that are not prudent. The goal should always be to ensure ratepayers receive the best value for the monies they are being asked to provide.

Q. PLEASE DESCRIBE THE MECHANICS OF YOUR PROPOSED DEFERRAL MECHANISM.

A. Under my proposed mechanism, the Commission would make a determination, in concept, of whether PG&E's approach to the proposed work is reasonable. If not, the Commission would render the appropriate disallowances, such as my recommended disallowance of the entire Work Required by Others program, as further discussed below.

Once a program is approved in concept, PG&E would be permitted to establish a memorandum account to record the capital and expense costs the Company incurs to implement the program as determined by prudent risk management. Capital expenditures in the memorandum account would earn interest based on the current Allowance for Funds Used During Construction (AFUDC) rate, and expenses would earn interest based on the 90-day rate on commercial paper.[12]

PG&E could then seek recovery of the recorded costs in an annual reasonableness review, with the first review submitted in March 2016. Once costs are authorized as "just and reasonable" PG&E could file an advice letter to implement the rate change. PG&E would then begin to recover the authorized expenditures and be able to place the authorized capital into rate base.

Q. DOES THE DEFERRAL MECHANISM CREATE A "POWERFUL INCENTIVE?"

A. Yes. A deferral mechanism reduces the "moral hazard" risk. I discuss this risk in relation to the Work Required by Others program, which covers facility removals and relocations performed by PG&E at the request of government agencies or developers. Whereas preapproval of costs allows spending up to an approved budget, without careful consideration of the benefit of each dollar spent as the program unfolds, a deferral program places the burden on management to determine the reasonableness of its actions.

An example, which I discuss later, is the Hydrostatic Testing program. PG&E proposes to spend its full budget to test 510 miles, potentially including "lower priority" segments, if the Commission approves the program. In the absence of Commission

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[12] *See, e.g., Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015 - 2017 (U39G),* Decision (D.) 14-06-012, June 12, 2014, p. 2.

preapproval, PG&E has an incentive to determine whether spending on what the Company admits are "lower priority" pipe segments is prudent, especially in comparison to other programs.

Q. WOULD THIS MECHANISM RESULT IN A REGULATORY ASSET AND, IF SO, WHAT WOULD BE THE RATE OF RETURN ON THAT ASSET?

A. Yes. The portion of deferred capital costs that are deemed prudent would earn a return equal to PG&E's AFUDC.

B. Ten-Year Amortization of Approved Expenses

Q. WHY ARE YOU PROPOSING LONG-TERM AMORTIZATION OF EXPENSES?

a. First, PG&E's proposal is part of a much larger system upgrade program that the Company testifies will take place over many years. For example, PG&E states that the Company's hydrostatic testing program will be completed in "roughly 12-15 years from the start of strength testing in 2011."[13] Similarly, PG&E states that the Company's valve automation programs will be implemented in three additional phases over nine years."[14] PG&E also states, regarding the Company's close interval survey, that "[c]onsistent with industry best practices … PG&E plans to perform the CIS program on a 15-year frequency."[15] Finally, the Company's Vintage Pipe Replacement (VPR) program is intended to replace 20 miles of pipe each year of the GT&S period and complete

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[13] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-33, lines 1-3.

[14] *Id.* at 4A-72, lines 8-9.

[15] PG&E Direct Testimony, Vol. 1, Ch. 7, p. 7-26, lines 22-30.

replacement of vintage pipe by the year 2025. These and other statements attest to the long-term nature of PG&E's programs.

Second, some of PG&E's programs, such as the Company's corrosion control and earthquake fault crossings, among others, are clear efforts by PG&E to play "catch up" with pipeline safety goals.

Third, this ten-year amortization approach is a component of a suite of measures at the Commission's disposal to mitigate the immense rate shock PG&E proposes, regardless of PG&E's diligence.

Q. CAN YOU EXPLAIN THE MECHANICS OF YOUR PROPOSAL?

A. Under my proposal, PG&E's approved, safety-related operating expenses would be placed into a balancing account and amortized over a ten-year period. For example, PG&E proposes $181 million for hydrostatic testing expenses in 2015. The Commission could direct PG&E to place those costs for pipeline into a balancing account to amortized evenly on a straight-line basis over Year 1 through Year 10.

Q. WHY DO YOU PROPOSE TO USE A 10-YEAR AMORTIZATION PERIOD?

A. In my opinion, a 10-year amortization period represents a reasonable compromise between avoiding rate shock and allowing PG&E to recover costs in a timely fashion. For example, PG&E's In-Line Inspection (ILI) program has a 10-year horizon,[16] as does the Company's VPR program.[17] Other long-term programs stretching beyond the rate

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[16] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-12 lines 12-15.

[17] *Id.* at 4A-54 lines 13-16.

period include Corrosion Control,[18] Valve Automation,[19] Earthquake Fault Crossing,[20] Programs to Enhance Integrity Management,[21] Gas Gathering,[22] Compressor Station Upgrades,[23] Simple Station Rebuilds,[24] Complex Station Rebuilds,[25] and Replace Obsolete Bristol Controllers.[26] Just as most home buyers spread their large, upfront investment costs over a period of years by taking out a mortgage, PG&E can avoid immediate rate shock to its ratepayers by amortizing its "lumpy" costs over a 10-year recovery period.

Q. WOULD RATEPAYERS BE RESPONSIBLE FOR THE CARRYING COST ON THE BALANCING ACCOUNT?

A. Yes. As with expenses placed into the memorandum account, all approved and amortized expenses would also earn a return equal to the yield on 90-day commercial paper.

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[18] A. 13-12-012, Workpapers, December 19, 2013 (PG&E Workpapers),WP 7-22, WP 7-63, WP 7-66.

[19] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-72 lines 9-11.

[20] *Id.* at 4A-44 lines 25-26.

[21] *Id.* at 4A-66 lines 5-7.

[22] *Id.* at 4B-30 lines 3-7.

[23] PG&E Direct Testimony, Vol. 1, Ch. 6, p. 6-42 lines 9-10.

[24] *Id.* at 6-47 line 19.

[25] *Id.* at 6-48 lines 22-24.

[26] *Id.* at 6-50 line 23.

Q. ARE YOU AWARE OF ANY CASES IN WHICH EXTRAORDINARY EXPENSES HAVE BEEN AMORTIZED?

A. Yes. The most common example I am aware of is expenses related to repairs caused by hurricanes. For example, if an offshore pipeline system suffers damage, the repair costs are amortized over multiple years to reduce rate shock.[27]

C. Reduced Return on Equity

Q. WHY ARE YOU PROPOSING TO REDUCE PG&E'S RETURN ON EQUITY (ROE) FOR CERTAIN CAPITAL INVESTMENTS MADE DURING THE GT&S PERIOD?

A. PG&E's deferral of work it might have done earlier, such as corrosion mitigation, has resulted in a lumpy capital investment profile for the GT&S period. More importantly, this deferral is a major contributing factor to the unprecedented rate shock for the Company's ratepayers. Consequently, one measure at the Commission's disposal is to mitigate the immense rate shock by reducing PG&E's allowed ROE. The Commission can always consider issues of management effectiveness and efficiency when setting the ROE. The request by PG&E to spend billions on gas pipeline safety over the next three years to make up for problems that have developed over decades suggests that management has not been effective or efficient in this important area.

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[27] *See e.g., Sea Robin Pipeline, LLC,* Opinion 516, 137 FERC ¶ 61,201 (2011) and Opinion 516-A, 143 FERC ¶ 61,129 (2013).

Q. CAN YOU EXPLAIN THE MECHANICS OF YOUR PROPOSAL?

A. Yes. Capital investments made in this rate case period related to pipeline safety would be separately identified in PG&E's rate base. Those assets would receive a 9.4% return on equity, rather than PG&E's current 10.5% ROE, for a ten-year period.

Q. WHY DO YOU PROPOSE A REDUCTION TO 9.4%?

A. An ROE of 9.4% represents the lowest value in the range of reasonableness adopted by the Commission in Cost of Capital D. 12-12-034 for SoCalGas.[28] I have chosen SoCalGas because that company, unlike PG&E, is a stand-alone natural gas distribution company, making it a more meaningful value in the context of PG&E's natural gas rate base. Setting the ROE at this level meets the long-established standards of *Bluefield*[29] and *Hope*,[30] while providing ratepayers a small measure of relief from rate shock.

Q. WHY DO YOU PROPOSE TO KEEP THE ROE REDUCTION IN EFFECT FOR 10 YEARS?

A. For the same reasons I have proposed to amortize expenses over a 10 year period. I believe this slightly lower ROE for safety-related capital investments helps address PG&E's attempt to bring its pipeline safety programs and practices up to date with

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28 *Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism,* et al, D.12-12-034 (Cost of Capital Decision), p. 42.

29 *Bluefield Water Works and Improv. Co. v. Pub. Serv. Comm'n. of W.Va*., 262 U.S. 679 (1923).

30 *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

current industry standards. As such, a 10-year period for this reduced, but still just and reasonable, ROE is appropriate.

Q. WHAT WOULD BE THE EFFECT OF THE ROE REDUCTION?

A. Based on PG&E's capital structure and weighted average cost of capital (WACC), as set forth in D.12-12-034, a reduction in allowed ROE to 9.4% would reduce PG&E's WACC from 8.06% to 7.54%, as shown in Table 4. Therefore, for every $1 billion of safety-related capital investment, ratepayers would save approximately $8.7 million, including estimated tax savings.[31]

TABLE 4: PG&E WACC with 9.4% ROE

Item	Percent	Rate	Weighted Rate
Long-term Debt	47.00%	5.52%	2.59%
Preferred Equity	1.00%	5.60%	0.06%
Common Equity	52.00%	9.40%	4.89%
Total	**100.00%**		**7.54%**

[31] Based on an assumed 40% average overall federal and state income tax rate.

VI. PG&E'S RISK MANAGEMENT APPROACH DOES NOT ASSURE THAT ITS PROPOSED EXPENDITURES WILL PRODUCE THE BEST VALUE FOR RATEPAYER DOLLARS

Q. CAN YOU SUMMARIZE YOUR CONCERNS REGARDING THE COMMISSION'S RELIANCE ON PG&E'S RISK MANAGEMENT APPROACH TO AUTHORIZE THE PROPOSED EXPENDITURES?

A. Yes. Although PG&E has stated an admirable goal to become the safest utility,[32] it has not explained what "the safest utility" means or how it will know when it has arrived. The Commission cannot gauge whether PG&E's improved safety and reliability goals will be met, to say nothing of whether the goals will be met cost-effectively, because PG&E has failed to:

(1) Identify the desired risk reduction it seeks to achieve through the proposed programs;

(2) Employ an analytical methodology to identify and mitigate risks to produce consistent and reasonable results;

(3) Utilize information on the current conditions of its pipeline assets and how those conditions are likely to change over time sufficient to achieve its objectives in the most cost-effective ways; and

(4) Demonstrate the risk reduction and improved reliability that will result from its measures.

These failures in PG&E's approach are discussed in the Joint Testimony, and I will not elaborate further in this testimony. While the Joint Testimony touched on the questions of budget and risk tolerance constraints, this testimony further elaborates on PG&E's failure to adequately address budget and risk tolerance constraints in its Application.

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[32] PG&E Direct Testimony, Vol. 1, Ch. 1, p. 1-5, line 20.

Q. WHICH PROPOSED PROGRAMS EXHIBIT THESE SHORTCOMINGS?

A. PG&E's failure to incorporate transparent budget and risk tolerance constraints affects its entire risk management approach and, consequently, each individual program relying on this approach. Without consideration of these factors, which allow an assessment of the value of the proposed reductions, the Commission is unable to conclude that the proposed programs will lead to just and reasonable rates.

Q. WHAT ACTION SHOULD THE COMMISSION TAKE TO ADDRESS THESE CONCERNS?

A. The Joint Testimony proposes measures for PG&E to undertake to improve its approach to risk management. Until that has been done, the Commission cannot have confidence that the measures PG&E has proposed are the right measures and that they have been implemented cost effectively. If the Commission overlooks these problems in the interest of immediate action, it should keep in mind the impact of the lack of clarity on budgets and affordability, risk tolerance and the expected risk reduction value of the measures on PG&E's ratepayers.

A. PG&E Has Failed to Incorporate Transparent Risk Tolerance Constraints in its Analysis

Q. WHAT IS RISK TOLERANCE, AND WHAT ROLE DOES IT PLAY IN RISK MANAGEMENT?

A. Risk tolerance recognizes that it is impossible to eliminate all risk, whether on a pipeline system or in our daily lives. PG&E must determine an acceptable level of affordability and remaining risk. An optimal (i.e., least expected cost) set of programs is selected to achieve a well-defined residual risk objective <u>or</u> an optimal set of programs is selected that falls within a well-defined budget constraint (and accounts for other constraints, such as manpower and equipment availability).

Q. CAN RISK TOLERANCE BE EVALUATED FROM DIFFERENT PERSPECTIVES?

A. Yes. Presumably, PG&E's risk tolerance represents the amount of risk it is willing to bear at the corporate level, within specific business units, or both, to meet its objectives. In some cases, willingness to assume risk may be evaluated from a shareholder perspective, examining Reputation and Financial Consequences. In other cases, willingness to bear risk may be evaluated in the context of ratepayers, examining the Health and Safety, Environmental Impact and Reliability consequences. Whereas the Company's willingness to bear risk from a shareholder perspective is considered a private business decision, for which PG&E management is given deference, risk tolerance decisions that affect ratepayers and the general public may require broader policy consensus, as discussed in the Joint testimony.[33]

Q. HOW HAS PG&E APPROACHED THE QUESTION OF RISK TOLERANCE?

A. PG&E clearly understands the need to establish risk tolerance to support its risk management approach.[34] PG&E witness Stavropoulos testifies: "[i]dentifying the right amount and pace of work requires a thorough risk assessment and risk ranking. In

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[33] Prof. Feinstein and I describe the mechanics of reaching such consensus in Section VI.A of the Joint Testimony.

[34] *See* GTS-RateCase2015_DR_IndicatedProducers_004-Q01(f), (g).

addition, the appropriate level of risk tolerance must be established."[35] Despite this clear recognition, PG&E has never defined "risk tolerance,"[36] nor does it have any recognizable standards to guide risk tolerance decisions affecting ratepayers.[37]

Q. DID PG&E CALCULATE THE LEVEL OF RISK REDUCTION THE COMPANY'S CHOICE OF RISK MANAGEMENT PROGRAMS AND THE RESULTING PROJECTED RATEPAYER COSTS PROVIDE?

A. No. PG&E states that, "PG&E did not identify a 'desired level of risk reduction' through industry benchmarking. PG&E used industry benchmarking to identify best practices. PG&E also does not numerically quantify risk reduction on a system level."[38] PG&E witness Stavropoulos testifies that:

> PG&E … performed a comprehensive risk assessment of its gas transmission and storage assets and operations, listened to stakeholders, and applied judgment, considering resources and affordability, to identify the appropriate level of residual risk and the appropriate pace to achieve the desired level of risk reduction….[39]

PG&E's nonetheless has not defined "desired level of risk reduction."[40] Thus, in this proceeding, PG&E requests that ratepayers pay $4.2 billion over the next three years so that PG&E can achieve an undefined and unmeasured "desired level of risk reduction." In light of the extraordinary rate impact PG&E's proposal will cause, PG&E should be required to tailor its programs to achieve the greatest risk reduction for the money spent.

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[35] PG&E Direct Testimony, Vol. 1, Ch. 1, p.1-9, lines 22-24 (emphasis added).

[36] *See* GTS-RateCase2015_DR_IS_004-Q001(a), attached as Exhibit JAL-4.

[37] *See* GTS-RateCase2015_DR_IS_004-Q001(b), attached as Exhibit JAL-4.

[38] GTS-RateCase2015_DR_IS_007-Q002(a), attached as Exhibit JAL-5.

[39] PG&E Direct Testimony, Vol. 1, Ch. 1, p. 1-10, lines 21-25 (emphasis added).

[40] GTS-RateCase2015_DR_IP_007-Q002(g), attached as Exhibit JAL-5.

Q: CAN THE COMMISSION DETERMINE WHETHER A GIVEN PROPOSAL IS PRUDENT WITHOUT KNOWING THE DESIRED LEVEL OF RISK REDUCTION OR THE LEVEL OF RISK TOLERANCE THAT ARE DRIVING PG&E'S FORECAST EXPENDITURES?

A. No. As discussed in the Joint Testimony, PG&E's entire risk prioritization approach suffers from fundamental mathematical and statistical flaws. As such, PG&E's proposed risk management plans are not optimal and therefore cannot provide ratepayer with the most risk-reduction value for the money PG&E wishes to collect from those ratepayers. Moreover, because PG&E never defines its risk reduction objectives in any measurable way, it is impossible for anyone to determine whether those objectives are reasonable. PG&E may claim that its risk management approach reflects industry "best practices." But avoiding the difficult question of risk tolerance in its risk management approach is not the best practice.

Q. CAN THE COMMISSION CONCLUDE THAT REDUCING PG&E'S REQUEST WILL HAVE ADVERSE CONSEQUENCES FOR SAFETY ON PG&E'S SYSTEM?

A No. The Commission *can* conclude that, however, because PG&E is using a fundamentally flawed methodology, has not identified measurable constraints, and has not defined measurable objectives, its proposed programs do not, and *cannot*, represent a cost-effective risk management strategy. PG&E's proposed programs fail, *in toto*, to meet the prudent investment standard.

B. PG&E Has Failed to Incorporate a Transparent Budget Constraint in Its Analysis

Q. WHAT ROLE DOES A BUDGET PLAY IN RISK MANAGEMENT?

A. PG&E cannot reasonably expect to be given a blank check to accelerate its system upgrade to meet state policy, especially when many of its proposed investments and expenditures are conceptual and lack detail and result from PG&E's own failure to upgrade its system on a more gradual, ongoing basis. Public Utilities Code §963(b)(3) requires the Commission to "take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates." Rate impacts must be considered in proposing capital expenditures and operating expenses to address safety. Indeed, as discussed previously, PG&E testifies that affordability is an issue it considered in determining the proposed risk management activities, but never identifies a threshold for "affordability" or how it determined that mysterious threshold.

Q. IS USING A BUDGET OR OTHER FINANCIAL CONSTRAINT CONSIDERED TO BE "BEST PRACTICE?"

A. Yes. PAS-55, for example, assumes that, along with time and resources, budgets will constrain the tasks the risk manager undertakes:

> It is important to understand the relationship between asset management activities and their actual or potential effect upon short-term and long-term costs … Only then can informed decisions be made about the optimal mix

> of life cycle activities … In many organizations, there will be more potential tasks to carry out than resources, time or budget will permit.[41]

Section 4.45 of PAS 55-2, "Asset Management System Documentation," also discusses budgets, stating: "[o]rganizations can have a number of asset management functional policies, functional strategies and functional plans. Typically these can include … planning and budgeting."[42]

In Section 4.5, PAS continues to highlight that "[t]his responsibility includes ensuring necessary resources are available to deliver the plan(s) on time, within the allocated budget and that the delivery of the plan(s) conforms to all applicable legislative, and statutory requirements, policies, standards, process(es) and/or procedure(s) and any other requirements to which the organization may subscribe."[43]

Q. HAS PG&E APPLIED A BUDGET CONSTRAINT IN DEVELOPING THE REVENUE REQUIREMENT OR CAPITAL EXPENDITURES PROPOSED IN THIS PROCEEDING?

A. PG&E "did not use a budget target to determine the forecast proposed in this application."[44] Instead, the Company uses a vague and undefined concept of "affordability." Witness Stavropoulos states:

> PG&E is presenting a forecast to achieve the greatest amount of risk reduction for the investment made given the constraints to perform the

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[41] PAS 55-2:2008 "Asset Management Part 2: Guidelines for the Application of PAS 55-1," p. vii. Section 0.4 titled "Decision making in asset management" addresses budget.

[42] PAS 55-2:2008 p. 26.

[43] PAS 55-2:2008 p. 36.

[44] *See* GTS-RateCase2015_DR_IS_004-Q001(e), attached as Exhibit JAL-4.

> work and after determining whether there is a less costly, or more affordable, way to achieve the same level of risk reduction.[45]

Witness Soto also claims that PG&E examined "customers' limited ability to absorb increased gas transmission and storage rates."[46] Both of these statements imply some sort of revenue requirement budget or threshold PG&E had in mind, yet no budget is evident. Developing a risk mitigation plan without any budget constraint is a luxury that only a regulated utility can afford.

Q. HAS PG&E PROVIDED ANY ANALYTICAL EXPLANATION AS TO HOW THE COMPANY DETERMINED ITS PROPOSED REVENUE REQUIREMENT AND CAPITAL EXPENDITURES ARE PRUDENT AND JUST AND REASONABLE?

A. No. PG&E simply states it has forecasted the needed work "to achieve the appropriate level of risk reduction over a reasonable timeframe and at a <u>reasonable cost</u>."[47] PG&E witness Stavropoulos simply testifies:

> A reasonable cost is the most amount of risk reduction for the investment made given the constraints to perform the work and after determining if there is a less costly or more affordable way to achieve the same result. In preparing the whole portfolio PG&E discussed risk reduction and affordability. PG&E's final product represents a portfolio of work reduced in scope and cost from initial proposals, but that still sufficiently addresses the most important risks."[48]

Furthermore, PG&E makes clear that rate impacts were an afterthought, stating:

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[45] *Id.*

[46] PG&E Direct Testimony, Vol. 1, Ch. 2, p. 2-5, lines 14-15.

