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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

COMMENTS OF THE INDICATED SHIPPERS ON PROPOSED DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT FOR 2015-2017 FOR GAS TRANSMISSION AND STORAGE SERVICES

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Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the Indicated Shippers[1] submit these Opening Comments on the Administrative Law Judges' Proposed Decision Authorizing Pacific Gas and Electric Company's (PG&E's) Revenue Requirement for 2015-2017 for Gas Transmission and Storage (GT&S) services (PD).

I. INTRODUCTION

Adoption of the PD will result in unprecedented and unconscionable rate shock, permitting PG&E to recover the unjustified costs of projects driven by a materially flawed risk management process. The PD attempts to soft-pedal the rate increase, characterizing it as a 32.1% increase over the 2014 authorized revenue requirement, but cannot mask the PD's true impact on ratepayers.

- ✓ The PD's revenue requirement far exceeds post-San Bruno levels that the Commission previously considered "extraordinary." The 2014 authorized revenue requirement to which the PD compares its results was *not* business as usual: it included not only the Gas Accord V Settlement, but

[1] Member companies include Aera Energy LLC, Chevron U.S.A. Inc., Phillips 66 Company, Tesoro Refining & Marketing Company LLC and Shell Oil Products US.

the Pipeline Safety Enhancement Plan (PSEP), which the Commission characterized as "extraordinary" investment needs in D.12-12-030.[2]

- ✓ The only material reductions in PG&E's forecast are disallowances resulting from PG&E's mismanagement that caused the San Bruno incident and resulted in its misconduct in this proceeding. Ignoring these conduct-related disallowances, the 2015 test year revenue requirement represents a 55% increase and by 2017 an increase of more than 80% over the "extraordinary" 2014 revenue requirement.[3]

- ✓ Even after conduct-related disallowances, ratepayers will experience increases ranging from 11.8% to 144.8%, escalating to a range of **12.8% to 242.1%** when 2015-16 revenue undercollections are amortized.[4]

The Commission lacks the specific findings necessary to conclude that rate increases of this magnitude are affordable to ratepayers and to make such a finding would constitute an abuse of discretion.[5]

The Commission has several means of further mitigating this extreme rate shock and avoiding legal error:

- Rejecting the PD's adoption of unjustified forecasts. These comments identify $180.731 million in additional reductions in 2015 expenses and $75.851 million in 2015 capital expenditures that are not consistent with well-established legal principles or supported by the record.

- Adopting two modifications in applying the $850 million San Bruno Penalty disallowance. Applying the full disallowance to 2015-17 expenses, rather than against capital expenditures, will reduce the impact of PG&E's increased spending in the short run. Proper sequencing in applying the San Bruno Penalty and the 5-month delay penalty will further reduce the impact.

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2 D.12-12-030, Finding of Fact 38 at 120.

3 The 2015 test year revenue requirement of $1,108.196 million represents a 55% increase over the 2014 authorized revenues of $715.380 million.

4 Rate tables provided by PG&E in response to the Indicated Shippers' May 11, 2016, discovery request demonstrate the final impact of the PD, including the five-month delay and the San Bruno Penalty disallowances and recovering the undercollection due to the remaining months of delay. *See* Motion of the Indicated Shippers, The Utility Reform Network, the California League of Food Processors and the California Manufacturers and Technology Association for Revised Rate Appendices and Extension of Time to File Comments on Proposed Decision and Alternate Proposed Decision, May 19, 2016, Exhibit A.

5 The Commission previously determined that a 50% increase in a Tier 3 electric residential rate – not even an average rate -- would produce "undue rate shock." D.11-05-047 at 80, Finding of Fact 18.

- Extending the amortization period for the 2015-16 undercollection to 48 months.

The magnitude of potential rate shock warrants the Commission's adoption of these and all other reasonable means of rate mitigation.

The PD also errs in concluding that "*PG&E's proposed risk management approach and asset family categories [are] reasonable*."[6] PG&E's entire investment plan is purportedly a direct outcome of this Program.[7] Despite the foundational importance of this issue, the PD ignores thousands of pages of record evidence demonstrating the fatal flaws in PG&E's approach and fails to support this determination with specific findings of fact or conclusions of law. This failure at the very heart of PG&E's application warrants a more rigorous review of its proposed revenue requirement and adoption of the further reductions proposed in these comments.

Attachment A summarizes additional reductions to expenses and capital expenditures and Attachment B presents proposed changes to the PD Findings of Fact and Conclusions of Law necessary to implement the changes proposed in these comments.

II. BURDEN OF PROOF

The PD adopts an overly narrow standard for disallowances that unreasonably limits shareholder responsibility for prior mismanagement. The PD relies on D.14-06-007 to conclude that "*a disallowance is warranted when the forecast work is necessary because: (1) PG&E had not originally performed the work properly, or (2) PG&E had failed to comply with regulatory requirements that it was previously funded to satisfy*."[8] This narrow, incomplete standard conflicts with prior Commission decisions and does not permit the Commission to disallow costs in response to mismanagement that takes the form of delaying necessary work. As a result, in lieu of PG&E being held accountable for its mismanagement, ratepayers are inequitably penalized for PG&E's

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6 PD at 26.