[47] *Id.* at Ch. 1, p. 1-2, lines 5-7.

[48] GTS-RateCase2015_DR_IP_002-Q003(c), attached as Exhibit JAL-6.

> [PG&E] sought to make the most of its limited resources in developing its forecast by focusing on reducing the most and highest risk possible during the rate case period as well as establishing an appropriate trajectory for additional risk reduction in the future while considering operational and resource constraints. Last, we took into account the impact of the proposed forecast on customer rates.[49]

Nowhere, however, does PG&E demonstrate its consideration of the rate impact of its risk management program on its customers.

Q. CAN THE COMMISSION ASSESS THE PRUDENCE AND THE REASONABLENESS OF PG&E'S RISK MANAGEMENT ACTIVITIES WITHOUT INFORMATION ON HOW THE COMPANY EVALUATED COMPETING CONSIDERATIONS?

A. In one respect, yes. Given the methodological flaws explained in the Joint Testimony, PG&E's proposed risk management programs cannot provide maximum value for ratepayers and therefore are not prudent.

However, even if one assumed, *arguendo*, that PG&E's prioritization methodology was reasonable, the Commission would need specific information as to how PG&E incorporated various constraints, including affordability, in its decisionmaking.[50] What is the total rate increase PG&E believes ratepayers can afford to bear for improved safety? How did PG&E determine that amount? How did PG&E balance affordability and risk tolerance? Neither the prudence of PG&E's proposed risk management actions nor the just and reasonableness of the resulting rates can be evaluated without understanding these fundamental criteria.

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[49] GTS-RateCase2015_DR_IP_002-Q012(a), (b), attached as Exhibit JAL-7 (emphasis added).

[50] In Section VI.A of Prof. Feinstein's and my accompanying testimony, we explain the correct methodology for making decisions with multiple attributes.

VII. PG&E'S PROGRAMS LACK SUFFICIENT SUPPORT TO WARRANT APPROVAL OF PROPOSED CAPITAL EXPENDITURES AND OPERATING EXPENSES AT THIS TIME

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section reviews and makes recommendations regarding the adequacy of the support PG&E has provided for its individual programs. As discussed in Section 6, PG&E's approach to risk management leaves the Commission unable to find that the resulting programs will deliver the best value for ratepayer dollars, or even whether the programs will meet safety goals. On these grounds alone, the Commission could deny cost recovery at this time, pending PG&E's correction and improvement of its risk assessment. If the Commission rejects this approach, it should reduce the extent of the upfront authorization of cost recovery to bring rates into a more reasonable zone. This section identifies programs where preauthorization of cost recovery is not warranted due to the lack of support provided by PG&E.

Q. WHICH PROGRAMS HAVE YOU IDENTIFIED AS LACKING THE SUPPORT NECESSARY TO WARRANT PRE-AUTHORIZED COST-RECOVERY?

A. My testimony addresses concerns regarding the sufficiency of PG&E's showing for the following programs:

- Corrosion Control
- Vintage Pipe Replacement
- Shallow Pipe
- Hydrostatic Testing
- Direct Assessment
- Valve Automation
- Work Required by Others
- In-Line Inspections

- Earthquake Fault Crossings
- Geo-Hazard Threat Identification and Mitigation
- Facilities
- Class Location

These programs lack sufficient project detail, have unsupported cost estimates, appear to overlap, and may duplicate previously funded costs.

A. Corrosion Control

Q. WHAT IS THE PURPOSE OF THIS PROGRAM?

A. According to PG&E witness Peralta, PG&E's corrosion control program is designed to address admitted past deficiencies in the Company's corrosion control practices, comply with new regulations and move towards industry best practices.[51]

Q. WHAT COSTS HAS PG&E FORECAST TO SUPPORT THIS PROGRAM?

A. PG&E forecasts expenses in 2015 of $99 million, as shown in Table 7-1 of Witness Peralta's testimony (reproduced as Figure 2 below).[52]

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[51] PG&E Direct Testimony, Vol. 1, Ch. 7, p. 7-5, lines 9-28.

[52] *Id.* at 7-3.

Figure 2: PG&E Corrosion Control Expenses

TABLE 7-1
PACIFIC GAS AND ELECTRIC COMPANY
CORROSION CONTROL
SUMMARY OF EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast(a)	2014 Forecast	2015 Forecast
1	Cathodic Protection (CP) Rectifier	–	$11	$305	$445	$450
2	Cathodic Protection Monitoring	$801	928	1,729	1,862	1,820
3	Cathodic Protection Resurvey	94	48	171	224	177
4	Cathodic Protection Troubleshooting	9	3	171	224	177
5	CP Corrective Maintenance	426	640	759	1,325	1,340
6	CP Systems – Replace	–	–	228	–	–
7	Coupon Test Stations	–	–	521	–	–
8	Corrosion Investigations	1,010	2,288	2,380	1,817	5,455
9	Close Interval Survey	–	–	220	389	8,759
10	Alternating Current (AC) Interference	–	–	1,189	1,378	2,552
11	Direct Current (DC) Interference	–	–	127	709	528
12	Casings	210	3,416	4,000	6,365	48,504
13	Internal Corrosion	–	–	334	1,180	8,784
14	Atmospheric Corrosion Inspection and Remediation	297	1,115	1,300	1,920	20,437
15	Total Expenses	$2,844(b)	$8,450(c)	$13,436	$17,839	$98,982

(a) Reflects January 2013 forecasts although, in some categories, the actual spend has exceeded these forecasts based on a reprioritization of the Gas Operations transmission budget portfolio to fund additional work.

(b,c) Excludes approximately $1.226 million and $42,000 of non-corrosion recorded costs of 2011 and 2012.

PG&E forecasts capital investment expenditures of $49.3 million in 2015, $57.4 million in 2016, and $48.6 million in 2017 ($155.3 million over the entire GT&S period), as shown in Table 7-2 of Witness Peralta's testimony [53] (reproduced as Figure 3 below).

[53] *Id.* at 7-4.

Figure 3: PG&E Corrosion Control Capital Expenditures

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
CORROSION CONTROL
SUMMARY OF CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast(a)	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
1	CP Systems – Replace	$3,400	$3,205	$1,054	$3,209	$3,252	$3,335	$3,423
2	CP Systems – New	577	779	535	919	8,186	8,393	8,614
3	Coupon Test Stations	1,000	943	399	3,817	5,136	6,582	6,756
4	AC Interference Mitigation	121	268	96	4,888	10,350	16,518	15,051
5	DC Interference Mitigation	665	936	202	459	802	822	844
6	Casings	62	2,029	1,063	2,162	21,039	21,141	13,068
7	Internal Corrosion	48	32	3	300	535	658	845
8	Total Capital Expenses	$5,872	$8,194(b)	$3,352	$15,754	$49,300	$57,448	$48,600

(a) Reflects January 2013 forecasts although, in some categories, the actual spend has exceeded these forecasts based on a reprioritization of the Gas Operations transmission budget portfolio to fund additional work.

(b) Excludes $519,277 of 2011 and 2012 costs which should have been mapped to Chapter 4A but are included in the Results of Operations calculation.

Q. DOES PG&E CONSIDER CORROSION TO BE A HIGH RISK TO ITS SYSTEM?

A. Yes. As witness Peralta explains, "PG&E ranks corrosion as one of its top risks for natural gas transmission assets. As one metric, PG&E's gas leak data indicates that of the gas leaks on PG&E's pipeline assets for which a cause was known (excluding the cause "other"), 25.4% were attributed to corrosion."[54]

Q. WHAT ARE YOUR CONCERNS ABOUT THIS PROGRAM?

A. I have three major concerns. First, PG&E's inability to produce corrosion records prior to 2009[55] and its own testimony suggest that ratepayers may have already paid for some or potentially all of the work PG&E proposes.

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[54] *Id.* at 7-12, lines 17-20.

[55] GTS-RateCase2015_DR_IP_002-Q113, attached as Exhibit JAL-8.

Second, a strong history of noncompliance with regulations and deficiencies evident in a report by a PG&E consultant demonstrates mismanagement in this area. Ratepayers should not be required to pay for corrosion work caused by past neglect.

Third, the forecast expenditures in a range of subprograms are inadequately supported.

The huge increase in corrosion control-related expenditures appear, as with other programs, to be an effort by PG&E to "play catch-up" for work that should have been performed years ago.[56] This accelerated spending is a contributing factor to rate shock and, because of the extremely high demand for work related to these activities, is likely to raise the costs of labor and equipment required, further burdening PG&E ratepayers.

1. Lack of Adequate Historical Records

Q. HAS PG&E MAINTAINED HISTORICAL RECORDS THAT ALLOW THE COMMISSION TO PLACE THE PROPOSED COSTS IN THE CONTEXT OF PG&E'S OVERALL CORROSION PROGRAM?

A. No. PG&E was unable to produce records of corrosion control activities prior to 2009 because "[h]istorically, PG&E's corrosion control programs were organized and

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[56] *See generally* GTS-RateCase2015_DR_IP_002-Q114, attached as Exhibit JAL-9 (IP_002-Q114(a) explains that IP_002-Q114 Attachments 1-49 are CPUC Regulatory Audit Finds and subsection (e) explains that Attachments 50-60 are PG&E Self-Reported Audit Findings, all of which demonstrate deficiencies regarding PG&E corrosion control practices); *see also* GTS-RateCase2015_ORA_073-13, Att. 1, p. 1, and "Analysis" §§ 1 – 12 (explaining which PG&E current guidance documents and future guidance documents are not in compliance with federal code, CPUC, and PHMSA requirements and best practices for general cathodic protection, pipe-to-soil monitoring, bonds, 10% rectifiers, alternating current interference, direct current interference, casings, coatings, internal corrosion, atmospheric corrosion, and equipment and calibration), attached as Exhibit JAL-10.

managed in a decentralized manner."[57] PG&E also admits that it cannot track what routine corrosion-related maintenance was performed in the past.[58]

Q. IS IT POSSIBLE THAT PG&E WILL PERFORM ROUTINE MAINTENANCE WORK IN THIS GT&S PERIOD THAT WAS ALSO PERFORMED PRIOR TO 2009, BUT FOR WHICH THE COMPANY LACKS ADEQUATE RECORDS?

A. Yes, it is likely. For example, PG&E states "Much of the same corrosion control work shown for 2009-2013 was also performed between 2003-2008 either as a routine maintenance activity or as a reactive measure (not addressed proactively through a formal program with an annual scope).[59]

Q. WHAT IMPLICATIONS ARISE FROM PG&E'S INADEQUATE CORROSION CONTROL RECORDKEEPING?

A. PG&E's failure to maintain adequate records has several implications. First, to the extent that PG&E failed to perform adequate corrosion control in the past, the costs to remediate corrosion damage are likely to be greater. Second, PG&E may have performed specific corrosion mitigation prior to 2009, but because the Company lacks adequate records of such mitigation, may perform duplicative work. Third, the failure to adequately address corrosion over time may have caused the conditions now requiring mitigation under PG&E's proposed Corrosion Control program.

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[57] PG&E Direct Testimony, Vol. 1, Ch. 7, p. 7-5, line 10.

[58] GTS-RateCase2015_DR_IP_002-Q115, attached as Exhibit JAL-12.

[59] GTS-RateCase2015_DR_IS_004-Q014, attached as Exhibit JAL-13.

2. History of Noncompliance

Q. WHY HAVE YOU CONCLUDED THAT THERE HAVE BEEN PROBLEMS WITH PG&E'S COMPLIANCE WITH CORROSION CONTROL REGULATIONS OR BEST PRACTICES?

A. PG&E provided a document prepared by Exponent Failure Analysis Associates titled "PG&E Gas Transmission & Distribution, Corrosion Program Health Assessment, Phase II: Corrosion Control Program Comparison of Best Practice, Revision C," dated May 2014 (Exponent Report).[60]

Q. WHAT DOES THE EXPONENT REPORT DESCRIBE?

A. The Exponent Report examines whether PG&E practices are aligned with best practices and identifies where PG&E's corrosion control programs are inferior. It discusses many drastic shortcomings with corrosion control. Exponent concluded that "15% of PG&E's activities were noncompliant with federal code" and only 20% were aligned with "best practices."[61]

Q. WHAT PROGRAMS DOES THE EXPONENT REPORT IDENTIFY AS THE LEAST COMPLIANT?

A. The report states that General Cathodic Protection (CP) and Alternating Current (AC) Interference rank the lowest for current PG&E practices.[62] For future PG&E practices, AC Interference and Direct Current (DC) Interference rank the lowest.[63]

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[60] GTS-RateCase2015_ORA_073-13, Att. 1, attached as Exhibit JAL-14.

[61] *Id.* at 2.

[62] *Id.*

[63] *Id.* at 3.

Q. WHAT ARE YOUR CONCERNS ABOUT THE LONG HISTORY OF CORROSION CONTROL NONCOMPLIANCE?

A. The Exponent Report's conclusions that only 20%, or 13 of the 66 areas examined by the report, were compliant with federal regulations and aligned with best practices demonstrates mismanagement in this area. Historical mismanagement likely led to some of the conditions PG&E seeks to mitigate with the proposed Corrosion Control program. Deferral of corrosion control activities also has led to a very high proposed level of spending in this rate case period, and the lumpiness in spending is contributing to rate shock.

3. Lack of Detailed Program Support

Q. WHAT TYPES OF CORROSION DOES PG&E'S PROGRAM ADDRESS?

A. PG&E states that the program will address external, internal, and atmospheric corrosion. Expenditures on external corrosion mitigation, including routine maintenance, improved cathodic protection, close interval surveys, and mitigating electrical interference account for about three-fourths of the total capital and expenses shown in Tables 7-1 and 7-2 of PG&E's testimony. Expenditures on internal corrosion mitigation include monitoring quality of gas, removing harmful substances from gas, and adding corrosion inhibitors to gas. Expenditures on atmospheric mitigation expenditures include sanding, repainting, and replacement costs.

Q. WHY ARE YOU CONCERNED ABOUT THE ACCURACY OF PG&E'S FORECAST COSTS IN THIS AREA?

A. As a general matter, because PG&E cannot produce records prior to 2009, it cannot have reviewed historical data before that time for guidance. PG&E also admits that "[i]n some instances, the recorded 2011 and 2012 figures do not capture all of the corrosion control work and thus reflect lower than actual recorded costs."[64] PG&E does not specifically identify where historical cost information is inaccurate.

In addition, a number of specific issues regarding cost forecasting concern me, as discussed below.

a) Cathodic Protection Systems

Q. PLEASE EXPLAIN YOUR CONCERNS FOR CATHODIC PROTECTION (CP) SYSTEM COST FORECASTING.

A. The workpapers state that "the total 2015-2017 forecast is calculated by adding the <u>anticipated</u> quantity of new and replacement CP systems … The quantity of CP system replacement is based on <u>design life criteria and historical life spans</u>."[65] PG&E does not have an accurate forecast of replacement because PG&E has no way to know what will need replacement without first doing some sort of assessment or identification study.

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[64] PG&E Direct Testimony, Vol. 1, Ch. 7, p. 7-16, lines 6-8.

[65] PG&E Workpapers, WP 7-58.

b) Cathodic Protection Rectifiers

Q. PLEASE EXPLAIN YOUR CONCERNS FOR CP RECTIFIER COST FORECASTING.

A. Instead of basing forecast costs on historical costs, PG&E has based CP Rectifier unit costs off of a 2013 forecast.[66] In other words, the CP Rectifier costs are a forecast of a forecast. Without having historical cost support, this cost forecast risks being very inaccurate.

c) Coupon Test Stations

Q. PLEASE EXPLAIN YOUR CONCERNS FOR COUPON TEST STATIONS COST FORECASTING.

A. PG&E does not have a long-founded understanding of how forecast coupon test station work may differ from recent historic work, which could result in an inaccurate forecast.[67] Additionally, costs are apparently based on historic 2010-2013 data but PG&E provides no proof to verify unit cost calculations.[68] PG&E has also admittedly inflated costs because of "specialized environmental permitting and support" as well as for needed traffic control in urban areas.[69] While this may be true, it is premature to add this cost inflation when PG&E does not know the actual locations where it will work.

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66 *Id.* at WP 7-9 and WP 7-10.

67 *Id.* at WP 7-62 ("PG&E proposes to implement a program to enhance its CP monitoring program by installing [Coupon Test Stations] …).")

68 *Id.* at WP 7-63 to WP 7-64.

69 *Id.* at WP 7-63.

d) Close Internal Survey

Q. PLEASE EXPLAIN YOUR CONCERNS FOR CLOSE INTERNAL SURVEY (CIS) COST FORECASTING.

A. CIS risks forecasting inaccuracies are due to both a lack of historical work and a lack of detail. PG&E explains that "[w]hile limited CIS work has been performed in the past, the program will be formally initiated in 2014 and the annual mileage will increase over the next few years …."[70] First, the problem with forecasting costs with a lack of historical work on which to base those costs should be apparent. Second, PG&E has no way of knowing "the annual mileage will increase over the next few years," or at least has not demonstrated any concrete evidence to make an accurate observation. The same inference could be that annual mileage will decrease due to unknown factors.

e) AC Interference

Q. PLEASE EXPLAIN YOUR CONCERNS FOR AC INTERFERENCE COST FORECASTING.

A. The AC Interference workpapers cover only the "general capital mitigation forecast" and "[f]or induced AC, the process for identifying locations is currently under development."[71] The workpapers are unclear whether PG&E received cost estimates from historic work or some type of forecast cost estimation. In other areas for corrosion control, PG&E is generally clear if cost forecast is determined from historical work or estimation. Here, no such identity exists.

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[70] *Id.* at WP 7-22.

[71] *Id.* at WP 7-66.

f) AC Coupon Installation

Q. PLEASE EXPLAIN YOUR CONCERNS FOR AC COUPON INSTALLATION COST FORECASTING.

A. PG&E only has an "estimated" unit cost and cannot provide accurate information from historical costs. There is no mention of vendor quotes to determine costs, such as what PG&E has done for atmospheric corrosion control. Furthermore, PG&E admits that "data will be evaluated to determine routes," yet the workpapers have specific hours that PG&E anticipates for its employees to work. If the routes have yet to be determined, then the accurate and realistic hours the employees will need to work have yet to be determined as well.

g) DC Interference

Q. PLEASE EXPLAIN YOUR CONCERNS FOR DC INTERFERENCE COST FORECASTING.

A. The Exponent Report stresses that "PG&E does not have a written plan to identify, test for, and minimize the detrimental effects of stray currents" caused by DC interference.[72] Furthermore, PG&E cannot accurately forecast costs because the forecast for investigation studies and expense mitigation "is based on the methods anticipated to be most effective."[73] Thus, PG&E's cost estimate is simply speculative.

h) Internal Corrosion

Q. PLEASE EXPLAIN YOUR CONCERNS FOR INTERNAL CORROSION COST FORECASTING.

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[72] GTS-RateCase2015_DR_ORA_073-Q13Atch01, p. 48.

[73] PG&E Workpapers, WP 7-26.

A. An example arises in the monitoring and mitigation at the Los Medanos, McDonald Island, and Pleasant Creek storage fields, PG&E states that "[t]he forecast is based on engineering judgment and historical costs." For the single largest cost component, excavations, PG&E specifies a cost of $135,000 each, and states that, "[r]ate based on typical ECDA excavation costs plus $20,000 increase due to greater depth, as internal corrosion digs are deeper than regular ECDA locations."[74]

Q. DOES PG&E PROVIDE ANY ADDITIONAL DOCUMENTS FOR EXCAVATION COSTS?

A. No.

Q. COULD THESE COSTS OVERLAP WITH FORECAST DIRECT ASSESSMENT COSTS?

A. PG&E does not say. However, as discussed in Section VII.E of my testimony, because the separate DA is designed to evaluate external corrosion, internal corrosion, and stress corrosion and because PG&E's external corrosion, internal corrosion, and stress corrosion cracking programs will also evaluate transmission lines, I conclude there is possible duplication of costs. Because PG&E's cost estimates are so vague, however, it is impossible to determine whether there is no duplication.

i) Casings

Q. DOES PG&E HAVE A WELL-DEFINED CASING MITIGATION PROGRAM?

A. No. PG&E admits that"[p]reviously, PG&E addressed casing mitigation on an ad hoc basis and therefor never previously asked for rate case funding. PG&E is in the

[74] PG&E Workpapers, WP 7-37, WP 7-40, WP 7-43.

process of formalizing its casing mitigation program in an effort to continuously reduce risk from the threat of external corrosion."[75]

Q. DO YOU HAVE SPECIFIC CONCERNS ABOUT PG&E'S PROPOSED CASING EXPENDITURES?

A. Yes. PG&E is requesting $48.5 million in 2015 for casings expenses, stating the Company intends to perform 117 mitigations at a cost of $384,000 each, based on 2012-2013 costs.[76] This accounts for just under half of the $99 million in overall corrosion control expenses. PG&E's capital expenditures for casings are $540,000 each, again based on 2012-2013 costs.[77] The Company states it will perform 36 such mitigations each year in 2015 and 2016, and an additional 22 such mitigations in 2017.[78] The total associated capital cost is $55.2 million.[79]

Q. DOES PG&E PROVIDE ANY SUPPORTING WORKPAPERS FOR THE CAPITAL EXPENSES?

A. Yes. Workpapers addressing casing capital expenses are the support for the $55.6 million capital expense.[80] PG&E provides a table with a breakdown of costs based on

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[75] *Id.* at WP 7-93.

[76] *Id; see also* PG&E Direct Testimony, Vol. 1, Ch. 7, p. 7-37, lines 32-34. These costs are then escalated by PG&E by 7% for 2015 in WP 7-95.

[77] *Id.* at 7-37, lines 23-25. These costs are then escalated by PG&E in WP-7-95 by 7% for 2015, 9.7% in 2016, and 12.6% in 2017.

[78] PG&E Testimony, Vol. 1, Ch. 7, p. 7-37, lines 21-23.

[79] PG&E Testimony, Vol. 1, Ch. 7, p. 7-38, Table 7-14.

[80] PG&E Workpapers, WP 7-93 to WP 7-95.

previous projects.[81] However, nowhere does PG&E identify what those projects are. Moreover, the references to specific capital cost components are vague. For example, for installation costs, which PG&E shows accounts for $405,000 of the $540,000 total cost, the Company states, "[c]ost based on average of similar projects in 2012-2013 with gained efficiencies."[82] Those "efficiencies" are never identified nor does the Company assume any ongoing efficiencies over the three-year GT&S period.

Q. DOES PG&E PROVIDE ANY SUPPORT FOR THE $47.2 MILLION IN CASING EXPENSE EXPENDITURES?

A. No. PG&E's entire support is that the unit cost of $384,000 is "based on the same forecast methodology described above for capital casings."[83] There are no supporting workpapers.

j) Atmospheric Corrosion

Q. HOW MUCH IS PG&E REQUESTING TO ADDRESS ATMOSPHERIC CORROSION?

A. PG&E proposes $20.4 million in expenses for 2015.[84]

Q. HAS PG&E RECORDED SIGNIFICANT ATMOSPHERIC CORROSION EXPENSES IN THE PAST?

A. No. According to Witness Peralta:

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[81] *Id.* at WP 7-95.

[82] *Id.* at WP 7-95.

[83] PG&E Testimony, Vol. 1, Ch. 7, p. 7-37, lines 33-34.

[84] *Id.* at 7-45, Table 7-17.

> There are no costs recorded for atmospheric corrosion inspection work in 2011-2013 because this work was performed in conjunction with other work (like leak survey) as mentioned above. Per PG&E's existing process, the scope of the atmospheric corrosion inspection is very limited, does not require much time and, therefore, has not required separate funding from these other programs.[85]

Q. DOES PG&E'S ATMOSPHERIC CORROSION PROPOSED WORK PRESENT AN ACCURATE FORECAST?

A. It is unlikely. Atmospheric corrosion is another PG&E program that has yet to develop. The testimony indicates that "mitigation locations will be prioritized," indicating PG&E does not know the actual work it needs to do. Other statements verify this lack of knowledge, such as "the atmospheric corrosions mitigation expense for 2015 include forecasted units expected to be mitigated in 2015 …."[86]

Q. IF PG&E CANNOT GIVE AN ACCURATE FORECAST OF THE QUANTITY OF WORK, WHAT ABOUT PG&E'S FORECAST FOR THE COST?

A. Cost forecasts are also unlikely to be accurate because PG&E lacks the records to determine an accurate forecast. No 2014 forecast costs exist "because the expanded inspection process <u>will be under development</u>," including new procedures and qualifying new personnel.[87] PG&E also lacks records of 2011-2013 recorded costs for atmospheric corrosion.[88]

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[85] *Id.* at 7-43, lines 23-28.

[86] *Id.*at 7-45, lines 13-15.

[87] *Id* at 7-43, lines 28-32.

[88] *Id.* at 7-44, lines 13-15.

Q. IF THERE ARE NO PREVIOUSLY RECORDED COSTS, WHAT IS THE COST FORECAST BASED ON?

A. According to Witness Peralta's testimony, the costs are "based on cost quotes provided by vendors of the unit cost to perform the new comprehensive inspection process multiplied by the number of units subject to atmospheric corrosion inspection in PG&E's transmission system."[89] Thus, none of the costs are based on actual historic costs.

Q. WERE THE VENDOR QUOTES RECEIVED BY PG&E BASED ON A COMPETITIVE BIDDING PROCESS?

A. No. According to PG&E's responses in discovery[90] it does not seem PG&E used a competitive bidding process.

Q. WHY IS IT A PROBLEM THAT PG&E COULD NOT PROVIDE BIDS FOR ATMOSPHERIC CORROSION CONTROL?

A. PG&E's explanation for its atmospheric corrosion control cost forecast is that it is based on quotes from vendors.[91] However, PG&E was not able to provide bids from vendors PG&E chose not to use. A prudent operator should retain any quotes from vendors that were not selected if it is justifying a forecast cost based on vendor quotes. PG&E is aware that all forecast costs are subject to the Commission's reasonableness review. Therefore, PG&E should be responsible to retain any evidence, such as vendor quotes, that PG&E used to determine a cost forecast.

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[89] *Id.* at 7-43, line 34 to7-44, line 4.

[90] GTS-RateCase2015_DR_IndicatedProducers_004-Q17; GTS-RateCase2015_DR_IndicatedProducers_002-Q121, both attached as JAL-15.

[91] PG&E Direct Testimony, Vol. 1, Ch. 7, p. 7-43, line 34 to7-44, line 4.

Q. WHAT IS YOUR RECOMMENDED SOLUTION FOR PG&E'S FAILURE TO PROVIDE BIDS?

A. Without analyzing bids from other vendors and without any knowledge of whether PG&E used a valid competitive bid process, the Commission has insufficient evidence to determine whether the cost forecast for atmospheric corrosion is reasonable or unreasonable. Since PG&E cannot provide the proof that the forecast is reasonable, the Commission should have a presumption that the atmospheric corrosion cost is unreasonable and disallow recovery from ratepayers. The burden should shift to PG&E to prove the costs are not unreasonable.

Q. WHAT CONCERN DO YOU HAVE ABOUT PG&E INFLATING FORECAST COSTS THROUGH VENDOR QUOTES?

A. Workpapers indicate that PG&E initiated an atmospheric corrosion control pilot program to determine forecast costs since PG&E lacked 2011-2014 data.[92] Apparently the result of the pilot program was 80% of locations examined did not require atmospheric corrosion mitigation.

Q. WHAT WAS PG&E'S EXPLANATION FOR RELYING ON VENDOR QUOTES INSTEAD OF RELYING ON THE PILOT PROGRAM?

A. PG&E did not provide an explanation, at least not one I could identify.

k) Shareholder Cost Responsibility

Q. ARE SHAREHOLDERS TAKING ANY RESPONSIBILITY VOLUNTARILY FOR THE FORECAST COSTS OF THIS PROGRAM?

A. Witness Peralta testifies that PG&E is not requesting any ratepayer funding for past deficiencies, and claims that PG&E will incur $21 million in capital costs and $58

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[92] PG&E Workpapers, WP 7-44.

million in expenses through 2017 which will be borne by shareholders.[93] Witness Peralta further testifies that, "[t]his funding level, while high, will address activities that have <u>not</u> previously been defined, requested, and, therefore, funded." [94]

Q. DOES THIS LEVEL OF FUNDING SEEM REASONABLE?

A. No. <u>Because</u> PG&E lacks adequate records before 2009, and b<u>ecause</u> the Company admits that the proposed expense and capital expenditures during the GT&S period are much larger than previous expenditure levels, PG&E cannot guarantee that ratepayers will <u>not</u> be paying for maintenance activities they have already paid for previously. Even though "PG&E is not requesting recovery of the costs to address those deficiencies arising from past practices,"[95] the lack of PG&E's corrosion control records make it extremely difficult, if not impossible, to prove that it is accurate.

4. Recommended Commission Action: Corrosion Control

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING PG&E'S CORROSION CONTROL PROGRAMS?

A. Because PG&E admits the Company failed to perform adequate corrosion control in the past, admits there are no records of corrosion control activities prior to 2009, and has failed to support its proposed costs, it is not reasonable for ratepayers to bear the corrosion control-related costs PG&E has presented.

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[93] *Id.;* PG&E Direct Testimony, Vol. 1, Ch. A, p. 7-6, lines 8-9.

[94] *Id.* at 7-5, lines 29-31.

[95] *Id.* at 7-6 lines 8-9.

First, prior to Commission approval of any corrosion-related capital or expense costs, PG&E should be required to demonstrate that ratepayers have not paid for such costs before. If PG&E cannot so demonstrate, then PG&E shareholders should bear those costs.

Second, prior to Commission approval of corrosion-related capital or expense costs, PG&E should be required to demonstrate that ratepayers are not paying for costs that are also included in other programs, such as direct assessment. If PG&E cannot so demonstrate, then the Company's shareholders should bear those costs.

Third, to the extent the Commission allows cost recovery for corrosion, PG&E's expensed costs and capital costs associated with corrosion control programs should be placed into corresponding memorandum accounts, subject to later reasonableness review. Any authorized expenses should be amortized over a ten-year period.

Fourth, all of the capital expenditures that are ultimately allowed by the Commission should have an associated return on equity set to 9.4%, the low end of the range of reasonableness determined by the Commission in its 2013 Cost of Capital decision.

Fifth, the Commission should require PG&E to undergo an independent forensic audit overseen by the Commission to determine historic corrosion control expenditures. To the extent that this audit reveals improper accounting of costs, the Commission should determine a penalty to be paid by Company shareholders.

B. Vintage Pipe Replacement Program

Q. WHAT IS THE PURPOSE OF THE VINTAGE PIPELINE REPLACEMENT PROGRAM (VPR)?

A. The VPR is intended to target 370 miles[96] of pipe that that was "designed, manufactured, constructed and installed before the advent of California safety laws in 1961."[97] These segments are identified as having characteristics that "make it more susceptible to certain construction threats"[98] because of interactions with land movement.[99] PG&E proposes replacement because fabrication and construction methods "are not as readily assessed using ILI or hydrostatic testing."[100] For 2015-2017, PG&E anticipates replacing approximately 60 miles of vintage pipe, at a rate of approximately 20 miles per year.[101]

Q. HOW HAS PG&E CHARACTERIZED THE THREATS RELATED TO VINTAGE PIPELINES?

A. PG&E states "[t]hese interactive threats [vintage pipeline and land movement] were identified as the greatest unmitigated risk to the Transmission pipeline system. As such,

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96 PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-54, lines 8-10.

97 *Id.* at 4A-39, lines 7-8.

98 *Id.* at 4A-52, lines 6-8.

99 PG&E considers "vintage pipe" to include "pipe manufactured or constructed and fabricated using certain historic practices that are no longer being used today. Historic manufacturing methods include pipe made with flash welds, low frequency ERW seam, single submerged arc welded seams, or furnace lap welded seams. Historic fabrication and construction methods include pipe that was installed using wrinkle bends, mechanical/compression couplings, miter bends and other non-standard fittings like orange peel reducers, chill ring welds, bell and spigot, or pipe that was constructed with the acetylene girth welding process." *Id.* at 4A-51, lines 11-21.

100 *Id.* at 4A-51, lines 21-23.

101 *Id.* at 4A-54, lines 16-18. According to WP-4A-712, the actual mileage to be replaced in the 2015-2017 timeframe is 58.9 miles.

all of the Vintage Pipe Replacement program sites are relatively high risk in relationship to other programs."[102]

Q. WHAT ARE PG&E'S FORECAST EXPENDITURES FOR VPR ACTIVITIES DURING THE 2015-2017 GT&S PERIOD?

A. As shown in Table 4A-16 of PG&E's testimony,[103] PG&E proposes $596.5 million in capital expenditures to replace 58.9 miles of pipe, implying an average replacement cost of $10.13 million/mile.

Q. WHAT ARE YOUR CONCERNS WITH THE VPR?

A. The VPR raises the same risk management concerns raised by all other programs, as explained in the Joint Testimony and in Section VI. Beyond the adequacy of risk management lie additional concerns:

- PG&E's proposed costs per mile of replacement are not adequately supported; and
- The VPR program appears to be an attempt to catch up with existing regulations to address construction threats.

PG&E has presented insufficient evidence to justify authorization of the proposed program expenditures at this time.

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[102] GTS-RateCase2015_DR_TURN_008-Q004(d), attached as Exhibit JAL-15.

[103] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-55.

1. Proposed VPR Costs are Not Supported

Q. WHY DO YOU CONCLUDE THAT THE PROPOSED PROGRAM COSTS ARE NOT SUPPORTED BY PG&E'S SHOWING?

A. The proposed unit costs, i.e., costs per mile, differ materially from the costs identified in the July 2013 Transmission Pipe Asset Management Plan (Transmission Pipe AMP),[104] which underpins the proposal.

Q. HOW ARE THE VPR PROGRAM AND THE UNDERLYING TRANSMISSION PIPE AMP RELATED?

A. The Transmission Pipe AMP, which is dated [redacted] is the basis for PG&E's VPR program. It provides estimates of the relative risks of different threats, such as those related to pipe corrosion, manufacturing defects, construction defects and other threats. The AMP describes data regarding pipe condition, as well as gaps in these data. And, the AMP sets out a variety of proposed programs to address risk, including vintage pipe replacement. The differences between the Transmission Pipe AMP and the various mitigation programs described in PG&E's testimony include: (1) the AMP sets out five-year budget projections for the years 2014 – 2018; and (2) different levels of effort in the AMP and the testimony. For example, PG&E's proposed annual expenditures on the VPR program presented in the Company's testimony are [redacted] shown in the AMP.

[104] PG&E Supplemental Testimony, Ch. 2A, Attachment B, Confidential; GTS-RateCase2015_DR_TURN_001-Q01, Att. 11.

Q. HOW DO UNIT COSTS DIFFER BETWEEN THE VPR PROGRAM AND UNDERLYING TRANSMISSION PIPE AMP?

A. Based on the projected capital expenditures in the AMP and the miles PG&E indicates would be replaced, the average per mile cost of replacement in the AMP is [redacted].[105] [redacted]

Q. HAS PG&E EXPLAINED THE CHANGES IN THE PROJECTED COSTS IN THE TRANSMISSION PIPE AMP TO THE VPR PROGRAM?

A. Yes, but the Company's explanation is vague. PG&E states that the change in costs from the Transmission Pipe AMP was driven by decreasing the miles of pipe to be replaced each year from 40 to 20 and focusing solely on construction threats, but not manufacturing threats.[107] PG&E states that manufacturing threats interacting with land movement will be "addressed via [in-line inspection] and hydrotest programs."[108] PG&E then states that, as a result of the refined scope, the estimated costs have increased.

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[105] The $/mile value is based on data in Table 13 of the Transmission Pipe AMP (p. 38), which indicates replacement of [redacted] of vintage pipe over the 2014 – 2018 period. The total capital cost is [redacted], implying an average cost of [redacted] per mile.

[106] PG&E Workpapers, WP 4A-711 to WP 4A-712. On WP 4A-711, add $193 million, $198.715 million, and $203.969 million for 2015, 2016, and 2017, respectively, found in the "Cost Calculation with Escalation (thousands of dollars)" table. The total is $596.508 million. On WP 4A-711 to WP 4A-712, the total mileage for PG&E to replace in 2015-2017 is 58.86 miles. $596.508 million divided by 58.86 miles equals an average of $10.1 million per mile.

[107] Supplemental Testimony, Ch. 2A, Attachment B, GTS-RateCase2015_DR_TURN_001-Q01Atch25, p. 1.

[108] *Id.*

Q. IS THIS EXPLANATION REASONABLE?

A. No. If those were the reasons, PG&E has not documented in its workpapers how [redacted] per mile to $9.1 million per mile in two estimates performed in the same year.

Q. WHAT COST DATA HAS PG&E PROVIDED?

A. Data on the forecast costs of replacing different vintage pipe segments is shown in PG&E's workpapers.[109] These costs are based on the PG&E's "cost calculator," which is shown in its entirety in Figure 2. The cost calculator, however, has no explanation how PG&E determined the forecast cost. In response to ORA-56-003, which requested historical information,[110] PG&E provided overall cost estimates for one PSEP <12"-diameter project, four 12-24" projects, and three 24+" diameter projects. These data are the basis for PG&E's workpaper shown in Figure 4. PG&E failed to provide any detail on the component costs for these projects.

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[109] PG&E Workpapers, WP-4A-711 to WP-4A-714.

[110] GTS-RateCase2015_DR_ORA_056-Q003, attached as Exhibit JAL-16.

Figure 4: PG&E VPR Cost Calculator

Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case
Workpapers Supporting Chapter 4A, Transmission Pipe Integrity and Emergency Response Programs
Vintage Pipe Replacement

Unit Cost Analysis

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

1) Phase 1 costs were validated by comparing to 2011 and 2012 actuals for completed projects

Q. DOES PG&E PROVIDE ANY ADDITIONAL SUPPORT FOR VPR PROGRAM COSTS OTHER THAN THIS SINGLE PAGE "COST CALCULATOR"?

A. No. As can be seen in Figure 4, PG&E's cost estimate is based on unidentified PSEP actual replacement costs in 2011 and PG&E's forecasts of 2012 and 2013 costs. As shown in note (1) of this Figure, PG&E also references 2012 actuals, thus it is not clear whether PG&E has used actual 2012 costs, forecast 2012 costs, or a combination of both. There is no breakdown of historic costs (e.g., labor, materials, etc.). PG&E has not identified any specific segments of pipe the Company replaced in 2011 or 2012, nor has it identified the costs associated with these replacements.[111] Additionally, Indicated Shippers requested PG&E to specifically identify how it came up with these cost

[111] PG&E Workpapers 4A-711 to 4A-722. These are the only Vintage Pipe Replacement workpapers detailing capital expenditures, but none of the pages reflect detailed historical costs.

estimates. Instead of providing a specific PSEP cost breakdown, PG&E provided a general statement about PSEP cost replacement and referred back to the cost calculator workpaper.[112]

It is impossible to verify the accuracy and reasonableness of PG&E's historic costs, and there is little explanation as to why the average cost per mile values is shown in Figure 2. Even for the smallest pipe sizes, costs are all [redacted].

Q. WHAT IS YOUR CONCLUSION?

A. PG&E's lack of sufficient supporting cost justification does not warrant pre-approval of these costs at this time.

2. The Proposal May Cause Ratepayers to Pay Twice to Address the Same Pipeline Segments

Q. ARE THERE OTHER REASONS YOU BELIEVE PG&E'S PROPOSED COSTS ARE NOT REASONABLE?

A. Yes. PG&E admits that it "did not exclude from this program those pipe segments subjected to a pressure test but not replaced during PSEP" because pressure tests "cannot ensure that any construction defects … will not become unstable."[113] PG&E did not need pressure tests for these segments to demonstrate the safety defects of vintage pipe, and both pressure testing and replacing the lines wastes ratepayer dollars.

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[112] GTS-RateCase2015_DR_IndicatedProducers_004-Q06(a)(i), attached as Exhibit JAL-17 (refers to DR_ORA_056-Q03, which is an additional spreadsheet that does not provide an explanation how PG&E determined the cost calculator. *See supra* note 110 and accompanying text for discussion of DR_ORA_056_Q03).

[113] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-57 lines 9-10.

Q. WAS THE HYDROTESTING PREVIOUSLY PERFORMED ON THESE LINES A RESULT OF A PRIOR CPUC ORDER?

A. Not exactly. The Commission ordered PG&E and other pipelines in D.11-06-017 "to prepare Implementation Plans to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test."[114] It contemplated that PG&E would "either" pressure test or replace, not both.

Q. IN CASES WHERE PG&E PERFORMED A PRESSURE TEST IN PHASE 1 AND IS NOW REPLACING THE SAME PIPELINE, SHOULD RATEPAYERS BEAR THE COSTS OF BOTH ACTIONS?

A. No. If PG&E replaces pipeline segments previously subjected to pressure tests and ratepayers were responsible for the costs of those tests, it would be unreasonable for ratepayers to pay the testing costs.

3. PG&E Fails to Provide Any Evidence of Risk Reduction Value

Q. WHAT IS THE SAFETY OBJECTIVE UNDERLYING THE VPR?

A. PG&E's safety objective is not stated explicitly. Whether better characterized as a result of the program or an objective, PG&E states that it will reduce "the risk posed by these interacting threats for over 90% of the population living within the [Potential

[114] *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans*, D.11-06-017, June 9, 2011, p. 19.

Impact Radius] of PG&E's pipelines by the end of 2017."[115] PG&E states it intends to address the remaining 10% of the population by 2025.[116]

Q. DOES PG&E EXPLAIN WHY THIS IS AN APPROPRIATE OBJECTIVE TO ACHIEVE IN THREE YEARS?

A. No. As discussed in the Joint Testimony, PG&E provides no evidence as to why achieving this objective over a three-year period is reasonable. It may be more appropriate to achieve the objective in one year. Then again, it may be more appropriate to achieve it over 10 years. We cannot know because PG&E's risk methodology is fundamentally flawed and it provides no evidence of the risk reduction benefits of the program.

4. PG&E Has Deferred Addressing the Issues Underlying the VPR

Q. WHY DO YOU BELIEVE PG&E HAS DEFERRED THE WORK PROPOSED IN THE VPR PROGRAM?

A. As a general matter, industry reports demonstrate how PG&E is playing catch-up. In the NTSB Accident Report released after San Bruno, the NTSB emphasized that "many of these deficiencies should have been recognized and corrected before the [San Bruno] accident."[117] PG&E had other serious safety issues before San Bruno occurred, such as leaks in 1981[118] and 1988,[119] as well as a distribution line explosion in 2008.[120]

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[115] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-54, lines 13-16.

[116] *Id.* at lines 20-27.

[117] National Transportation Safety Board, "Accident Report: Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010," NTSB/PAR-11/01 PB2011-916501, August 30 2011, p. 116.

[118] *Id.* at 116.