7 Ex. PG&E-1 at 2-11:5-8 (PG&E/Soto): "The risk management process is fully integrated into PG&E's Integrated Planning Process to ensure risk informs the chosen strategies, which in turn drives the allocation of resources."

8 PD at 21.

previous mismanagement, unfairly forced to compensate the utility to rectify its past mistakes and are further obligated to absorb the resulting rate shock.

The PD's narrow focus underplays the importance of other language in D.14-06-007 that is critical to the Commission's review in this GT&S. As the PD acknowledges, the Commission found in D.14-06-007 that "*costs are just and reasonable when they 'have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well informed and conscientious employees and contractors who are doing their jobs properly.'*"[9] A proposed cost that does not meet this standard is "*unjust or unreasonable [] [and] must not be recovered in rates from ratepayers*."[10] Thus, two tests must both be met for a cost to be deemed reasonable and recoverable in rates:

- The cost was "*incurred by competent management exercising the best practices of the era*"; and[11]
- The cost was incurred completing work "*using well-trained, well informed and conscientious employees and contractors who are doing their jobs properly.'*"[12]

Otherwise, the cost is unreasonable. D.14-06-007 makes clear that in those cases "*where imprudent actions by the gas system operator have led to unreasonable costs, we will assign those costs to shareholders*."[13] The PD does not adhere to this standard and improperly assigns the cost for management's imprudent actions to ratepayers.

In some cases PG&E admits, and elsewhere the PD finds, that PG&E has previously failed to comply with best practices or regulation. The PD also acknowledges the arguments of TURN, ORA and the Indicated Shippers that PG&E is playing catch-up to remedy years of mismanagement. Yet, rather than disallowing the costs forecasted to bring the infrastructure up to acceptable levels, the PD declines to disallow these costs relying on its exceedingly narrow standard to argue that a disallowance is improper when PG&E previously had not received funding for this

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9 PD at 20-21, *citing* D.14-06-007 at 31.
10 D.14-06-007 at 31.
11 PD at 20-21, *citing* D.14-06-007 at 31.
12 PD at 20-21, *citing* D.14-06-007 at 31.
13 D.14-06-007 at 31.

purpose. The Gas Accord structure used to settle PG&E's most recent GT&S applications makes it difficult, if not impossible, to identify the exact programs for which PG&E previously received funding. Furthermore, it is unjust to consider whether the utility had previously received funding for a proposed project in the case of management failures that have been acknowledged by all parties.

The PD's standard for determining reasonableness fails to acknowledge that but for these "*identifiable utility failures*" to follow best practices and regulation utility ratepayers would not be facing the rate shock resulting from the forecast adopted by the PD.[14] A competent manager is obligated to request a budget sufficient to comply with best practices and regulations, and utilize the budget properly to comply with all requirements. Similarly, management should not have agreed to enter into settlement agreements, such as the past five Gas Accord settlements, if such settlements will result in revenue requirements inadequate to uphold the utility's responsibilities to act as a prudent manager. PG&E shareholders, not current PG&E ratepayers, must take full responsibility for the failures of previous PG&E management.

III. RISK MANAGEMENT

The PD dispenses with thousands of pages of the record devoted to PG&E's risk management procedures in a scant four pages.[15] Rather than reach specific findings and conclusions, the PD punts this issue to a pending generic proceeding, A.15-05-002, the Safety Model Assessment Proceeding (S-MAP). The failure to address this issue is particularly striking because both PG&E and the Commission made risk management a central issue in this case; PG&E claims that its entire forecast is "*a product of this risk based process,*"[16] and the PD finds that this is "*the first GT&S case where PG&E is required to develop a revenue requirement explicitly based on risk*."[17]

Given this central role of risk management, the Public Utilities Code requires greater rigor in reaching its conclusions. Public Utilities Code §1705 requires that the Commission provide "*separately stated, findings of fact and conclusions of law by the*

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14 PD at 21.
15 PD at 22-26.
16 *See* Indicated Shippers Opening Brief at 25 at note 88.
17 PD at 386, FoF 3.

commission on all issues material to the order or decision."[18] Issues material to the decision include, "*every issue that must be resolved to reach that ultimate finding*."[19] The Commission must make findings of fact on every issue "*on which evidence was introduced*."[20] With this obligation in mind, §1757[21] provides for appellate review of a Commission decision when "*the findings in the decision of the commission are not supported by substantial evidence in light of the whole record."*

The Indicated Shippers devoted 60 pages of its briefs and 134 pages of testimony to risk management.[22] PG&E submitted 21 pages of briefing and almost 2000 pages of testimony and attachments on risk management.[23] There are 450 pages of transcript devoted to the risk panel alone, not including the cross examination of PG&E Witness Stavropolous on risk issues.[24] Additionally, there was significant discovery on risk management issues, and it was a topic covered at the Oral Argument in this case.

The Indicated Shippers offered evidence and discussion of the failings of PG&E's risk management process, including, but not limited to:

- PG&E's failure to quantify risk reduction;[25]
- PG&E's failure to properly prioritize safety; and[26]
- The numerous errors in PG&E's risk management process.[27]

Despite acknowledging the broad scope of Indicated Shippers' risk management criticism,[28] the PD includes only three general Findings of Fact and two Conclusions of

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18 Cal. Pub. Util. Code §1705.

19 Cal. Motor Trans. Co. v. Pub. Util. Comm'n, 59 Cal.2d 270, 273 (Cal. 1963).

20 Greyhound Lines, Inc. v. Pub. Util. Comm'n, 65 Cal.2d 811, 813 (Cal. 1967).

21 Cal. Pub. Util. Code §1757.

22 *See* Indicated Shippers-8, Indicated Shippers-5, Indicated Shippers Opening Brief at 20-76 and Indicated Shippers Reply Brief at 10-21.

23 *See* PG&E-1, Chapter 2; PG&E-30; PG&E-31; PG&E-32; PG&E-33, PG&E-37, PG&E-38; PG&E-39, Chapter 2, Chapter 2A, Chapter 2C, PG&E Opening Brief at Chapter 2; PG&E Reply Brief at Chapter 2.

24 *See* 13 Tr.1049:4-15 Tr. 1416:27 (PG&E/Risk Panel)

25 *See* Indicated Shippers Opening Brief at 33-40.

26 *Id*. at 40-44.

27 *Id*. at 52-67.

Law related to risk management.[29] It lacks any specific findings on the evidence opposing PG&E's position. Sufficient, specific findings are required to demonstrate that the evidence favors one outcome over another, and without these findings the Commission lacks a record adequate to demonstrate that it has not acted arbitrarily.[30]

The PD skirts the difficult question of what to do in the face of a revenue request grounded in a flawed risk management process. Rather than answer this question, the PD focuses on PG&E's admission that its process is evolving[31] and the Indicated Shippers' general acknowledgment that additional funding is required to implement a safer natural gas system.[32] The PD then leaps to the conclusion, unsupported by specific findings, that PG&E's risk management is reasonable.[33]

The PD justifies its failure to address risk management evidence by anticipating that any weaknesses in its approach will be addressed in the pending S-MAP.[34] The Commission cannot relieve PG&E of its responsibility to provide a reasonable, risk-based analysis in this proceeding simply because the utility is attempting to improve its risk management practices elsewhere. The PD's conclusion that PG&E's risk management approach is "reasonable" could, in fact, tie the Commission's hands in resolving the S-MAP and encourage similar approaches by other utilities.

The PD also mischaracterizes the Indicated Shippers' acknowledgement that additional funding may be required. Acknowledging the need for work on PG&E's system, much of which results from PG&E's own mismanagement and failures, cannot be reasonably interpreted as an agreement that such funding should be imposed on ratepayers. In fact, the Indicated Shippers' testimony called for a 32% reduction in PG&E's proposed test year 2015 expenses based in large part on the inadequacy of PG&E's showing. There is no reasonable basis to conclude that the Indicated Shippers

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28 PD at 25, note 30. The PD acknowledges that the Indicated Shippers submitted over 50 pages on risk management. The Indicated Shippers incorporate its Opening Brief discussion of risk management by reference.

29 *See* PD at 386-387, Findings of Fact 3,4,5; PD at 411, Conclusions of Law 4, 5.

30 *Cal. Mft. Assc. v. Pub. Util. Comm.*, 24 Cal.3d 251 (1979) at 258-259.

31 PD at 26. The Indicated Shippers would note, that despite the suggestions that PG&E is making improvements to its risk management program, the process described in its S-MAP testimony largely resembles the process relied on to develop its GT&S forecast.

32 PD at 25, *citing* Indicated Shippers Opening Brief at 76.

33 PD at 26.

34 PD at 26.

support in any way deferring consideration or action on PG&E's risk management practices.

PG&E's opening testimony explicitly acknowledged the role of risk-based decision-making in the management of its natural gas system.[35] Given PG&E's claims that its proposed forecast is a result of its risk management the Commission should not ignore significant concerns with PG&E's decision making simply because these concerns are pending in another docket. Ultimately, given PG&E's failures, its risk management process cannot be relied on as a reasonable basis for its forecast. Accordingly, the Commission should adopt the additional revenue requirement reductions proposed by the Indicated Shippers in these comments.

IV. CUSTOMER IMPACT

The Indicated Shippers acknowledge the encouraging remarks in the PD regarding the importance of affordability of customer rates:

> *We agree with Indicated Shippers that customer affordability must be considered in determining the reasonableness of PG&E's requested revenue requirement. To that end, this Decision makes various adjustments to PG&E's forecast in instances where we have found PG&E's forecast to be unreasonable and slowed the pace of work where appropriate*.[36]

The final revenue requirement and associated rate increases, unfortunately fail to reflect such a commitment to affordability. The PD adopts an overly narrow and restrictive standard for disallowances, directs only limited changes to the pace of work, and makes no material changes to PG&E's request. As a result, PG&E's ratepayers will be burdened with unprecedented and unconscionable rate shock in order to compensate for PG&E's prior mismanagement, costs that should properly fall on PG&E's shareholders.