Activity occurring after San Bruno is a reactionary catch-up by PG&E: "[t]he San Bruno pipeline rupture was an organizational accident. PG&E did not effectively utilize its resources to define, implement, train, and test proactive management controls to ensure the operational and sustainable safety of its pipelines."[121] It is likely that at least some of the work proposed in this program is due to past deficiencies. PG&E is attempting to squeeze vast amounts of spending – spending that should have occurred over several decades – into three years.

Q: HAVE THESE TYPES OF "VINTAGE PIPE" MANUFACTURING, CONSTRUCTION AND FABRICATION THREATS BEEN PREVIOUSLY IDENTIFIED BY THE NATURAL GAS PIPELINE INDUSTRY?

A. Yes. The Interstate Natural Gas Association of America (INGAA), in coordination with the INGAA Foundation and American Gas Foundation, commissioned the Battelle Memorial Institute to prepare a report titled, "Integrity Characteristics of Vintage Pipelines" (Battelle Report), which was published in October 2004.[122]

(cont.)

[119] *Id.* at 38.

[120] *Id.* at 116.

[121] *Id.* at 117.

[122] This report can be found on the Pipelines and Hazardous Materials Safety Administration's (PHMSA) website under Technical Resources. http://primis.phmsa.dot.gov/gasimp/docs/IntegrityCharacteristicsOfVintagePipelinesLBCover.pdf.

Q: DID THE BATTELLE REPORT ADDRESS THE HISTORICAL MANUFACTURING AND CONSTRUCTION METHODS IDENTIFIED BY PG&E IN ITS VINTAGE PIPELINE REPLACEMENT PROGRAM?

A: Yes. Battelle identified and addressed the concern of failure for wrinkle bends, mechanical/compression couplings, miter bends or pipe that was constructed with the acetylene girth welding process. Battelle did not specifically address the other non-standard fittings like orange peel reducers, chill ring welds, or bell and spigot.

Q. HOW DOES THE BATELLE REPORT SUPPORT YOUR CONCLUSION THAT PG&E LIKELY HAS DEFERRED ASSESSMENT AND WORK ON VINTAGE PIPELINES?

A. First, the Battelle Report was issued ten years ago, giving PG&E a reason to begin addressing the issues at that time.

Second, PG&E itself acknowledges that "the Pipeline and Hazardous Material Safety Administration has urged operators to consider" these types of threats "for some time."[123] The PHMSA regulations promulgated pursuant to the Pipeline Safety Improvement Act of 2002 require gas transmission pipeline operators to reassess their pipelines for all safety risks — such as corrosion, excavation, land movement, or incorrect operation — at regular intervals based on industry consensus standards.[124]

Third, PG&E's pace of work suggests that it has been deferring what it believes to be important work. PG&E plans to reduce vintage pipeline risks stemming from land movement to protect 100% of the population in the vicinity of its pipelines by 2025. In

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[123] PG&E Direct Testimony, Vol. 1, Ch. 4, pp. 4A-52, lines 25-29 to 4A-53, line 1.

[124] http://www.gao.gov/assets/660/655576.pdf.

2015-17, however, PG&E will reach 90% coverage of the population.[125] Thereafter, PG&E proposes another seven years to reach 100% coverage.[126] PG&E is condensing the replacement work into this three-year GT&S period,[127] and doing so without determining which work is actually necessary to achieve a safe pipeline system.

Q. WHY DOES IT MATTER TO RATEPAYERS IF PG&E HAS DELAYED NECESSARY WORK AND NOW WISHES TO ACCELERATE THAT WORK?

A. Ignoring questions about risk exposure over time and focusing solely on cost aspects, the sudden increase in proposed activity will increase the demand for labor and equipment needed to perform such work. PG&E has identified labor and equipment as constraints on what the Company can accomplish during the GT&S period. Although I do not know what specific qualifications are required for working on pipelines, I assume that, given contract labor rates of as much as $200/hour, PG&E has specified in workpapers for various activities, workers must have specialized training and expertise. Because there surely is a limited supply of such workers, a rapid increase in the pace of work will increase the demand for labor and lead to higher wages. In fact, it may that PG&E's forecast labor costs already reflect that increased labor demand. Similarly, assuming the supply of specialized construction equipment is similarly constrained, the greater will be the increase in equipment costs.

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[125] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-55 lines 19-20.

[126] *Id.* at 4A-54 l. 14.

[127] *Id.* at 4A-55, lines 20-27.

5. Recommended Commission Action: VPR Program

Q. IN LIGHT OF THE ISSUES YOU HAVE IDENTIFIED, WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION UNDERTAKE REGARDING THE VPR PROGRAM?

A. First, PG&E should use a corrected methodology to demonstrate how its VPR program, as structured, is part of an optimal risk management plan, as discussed in Section V of the Joint Testimony. Proceeding with the work before having this certainty may unnecessarily increase costs to ratepayers or fail to meet the yet-undefined safety objectives.

Second, because PG&E admits that the Company has "not yet formally completed a relative prioritization of these potential projects using the likelihood of failure component,"[128] preauthorization of costs is not appropriate. Once PG&E's management has a sufficient level of certainty about the program and begins to spend, it should be permitted to record costs in a memorandum account, subject to reasonableness review by the Commission.

Third, because the risks associated with vintage pipe have been known by PG&E for many years without taking action, I recommend that the Company's allowed return on VPR investment resulting from this proceeding be reduced to 9.4%, which is the low-end value of the Commission's range of reasonableness for gas transmission and distribution companies, as set forth in the Commission's SoCalGas Cost of Capital decision.[129]

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[128] GTS-RateCase2015_DR_TURN_008_4.d, attached as Exhibit JAL-18.

[129] *Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism; and Related Matters*, A.12-04-015, D.12-12-034, December 20, 2012, p. 42.

Fourth, ratepayers should not be responsible to pay for both a strength test that occurred under PSEP and replacement that occurred under this program. If ratepayers previously paid for hydrostatic testing of a pipeline segment that PG&E now proposes to replace, any recoverable replacement costs should be reduced by the cost of the Phase 1 testing.

C. Shallow Pipe Program

Q. WHAT IS THE PURPOSE OF THE SHALLOW PIPE PROGRAM?

A. According to PG&E, "[t]he purpose of PG&E's Shallow Pipe Program is to identify, prioritize and mitigate locations where pipeline has insufficient cover and is vulnerable to exposure from third parties."[130] It is intended to mitigate time independent threats, such as subsidence, excavation and grading, ground penetrating activities, agricultural activities and erosion.[131]

Q. WHAT ARE PG&E'S FORECAST EXPENDITURES FOR THIS PROGRAM?

A. PG&E proposes capital spending of $73.9 million over the three-year GT&S period, with forecast expenses in 2015 of approximately $3 million.[132]

Q. WHAT ARE YOUR CONCERNS WITH THE SHALLOW PIPE PROGRAM?

A. The Shallow Pipe program raises the same risk management concerns raised by all other programs, as explained in the Joint Testimony. PG&E has not employed budget

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[130] PG&E Direct Testimony, Vol. 1, Ch. 4B, p. 4B-19, lines 23-25.

[131] *Id.* at 4B-20, lines 19-30.

[132] *Id.* at 4B-25.

or risk tolerance constraints, used a risk management methodology capable of determining how the VPR fits within an optimal risk management plan nor demonstrated the risk reduction value of the program.

Beyond the adequacy of risk management, the Shallow Pipe program is unsupported by sufficient project detail to justify the expenditures.

Q. WHAT IS THE SCOPE OF WORK PG&E WILL PERFORM UNDER THE PROGRAM?

A. PG&E forecasts engineering analysis, expense mitigation, and capital replacement or relocation by miles, as shown in Figure 5.

Figure 5: PG&E Forecast Shallow Pipe Miles

TABLE 4B-7
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL MILES PLANNED FOR ENGINEERING ANALYSIS, EXPENSE MITIGATION, AND CAPITAL REPLACEMENT/RELOCATION (FROM 2015-2017)

Line No.	Description	2015 Planned	2016 Planned	2017 Planned	Total
1	Miles of Expense Engineering Analysis	56.0	150.0	150.0	356.0
2	Miles of Expense Mitigation	0.3	0.3	0.4	1.0
3	Miles of Capital Replacement/Relocation(a)	2.5	2.5	3.4	8.4

(a) Miles of Capital Replacement/Relocation are the result of Miles of Expense Engineering Analysis from previous year.

Q. HAS PG&E PROVIDED A DETAILED DESCRIPTION OF ITS CAPITAL PROJECTS?

A. No. Despite what appears to be a detailed forecast, PG&E has not actually identified the work it will undertake. PG&E states that "Currently, 411 miles of shallow pipe are projected within high- and medium-risk areas.[133] PG&E thus is not certain how much shallow pipe exists. Moreover, PG&E does not know which of those locations will actually become mitigation, replacement, or relocation projects. PG&E explains that "it is through this engineering analysis that PG&E will determine the pipeline locations that will become projects versus those that can be addressed through routine maintenance."[134] PG&E also acknowledges that "As the engineering analysis forecast is not yet complete, mitigation projects have not yet been identified, thus the AOC prioritization has not yet taken place."[135] PG&E simply does not know the extent to which capital investment will be necessary as a result of this program.

Q. HOW MUCH SHALLOW PIPE MITIGATION DOES PG&E FORECAST?

A. PG&E forecasts "mitigation of approximately 2.5 miles of identified high-risk shallow pipe per year for 2015-2016, and 3.4 miles of medium-risk shallow pipe in 2017 based on this analysis."[136] It forecasts one mile of expense mitigation over the period.[137]

Q. DO PG&E'S WORKPAPERS ON THE SHALLOW PIPE PROGRAM PROVIDE ANY JUSTIFICATION FOR THE PROPOSED $73.9 MILLION IN CAPITAL EXPENDITURES OVER THE 2015-2017 PERIOD?

A. No. PG&E's shallow pipe program workpapers[138] contain no discussion whatsoever of the proposed capital expenditures.

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[133] *Id.* at 4B-23, line 4 to 4B-24, line 2; GTS-RateCase2015_DR_IP_002_Q85Atch04, attached as Exhibit JAL-19.

[134] GTS-RateCase2015_DR_IP_002_Q85(b), attached as Exhibit JAL-20.

[135] *Id.*

[136] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4B-24, lines 9-11.

[137] *Id.* at 4B-25, Table 4B-7.

Q. IS THIS A SUFFICIENT BASIS TO AUTHORIZE RECOVERY OF PG&E'S FORECAST EXPENDITURES?

A. No. PG&E provides an unsupported guess of how many miles of shallow pipe will require replacement, based on an estimate of how much shallow pipe exists in high- and medium-risk areas. Furthermore, PG&E has failed to provide information regarding the cost of shallow pipe replacement. Thus, PG&E's request that the Commission preauthorize recovery of $73.9 million in capital expenditures and $5.3 million in annual expenses is unsupported and fails the known and measurable standard.

Q. DO YOU HAVE OTHER OBSERVATIONS?

A. Yes. This program, like other programs in PG&E's proposal, has the potential for overlap. Pipeline replacement will occur in the following programs: Vintage Pipe Replacement, Hydrostatic Testing, Earthquake Fault Crossing, Direct Assessment, In-Line Inspection, Valve Automation, Inoperable and Hard to Operate Valves, Shallow Pipe, Work Required by Others, Class Location, Water and Levee Crossing, Simple Station Rebuilds, Complex Station Rebuilds, Transmission Terminal Upgrades, ECA Phases 1 and 2, Corrosion Control, Pipeline Maintenance, and Expense Projects.[139]

(cont.)

[138] PG&E Workpapers, WP 4B-11 – 4B-13.

[139] GTS-RateCase2015_DR_IS_004-Q05, attached as Exhibit JAL-21.

1. Recommended Commission Action: Shallow Pipe Program

Q. IN LIGHT OF THE ISSUES YOU HAVE IDENTIFIED, WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION UNDERTAKE REGARDING THE SHALLOW PIPE PROGRAM?

A. First, the Commission should authorize only recovery of the portion of PG&E's forecast expense costs for its proposed engineering analysis, which will enable the gathering of important asset condition information. PG&E proposes to analyze 356 of the estimated 411 miles of pipe at $15,000 per mile, or roughly $5.3 million in expense.

Second, the Commission should allow PG&E to begin expense mitigation and capital replacement only as the Company acquires the necessary data. PG&E should be permitted to record the expense and capital costs in memorandum accounts for later recovery, subject to reasonableness review by the Commission.

D. Hydrostatic Testing

Q. WHAT ACTIVITIES WILL PG&E UNDERTAKE IN ITS PROPOSED HYDROSTATIC TESTING PROGRAM?

A. The Hydrostatic Testing program is "designed to mitigate stable/resident threats by testing the yield strength of the pipe for the presence of manufacturing defects, such as a lack of fusion in a seam weld."[140] PG&E forecasts testing approximately 170 miles annually during the GT&S period, or 510 miles in total, which is "close to the average yearly mileage strength tested in the PSEP."[141]

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[140] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-32, lines 4-6.

[141] *Id.* at 4A-32, lines 8-10.

Q. WHAT COSTS HAS PG&E FORECAST FOR HYDROSTATIC TESTING?

A. PG&E forecasts total expenses of $181.8 million in 2015, including $174.0 million for strength testing.[142] The forecast also includes an additional $5.3 million for "strength tests needed to address pressure restoration work or uprates for pressure increase to pipelines requiring a higher MAOP to support increased customer load,"[143] plus an additional $2.5 million "for ongoing maintenance of LNG/CNG portable assets."[144] These expenses are summarized in Table 5.

Table 5: PG&E 2015 Hydrostatic Testing Expenses

Program	Proposed Expense (Millions of $)
Strength Tests	$173.97
Uprates	$5.275
LNG/CNG Tests	$2.548
Total	$181.792

Source: PG&E WP 4A-51, WP 4A-62

According to PG&E's workpapers, the $174.0 million for strength testing is based on an average cost of $970,000 per mile of pipe tested in 2013, as shown in Table 4A-11 of PG&E witness Barnes's testimony.[145] PG&E then applies this average cost, escalated by 7%, to calculate the total cost of testing the 170 miles of pipe the Company states it plans to test in 2015.

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142 *Id.* at 4A-32 lines 11-12 and Table 4A-8.

143 *Id.* at 4A-41 lines 11-13. The actual expense for this work, as shown on PG&E WP 4A-51 is $5.275 million.

144 *Id.* at 4A-36 lines 16-17.

145 *Id.* at 4A-4.

PG&E forecasts total capital expenditures of $65.86 million over the three-year GT&S period, distributed as shown in Figure 6.

Figure 6: PG&E Hydrostatic Testing Capital Expenditures

TABLE 4A-9
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF CAPITAL EXPENDITURES
($ THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
1	Hydrostatic Testing	$5,863	$12,094	$27,200	$25,800	$21,400	$21,940	$22,520
2	Hydrostatic Testing - LNG/CNG	4,929	5,887	5,000	7,150	2,916	878	647
3	Total Capital Expenditures	$10,791	$17,981	$32,200	$32,950	$24,316	$22,818	$23,167

Q. WHAT ARE YOUR CONCERNS WITH THE HYDROSTATIC TESTING PROGRAM?

A. The Hydrostatic Testing program raises four concerns:

- The proposal requests recovery of costs that were disallowed by the Commission in D.12-12-030;
- The proposal lacks assurance that PG&E will spend the money on high-priority strength testing;
- The proposed expenses are unreasonable; and
- The proposed capital costs are unreasonable.

Finally, the program raises the same risk management concerns as nearly all of PG&E's other programs: a lack of any quantified risk reduction benefit.

1. The Proposal Would Allow Recovery of Costs Disallowed by D.12-12-030

Q. DOES PG&E'S REQUEST VIOLATE THE PSEP DECISION? WHY?

A. Yes. At issue is whether ratepayers or PG&E shareholders should bear the costs of re-testing of segments of pipe installed between 1955 and 1961 because PG&E has no pressure test records for these segments. In the PSEP decision, the Commission summarizes PG&E's argument:

> PG&E states that while it began to follow the industry guidelines in 1955, it did so on a voluntary basis rather than due to a legal or regulatory requirement. Because it was not required to perform pre-service pressure tests from 1955 to 1961, PG&E posits that ratepayers should fund pressure testing for any pipeline placed into service during that time for which PG&E cannot locate pressure test data. PG&E summarizes its position: even though it may have "lost, destroyed, or misplaced" some of its records, it was able to prudently operate its natural gas transmission system by relying on the historical exemption in subpart J, thus the newly required pressure testing or replacement should be at ratepayers expense.[146]

The Commission rejected PG&E's argument, finding that the costs associated with PG&E's own error — losing pressure test records — should not be borne by ratepayers:

> We find that where PG&E undertook or stated that it undertook to comply with industry standards but no longer possesses the records of such compliance, the costs of retesting required by the missing records is a result of an error in PG&E's operation of its natural gas transmission system. <u>Where PG&E's record retention errors have led to re-testing pipeline installed between 1955 and 1961, the costs of such re-testing is not a just and reasonable cost of providing public utility service</u>. Such costs, therefore, should be excluded from authorized revenue requirement to be recovered from ratepayers.[147]

PG&E repeats its PSEP argument in this case, and it should be rejected again. Witness Barnes states:

> While we recognize the Commission previously denied recovery of pressure test costs associated with pipe installed between 1956-1961 on the basis of missing records in PG&E's PSEP proceeding, we believe these costs should be recoverable because: (1) there were no requirements

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[146] D.12-12-030, p. 58 (footnote omitted).

[147] *Id.* (emphasis added).

to hydrostatically test pipe when it was installed between 1956-1961; (2) at the time of enacting pipeline safety regulations, the Commission and federal government consciously chose not to require hydrostatic tests for pipe installed prior to that time; (3) the hydrostatic test provision in the American Standards Association (ASA) code was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961; (4) the ASA code did not require pipe operating below 30% SYMS to be hydrostatically tested (a point which was not addressed by the recent Commission decisions denying recovery of certain PSEP costs); and (5) it was unlikely the CPUC would have provided rate recovery for hydrostatic testing activities in 1956-1961 given that it was not a requirement.[148]

Q. IS PG&E'S ARGUMENT REASONABLE?

A. No. None of the reasons PG&E cites represent a change in fact since D.12-12-030 was issued.

Q. IN YOUR EXPERIENCE, IS FORCING RATEPAYERS TO PAY A UTILITY TWICE FOR THE SAME COSTS CONSISTENT WITH STANDARD REGULATORY PRACTICE?

A. No. Losing records is not consistent with Good Utility Practice and prudent management. As the Commission stated, "Having paid for such testing once, the ratepayers should not be required to pay for re-testing due to PG&E's failures in document management."[149] Forcing ratepayers to pay twice as a result of mismanagement is inefficient and grossly inequitable.

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[148] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-43, lines 1-17.

[149] D.12-12-030, p. 60.

Q. HOW MUCH OF THE PIPE PG&E PROPOSES TO TEST FALLS INTO THIS CATEGORY?

A. According to PG&E's testimony, 47 miles, or 9.2% of the 510 miles PG&E proposes to test, was installed between 1956 and 1961.[150] Thus, the Commission should deny PG&E recovery of at least 9.2% of the $174.0 million in expenses for strength testing that are shown in Table 4, or $16.01 million. (PG&E has already agreed to exclude the costs of testing 74 miles of pipe installed after 1961 for which it lacks any records.)

2. The Proposal Lacks Assurance that PG&E Will Spend Approved Dollars on High-Priority Strength Test

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE HYDROSTATIC TESTING PROGRAM?

A. Yes. Although PG&E states it intends to test 510 miles of pipe over the GTS period, there is significant uncertainty as to the actual testing the Company will perform. Without that level of detail, the proposal lacks sufficient support to assure the Commission that the dollars approved will go toward high-priority hydrotests and not something else.

Q. WHAT IS THE BASIS FOR THE SIGNIFICANT UNCERTAINTY REGARDING WHAT TESTING PG&E WILL ACTUALLY PERFORM?

A. PG&E witness Barnes testifies that "PG&E expects that as each engineering analysis is completed on planned hydrostatic tests, the scope of the projects may change.

[150] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-43, Table 4A-12.

In some cases, the change may be to no longer strength test the segment." [151] He also acknowledges "[a]s a result, the number of miles as well as the location and number of pressure tests may change during the course of the rate case period."[152] Furthermore, PG&E has admitted that, as of March 14, 2014, it "has not begun to engineer the 2015-2017 strength tests …."[153]

Q. HOW DOES PG&E ADDRESS THIS UNCERTAINTY?

A. Rather than refunding unspent dollars back to ratepayers, PG&E proposal is as follows:

> If the volume of planned strength tests drops below that planned, PG&E will add strength tests from a "flex list" of future tests of Class 1 and Class pipe that were not included in the 2015-2017 program to maintain the target number of miles to be tested near 510 miles.[154]

If miles are added based on test findings, however, PG&E proposes to limit work to 510 miles and "defer the lower priority Class 1 and Class 2 tests."[155]

Q. PG&E WITNESS STAVROPOULOS TESTIFIES THAT THE COMPANY HAS A COMPREHENSIVE HYDROTESTING PLAN.[156] DO YOU AGREE?

A. No. In response to IS-2-017,[157] PG&E simply refers back to Mr. Barnes's testimony.[158] Given the concerns I have identified above with Mr. Barnes's testimony,

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[151] *Id.* at 4A-34, lines 1-4.

[152] *Id.* at 4A-34, lines 16-17.

[153] GTS-RateCase2015_DR_IP_002-Q072(b), attached as Exhibit JAL-22.

[154] *Id* at p. 4A-35, lines 8-10.