The Indicated Shippers raised concerns throughout this proceeding regarding the potential for rate shock, highlighting PG&E's proposed 91% increase for transmission

35 Ex. PG&E-1 at 2-3:5-8 (PG&E/Soto).
36 PD at 28.

level industrial customers and 135% increase for electric generators.[37] PG&E's rate tables show that, even with the San Bruno Penalty mitigation, after incorporating the proposed 18 month amortization, **Industrial-Transmission customers will face a 112% increase in rates and Electric Generators, at Distribution/Transmission voltages, a 242% increase**.[38] Despite the PD's reference to affordability, its conclusions conflict with any reasonable understanding of the concept.

In the interest of affordability, the final decision should adopt the additional disallowances provided for in these comments. It further should modify the proposed allocation of the $850 million San Bruno Penalty, as discussed in Section X.

V. TRANSMISSION PIPE

A. Hydrostatic Testing

The PD reduces PG&E's proposed expense forecast by $33.402 million to disallow the recovery of hydrostatic testing costs related to 97 miles of pipe installed between 1956-61.[39] While the Indicated Shippers support this disallowance, it is not sufficient given the infirmities of PG&E's forecast to protect ratepayers from rate shock. The final Commission decision should also rely on the unit costs developed by ORA and disallow additional costs identified by TURN.

PG&E forecasts hydrostatic testing expenses relying on both historical costs and forecasts of 2013 costs. ORA's testimony demonstrated that by relying on forecast costs and ignoring potential efficiencies, PG&E's unit costs for hydrostatic testing are overstated. As an initial matter, PG&E's unit costs should be updated to reflect the most recent and accurate cost information, in this case, $0.72 million per mile. As the PD notes in reference to the earthquake fault crossing program, PG&E should not "*benefit from the use of older data, when more recent historical data is available*."[40] Additionally, this unit cost should be further adjusted downward since, as the PD acknowledges and "*generally*

37 *See* PD at 27-28.
38 *See supra* note 4.
39 PD at 60.
40 PD at 68.

agree[s]… that hydrostatic testing costs should decrease over time as the result of efficiency gains and non-emergency nature of the work."[41] It is not appropriate for ratepayers to incur inflated costs and egregious rate shock simply because the potential efficiencies are currently unknown.[42] Given that PG&E failed to make any estimate of the potential scope of program efficiencies, the final decision should rely on the ORA estimate of how these costs should decrease and reflect unit costs of $0.56 million/mile.

The PD should also adopt TURN's proposed additional disallowances to reflect costs of pipe installed after 1961 for which PG&E has no records.[43] PG&E has already committed that it will not charge ratepayers for these tests, but the PD provides no vehicle for the tracking or return of these funds to ratepayers.[44]

Ultimately, the PD should disallow testing costs for an additional 97 miles of pipe, resulting in 315 miles of pipe being tested over the course of the rate case period. As a result of these two changes, PG&E's forecast expenses for 2015 should be reduced to $58.8 million.

B. Vintage Pipe Replacement

The Indicated Shippers support the PD's reductions to the unit costs used by PG&E to forecast the cost of its Vintage Pipe Replacement (VPR).[45] Despite its suggestions that it would modify program pace to address affordability concerns,[46] the PD approves PG&E's unnecessarily aggressive VPR pace. The final forecast adopted by the Commission should reflect a more reasonable and justified pace of work.

PG&E justifies the proposed pace of its VPR program relying on a mischaracterization of industry best practices, suggesting that the proposed pace is based on its commitment as a member of the Interstate Natural Gas Association of America (INGAA).[47] PG&E claims that, consistent with this commitment, it will address the risk of vintage construction and land movement for 90% of the population living

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41 PD at 58.
42 *Id*.
43 PD at 56.
44 PD at 59-60.
45 PD at 82.
46 PD at 28
47 See Indicated Shippers Opening Brief at 127.

within the Potential Impact Radius (PIR) of PG&E's pipelines during the GT&S term, and 100% of the population by 2025.[48] PG&E's proposed program pace is unnecessary in order for the utility to comply with its INGAA commitment, which requires the utility to address 90% of the population by 2020 (not 2017) and 100% of the population by 2030. Moreover, PG&E's data demonstrates that the utility has already met its INGAA commitments,[49] having protected 99.8% of its population from this risk.[50]

PG&E failed to meet its burden of proof that the proposed VPR work is necessary.[51] In D.14-08-032 addressing PG&E's last General Rate Case, the Commission found that "*the utility must demonstrate that the overall benefits justify the costs imposed on ratepayers…it is not enough to merely assert that safety would be compromised absent…a particular work effort*."[52] The Indicated Shippers introduced evidence showing that PG&E's program scope and pace were not the result of proper risk-based decision-making.[53] Without a proper assessment of its assets and understanding of the associated risks, PG&E cannot demonstrate that the work it proposes is required or will provide ratepayers with benefits that outweigh the costs of the program. Given the enormous capital expenditures forecasted under the program, the Commission must require additional justification for the accompanying rate increases.

Despite acknowledging this mischaracterization and the Indicated Shippers' concerns regarding program pace,[54] the PD does not address either the faulty risk assessment underlying the program or program pace.[55] The final decision adopted by the Commission should address this oversight and reduce the pace of the program, further mitigating the rate shock. Considering that PG&E has already met its INGAA commitment, as noted above, the Commission should ideally direct PG&E to propose a more reasonable pace of work based on a valid risk management model and segment

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48 *See* Indicated Shippers Opening Brief at 126.
49 *Id*. at 127-28.
50 *Id*. at 127-28.
51 *Id*. at 28-29.
52 D.14-08-032 at 27.
53 *Id*. at 122-126. The Indicated Shippers incorporate these arguments by reference.
54 PD at 78.
55 *See* PD at 78-83.

specific data.[56] Alternatively, and ignoring PG&E's errors and mischaracterization, the Commission should reduce the number of miles PG&E will mitigate from 60 to 46, the number of miles that PG&E erroneously represents would be required to address 90% of total population in the PIR by 2020.[57] Reducing the number of miles is a 23.4% decrease in pace and adjusting the PD's proposed capital expenditure forecast by the same percentage results in a forecast of $126.033 million.

C. Shallow Pipe

The PD adopts PG&E's forecast for its Shallow Pipe Program ignoring evidence (introduced by TURN and the Indicated Shippers) demonstrating that PG&E previously overlooked shallow pipe maintenance.[58] PG&E's accelerated schedule would not be required had PG&E prudently managed its program previously. With the past failures of PG&E management and extraordinary rate shock resulting from the PD, the Commission should disallow PG&E's full forecast of $3.073 million in 2015 expenses and $17.288 million in 2015 capital.

VI. FACILITIES

A. ECA Phase 1/ECA Phase 2 and Hydrostatic Testing

The PD adopts PG&E's forecasts for ECA Phase 1 and 2 and Hydrostatic Testing programs.[59] Each of these programs, however, is subject to balancing account treatment to ensure that PG&E shareholders are paying for any cost to address station components for which it should already have a record.[60] Indicated Shippers agree that it is appropriate for PG&E shareholders to be responsible for these costs, but more aggressive disallowances are required to protect ratepayers.

For the first time in its Reply Brief, PG&E acknowledged that it was improper for ratepayers to compensate the utility to gather new documents where it was required to have, but management failed to possess, "*traceable, verifiable*

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56 Indicated Shippers Opening Brief at 145.
57 *Id*. at 129.
58 *See* Indicated Shippers Opening Brief at 158-159. The Indicated Shippers incorporate by reference these arguments.
59 PD at 126-27.
60 *See* PD at 126.

and complete" records.[61] PG&E proposed a basis for allocating program costs on a per station basis based on the "*number of pre-1961 components plus post-1961 components with traceable, verifiable, and complete records divided by the total components at each station*."[62] The PD adopts the PG&E proposal but directs PG&E to recover from shareholders costs for facilities installed on or after 1956.[63] As a result, the PD allows upfront recovery costs that are the responsibility of shareholders, setting rates at an unreasonable and unjust level.

Additional disallowances are essential to address the speculative nature of the forecast for ECA Phase 1 and ECA Phase 2 highlighted by the Indicated Shippers.[64] Neither PG&E (nor any other utility) has previously completed the work of the type forecast to be completed in the programs, and PG&E's forecast is based on work it cannot prove is similar in nature.[65] Additionally, PG&E estimated the required scope of the program, and the actual work required for ECA Phases 1 and 2 may not reflect the estimates used to develop the forecast.[66] The PD "*acknowledge[s] that there is little historical data on which PG&E could base its forecasts*," but declines to make any adjustments to the forecast.[67]

The proposed balancing accounts are a means of protecting ratepayers from paying for the development of records PG&E should already have, but granting PG&E's forecast, even subject to refund, will exacerbate rate shock. Additionally, it potentially incentivizes PG&E to overspend rather than complete work at the most reasonable cost. Instead, the Commission should provide for an upfront disallowance based on a rough proportion of facilities that were installed before the 1956 cut off. An upfront disallowance would not only protect ratepayers from rate shock, but would also address the speculative nature of PG&E's forecast.

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61 *See* PG&E Reply Brief at 9-3.
62 PG&E Reply Brief at 9-4, PD at 126.
63 PD at 126.
64 *See* Indicated Shippers at 178-181 (ECA Phase 1), 181-183 (ECA Phase 2).
65 *See* Indicated Shippers Opening Brief at 179, 182.
66 *See* Indicated Shippers Opening Brief at 180, 181.
67 PD at 125.