[155] *Id.* at 4A-35, lines 10-18.

[156] PG&E Direct Testimony, Vol. 1, Ch. 1, p. 1-12, lines 11-14.

[157] GTS-RateCase2015_DR_IP_002-Q017, attached as Exhibit JAL-23.

PG&E's admitted uncertainty about what will actually be tested, and the unreasonable capital costs of the program (discussed in the next section), Mr. Barnes's testimony does not constitute a "comprehensive" testing strategy.

Q. IS THIS APPROACH CONSISTENT WITH THE NOTION OF TRYING TO OPTIMIZE RISK REDUCTION WITH AVAILABLE RATEPAYER DOLLARS?

A. No. Preauthorizing costs for uncertain work plans, which could accelerate work PG&E deems "lower priority," is unreasonable in light of the magnitude of the rate request PG&E has proposed.

3. The Proposed Capital Costs are Unreasonable

Q. HOW DO PG&E'S FORECAST CAPITAL EXPENDITURES FOR HYDROSTATIC TESTING COMPARE WITH ACTUAL RECORDED EXPENDITURES?

A. According to PG&E witness Barnes's testimony, in 2012 the Company recorded capital expenditures of approximately $12.1 million for hydrostatic testing of 176 miles of pipe, implying an average capital cost of $68,880 per mile, as shown in Table 6. In 2013, PG&E projected total capital costs of $25 million to test 195 miles of pipe, implying an average cost of $139,500/mile, a 138% increase over the 2012 average per-mile cost.[159] PG&E's workpapers further show 2014 projected capital costs of $25.8 million for 148 miles, or $174,300/ mile, a 253% increase over the average per-mile capital cost in 2012.

(cont.)

[158] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-38 – 4A-43.

[159] *Id.* at 4A-41, Table 4A-11 and lines 19-22.

Table 6: Hydrostatic Testing: Capital Costs, 2012 – 2014

Year	Miles of Pipe Tested	Capital Expense (Millions of $)	Average Capital Cost per Mile	Increase Over 2012 Cost per Mile
2012	176	$12.1	$68,880	--
2013 est	195	$27.2	$139,500	137%
2014 est	148	$25.8	$174,300	253%
Totals	**519**	**$65.1**	**$125,400**	**82%**

Q. WHAT CAPITAL COST FOR HYDROSTATIC TESTING DOES PG&E ASSUME IN THIS PROCEEDING?

A. PG&E proposes a cost of $125,400 per mile for the 2015-17 period, equal to the average per-mile capital cost for the entire 2012- 2014 period. As shown in Table 4, that is still an 83% increase over the 2012 average per-mile capital cost. PG&E's justification for using this value is that, "Give [sic] that the scope of the work varies dramatically based on where the test is, how long of a test is being performed etc. a cost per mile of capital was estimated using 2012-2014 numbers."[160]

Q. IS PG&E'S JUSTIFICATION SOUND?

A. No. PG&E's estimate using 2012 – 2014 numbers includes actual expenses only for 2012. The values for 2013 and 2014 that PG&E used are themselves forecasts. Thus, PG&E is basing forecast expenditures for 2015 – 2017 solely on one actual annual expense value.

Q. HAS PG&E PROVIDED A DETAILED EXPLANATION OF WHY THE COMPANY'S CAPITAL COSTS ARE SO HIGH?

A. No. PG&E witness Barnes provides a one-sentence explanation: "The increase in capital from 2012-2013 was due to: (1) an increase in the length of tests, which spans

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[160] PG&E Workpapers, WP 4A-487 to WP 4A-488.

more valves and PCFs that have to be replaced or removed; and (2) the number of Distribution Feeder Mains and small diameter pipelines which have a lot of customer taps and utilize more PCFs."[161] Mr. Barnes provides no explanation why 2014 costs are 25% over the 2013 costs.

Q. HAVE THE 2013 ACTUAL COSTS THAT PG&E PROVIDED IN DISCOVERY BEEN ADEQUATE TO SUPPORT ITS COST FORECAST?

A. No, PG&E has left the responsibility to intervenors to resolve that 2013 actual costs are an accurate reflection of the 2015-2017 forecast costs when the responsibility should be on PG&E. While PG&E did provide 2013 actual costs, PG&E led intervenors on a treasure hunt to understand 2013 actual costs.[162] Instead of providing 2013 costs in an organized manner, as PG&E presented other historical costs in testimony, PG&E threw numbers into a spreadsheet for intervenors to decipher.[163] PG&E's explanation was "[u]sing these, Indicated Shippers can do all the cost analysis that is required above."[164] Apparently PG&E believes it is intervenors' responsibility and not PG&E's to meet PG&E's burden that forecast costs are reasonable.

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[161] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-42, lines 4-8.

[162] GTS-RateCase2015_DR_ORA_058-Q01.b, attached as Exhibit JAL-24; *see also* GTS-RateCase2015_DR_ORA_058-Q01Atch03 (a spreadsheet over 200 pages listing intricate yet convoluted 2013 individual hydrostatic testing costs, available at http://apps.pge.com/regulation/).

[163] *See* GTS-RateCase2015_DR_IS_010-Q01; GTS-RateCase2015_DR_ORA_058-Q01.b; GTS-RateCase2015_DR_ORA_059-Q04; GTS-RateCase2015_DR_ORA_059-Q04Atch01; GTS-RateCase2015_DR_ORA_059-Q04Atch02, all attached as Exhibit JAL-25; *see also* GTS-RateCase2015_DR_ORA_058-Q01Atch03 (a spreadsheet over 200 pages listing intricate yet convoluted 2013 individual hydrostatic testing costs, available at http://apps.pge.com/regulation/).

[164] GTS-RateCase2015_DR_IS_ 010-Q01, attached as Exhibit JAL-26.

4. Recommended Commission Action: Hydrostatic Testing

Q. IN LIGHT OF THE ISSUES YOU HAVE IDENTIFIED, WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION UNDERTAKE REGARDING THE HYDROSTATIC TESTING PROGRAM?

A. First, as noted previously, the Commission should reduce PG&E's revenue request by $16.01 million to address the absence of strength test records for pipe installed between 1956 and 1961, consistent with the Commission's ruling in the PSEP decision.

Second, given the degree of uncertainty in the proposed costs, the Commission should allow PG&E to record the remaining capital costs in a memorandum account and place them into rate base only after a reasonableness review by the Commission.

Third, the Commission should not permit PG&E to "backfill" proposed hydrostatic test miles that the Company is not ultimately required to test with lower priority miles, merely to spend its proposed GT&S budget.

E. Direct Assessment Program

Q. WHAT ACTIVITIES WILL PG&E UNDERTAKE IN ITS PROPOSED DIRECT ASSESSMENT PROGRAM?

A. Direct Assessment (DA) is a method of assessing pipeline integrity, used primarily to "evaluate the possibility of time dependent threats of external corrosion, internal corrosion, and stress corrosion cracking."[165] PG&E witness Barnes testifies that external corrosion DA (ECDA), internal corrosion DA (ICDA), and stress corrosion cracking DA (SCCDA) will be used to assess: (1) unpiggable, High Consequence Areas (HCA) mileage that is due for reassessment under Integrity Management rules; (2) new HCA segments created as a result of PG&E's

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[165] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-24, lines 12-15.

recharacterization of certain distribution facilities as transmission facilities, and (3) to ascertain the "asset health" of a segment based on cathodic protection data.[166]

Q. WHAT COSTS HAS PG&E FORECAST FOR DIRECT ASSESSMENT?

A. PG&E forecasts expenses of $155.1 million over the 2015 – 2017 GT&S period, as shown in Figure 7:

Figure 7: PG&E Forecast Direct Assessment Expenses

TABLE 4A-7
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF EXPENSES
($ THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
1	External Corrosion Direct Assessment	$12,165	$36,339	$16,850	$23,574	$26,227	$30,274	$39,621
2	Internal Corrosion Direct Assessment	377	6,202	1,700	9,013	15,328	18,762	22,008
3	Stress Corrosion Cracking Direct Assessment	407	–	500	2,532	2,857	(a)	(a)
4	Total Direct Assessment	$12,949	$42,540	$19,050	$35,119	$44,412	$49,036	$61,629

(a) While PG&E is not requesting special attrition for these programs, PG&E expects the scope of work in these programs will expand significantly in the attrition years.

Q. HAS PG&E IDENTIFIED SPECIFIC PIPE IT INTENDS TO ASSESS AS PART OF THIS PROGRAM?

A. Yes, to a limited extent. PG&E lists general pipelines scheduled for inspection, but no specific pipeline segments are shown.[167]

Q. DOES PG&E ADMIT THERE IS UNCERTAINTY AS TO HOW MUCH PIPE WILL BE ASSESSED?

A. Yes. For example, PG&E witness Barnes testifies that:

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[166] *Id.* at 4A-26, lines 21-30.

[167] PG&E Workpapers, 4A-2 – 4A-3.

> For [external corrosion direct assessment] ECDA, the pre-assessment phase involves collecting and evaluating historical data on the design, construction, operation, inspection, maintenance history, and other factors that may influence the longevity of the pipeline system to determine the feasibility of using DA. If DA is appropriate, then the pipeline is divided into regions with similar exposure and areas where the same two or more above ground inspection tools may be used.[168]

Mr. Barnes's testimony indicates that the actual amount of pipe that will be subject to ECDA won't be determined until after PG&E completes its "pre-assessment" phase. Similarly, regarding ICDA, Mr. Barnes testifies that:

> Although only the mileage in HCAs is being assessed using ICDA, the process requires assessment of gas receipts and low spots for many non-HCA miles leading into the HCA miles being assessed. This could mean, for instance, PG&E would need to evaluate 75 miles of the pipeline system to conduct an appropriate ICDA evaluation of one mile of HCA.169

As with ECDA, Mr. Barnes's testimony regarding the amount of pipe that will be inspected using ICDA is highly uncertain. Finally, regarding SCCDA, Mr. Barnes states that "PG&E also proposes to perform SCCDA on approximately 60 miles of pipeline in HCAs in 2015, at a cost of approximately $2.9 million."[170] However, WP 4A-3 does not identify any specific pipeline segments where SCCDA will be performed.

[168] *Id.* at 4A-25, lines 3-9.

[169] *Id.* at 4A-27, lines 13-18.

[170] *Id.*at 4A-27, lines 29-30.

Q. HOW DO THE FORECASTED DA COSTS COMPARE WITH OTHER ESTIMATES FOR SIMILAR ACTIVITIES?

A. PG&E provides estimates of total costs, based on projected numbers of inspections and projected cost data for 2013.[171] Table 7 summarizes PG&E's unit costs for ECDA, ICDA, and SCCDA.

Table 7: PG&E Per-Unit Direct Assessment Costs

DA Method	2013	2015	2016	2017
ECDA				
Cost per Dig	$115,625	$121,985	$125,034	$128,160
Survey Cost (per mile)	$46,728	$49,298	$50,531	$51,794
Engineering per Dig	$11,765	$12,412	$12,706	$13,012
ICDA				
Cost per Site	$315,856	$333,228	$341,124	$349,337
SCCDA				
Cost per Site	$115,625	$121,985	na	na
Engineering per Dig	$13,333	$14,067	na	na
Source: PG&E WP 4A-17 – 4A-22				

Q. DOES PG&E PROVIDE ANY BREAKDOWN OF THE $115,625 COST PER DIG FOR ECDA AND SCCA?

A. No. PG&E simply reports a total cost number of $12,371,915.28 as the recorded dig costs in 2013. There is no breakdown of this cost to determine whether it is just and reasonable.[172]

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[171] PG&E Workpapers, WP 4A-17 – 4A-22.

[172] *Id.* at WP 4A-18.

Q. DOES PG&E PROVIDE THE BASIS FOR THE $80,000 ESTIMATED PRE-ASSESSMENT COST AND $30,000 POST-ASSESSMENT COST FOR EACH PROJECT, AS SHOWN ON WP 4A-18?

A. No. Both of these costs are reported as estimates.

Q. WHAT IS THE RANGE OF ICDA INSPECTION COSTS PER SITE FOR 2012 AND 2013?

A. Using the data provided by PG&E, in 2012 inspection costs per site ranged between $21,065 for the 191-1 DE project to $669,810 for the Peninsula project. In 2013, project cost ranged between $221,589 for project 191-2013 to $405,765 for project 123-2013.[173] PG&E bases future project costs on the average cost of these projects. Given the tremendous variation in costs per project, an average value is a poor predictor of actual future costs per project.

Q. DOES PG&E PROVIDE ANY BREAKDOWN OF THESE PROJECT COSTS?

A. No.

1. Recommended Commission Action: Direct Assessment

Q. IN LIGHT OF THE ISSUES YOU HAVE IDENTIFIED, WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION UNDERTAKE REGARDING THE DIRECT ASSESSMENT PROGRAM

A. Given PG&E witness Barnes's testimony as to the significant uncertainty regarding how much DA PG&E will actually perform, the Commission should allow PG&E to record actual DA costs in a memorandum account and recover them at a later

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[173] PG&E Workpapers, WP 4A-20.

time, subject to reasonableness review by the Commission. Once expenses have accrued, PG&E should be required to amortize them over a 10-year period.

F. Valve Automation Program

Q. WHAT ACTIVITIES WILL PG&E UNDERTAKEN IN ITS PROPOSED VALVE AUTOMATION PROGRAM?

A. The Valve Automation Program will automate, through replacement or upgrade, inoperable or hard-to-operate isolation valves, which enable emergency shut-off responses. It "is designed to enhance emergency response in the event of a gas transmission pipeline rupture."[174] PG&E plans to replace 120 isolation valves at 60 individual sites,[175] extend its PSEP program to enable automatic controls of 384 miles of additional gas transmission pipeline, including 223 miles of Class 3 and Class 4 (HCA) areas.[176]

Q. WHAT COSTS HAS PG&E FORECAST FOR VALVE AUTOMATION?

A. PG&E forecasts $152.5 million in capital expenditures over the GT&S period, distributed as shown in Figure 8:

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[174] *Id.* at 4A-67, lines 4-5.

[175] *Id.* at 4A-69, lines 17-18.

[176] *Id.* at 4A-67, lines 13-16.

Figure 8: PG&E Forecast Valve Automation Capital Expenditures

TABLE 4A-22
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF CAPITAL EXPENDITURES
($ THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
1	Valve Automation	$13,344	$29,764	$50,583	$49,915	$52,502	$55,772	$44,181
2	Total Capital Expenditures	$13,344	$29,764	$50,583	$49,915	$52,502	$55,772	$44,181

Q. WHY HAS PG&E PROPOSED TO FUND THIS PROGRAM?

A. The primary reasons are that: (1) the California Legislature required utilities to install automated valves in HCAs or where pipelines cross active seismic faults;[177] and (2) the Commission approved a plan to automate 228 valves in D.12-12-030.[178]

Q. DOES PG&E'S PROGRAM INCLUDE ONLY VALVES IN HCAS OR ON PIPELINES CROSSING ACTIVE SEISMIC FAULTS?

A. According to PG&E's testimony, "PG&E proposes to automate an additional 120 valves on larger diameter high pressure gas transmission pipelines located primarily within Class 3 HCA and Class 3 non-HCA areas where there is a significant [potential impact radius]."[179]

[177] Cal. Pub. Util. Code §957.

[178] D.12-12-030, Conclusion of Law 12.

[179] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4A-67, lines10-13.

Q. IS THIS WORK REQUIRED BY PHMSA?

A. PHMSA regulations do not require automated shutoff valves. Furthermore, as PG&E witness Barnes testifies, "[t]he natural gas industry generally has not fully embraced a holistic valve automation program," due to questions regarding effectiveness, potential adverse impacts and the "cost vs. value" of the measure.[180] PG&E nonetheless "believes the advantages of automating isolation valves outweighs the risks through the judicious use of remote controlled valve automation, and select use of automatic shutdown valves."[181]

Q. HAS PG&E PREPARED ANY STUDIES THAT COMPARE THE COSTS OF AUTOMATED VALVE WITH THE BENEFITS OF AUTOMATED VALVES?

A. No. PG&E's only assessment of automatic valves is the Company's belief that the benefits outweigh the costs.

Q. HAS PG&E DETERMINED THE RISK REDUCTION IMPACT OF AUTOMATED VALVES AS PART OF ITS RISK REGISTER PROCESS?

A. No. There is no evidence of any such calculations in the Company's Transmission Pipe AMP or in its Measurement and Control AMP.

Q. WHAT ARE THE COSTS PER VALVE FORECAST BY PG&E, AND HOW DOES THAT FORECAST COMPARE WITH PSEP COSTS?

A. PG&E's forecast valve replacement cost is 131% higher than the valve replacement costs in the PSEP. Table 4A-24 of PG&E witness Barnes's testimony shows

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[180] *Id.* at 4A-68, lines17-25.

[181] *Id.* at 4A-68, lines 26-28 (emphasis added).

an average capital cost of $1.34 million per valve in the GTS forecast, compared against an average capital cost of $0.58 million per valve replaced in the PSEP.[182]

Q. DOES PG&E PROVIDE ANY EXPLANATION FOR THE DIFFERENCE IN AVERAGE COSTS PER VALVE IN THIS PROCEEDING COMPARED WITH THE PSEP AVERAGE COST?

A. Yes. PG&E witness Barnes offers four reasons for the cost increase. These are: (1) fewer valves requiring automation, reducing economies of scale; (2) a greater percentage of valves requiring concrete vaults; (3) an increased percentage of new valves and new valve sites to reduce distance per valve; and (4) more valve sites that require electric power, emergency backup power and new SCADA communications.[183]

Q. IS THIS A REASONABLE EXPLANATION?

A. No. First, the "lack of economies of scale" is unsupported and vague. Mr. Barnes never explains what sorts of economies of scale PG&E realized in replacing 228 valves during 2011 – 2014, or 57 per year, or why PG&E cannot improve the cost-efficiency of future valve automation.

Second, a comparison of PG&E's projected costs with valve automation costs estimated by SoCalGas reveals significant differences for what appears to be similar work.

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[182] *Id.* at 4A-74, Table 4A-24.

[183] *Id.* at 4A-74, lines 7-25.

Q. HOW DO PG&E'S PROJECTED VALVE REPLACEMENT COSTS COMPARE WITH THOSE ESTIMATED BY SOCALGAS IN ITS PSEP COMPLIANCE FILING?

A. Even taking account of the reasons proffered by Mr. Barnes for higher average costs, PG&E's automated valve costs appear to be significantly higher than those used by SoCalGas. For example, consider PG&E's forecast cost to automate a 24 inch valve located at L105N, MP10.11 Timber, which is scheduled to be operative on June 1, 2015. PG&E shows the total costs of installing this valve[184] and a detailed breakdown of the labor, engineering, and capital costs.[185] PG&E estimates the total cost for this project to be $2,330,557. PG&E estimates construction labor costs to $1,192,000, engineering costs to be $240,000, and materials costs to be $188,320.[186] To these, PG&E adds $359,707 for capital-related administrative and general (A&G) costs, $178,233 for project management and "PG&E Oversight," $36,258 in AFUDC costs, and $136, 059 for cost escalation.

SoCalGas presents generic estimates for the cost of installing new automated valves or automating an existing valve. These costs were then applied by SoCalGas to all of the specific valves the company workpapers indicated would be upgraded.[187]

. For example, SoCalGas estimated the <u>entire</u> cost of installing a new 20-inch vaulted valve at $1,007,800 based on the average estimated cost for installation by either

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[184] PG&E Workpapers, WP 4A-527.

[185] *Id.* at WP-4A-529.

[186] *Id.*

[187] SoCalGas PSEP Workpapers WP-IX-2-14, 2-24, 2-29 and 2-33, attached as Exhibit JAL-26.

SoCalGas or a third party, including electric power and SCADA communications.[188] The cost for installing a new 24-inch vaulted valve is similarly shown as $1,119,200, an 11% increase.[189] Table 8 provides a comparison of specific cost categories forecast by PG&E against those of SoCalGas.

Table 8: Valve Automation Cost Comparison

Category	PG&E (Timber -24"	SoCalGas 24-inch**	Percent Difference
Labor [1]	$1,610,233	$676,206	138%
[2]	$188,300	$349,042	-46%
Contingency/Escalation	$136,059	$82,957	64%
A&G Costs	$359,707	included	Na
AFUDC	$36,258	included	Na
Total	$2,330,557	$1,119,200	108%

** 20-inch costs shown on WP-IX-2-31 escalated uniformly by 11.05% to equal costs of 24-inch valve shown on WP-IX02-29.

[1] Includes project management, permitting, and engineering costs.

[2] SoCalGas cost includes new valve; actuator cost alone = $14,900. PG&E actuator cost = $71,900.

As Table 6 shows, the PG&E's estimated cost to automate the 24-inch valve at Timber is more than double the estimated cost SoCalGas uses to install a completely new 24-inch valve. The most striking differences are PG&E's labor costs, which are 138% higher than those assumed by SoCalGas.

[188] *Id* at WP-IX-2-31.

[189] *Id.* at WP-IX-2-29.

Q. IS IT REASONABLE TO COMPARE THE COSTS OF PG&E'S SPECIFIC VALVE AUTOMATION PROJECT WITH SOCALGAS' GENERIC COST ESTIMATE?

A. In this case, yes it is. PG&E's cost estimate for the Timber project, and the Company's other projects, are all based on generic cost components and percentage adders. For example, the engineering costs shown for the Timber project include $200,000 for "Design and Engineering – Major," which PG&E uses for all "major" projects. Similarly, PG&E includes $10,000 for each project to cover the costs of "Mapping/Records/Estimating." PG&E's $380,000 construction labor cost to install a 24-30 inch actuator, $380,000, is also generic, and applied to different projects. Moreover, PG&E calculates "Capital A&G" costs as 22.2% of total construction labor, engineering, and materials costs. Similarly, PG&E calculates the allowance for funds used during construction (AFUDC) at 2.238% of total construction labor, engineering, and materials costs. Most importantly, SoCalGas applied its "generic" cost estimates to determine the costs of specific valve upgrades in its PSEP filing. Thus, I conclude that comparing the cost estimates prepared by PG&E for this proceeding can be reasonably compared to those estimated by SoCalGas.

Q. IS IT POSSIBLE THAT AN INCREASE IN LABOR AND MATERIALS COSTS IS RESPONSIBLE FOR THE 138% COST DIFFERENCE?

A. That is unlikely. PG&E has provided no evidence that general labor rates have increased by 138% in two years. A more likely explanation is that, as previously discussed, PG&E's increased demand for labor caused by the acceleration of its programs is increasing estimated labor costs. To the extent that PG&E is playing "catch-up," and accelerating many of its programs, the demand for labor to perform the necessary work will be greater and thus able to command higher wages.

1. Recommended Commission Action: Valve Automation

Q. IN LIGHT OF THE ISSUES YOU HAVE IDENTIFIED, WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION UNDERTAKE REGARDING THE VALVE AUTOMATION PROGRAM?

A. PG&E presents no evidence of the risk reduction benefits that will be provided by valve automation, other than its "belief" that the advantages of automating isolation valves outweigh the risks. PG&E also admits that the natural gas industry is not "sold" on valve automation owing to questions regarding its effectiveness, potential adverse impacts and "cost vs. value." Finally, PG&E's estimated costs appear to be grossly inflated in comparison with the cost estimated developed by SoCalGas for its PSEP filing.

In addition, PG&E's proposed costs are not adequately supported. The Commission should require PG&E to provide more definitive evidence that the benefits of valve automation exceed the costs and provide estimates of how valve automation for pipelines that are not within HCAs or cross active earthquake fault lines will reduce risk.

Thus, the Commission should not preauthorize any valve replacement costs. Instead, for valves in locations requiring automation, the costs should be place into appropriate memorandum accounts and recovered after the Commission has determined the costs to be just and reasonable. For valve replacement costs in areas where there is no statutory automation requirement, PG&E should first be required to provide evidence that the benefits of automation exceed the costs and, if so, those costs can also be place into memorandum accounts to ensure the actual costs are just and reasonable.

G. Work Required by Others Program

Q. WHAT IS THE "WORK REQUIRED BY OTHERS" PROGRAM?

A. The "Work Required by Others" (WRO) program "covers transmission pipeline or related facility removals and relocations performed by PG&E at the request of third parties," typically government agencies and occasionally private developers.[190] The work typically leads to relocation of pipeline facilities.[191]

Q. WHAT WRO PROGRAM COSTS HAS PG&E FORECAST?

A. PG&E forecasts 2015 expenses of $738,500 and total capital expenditures for the period of $79.2 million, distributed as shown in Figure 9.

Figure 9: PG&E Forecast WRO Capital Expenditures

TABLE 4B-12
PACIFIC GAS AND ELECTRIC COMPANY
WORK REQUIRED BY OTHERS (WRO) PROGRAM REQUEST
SUMMARY OF CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
1	Work Required by Others	$5,443	$8,843	$14,292	$5,850	$24,610	$26,328	$28,150

Q. WHY SHOULD WORK REQUIRED BY OTHERS HAVE ANY COST TO PG&E RATEPAYERS?

A. PG&E typically performs this work under Master Agreements with the agency requesting the work. PG&E observes that under the 1952 Master Agreement with

[190] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4B-32, line. 8.

[191] *Id.* at 4B-35, lines 7-8.

CalTrans, for example, "reimbursement amount can range from 0 to 100% of the utility relocation project costs."[192]

Q. WHAT ARE YOUR CONCERNS WITH THE WRO PROGRAM FORECAST EXPENDITURES?

A. The forecast expenditures are unsupported. Moreover, PG&E's forecast annual capital expenditures are five times greater than the Company's estimated 2014 capital expenditures.

Q. WHY DO YOU BELIEVE PG&E'S WRO FORECAST IS UNSUPPORTED?

A. PG&E has not forecast a specific project that will require PG&E pipeline relocation during the GT&S period. The Company's proposal is based solely on general observations regarding the state of the economy. As PG&E witness Mojica testifies:

> Work Required by Others follows a cyclical pattern. When the economy is strong and there is an abundance of federal, state and private investor funds available, the number of these WRO projects increase and when economic times falter the number of projects decrease. An increase in the number of high-speed and light rail projects is forecasted for 2015-2017, and a significant number of highway and freeway projects remain in the forecast. These 2015-2017 WRO projects are primarily capital relocation projects.[193]

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[192] *Id.* at 4B-34, lines 21-22.

[193] *Id.* at 4B-35, lines 1-8.

PG&E's proposal is supported solely by a statement by Moody's Analytics that PG&E's service area is in economic recovery and Moody's projects economic growth in the service area to be above average compared with the rest of the United States.[194]

Q. HOW DOES PG&E'S WRO EXPENSE FORECAST COMPARE WITH PRIOR YEARS' EXPENDITURES?

A. PG&E's expense forecast of $738,500 approximates the average of recorded expenses in 2011 and 2012, and forecast expenditures in 2013 and 2014.[195] As shown on WP 4B-10, that average is $691,593, which PG&E rounded up to $700,000 and then escalated by 5.5% for 2015. A further oddity is that the recorded expenses for 2011 and 2012 shown in Table 4B-11 of PG&E witness Mojica's testimony[196] and on page WP 4B-9, $2,376,000 and $3,819,000, respectively, do not match the expenses shown for those years on page WP 4B-10, which are $682,805 and $861,844, respectively.

Q. HOW DOES THE HISTORIC RATIO OF EXPENSE EXPENDITURES TO CAPITAL EXPENDITURES OVER THE 2011 – 2014 PERIOD COMPARE WITH PG&E'S FORECAST IN THIS PROCEEDING?

A. Table 9 provides a comparison of expense expenditures, capital expenditures and their ratios for the four-year period, 2011 – 2014.

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[194] GTS-RateCase2015_DR_IP_002_Q87, attached as Exhibit JAL-27.

[195] PG&E Workpapers, WP 4B-9 to4B-10,

[196] PG&E Direct Testimony, Vol. 1, Ch. 4, p. 4B-36, Table 4B-11.

Table 9: 2011-2014 Expense and Capital Expenditures (1000$): WRO

Cost Category	2011	2012	2013	2014	Average 2011-2014	2015
Expense	$2,376	$3,820	$700	$522	$1,855	$739
Capital	$5,443	$8,843	$14,292	$5,850	$8,607	$24,610
Ratio (E/C)	43.7%	43.2%	4.9%	8.9%	21.5%	3.0%

As Table 9 shows, expense expenditures averaged just over 21% of capital expenses between 2011 and 2014. Yet, despite forecasting capital expenditures that are five times higher than those in 2014 and three times higher than the average between 2011 and 2014, PG&E's forecast expense expenditures, $739,000, are expected to be only 3% of capital expenditures. This is inconsistent with the four-year pattern and calls into question PG&E's capital expenditures forecast.

Q. WHY DOES IT MATTER IF PG&E'S FORECAST IS WRONG?

A. It matters because PG&E is asking ratepayers for upfront funding of forecast WRO expenditures for which the Company may not be reimbursed at a later time. Doing so forces ratepayers to provide an interest-free loan to PG&E <u>and</u> bear all of the risk of PG&E not collecting for monies the Company spend on WRO. As such, it is a classic example of what economists call "moral hazard," in which the risks of an action are borne by a third party. Allowing PG&E to recover these costs <u>before</u> they are incurred reduces the incentive for PG&E to recover money from those for whom it performs work in a timely manner. Moreover, the uncertainty of PG&E's expense forecast and lack of evidentiary basis for its capital expenditure forecast are further reasons why all of PG&E's WRO costs should not be included in the GT&S revenue requirement.

1. Recommended Commission Action: WRO

Q. DO YOU RECOMMEND THE COMMISSION PREAUTHORIZE PG&E'S FORECAST WRO EXPENDITURES?

A. No. For the reasons discussed above, the Commission should disallow <u>all</u> proposed WRO expenses and capital costs. Instead, PG&E can recover those expenditures directly from the parties for which it performs work. There is no economic rationale to force PG&E ratepayers to subsidize WRO costs and create a situation for which PG&E has no economic incentive to collect those costs.

H. In-Line Inspections

Q. WHAT IS THE PURPOSE OF THE IN-LINE INSPECTION (ILI) PROGRAM?

A. PG&E has identified numerous segments and sections[197] of pipelines that cannot hold ILI tools for various reasons, depending on the construction and manufacturing of the different pipeline segments. After conducting studies on these segments, PG&E forecasts doing the necessary work to make the lines capable of ILI inspection, run the ILI inspection, and then perform repair work based on the inspection results.[198] Another term synonymous with making a line capable of ILI is to make the line "piggable"[199] with "smart pigs."[200]

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[197] A "section" of pipeline is several segments of the same diameter connected together and capable of handling the same ILI tools. PG&E Workpapers, WP 4A-154.

[198] PG&E Direct Testimony, Vol. 1, Ch. 4A, pp. 4A-6 to 4A-8.

[199] *Id.* at 4A-12 l. 4; PG&E Workpapers, WP 4A-153.

[200] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-5 line 12.

Q. HAS PG&E PROVIDED GREATER GRANULARITY WITHIN THE SCOPE OF THE ILI PROGRAM?

A. Yes. PG&E identifies four distinct elements of scope: [201]

- Make Piggable: upgrading pipelines to increase the miles that can be assessed through ILI tools;
- Inspection and Re-inspection Runs: post-upgrade traditional ILI inspections to enhance data collection;
- Non-Traditional ILI Runs: post-upgrade non-traditional ILI inspections that must use different technology than traditional ILI;
- Direct Examination and Repair Digs (DE&R): excavations, repairs and replacements identified by ILI findings.

Q. WHAT ARE PG&E'S FORECASTED CAPITAL EXPENDITURES AND EXPENSES FOR THE IN-LINE INSPECTION PROGRAM?

A. PG&E places total capital expenditures over all programs within ILI at $74.3 million, $110.5 million, and $113.6 million for 2015, 2016, and 2017 respectively.[202] For expenses, the PG&E forecast stands at $31.5 million, $27.8 million, and $52.8 million for 2015, 2016, and 2017 respectively.[203] These costs are distributed among the different types of ILI projects as shown in Table 10.

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[201] *Id.* at 4A- 12 to 4A-15.

[202] *Id.* at 4A-15 Table 4A-5.

[203] *Id.* at 4A-16 Table 4A-6.

Table 10: Forecast ILI Costs

Program	2015	2016	2017	Total
Capital				
Traditional ILI	$71,279,000	$97,651,000	$100,075,000	$269,005,000
Non-Traditional ILI	$2,980,000	$12,897,000	$13,559,000	$29,436,000
Total Capital Expense	$74,261,015	$110,550,016	$113,636,017	$298,441,000
Operating Expense				
Traditional ILI	$14,521,000	$17,737,000	$34,535,000	$66,793,000
Non-Traditional ILI*	$146,000	$146,000	$146,000	$438,000
Traditional ILI DE&R	$13,310,000	$10,126,000	$18,328,000	$41,764,000
Non-Traditional ILI DE&R	N/A	N/A	N/A	N/A
ILI Casings*	$3,545,000	$3,545,000	$3,545,000	$10,635,000
Total Operating Expense	$31,522,000	$31,554,000	$56,554,000	$119,630,000
Total Capital & Operating Expense	**$105,783,015**	**$142,104,016**	**$170,190,017**	**$418,071,000**

*Did not escalate request in 2016 & 2017

Q. WHAT ARE PG&E'S SAFETY OBJECTIVES FOR THE ILI PROGRAMS?

A. PG&E witness Barnes testifies that ILI capability will allow the Company "to learn about the condition of its pipelines and to predict the integrity of those pipelines into the future to address time dependent as well as other threats to pipeline integrity."[204]

Q. IS BETTER KNOWLEDGE OF CURRENT AND FUTURE PIPELINE ASSET CONDITION AN IMPORTANT COMPONENT OF RISK MANAGEMENT?

A. Yes. As discussed in the Joint Testimony, determining so-called condition-based hazard functions is integral to determining an optimal risk management strategy.

[204] *Id.* at 4A-5 lines 7-10.

Q. DOES PG&E EXPLAIN WHY THE COMPANY NEEDS TO GREATLY INCREASE THE MILES OF PIPE INSPECTED EACH YEAR?

A. Yes. As PG&E witness Barnes testifies:

> [w]e realized that proceeding at the historical rates, even at the most aggressive historical pace of 100 miles per year, it would take more than 26 years for PG&E to meet the goal of inspecting all of our pipeline system that is feasible with ILI. This pace is too slow, given the significant risk reduction benefits resulting from ILI.[205]

Q. DID PG&E PROVIDE ANY ACTUAL NUMERICAL ESTIMATES OF THE MAGNITUDE OF THE RISK REDUCTION THAT WOULD RESULT FROM THE INCREASED PACE OF ILI?

A. No. As PG&E states in its data response, "PG&E forecasted risk reductions that represent an appropriate balance of providing the greatest level of risk reduction in the shortest amount of time that can be accommodated based on resource and execution constraints."[206] However, in part (b) of that same response, PG&E states that it "does not numerically quantify risk reduction on a system level."[207] There are no estimates in PG&E's workpapers or in its AMPs for ILI.

Q. WHAT INSPECTION PACE DID PG&E CHOOSE?

A. PG&E chose an inspection pace of 10 years to complete all ILI work, after considering an 8-year pace and a 12-year pace. The Company rejected the 8-year pace,

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[205] *Id.* at 4A-16, lines 19-23.

[206] GTS-RateCase2015_DR_IS_007-Q002(a), attached as Exhibit JAL-5.

[207] GTS-RateCase2015_DR_IS_007-Q002(b), attached as Exhibit JAL-5.

"because it was infeasible from a resource and system hydraulic standpoint."[208] As for the 12-year option, PG&E witness Barnes testifies that:

> We rejected the 12-year plan even though the direct impact to the Total Occupancy Count (TOC) was minimal. Although the cost of traditional ILI Upgrades under a 12-year plan is lower by approximately $84 million over the rate case period, the risk reduction benefit of the increase in make piggable under the 10-year plan was more important than the cost impact.[209]

Oddly, despite saying that, "RMP-01 is using a relative risk methodology and as such cannot be used to quantify risk reduction,"[210] PG&E witness Barnes testifies that PG&E somehow determined that "the risk reduction benefit of the increase in make piggable under the 10-year plan was more important than the cost impact."[211] Such a conclusion is impossible, given PG&E's statements that it never calculated the risk reductions for any programs, as the Company admitted in response to IS-7-002. The only conclusion that can be drawn from this testimony is that PG&E's assessment of the risk reduction benefit of the 10-year plan is merely PG&E's opinion.

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[208] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-17, lines 26-27.

[209] *Id.* at 4A-18, lines 1-6.

[210] GTS-RateCase2015_DR_IS_007-Q002(e), attached as Exhibit JAL-5.

[211] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-17 lines 4-6.

Q. DOES THE COMMISSION SAFETY AND ENFORCEMENT DIVISION STAFF PRELIMARY REPORT (SED REPORT) DISCUSS PG&E'S CHOICE OF A 10-YEAR PROGRAM?

A. Yes. The SED Report[212] states:

> In considering alternatives to decisions made on pace and scope, PG&E rejects alternatives with a rather cursory explanation. … PG&E does not, however, quantify or discuss the "risk reduction benefit" versus cost under the 10-year plan as compared to either the 8-year plan or 12-year plan. Although PG&E states that the delay between the 10-year and 12-year plans would delay its ability to collect more data about the system, it does not discuss how it plans to use this data or justify why the same delay in data collection between the 8-year and 10-year plan is tolerable. <u>PG&E should provide more detailed analysis of the basis for the risk control measures that were selected and how the resources required for those risk control measures were estimated</u>.[213]

Q. CAN YOU SUMMARIZE THE ISSUES WITH PG&E'S ILI PROGRAM REVENUE REQUEST?

A. Yes. In addition to the "cursory explanation" by PG&E as to why a 10-year program is the best alternative, PG&E's proposal also demonstrates:

- Lack of evidentiary support for PG&E's decision to increase forecast expenses over those in the May 2013 Willbros Engineering Study report;
- Lack of specific information to forecast non-traditional ILI inspection costs; and
- Lack of specific information to support spending for Direct Examination and Repair (DE&R).

[212] SED Report, p. 13.

[213] *Id.* at 13-14 (emphasis added).

1. PG&E'S Adjustment to the Willbros Engineering Cost Estimates Are Not Justified

Q. HOW DID PG&E DETERMINE THE SCOPE OF WORK NECESSSARY TO ACCOMMODATE ILI TOOLS?

A. PG&E witness Barnes states that the Company relied on the Willbros Piggability Study (Willbros Study), which the Company commissioned to determine upgrades that PG&E's gas transmission system required to accommodate ILI.[214] As he testified:

> Cost estimates for the proposed ILI work were derived from an extensive, detailed study conducted by a leading gas pipeline engineering firm. The study utilized PG&E's newly completed pipeline features list database in addition to historical cost data from actual projects.[215]

Q. WHAT INFORMATION DOES THE WILLBROS STUDY CONTAIN?

A. The Willbros Study identifies specific segment locations that PG&E could upgrade to accommodate ILI tools and forecasts costs based on that work.

Q. HOW DID THE WILLBROS STUDY DETERMINE WHETHER A LINE COULD ACCOMMODATE TRADITIONAL ILI OR NON-TRADITIONAL ILI?

A. Willbros used "PG&E operating maps and diagrams"[216] as well as PG&E's "Pipeline Features List"[217] to determine line improvements for ILI accommodations. Based on these data, Willbros broke down what lines could already support ILI and what additional features certain lines would need to allow for ILI tools to pass through.[218]

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[214] A copy of the entire Willbros Study can be found in PG&E's workpapers, WP 4A-150 to WP 4A-443.

[215] PG&E Direct Testimony, Vol. 1, Ch. 4A, pp. 4A-15, line 28 to 4A-16, line 1.

[216] PG&E Workpapers, WP 4A-154.

[217] *Id.* at WP 4A-156.

[218] *Id.* at WP 4A-154 to 157.

Q. DID PG&E ACCEPT THE WILLBROS CONCLUSIONS WITHOUT CHANGE?

A. No. PG&E adjusted the Willbros Study results, relying on an internal analysis and report that was issued three months after PG&E received the Willbros Study. The PG&E report is titled "GT&S ILI Project Cost Evaluation" (PG&E ILI Report).[219]

Q. CAN YOU SUMMARIZE HOW THE COSTS IN THE PG&E ILI REPORT DIFFER FROM THOSE IN THE WILBROS STUDY?

A. Yes. The PG&E ILI Report increased the cost of 39 projects, decreased the cost of 15 projects, and did not change the costs of 29 projects. As a result, total ILI costs increased by $23,978,150.[220] Of that total, just over $2.1 million were increases in costs for nontraditional ILI projects.

Q. WHY DID PG&E INCREASE THE WILLBROS STUDY COSTS?

A. The PG&E ILI Report discusses individual project reviews, excluding projects that were already completed, and so forth. Moreover, the report states:

> [f]or those proposed ILI retrofit projects rated as "High" in regards to construction difficulty or impact, a more detailed review was performed to consider the potential impacts specific to that project due to geography, jurisdictions, congestion, traffic control, ingress and egress, and general constructability.[221]

Although the PG&E ILI Report refers to historic data and experience, no specific data was provided. As such, the basis for the specific adjustments to project costs is not clear.

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[219] *Id.* at WP 4A-444 to WP 4A-454.

[220] *Id.* at WP 4A-451.

[221] *Id.* at WP 4A-448.

a) Recommended Commission Action: Traditional ILI Costs

Q. IN LIGHT OF PG&E'S ADJUSTMENTS TO THE WILLBORO STUDY COSTS, HOW DO YOU RECOMMEND THE COMMISSION ADDRESS PG&E'S FORECAST OF TRADITIONAL ILI COSTS?

A. The Commission should disallow the forecast increase added by PG&E onto the Willbros Study estimates until such time that PG&E provides sufficient detail to justify the cost increases. Any additional costs can be placed in a memorandum account, with PG&E allowed to recover those costs at a later time, subject to reasonableness review.

2. Non-Traditional ILI Cost Forecast is Inadequately Supported

Q. PLEASE DESCRIBE PG&E'S PROPOSAL FOR NON-TRADITIONAL ILI.

A. Non-traditional ILI will occur on lines too short or operating at a low pressure that will not allow traditional ILI tools to pass through.[222] PG&E explains non-traditional ILI work on its system as necessary "to assess the potential presence of historical corrosion in the carrier pipe. Any anomalies found through this process will be excavated, repaired and replaced through a Non-Traditional ILI DE&R program."[223]

Q. DOES PG&E HAVE ALL THE RESOURCES NECESSARY TO COMPLETE THIS WORK?

A. No. PG&E admits non-traditional ILI technology is not yet commercially available:

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[222] *Id.* at WP 4A-154.

[223] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-15 lines 11-14.