An estimate of costs that would not be subject to refund can be developed based on PG&E's Opening Testimony.[68] Approximately,

- 15% of Compression and Processing assets were installed prior to 1956.[69]

- 16% of Complex Measurement and Control stations were installed prior to 1956.[70]

- 11% of Simple Measurement and Control stations were installed prior to 1956.[71]

Based on these estimates, an 85% disallowance is proper. This would reduce PG&E's 2015 expenses to $2.345 million for ECA Phase 1, $1.302 million for ECA Phase 2 and $0.889 million for hydrostatic testing. To the extent that additional funds are then required to complete this work, the Commission could direct PG&E to file an application requesting additional funds.

B. Critical Documents

The PD provides that the critical documents program would be treated similarly to the ECA Phase 1 and 2 and Hydrostatic Testing programs, with shareholder responsibility for costs of gathering documents for facilities built on or after January 1, 1956.[72] As also seen in Section VI.A above, the PD allows costs that are not properly included in rates — costs that are the responsibility of shareholders — setting rates at an unreasonable and unjust level. Specifically, the PD calls for establishment of a balancing account with refunds paid to ratepayers.[73] Despite the fact that many of the costs of this program would be refunded to ratepayers, the PD grants PG&E's full request, by definition establishing unjust and unreasonable rates. Further, as also noted in

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[68] These numbers are estimates, and even these stations may have components that were installed later so would be subject to refund

[69] *See* PG&E-1 at 6-16. Two out of 13 stations have in service dates before 1956.

[70] *See* PG&E-1 at 6-12 and 6-17 (Figure 6-3). It appears from Figure 6-3 that approximately 18 out of 111 total complex stations were constructed before 1956.

[71] *See* PG&E-1 at 6-12 and 6-18 (Figure 6-4). It appears from Figure 6-4 that approximately 44 out of 384 total complex stations were constructed before 1956.

[72] PD at 130.

[73] PD at 130.

Section VI.A above, this exacerbates rate shock and incentivizes unreasonable spending. Based on the estimated age of PG&E's assets, the Commission should adopt an 85% disallowance and provide PG&E with a means to request additional funds if necessary. The resulting 2015 forecast for critical documents is $1.73 million.

VII. CORROSION CONTROL

The PD makes no substantial adjustments to PG&E's corrosion control program, despite PG&E's admission that its program previously failed to comply with regulatory requirements.[74] The PD instead accepts, despite the evidence to the contrary, PG&E's disproved contention that the program's dramatic expansion is not a result of previous non-compliance.[75] The PD's findings regarding corrosion control conflict with the standard laid out in D.14-06-007 and exacerbate the rate shock to be absorbed by PG&E's customers.

The Indicated Shippers identified a number of broad concerns with each of PG&E's proposals for individual corrosion control programs and proposed a full disallowance of corrosion control costs.[76] Most notably, the Indicated Shippers highlighted the results of the Exponent study commissioned by PG&E. This report found that 15% of all corrosion control programs were out of compliance with regulations, with a number of other programs inconsistent with industry best practices.[77] TURN also advocated for a full disallowance of corrosion control programs and ORA proposed specific disallowances given the appearance that much of PG&E's proposed work is to bring its "*facilities into compliance with longstanding federal regulations*."[78]

Under the D.14-06-007 standard for just and reasonableness, additional disallowances are proper here since PG&E failed to follow industry best practices or regulations, regardless of whether it had previously received funding for these programs. The PD improperly concludes instead, even in the face of PG&E's own

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74 PD at 150

75 PD at 150

76 The Indicated Shippers incorporate by reference those arguments here. Indicated Shippers Opening Brief at 193-206.

77 *See* PD at 153-154, *citing* the Indicated shippers Opening Brief at 197-202.

78 PD at 151.

admission that its program has previously failed to comply with regulatory requirements,[79] that there is no evidence that PG&E never correctly performed corrosion control and that proposed work is to remedy past imprudence.[80] As discussed in Section II above, failure to comply with regulatory requirements merits disallowance. Additionally, corrosion is a "time-dependent" threat, meaning it that without proper maintenance and monitoring, it is likely to worsen over time.[81] This fundamental characteristic makes it difficult to conclude that future work is not, at least in part, a result of previous failures.[82]

Given the previous imprudence of PG&E management and rate shock resulting from this decision, the Indicated Shippers recommends additional disallowances in the corrosion control program as outlined below.[83]

A. Cathodic Protection Systems

Indicated Shippers support the PD adjustments to the Coupon Test Station program and associated disallowances.[84]

B. Corrosion Investigations

As acknowledged by the PD, "*PG&E concedes that its Corrosion Investigations Program had not previously been compliance with federal regulations*."[85] The PD finds that "*PG&E should have made the expenditure at an earlier time*." The PD, however, declines to make any disallowance because PG&E did not previously request funding for the program. As discussed in Section II above, under the D.14-06-007 standard, as a prudent manager PG&E had an obligation to comply with regulation, and request the funding required to comply with regulation. While it may be difficult to untangle precisely how delay increased corrosion control costs in this GT&S, failing to provide for material disallowances of these program costs in the face of the PD's clear findings inexplicably validates prior mismanagement, unjustly rewards shareholders for

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79 PD at 150.
80 PD at 159.
81 Ex. PG&E-39 at 2C-Atch B-13 (PG&E/Hereth).
82 PD at 147.
83 *See* PD at 154.
84 PD at 168.
85 PD at 169.

management incompetence and inequitably allows recovery of costs for untimely compliance with regulatory requirements. Finally, inclusion of the costs further increases rate shock to rate payers. The final decision should disallow PG&E's 2015 forecast expenditures of $5.455 million for Corrosion Investigations.