> [i]n the case of several planned Non-Traditional ILI projects, some technologies are not yet commercialized and will need to be fully designed and tested in years to come. To that end, PG&E will continue its active involvement in several industry R&D groups including Pipeline Research Council International (PRCI), NYSEARCH, and Gas Technology Institute (GTI) to help develop these technologies (as described in Chapter 12).[224]

Q. ARE PG&E'S NON-TRADITIONAL ILI REQUESTS REASONABLE?

A. No. PG&E's revenue request fails to meet the just and reasonable standard. Without more certain information about when the necessary technologies will be commercially available and how much it will cost once it is available, it is unreasonable to preauthorize specific dollar amounts. This is true even if non-traditional ILI will provide great safety enhancements.

Q. HOW DID PG&E FORECAST COSTS FOR NON-TRADITIONAL ILI INSPECTIONS?

A. It is not clear. PG&E's testimony makes no distinction whether PG&E used traditional or non-traditional ILI historic work to forecast costs.[225] Furthermore, it does not seem PG&E has any historical data on non-traditional ILI costs, but only on traditional ILI and traditional DE&R costs. For example, PG&E explains that it is "among the few companies in the industry developing and using non-traditional ILI tools" and that it "expects to upgrade the pipeline system to accommodate the use of nontraditional tools in 2015."[226] Such statements imply that non-traditional ILI work has not occurred in the past, or if it has occurred then historical work seems to be very

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[224] *Id.* at 4A-18 lines 23-29 (emphasis added).

[225] *Id.* at 4A-19 l. 31 (In-Line Inspection), 4A-24 l. 8 (DE&R).

[226] *Id.* at 4A-13 lines 21-22, 25-26.

limited. Without this technology being commercially available and without PG&E using it in the past, PG&E cannot provide an accurate forecast of non-traditional ILI costs.

Q. DO YOU HAVE SPECIFIC EXAMPLES OF NOT BEING ABLE TO VERIFY COST ESTIMATES?

A. Yes. For example, the workpapers have several non-traditional ILI "cost" columns with numbers inserted but a lack of explanation how it derived these numbers.[227] Note (1) at the bottom of WP 4A-492 states there was an "initial base project cost estimation" from Willbros Engineers,[228] but the Willbros Study does not provide any cost estimates for non-traditional ILI. The Willbros Study contains detail for "non-traditional ILI section listing" in Appendix B, yet nowhere in Appendix B is there any cost estimation.[229] Instead, the Willbros Study provides cost estimates in Appendices D, E, F, and G.[230] Yet, the actual cost explanation in the Willbros Study explicitly states that Appendices D, E, F, and G only reflect costs for traditional ILI.[231]

Also troubling are the columns on the right side of WP 4A-492 labeled the "Cost Adjustments to be Applied to Standard Job Cost Based on Site Evaluation."[232] Notes at the bottom specify that these adjustments came from the "ILI Project Cost Evaluation Report," the "Cost Evaluation Tracking Tool," and that "costs were further refined after review of project specific conditions by engineering, environmental, land access,

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[227] PG&E Workpapers, WP 4A-492.

[228] *Id.* at WP 4A-492.

[229] *Id.* at WP 4A-170 to WP 4A-185.

[230] *Id.* at WP 4A-335 to WP 4A-432.

[231] *Id.* at WP 4A-161.

[232] *Id.* at WP 4A-492.

customer impact and construction."[233] The only one of these I could locate in the workpapers is the "ILI Project Cost Evaluation Report," or PG&E ILI Report mentioned above, which contains no numerical, quantified explanation of adjusting the costs in the manner WP 4A-492 adjusts the costs.[234]

Furthermore, the costs shown on WP 4A-493 to install elbows, launchers and receivers, tees, and valves in different sizes of pipe have no backup formulas and were clearly "pasted" into the spreadsheet. Moreover, the relationships between costs and pipe size are, in some cases, counterintuitive. For example, the estimated engineering costs associated with installing launchers/receivers increases as pipe size increases from 6 inches to 42 inches, but then decreases by 10% for 44-inch pipe. For pressure control fittings, PG&E provides no cost breakdown at all. Instead, WP 4A-493 simply shows a cost of $175,000 for pipe sizes less than 12 inches, and $225,000 for larger pipe.

Q. IS THERE ANY ATTEMPT IN THE WORKPAPERS TO JUSTIFY THESE COSTS?

A. No. PG&E seems to believe its "Cost Calculator" for Non-Traditional ILI work, which gives "Cost Tables for Specific Facilities," is enough to justify the forecast, but again there is no explanation where these numbers come from.[235] I assume the numbers come from the Willbros Study but again the Willbros Study only gives cost estimates for traditional ILI. There is no reason why PG&E could not have provided citations or an

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[233] PG&E Workpapers, WP 4A-492.

[234] *See* "GT&S ILI Project Cost Evaluation," PG&E Workpapers, WP 4A-444 to WP 4A-454.

[235] PG&E Workpapers, WP 4A-493.

explanation where the numbers came from instead of forcing evaluators to complete an extremely complex puzzle from a myriad of numbers spanning across hundreds of pages.

3. Recommended Commission Action: Non-Traditional ILI

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS PG&E'S FORECAST OF NON-TRADITIONAL ILI COSTS?

A. Given the uncertainty regarding the commercial availability of non-traditional ILI technology and its benefits, the Commission should not preauthorize any of PG&E's proposed non-traditional ILI capital and expense expenditures. Instead, non-traditional ILI costs should be placed in a memorandum account, with PG&E allowed to recover those costs at a later time, subject to reasonableness review.

4. Lack of Support for Direct Examination and Repair Digs (DE&R) Forecast Costs

Q. WHAT IS THE PURPOSE OF THE DE&R PROGRAM?

A. After PG&E has completed the first two ILI phases, which are to (1) upgrade old lines to accommodate ILI tools[236] and (2) run the ILI inspections,[237] the final third phase is (3) to conduct DE&R.[238] DE&R consists of "remediation efforts,"[239] such as "anomaly excavations, repairs, and replacement."[240]

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[236] PG&E Testimony Vol. 1, Ch. 4A, p. 4A-6 lines 18-26.

[237] *Id.* at 4A-6 to 4A-8 lines 27-5.

[238] *Id.* at 4A-8 lines 6-17.

[239] *Id.* at 4A-8 l. 8.

[240] *Id.* at 4A-8 lines 6-10, 4A-14 lines 2-3.

Q. WHAT IS YOUR CONCERN REGARDING PG&E'S DE&R REQUESTS?

A. The costs PG&E assigns to DE&R are uncertain and speculative, and thus fail to meet the just and reasonable standard. PG&E explains forecasting these costs as follows: "Since DE&R work is determined based on data collected through ILI, PG&E's forecast is based on historical data of ILI excavation, repair and replacement projects."[241]

Q. ARE YOU SAYING THAT DE&R IS NOT IMPORTANT FOR PG&E TO CONDUCT?

A. No, I recognize and agree with the importance of DE&R. However, the costs PG&E provides for DE&R are too speculative to give an accurate forecast.

Q. CAN YOU DESCRIBE YOUR COST FORECAST CONCERNS IN DETAIL FOR PG&E'S DE&R PROGRAM?

A. PG&E's DE&R program is based on speculative cost forecasting because future work may differ from historical work. PG&E does not have a way to accurately determine how much DE&R is required without first running ILI inspections. For example, PG&E claims that DE&R "Digs <u>will be selected</u> by the ILI Engineer to expose pipeline anomalies identified by the ILI tool which could pose an integrity threat. Where necessary, repairs will be performed. Digs will also be selected to validate the accuracy of the ILI data."[242] Furthermore, in a data response, PG&E stated "<u>it does not yet know where it may have to dig</u> within the segment of pipe that is being inspected by In-Line

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[241] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-23 lines 1-3.

[242] PG&E Workpapers, WP 4A-70.

Inspection (ILI) tools. Therefore, a method was developed to estimate the cost of Direct Examination and Repair Digs before having data from ILI to scope specific projects."[243]

Q. HOW DOES THIS RESULT AS AN INACCURATE COST FORECAST FOR DE&R?

A. I understand that PG&E must conduct ILI to know what DE&R work is necessary. I do not understand, however, how PG&E was able to assign specific dollar amounts to DE&R projects when PG&E has yet to conduct many of the forecast ILI inspection runs. These ILI inspection runs are necessary to accurately determine the needed DE&R work.

Q. IS THIS THE ONLY EVIDENCE OF SPECULATIVE COST FORECASTING?

A. No. It is also evident in PG&E's workpapers that provide PG&E's cost forecast for DE&R work in 2015, 2016, and 2017.[244] Each page contains a chart with the "Project Detail" and "Cost Detail" for each year. In the "Project Detail" section on the left side is a row saying "Average Number of Digs Per Mile" and in the "Cost Detail" section is a row saying "Number of Digs Expected," which is based, in part on a "Reinspection Multiplier" value. This multiplier is based on the following assumption by PG&E: "ILI Re-Inspections on average will yield 30% less [sic] digs compared to first time ILI. This is because the overall condition of a pipeline is typically better after performing ILI for the first time. However, validation digs are still required to confirm the accuracy of the

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[243] GTS-RateCase2015_DR_TURN_006-Q002, attached as Exhibit JAL-28.

[244] PG&E Workpapers, WP 4A-70 to WP 4A-77.

ILI run."[245] PG&E provides no evidence of the basis for this assumption on the lower percentage of digs.

Q. HAS PG&E'S ANNUAL WORK EFFORT FOR DE&R VARIED SIGNIFICANTLY OVER TIME?

A. Yes. As shown in workpapers, the annual "Total Number of Dig Sites" per line varying between 3 and 38.[246] Moreover, there is little or no correlation between dig sites and mileage, which vary between 0.05 digs per mile to 1.59 digs per mile.[247]

Q. WHAT DOES PG&E REQUIRE TO ACCURATELY FORECAST DE&R WORK WHEN THE HISTORICAL AVERAGES ARE NOT SUFFICIENT?

A. In testimony PG&E explains that it must first collect data from ILI before it can determine what needs to be done for DE&R.[248]

Q. DO THE WORKPAPERS PROVIDE SUFFICIENT DATA FOR PG&E TO ACCURATELY FORECAST FUTURE DE&R WORK?

A. No. In the "Project Detail" section on the left side is a row saying "First Time or ILI Re-Inspection." Many of the columns describing work forecast on each line list "First," signifying the first time PG&E will conduct ILI on the line.[249] If PG&E has not run ILI on the lines described in the workpapers, then PG&E cannot give an accurate forecast of digs or other work required.

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[245] *Id.* at WP 4A-72 n.6.

[246] *Id.* at WP 4A-77.

[247] *Id.* at WP 4A-77.

[248] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-23 l. 1.

[249] GTS-RateCase2015_DR_IS_011-Q03(a), attached as Exhibit JAL-29.

Q. WHAT ABOUT PG&E'S COST FORECAST FOR DE&R?

A. Without an accurate work forecast, PG&E cannot provide an accurate cost forecast.

Q. ARE YOU SAYING THAT PG&E'S DE&R WORK AND COSTS ARE SPECULATIVE?

A. Yes. The wide variation of historic work effort, coupled with the need to perform ILI before determining whether DE&R work is required, leads me to conclude that PG&E's forecast DE&R costs fail to meet the just and reasonable standard.

a) Recommended Commission Action: DE&R

Q. WHAT SOLUTION DO YOU PROPOSE TO ADDRESS SPECULATION IN DE&R COSTS?

A. Since PG&E cannot give a cost forecast with any degree of certainty, the Commission should not preauthorize these costs and, instead, defer the costs through a memorandum account mechanism and subject to a later reasonableness review.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE OVERALL ILI PROGRAM?

A. I recommend that the Commission allow PG&E to record operating expenses and capital costs in separate memorandum accounts to be recovered following a reasonableness review by the Commission. PG&E should amortize any authorized expenses over a 10-year period.

I. Facilities

Q. WHAT IS PG&E'S STATED PURPOSE FOR THE PROPOSED EXPENSES AND CAPITAL SOUGHT FOR COMPRESSION AND PROCESSING (C&P) AND MEASUREMENT AND CONTROL (M&C)?

A. The proposed expense and capital budgets for C&P and M&C, together referred to as "Facilities," encompass routine spending and other specific programs aimed to improve the safety of C&P and M&C stations. The programs include, among others, the Engineering Critical Assessments (ECA), including validation of Maximum Allowable Operating Pressure (MAOP) for station piping, the Critical Documents Project, and the Data Acquisition and Metric Development Project.

Q. WHAT EXPENSES HAS PG&E FORECAST TO SUPPORT THESE PROGRAMS IN 2015?

A. PG&E forecasts total expenses of $65.7 million in 2015, as shown in Table 6-1 of PG&E witness White's testimony and reproduced below as Figure 10.

Figure 10: PG&E Forecast Facilities Expenses

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2011 Recorded	2012 Recorded	2013 Forecast	2014 Forecast	2015 Forecast
1	Engineering Critical Assessment (ECA) Phase 1	–	–	$10,000	$25,200	$15,633
2	Engineering Critical Assessment (ECA) Phase 2	–	–	–	–	8,682
3	Hydrostatic Testing Station Facilities C&P	$4,220	(24)	–	–	455
4	Hydrostatic Testing Station Facilities M&C	–	–	–	–	5,471
5	Critical Documents	1,967	1,853	–	13,400	11,573
6	Data Acquisition and Metric Development M&C	87	775	–	–	1,583
7	Physical Security	–	–	–	–	1,055
8	Becker Upgrade	–	983	–	4,600	–
9	Gas Quality Practices Assessment M&C	1,354	1,393	–	490	2,110
10	Gill Ranch Operating and Maintenance Costs	1,389	1,431	2,500	1,835	2,306
11	Routine Spend C&P	8,161	7,161	7,600	8,916	8,440
12	Routine Spend M&C	2,395	3,027	8,226	8,649	8,390
13	Total Facilities Expense	$19,573	$16,599	$28,326	$63,090	$65,698

As can be seen, of the $65.7 million, "routine" spending for C&P and M&C facilities accounts for $16.8 million (lines 11 plus 12), critical documents account for $11.6 million, and Engineering and Critical Assessment, Phase 1 and Phase 2, account for $24.3 million (lines 1 plus 2).

1. ECA Expenses

Q. HOW DOES PG&E ESTIMATE ECA COSTS?

A. PG&E's estimation approach is set out in the ECA & Hydrotesting White Paper included with Company workpapers.[250] PG&E's cost estimates for ECA Phase 1 begin with an assumed cost to evaluate a district regulator of $5,000, which PG&E states is based on "extrapolated data from Pipeline MAOP."[251] PG&E then determines relative "complexity" to evaluate different types of equipment. For example, PG&E determines that evaluation of a "Category B" station is six times more complex than a distribution regulator (DREG), and thus estimates an evaluation cost of $30,000 (6 x $5,000). To this, PG&E adds a 20% overhead cost for all work. These NDT costs are shown in the top half of Table 11.

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[250] PG&E Workpapers, WP-6-198 to WP 6-204 "ECA & Hydrotesting White Paper".

[251] *Id.* at WP 6-199.

Table 11: ECA Phase 1 Costs

Station Type	Number	Cost/Unit	Subtotal	Overhead	Total
Revew and Assessment					
Category B	388	$30,000	$11,640,000	$2,328,000	$13,968,000
Category A	111	$120,000	$13,320,000	$2,664,000	$15,984,000
Terminal	3	$360,000	$1,080,000	$216,000	$1,296,000
Unman. Compresso	7	$540,000	$3,780,000	$756,000	$4,536,000
Manned Compr.	2	$864,000	$1,728,000	$345,600	$2,073,600
Storage	5	$1,296,000	$6,480,000	$1,296,000	$7,776,000
Total Reveiew and Assessment			**$38,028,000**	**$7,605,600**	**$45,633,600**
Station Type	**Number**	**Likelihood**	**Cost/Unit**	**ExpectedCost**	**Total**
NDT Testing					
Category B	388	6%	$100,000	$6,000	$2,328,000
Category A	111	24%	$146,000	$35,040	$3,889,440
Terminal	3	72%	$232,000	$167,040	$501,120
Unman. Compresso	7	108%	$257,000	$277,560	$1,942,920
Manned Compr.	2	173%	$257,000	$444,610	$889,220
Storage	5	259%	$187,000	$484,330	$2,421,650
Total NDT Testing					**$11,972,350**

Q. DOES PG&E PROVIDE ANY DEFINITION OF "COMPLEXITY"?

A. No.

Q. DOES PG&E PROVIDE ANY BASIS FOR THE $5,000 EVALUATION COST OF A "DREG" USED AS BASIS FOR THE EVALUATION COSTS OF ALL OF THE ECA STATIONS?

A. No.

Q. DOES PG&E EXPLAIN WHY THERE IS A LINEAR RELATIONSHIP BETWEEN COMPLEXITY AND EVALUATION COST?

A. No. Moreover, such a relationship seems to ignore certain fixed costs associated with an evaluation. For example, one would expect the cost of driving a crew to evaluate a station to depend only on the distance driven, not the "complexity" of the evaluation.

Q. HOW DOES PG&E ESTIMATE THE COSTS OF NON-DESTRUCTIVE TESTING (NDT) OF THE DIFFERENT TYPES OF STATIONS?

A. First, PG&E determines how many such tests the Company expects to perform. The Company states that about 1% of distribution regulators have required such examinations. Second, PG&E assumes that the number of stations requiring examination will be based on their relative "complexity" to the DREG. For example, because an unmanned compressor station is assumed by PG&E to be 108 times more complex than a DREG, PG&E uses that each unmanned station will require 1.08 inspections (=108 x 1%).

Q. DOES PG&E PROVIDE ANY BASIS FOR THE LINEAR RELATIONSHIP BETWEEN COMPLEXITY AND EXAMINATIONS PER STATION?

A. No.

Q. DOES PG&E PROVIDE ANY BASIS FOR THE LINEAR RELATIONSHIP BETWEEN COMPLEXITY AND EXAMINATIONS PER STATION?

A. No.

Q. DOES PG&E DISCUSS HOW THE COMPANY ESTIMATED "COST PER ISSUE ASSOCIATED WITH NDT TESTING"?

A. Yes. PG&E assumes that the cost of resolving an issue will equal 10% of the cost of the station. PG&E admits this cost estimate is simply a guess. As stated in the ECA & Hydrotesting White Paper, "Since the industry has little experience with applying NDT methods to stations, this cost basis comes with a level of uncertainty. However, a 10%

threshold appears to be reasonable considering the scope of work involved."[252] These NDT costs are shown in the bottom half of Table 10.

Finally, PG&E adds $260,000 for a "Procedure for Resolving Unknown Station Features (PRUSF). This tool is a database of minimum assumptions for components, based on their age, manufacturer, and/or purpose (piping, regulation, etc.)."[253]

Q. ARE THE COSTS SHOWN IN TABLE 9 DISTRIBUTED ACROSS THE THREE YEARS?

A. Yes. It appears PG&E intends to test the same number of stations in 2015 and 2016, and about half as many is 2017, based on the annual cost estimates shown in Table 4 of the ECA & Hydrotesting White Paper.

Q. WHY DO THE NDT COSTS SHOWN IN TABLE 9 ABOVE NOT MATCH THOSE SHOWN IN TABLE 3 AND TABLE 4 OF THE ECA & HYDROTESTING WHITEPAPER?

A. First, the costs in Table 3 for the NDT cost estimates are rounded, and not exact multiples based on "complexity." Second, the costs shown in the rightmost column of Table 3 of the White Paper[254]are all reduced by 10% from the calculated values shown in the rightmost column of Table 9 above. PG&E provides no explanation in the ECA & Hydrotesting White Paper for this adjustment.

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[252] *.Id.* at WP 6-201.

[253] *Id.*

[254] *Id.*

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a) Recommended Commission Action: ECA Phase 1

Q. WHAT DO YOU CONCLUDE ABOUT PG&E'S FORECAST ECA PHASE 1 COSTS?

A. I conclude PG&E's forecast ECA Phase 1 costs are vague and unsupported. PG&E admits NDT costs are uncertain because of lack of industry experience. PG&E fails to provide any explanation for some costs, such as the evaluation costs for each DREG, on which all of the Company's cost estimates are based. Neither does PG&E provide any definition of "complexity" nor explain how it determined complexity "multiples" for the different types of stations. Therefore, none of these costs should be approved. Instead, they can be placed in memorandum accounts subject to later approval.

Q. CAN YOU DISCUSS PG&E'S ESTIMATED ECA PHASE 2 COSTS?

A. Yes. PG&E's estimated ECA Phase 2 costs simply build upon the uncertainties of the ECA Phase 1 cost estimate. As the ECA & Hydrotesting White Paper states:

> It is assumed that the number of situations requiring ECA Phase 2 action will be commensurate with the expected number of ECA Phase 1 NDTs that will be conducted. This conservative assumption relies on the assertion that each NDT will positively confirm that additional mitigation is required. Therefore, the expected frequency of ECA Phase 2 actions can be modeled upon the basis of NDT.
>
> The cost per occurrence is not based on historical data, but must be estimated since the industry has minimal experience with these types of procedures as well. ECA Phase 2-type mitigation costs are estimated to be half the cost for HST of a specific site application.[255]

[255] *Id.* at WP 6-202.

PG&E thus admits the ECA Phase 2 costs it has included are completely conceptual and have not basis in actual costs incurred.

Q. WHAT DO YOU CONCLUDE ABOUT PG&E'S FORECAST ECA PHASE 2 COSTS?

A. I conclude that these costs are unsupported and that the scope of PG&E's program is not well-defined. Therefore, the proposed costs do not meet the known and measurable standard and should be disallowed.