C. AC Interference

The PD declines to make any disallowances to PG&E's AC Interference program despite acknowledging that the Exponent Report identified deficiencies "*in comparison to industry best practices*."[86] The PD also finds that PG&E has not previously recovered funding for this program in rates.[87] Under the D.14-06-007 standard identified above, a finding that PG&E's work was out of compliance with best practices is sufficient grounds for a disallowance of program costs. Moreover, PG&E made no evidentiary showing that these costs were not previously requested in a prior rate case. Acknowledging that work is required to mitigate AC interference, while still protecting ratepayers from compensating PG&E for its prior imprudence, the Commission should adopt ORA's proposed 50% cost cap on the program limiting PG&E capital expenditures to $5,750,497.

D. DC Interference

As with the AC Interference program, the Exponent report found that "*PG&E's activities fall short of industry best practices*."[88] Under the standard laid out in D.14-06-007, but acknowledging the work required to bring PG&E's program into compliance with best practices and regulation, the Commission should adopt ORA's proposed cost caps on the program.[89] The cost cap would result in PG&E recovering 2015 expenses of $2,023,231 and 2015 capital expenditures of $400,893.

E. Casings

The PD adopts a limited disallowance for the casings program based on its finding that 19% of previous casings work was not performed properly.[90] This

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86 PD at 175.
87 *Id*.
88 PD at 177.
89 *See* PD at 176.
90 PD at 183.

conclusion is inconsistent with the PD's own findings that PG&E imprudently delayed casings mitigation.[91] The PD declines to make greater disallowances since "*the record does not demonstrate that PG&E previously received funding to perform mitigations*."[92] Again, under the language of D.14-06-007, given PG&E's imprudent failure to comply with federal regulations, disallowance is proper regardless of whether PG&E previously received funding for the casings program.

Rather than the limited disallowances adopted by the PD, the Commission should protect ratepayers from costs associated with PG&E's prior imprudence and adopt ORA's more aggressive disallowances for casings work.[93] The Indicated Shippers support ORA's recommendation that ratepayers fund $4.896 million in expense and $1.93 million in capital expenditures per year.[94]

F. Internal Corrosion

PG&E admits that its internal corrosion program "*did not meet industry best practices*."[95] Given this express admission and the requirements of D.14-06-007, it is improper and unjust to grant PG&E's request and require ratepayers to compensate the utility for PG&E's prior mismanagement. The Commission should instead adopt TURN's full disallowance for the Internal Corrosion program expenses of $8.784 million in 2015.

G. Atmospheric Corrosion

The Proposed Decision highlights language in the Exponent Phase 2 report that finds that PG&E previously failed to comply with federal regulations.[96] While the PD notes that PG&E preliminarily excluded some costs related to its non-compliance,[97] it does not address PG&E's admission that its increase in requested expenses is "*to move the atmospheric corrosion program towards industry best practices*."[98] Given that the proposed work likely reflects the deferred maintenance required in order to comply with industry best practices, under the D.14-06-007 standard, prudence demands that

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91 PD at 182-83.
92 PD at 183.
93 *See* PD at 181.
94 PD at 181.
95 PD at 186.
96 PD at 191.
97 *Id.*
98 PD at 189.

the Commission protect ratepayers and reduce rate shock by adopting ORA's cap on forecast expenses. Ultimately, ratepayers should only be responsible for $16.143 million in 2015 expenses.[99]

VIII. REPORTING REQUIREMENTS AND PROGRAM MANAGEMENT

A. PG&E/Calpine Joint Stipulation

The Indicated Shippers support the PD's treatment of the PG&E and Calpine Joint Stipulation. The final decision adopted by the Commission should reflect the PD's disposition of this issue.

IX. COST RECOVERY ISSUES

A. Transmission Integrity Management Program Balancing Account

The Indicated Shippers support the PD's treatment of the Transmission Integrity Management Program Balancing Account. The final decision adopted by the Commission should reflect the PD's disposition of this issue.

X. APPLICATION OF $850 MILLION PENALTY FOR FUTURE PIPELINE SAFETY IMPROVEMENTS

A. The Commission Should Not Deviate from the Process Adopted in the Revised Scoping Memo

The Indicated Shippers disagree with the PD's proposal to address the GT&S revenue requirement and $850 million penalty in a single decision and asks the Commission to follow the process adopted in the Second Amended Scoping Memo. As noted above, the PD results in rate shock for PG&E customers, and includes a number of costs that are neither just nor reasonable that properly should be disallowed. The concern remains that a discrete list of disallowances should be developed before the penalty is applied, but this concern goes beyond simply ensuring that these projects are not reflected in rate base as the PD suggests.[100]

The Second Amended Scoping Memo adopted a process that parties relied upon to ensure due process. The process adopted provided an opportunity to comment on both the proposed revenue requirement as well as the preferred application of the $850

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[99] PD at 190.
[100] PD at 382.

million penalty. Instead, the PD limits parties' ability to comment on both the proposed revenue requirement and the proper disposition of the penalty. Combining the two steps requires parties to the proceeding to use a portion of their already limited opportunity to comment to address the propriety of changing a previously settled procedural issue.