2. Critical Documents Expenses

Q. WHAT DOES PG&E INCLUDE WITHIN THE CRITICAL DOCUMENTS CATEGORY OF EXPENSES?

A. PG&E explains the documentation accounted for in this expense category as follows:

> Many types of documents and drawings are routinely, but not consistently, prepared for gas transmission facilities for construction or modification, and to communicate requirements for operation and maintenance. In 2012, PG&E developed and implemented a Utility Standard TD-4551S, "Station Critical Documentation" that identifies and establishes requirements for facility drawings that are necessary to promote safe O&M of station facilities based on the complexity of the operations at the station. The standard describes what minimum critical documentation must be created and maintained current to promote safe operation of a facility, and when various types of documentation are required.[256]

[256] PG&E Direct Testimony, Vol. 1, Ch. 6, pp. 6-31, line 22 to 6-32, line 6.

Q. WHAT EXPENSES DOES PG&E FORECAST FOR THIS PROGRAM?

A. The total Test Year 2015 expense forecast is $11.5 million, with $6.4 million for Compression and Processing stations and $5.2 million for Measurement and Control stations.

Q. DO YOU HAVE CONCERNS ABOUT THE CRITICAL DOCUMENTS COST?

A. Yes: If these documents are truly "critical," why did PG&E not previously maintain accurate documentation? PG&E admits that "[a]ccurate documentation is critical for the safe operation of station facilities."[257] Yet, as noted above, PG&E developed and implemented the standard in 2012. Maintaining accurate documentation particularly if it is "critical for the safe operation" of PG&E's system is, in my opinion, a basic management function.

The Commission addressed similar problems in D.12-11-030:

> Over the years, PG&E has sought and obtained ratepayer funding for its record-keeping functions. <u>PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies</u>. Having created the need for this remedial work by its imprudent historic document management practices , PG&E has not shown by a preponderance of the evidence that the costs of the current document search and organization projects can be included in revenue requirement and that the resulting rates will be just and reasonable.[258]

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[257] PG&E Workpapers, WP 6-12.

[258] D.12-12-030, p. 87 (emphasis added).

Consequently, the Commission directed: "PG&E is required to continue its record management improvement project; however, due to past deficiencies in document management, the costs of this project and its computer data base may not be recovered from ratepayers."[259] The Commission's observations in D.12-12-030 apply in PG&E's Critical Documents program.

a) Recommended Commission Action: Critical Documents

Q. WHAT DO YOU CONCLUDE ABOUT PG&E'S FORECAST CRITICAL DOCUMENTS COST ESTIMATE?

A. Ratepayers should not be required to pay for PG&E's forecast Critical Documents program expenses. PG&E's actions indicate management imprudence: the Company should have been maintaining the "critical" information using the funding granted in previous rate cases. Asking ratepayers to pay for this program would mean that they would pay twice for the same costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TREATMENT OF PG&E'S FORECAST EXPENSES FOR CRITICAL DOCUMENTS?

A. The Commission should direct PG&E to implement its Critical Documents program, but should disallow recovery of the associated expenses from ratepayers.

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[259] *Id.* at 3.

3. Data Acquisition and Metric Development Expenses

Q. WHAT DOES PG&E MEAN BY "DATA ACQUISTION"?

A. PG&E witness White testifies that:

> Data acquisition refers to the gathering of information that will give insight into asset health and performance. The information that is collected will assist in the development of KPIs and other metrics that will be tracked and recorded on a regular frequency. Comparing the recorded trend of the KPIs and metrics to the desired state provides the basis for setting asset performance goals and targets.[260]

Q. HOW DID PG&E DEVELOP ITS FORECAST COST FOR THIS PROGRAM?

A. PG&E explains:

> The dollars forecasted in this program are based on scope for data procurement and database development to provide visibility into the Measurement and Control assets. Project costs for project management and oversight, engineering, design, procurement, construction and material costs were assumed proportional to the project size. The actual scope to be performed will be based on the results of an on-going assessment of KPIs and Operational Metrics.[261]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COSTS OF THIS PROGRAM?

A. Yes. I have two concerns. First, there is the potential for overlap between "gathering information" as part of this program and the "Critical Documents" program. Specifically, if PG&E is planning to develop a database as part of the Critical Documents program, it seems reasonable that such data will also be used to establish performance metrics. PG&E ratepayers should not be required to pay twice for the same data

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[260] PG&E Direct Testimony, Vol. 1, Ch. 6, p. 6-33, lines 6-11.

[261] PG&E Workpapers, WP 6-21.

gathering. Second, PG&E admits the actual costs will depend on factors not yet developed. The costs are conceptual, rather than known and measurable.

a) Recommended Commission Action: Data Acquisition and Metric Development

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TREATMENT OF PG&E'S FORECAST EXPENSES FOR DATA ACQUISITION?

A. I recommend the Commission disallow these costs to the extent PG&E cannot demonstrate they are not duplicative of critical information gathering costs. However, if the Commission concludes that ratepayers should pay these costs, then given the vagueness and potential for duplication of costs, I recommend the Company place any such costs into a memorandum account subject to later Commission review for prudence and accuracy.

4. Station Rebuild Capital Expenditures

Q. WHAT IS PG&E'S STATION REBUILD PROGRAM?

A. PG&E proposes to rebuild 22 "simple" M&C stations and six "complex" M&C stations "to address station equipment aging and obsolescence."[262] PG&E is also rebuilding the Burney and Los Medanos stations. PG&E testifies that the frequency of station rebuilds is based on the condition of the station and on maintaining an overall average age of approximately 30 years.[263]

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[262] PG&E Direct Testimony, Vol. 1, Ch. 6, p. 6-46, lines 21-22.

[263] *Id.* at 6-47, lines 3-4, p. 6-48, lines 5-6.

Q. WHAT ARE YOUR CONCERNS ABOUT THE REPLACEMENT COST ESTIMATES FOR THE BURNEY AND LOS MEDANOS COMPRESSOR STATIONS?

A. I have two concerns. First, as with my discussion of apparent cost duplication for critical documents expenses, there appears to be similar cost duplication for replacing these compressors. As shown on WP 6-131 and 6-133, on the bottom table on page WP 6-132 there is a separate line item for PG&E costs of about $3 million (based on costs derived from Table B on page WP 6-133) for various activities that also appear above the PG&E line item.

Second, the cost estimates for replacing both compressors appear generic. The unescalated estimated cost for Burney is $50,000,000, and the unescalated cost for replacing Los Medanos is $25,000,000. PG&E states:

> Preliminary Analysis study has been performed for five (5) compressor units; project scope is for a single unit; assume that replacement units will be gas turbines, erected on the same location as existing.[264]

Because PG&E admits its cost analysis is preliminary, the replacement costs do not meet the known and measurable standard.

Q. WHAT ARE YOUR CONCERNS ABOUT PG&E'S PROPOSED CAPITAL EXPENDITURES FOR STATION REBUILDS?

A. First, I am concerned about an apparent disconnect between information gathering discussed previously and PG&E's statements about rebuilding 22 "simple" M&C stations and six "complex" M&C stations. Does PG&E intend to collect critical information for stations which will then be rebuilt? If so, why?

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[264] PG&E Workpapers, WP 6-131.

Second, PG&E appears to have adopted a replacement strategy based on asset age, which as the Joint Testimony discusses is not an optimal policy because it fails to consider asset condition.

a) Recommended Commission Action: Station Rebuild

Q. HOW SHOULD THE COMMISSION ADDRESS PG&E'S PROPOSED STATION REBUILD CAPITAL EXPENDITURES?

A. I recommend that the costs associated with station rebuilds be placed into a memorandum account subject to later approval. For each station rebuild, PG&E should demonstrate that complete rebuilding was a least-cost risk management strategy.

Q. DO YOU HAVE OTHER QUESTIONS OR CONCERNS?

A. Yes. It is not entirely clear whether the M&C stations identified by PG&E include stations that are more appropriately treated as regulation stations, with more of a metering and distribution function. If so, they should be excluded from recovery through this application.

J. Earthquake Fault Crossings Program

Q. WHAT IS THE PURPOSE OF THIS PROGRAM?

A. The Earthquake Fault Crossings program is aimed to address "the specific threat of land movement strains at known earthquake faults damaging a pipeline due to seismic events."[265]

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[265] PG&E Direct Testimony, Vol. 1, Ch. 4A, p. 4A-43, lines 20-22.

Q. HOW LONG HAS THIS PROGRAM BEEN IN PLACE?

A. PG&E began its fault crossing program in 1985.[266] Acquisition of a data base in 2008 enabled PG&E to more accurately identify where its pipelines are aligned with faults.[267] The work PG&E has done and the forecast work it proposes in this proceeding is shown in Figure 11.

Figure 11: PG&E Forecast Fault Crossing Studies

TABLE 4A-13
PACIFIC GAS AND ELECTRIC COMPANY
APPROXIMATE NUMBER OF FAULT CROSSINGS TO BE STUDIED

Line No.	Population Grouping	Pre-2013	2013 to 2014	2015 to 2017	Post Rate Case	Totals
1	HCA	18	2	15	0	35
2	Class 3 or 4 (Non-HCA)	0	1	11	0	12
3	TOC > 0	3	1	5	0	9
4	Class 2	0	6	16	0	22
5	TOC = 0	8	6	51	29	94
6	Total	29	16	98	29	172

Q. WHAT COSTS HAS PG&E FORECAST TO SUPPORT THIS PROGRAM?

a. PG&E requests $4.4 million in expenses for 2015 to complete 44 fault crossing studies, in order of proximity to population, with another 54 to be completed in the attrition years for an unspecified expense. PG&E proposes capital expenditures for the GT&S period of $16.1 million for mitigation of three fault crossings per year of the GT&S period.

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[266] *Id.* at 4A-43, l. 24.

[267] *Id.* at 4A-45, lines 11-14.

Q. WHAT ARE YOUR CONCERNS WITH THIS PROGRAM?

A. First, the proposal seems to be yet another "catch up" attempt to rapidly bring its system up to date. Although PG&E states that it started the program almost 30 years ago, prior to 2013, the Company had studied only 29 of the 172 (16.8%) of the crossings requiring study. PG&E forecast the study of another 16 crossings in 2013-2014. It now forecasts studies of another 98 crossings (57%) from 2015-2017. Moreover, as shown in Table 4A-13, 51 of the 98 crossings are in areas where the Total Occupancy Count (TOC) is zero. PG&E has not demonstrated that there is any risk reduction value in playing catch-up so quickly.

Q. DO YOU HAVE OTHER CONCERNS?

A. Yes. PG&E's proposed capital expenditures, like many other cost forecasts in its Application, are conceptual and lack detail. Until PG&E conducts its fault crossing studies, it will have no idea how many fault crossings require attention and will require capital expenditures.

1. Recommended Commission Action: Earthquake Fault

Q. SHOULD THE COMMISSION PREAUTHORIZE PG&E'S REQUESTED EXPENDITURES?

A. No. The Commission should grant PG&E's expense request only if the Company can demonstrate a well-defined risk reduction value of accelerating its studies. Moreover, given the longer term nature of the information gathering PG&E is undertaking, any expenses the Commission allows PG&E to recover should be amortized over a ten year period. The Commission should defer recovery of the proposed capital expenditures until PG&E has sufficient information that will enable it to articulate capital requirements with greater precision.

K. Geo-Hazards Threat Identification and Mitigation Program

Q. WHAT IS PG&E'S STATED PURPOSE FOR THE GEOHAZARDS THREAT IDENTIFICATION PROGRAM?

A. The Geo-Hazard Threat Identification and Mitigation program involves risk assessment of identified geohazard sites and develops mitigation or monitoring strategies depending on the circumstances encountered at each site.[268]

Q. WHAT COSTS HAS PG&E FORECAST TO SUPPORT THIS PROGRAM?

A. PG&E forecasts expenses of $211,000 for 2015 and capital expenditures for mitigation totaling $24.6 million over the rate case period.[269]

Q. WHAT ARE YOUR CONCERNS WITH THIS PROGRAM?

A. Once again, PG&E's proposed capital expenditures are conceptual and lack detail. As PG&E acknowledges, it will have no way of knowing what mitigation expenditures will be required until it has performed its risk assessment of each site.

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[268] *Id.* at 4A-61, lines 3-10.

[269] *Id.* at Table 4A-17 and p. 4A-62, Table 4A-18.

1. Recommended Commission Action: Geohazards Threat Identification

Q. SHOULD THE COMMISSION PREAUTHORIZE PG&E'S PROPOSED EXPENDITURES?

A. Not all of them. The Commission should authorize recovery only of the forecast expenses for risk assessment. To the extent the forecast capital is aimed at mitigation efforts, however, it should defer recovery of these costs.

L. Class Location Program

Q. WHAT IS THE PURPOSE OF THE CLASS LOCATION PROGRAM?

A. PG&E asserts that this program is "a compliance requirement to ensure that pipelines are operating within the appropriate class as determined by population density"[270] consistent with PHMSA. The program supplements information gathered through "an annual class location study, routine pipeline patrols and other maintenance and inspection activities."[271] The program also includes "the use of high resolution aerial photography, a digitized structures layer of buildings and Well-Defined Outside Areas…. within a Geographical Information System."[272]

Q. WHAT COSTS HAS PG&E FORECAST TO SUPPORT THIS PROGRAM?

A. PG&E forecasts test year expenses of $7.269 million, and total rate case period capital expenditures of $61.453 million. [273] Although it is not entirely clear, it appears

[270] PG&E Direct Testimony, Vol. 1, Ch. 4B, p. 4B-5, lines 4-6.

[271] *Id.* at 4B-35 lines 13-15.

[272] *Id.* at 4B-6, lines 3-7.

[273] *Id.* at 4B-9 to 4B-10 at Table 4B-3 and 4B-4.

that the costs are all associated with mitigation efforts, which include strength testing and pipeline replacement.[274] PG&E suggests that the funding of the annual class location study is included in the forecast of Gas Transmission System Operations and Maintenance,[275] but then discusses the forecast methodology for these costs.[276]

Q. WHAT ARE YOUR CONCERNS WITH THIS PROGRAM?

A. First, PG&E has not demonstrated that these costs, which cover activities included in other funded programs, are not duplicative. Costs cover strength testing, and costs for those activities are also forecast in the Hydrostatic Testing Program. Costs also cover pipeline replacement, and costs for those activities are also forecast in the Vintage Pipeline Replacement Program. In fact, I would argue that there is no way to prove that the programs will not overlap, since PG&E cannot today forecast which line segments will require this mitigation. Absent this demonstration, the Commission cannot be certain that ratepayers will not pay twice for the same activities.

Second, the mitigation costs are speculative. PG&E simply states: "[t]he units are estimated based on the combination of the historical and current change-ups in class location." [277] Complicating matters further, PG&E's forecast capital expenditures bear little relationship to its recent expenditures.

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[274] *Id.*at 4B-9, line8 to 4B-10, line 9.

[275] *Id.* at 4B-9, lines 4-7.

[276] *Id.* at 4B-10, line 21 to 4B-11, line 4.

[277] *Id.* at 4B-9, lines 22-24.

1. Recommended Commission Action: Class Location

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CLASS LOCATION PROGRAM?

A. I recommend that none of these costs be preauthorized. Instead, all expenses and capital expenses should be recorded in memorandum accounts subject to later authorization. Such costs should be authorized only if PG&E can demonstrate they are not duplicative and are just and reasonable.

M. Summary of Proposed Cost Recovery Deferrals and Disallowances

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS REGARDING COST RECOVERY BY PG&E IN THIS CASE?

A. Yes. I first discuss two general recommendations, which permeate all expense or capital proposals in the Application. I then summarize the recommendations for each individual program. The effect of the proposals on PG&E's request are presented in Exhibits JAL-2 and JAL-3.

Q. WHAT GENERAL RECOMMENDATIONS HAVE YOU OFFERED THAT CUT ACROSS ALL PROPOSED PROGRAMS?

A. My testimony, along with the Joint Testimony, recommends that the Commission require PG&E to correct flaws in its risk management approach before approving any of the proposed costs. In addition, my testimony has two general recommendations. First, the Commission should amortize safety-related expenses over a 10-year period. Second, the Commission should reduce PG&E's ROE for safety-related capital investments during this rate case period to 9.4%, the lowest ROE in the range of reasonableness adopted by the Commission in the most recent cost of capital proceeding for a stand-alone gas utility. These two actions recognize a role for shareholders in mitigating rate shock; they also recognize that these expenses are a part of a long-term program and, in some cases, result from a historical deferral of work on PG&E's system.

Q. WOULD YOU PLEASE SUMMARIZE YOUR OTHER PROGRAM SPECIFIC RECOMMENDATIONS?

A. Yes.

- ***Corrosion Control***: (1) Prior to Commission approval of capital or expense costs, PG&E should be required to demonstrate that ratepayers have not paid for such costs before. If PG&E cannot so demonstrate, then its shareholders should bear those costs. (2) PG&E should be required to demonstrate that ratepayers are not paying for costs that are also included in other programs, such as direct assessment. If PG&E cannot demonstrate this, then its shareholders should bear those costs. (3) To the extent the Commission allows cost recovery for corrosion, PG&E's expensed costs and capital costs associated with corrosion control programs should be placed into corresponding memorandum accounts, subject to later reasonableness review. Any authorized expenses should be amortized over a ten-year period. (4) All capital expenditures that are ultimately allowed by the Commission should have an associated return on equity set to 9.4%. (5) The Commission should require PG&E to undergo an independent forensic audit to determine historic corrosion control expenditures. To the extent that this audit reveals improper accounting of costs, the Commission should determine a penalty to be paid by PG&E shareholders.

- ***Vintage Pipeline Replacement Program***: (1) Once PG&E's management has a sufficient level of certainty about VPR and begins to spend, it should be permitted to record costs in a memorandum account, subject to reasonableness review by the Commission. (2) PG&E's allowed return on VPR investment resulting from this proceeding should be reduced to 9.4%.
- ***Shallow Pipe Program***: (1) The Commission should only authorize recovery of the proposed engineering analysis portion of PG&E's forecast expense costs, which add up to approximately $5.3 million. (2) The Commission should allow PG&E to begin expense mitigation and capital replacement only as it acquires the necessary data. PG&E should be permitted to record the expense and capital costs in memorandum accounts for later recovery, subject to reasonableness review by the Commission.
- ***Hydrostatic Testing***: (1) The Commission should reduce PG&E's revenue request by $16.01 million to address the absence of strength-test records for pipe installed between 1956 and 1961. (2) The Commission should allow PG&E to record the remaining capital costs in a memorandum account and recover those costs at a later time, subject to reasonableness review by the Commission. (3) The Commission should not permit PG&E to "backfill" proposed hydrostatic test miles that the Company is not ultimately required to test with lower priority miles, merely to spend its proposed GT&S budget.
- ***Direct Assessment***: The Commission should allow PG&E to record actual DA costs in a memorandum account and recover them at a later time, subject to reasonableness review by the Commission. Once expenses have accrued, PG&E should be permitted to recover them over a 10-year period.

- ***Valve Automation***: The Commission should require PG&E to provide more definitive evidence that the benefits of valve automation exceed the costs, and provide estimates of how valve automation for pipelines that are not within HCAs or cross active earthquake fault lines will reduce risk. Following the provision of such evidence, we will be better equipped to make recommendations regarding the treatment of these capital expenditures and operating expenses.
- ***Work Required by Others***: The Commission should disallow all WRO costs.
- ***Traditional ILI Costs***: The Commission should disallow the forecast increase added by PG&E onto the Willbros Study estimates until PG&E provides sufficient detail to justify the cost increases. Any additional costs can be placed in a memorandum account, with PG&E allowed to recover those costs at a later time, subject to reasonableness review.
- ***Non-Traditional ILI Costs***: Non-traditional ILI costs should be placed in a memorandum account, with PG&E allowed to recover those costs at a later time, subject to reasonableness review.
- ***DE&R***: The Commission should defer DE&R costs through a memorandum account mechanism, subject to a later reasonableness review.
- ***ECA Phase 1***: The Commission should defer ECA Phase 1 costs through a memorandum account mechanism, subject to a later reasonableness review.
- ***ECA Phase 2***: The Commission should disallow all ECA Phase 2 costs, as they are completely unsupported, and the scope of the program is not well-defined. The proposed costs do not meet the just and reasonable standard.

- ***Critical Documents***: The Commission should direct PG&E to implement its Critical Documents program, but should disallow recovery of all associated expenses from ratepayers.
- ***Data Acquisition and Metric Development***: The Commission should disallow these costs to the extent PG&E cannot demonstrate they are not duplicative of critical information-gathering costs. If the Commission concludes that ratepayers should pay these costs, then PG&E should place those costs into a memorandum account subject to later Commission review for prudence and accuracy.
- ***Station Rebuild***: The Commission should not preapprove the costs associated with station rebuilds. Instead, these costs should be placed into a memorandum account subject to later approval after PG&E demonstrates that complete rebuilding was a least-cost risk management strategy.
- ***Earthquake Fault Crossing:*** Any Earthquake Fault Crossing expenses the Commission allows PG&E to recover should be amortized over a 10-year period. The Commission should defer recovery of the proposed capital expenditures until PG&E articulates its capital requirements with greater precision.
- ***Geohazards Threat Identification:*** The Commission should only authorize recovery of the forecast expenses for risk assessment. To the extent the forecast capital is aimed at mitigation efforts, it should defer recovery of these costs.
- ***Class Location:*** The Commission should not preauthorize any class location costs. Instead, these costs should be placed in a memorandum account and allowed only if PG&E can demonstrate they are not duplicative and are just and reasonable.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.