As noted in Sections X.B and X.C. below, alternative applications of the penalty should be considered in order to address the rate shock resulting from incorporation of this decision into rates. As noted throughout these comments, The Indicated Shippers challenge the standard applied in this PD and recommend additional disallowances. The Commission's final disposition on these issues will impact the overall revenue requirement for the GT&S and may further impact parties' positions on the most reasonable application of the $850 million.

B. The Commission Should Revisit the Proportions of the Penalty to be Applied to Capital and Expense

The Penalties Decision articulates the Commissions clear intent in adopting the $850 million penalty. It states: "We believe that a significant portion of the total penalty should be committed to making PG&E's gas transmission system as safe as possible for the public, ratepayers, utility workers, and the environment."[101] The Commission concluded, based on the costs adopted in the PSEP, 19%[102] of the penalty would be applied to "safety-related"[103] operating expenses, with the remainder committed to capital expenditures. The Commission observed that by applying the penalty to capital expenditures, PG&E "will not earn any profit" on the assets.[104] The Indicated Shippers request that the Commission reconsider this allocation and use the penalty to mitigate the rate shock that will result from this proceeding.

The allocation of the penalty adopted in the Penalties Decision is not in the best interest of ratepayers in the face of the exorbitant rate increases they face. The Indicated Shippers agree that use of the penalty for capital expenditures, rather than expenses, benefits ratepayers in the long run by eliminating the return on the capital investments made with the penalty. In the present case, however, ratepayers face rate increases that could range from 12.8% to 242.1% when 2015-16 revenue undercollections are amortized.[105] Given the degree of rate shock arising from this proceeding, the Commission has a duty to consider whether a different allocation of the penalty to expense and capital would better serve ratepayers and blunt the enormous impact on ratepayers. This would be consistent with the Consumer Protection Safety

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101 Penalties Decision (D.15-04-024) at 3.
102 Id. at 94-95.
103 Id. at 96. It characterized as "safety related": "(i) costs for safety inspections and testing of transmission pipeline; (ii) any costs for repairing or replacing transmission lines that are properly expensed, and (iii) projects or programs to improve transmission line record-keeping, including GIS equipment and systems, but excluding any items that shareholders were required to fund by the PSEP Decision (D.12-12-030, in R.11-02-019)."
104 Id. at 3.
105 *See supra* note 4.

Division litigation position in the San Bruno case, arguing that the San Bruno penalty should apply to safety costs in order to "*decrease the burden on ratepayers*."[106]

The Indicated Shippers recommend that rather than applying the majority of the penalty to capital, the full $850 million penalty should be applied to expenses over the GT&S term. The value of applying the penalty to capital in the long run cannot outweigh the urgency of immediate mitigation of the stratospheric rate increases. In addition, applying the bulk of the disallowance to capital results in a very slow recovery of the penalty by ratepayers – future, not current, ratepayers -- since the benefits are realized only through avoided depreciation expense and return over the life of the assets of up to 60 years. Finally, applying the penalty to expense in this rate case period also fosters administrative efficiency; application of the penalty to capital costs creates a tracking problem, increasing the complexity, cost and time needed to ensure that ratepayers receive the full benefit of the disallowance.

The Commission can be assured that applying the penalty in this manner will make "PG&E's gas transmission system as safe as possible for the public, ratepayers, utility workers, and the environment for safety-related purposes." There is a strong argument that all inspections, repairs, compliance work, and other maintenance serve this objective. Indeed, PG&E claims that "virtually every dollar that's spent on the gas network relates to safety." [107]

The Indicated Shippers ask the Commission to keep its previous commitment to a separate process to address the application of the penalty to provide the greatest transparency possible in a final rate decision. Regardless of when the issue is addressed, the Commission should modify D.15-04-024 on its own motion to direct the

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[106] Penalties Decision at 89, *citing* CPSD Amended Reply Brief on Fines and Remedies at 1-3.

[107] 12 Tr. 905:2-3 (PG&E/Stavropoulos); *see also* 12 Tr.906:12-27 (PG&E/Stavropoulos): "*We do not segregate our programs into individual safety, integrity, reliability, and capacity categories. Many of our programs deal with multiple drivers and address multiple risks and therefore we do not believe it's appropriate to break them down into those individual categories. Q So if you have a particular program that you've developed, can you tell for certain what precisely the driver was of any given program or project? A Like I say, I would – the overwhelming majority of the work that we do is safety related. So, for example, in my mind here, safety and integrity are the same thing.*"

application of the full $850 million penalty against 2015-17 expenses to mitigate rate shock.

C. PG&E Has Incorrectly Sequenced the Application of the $850 Million San Bruno Penalty.

The *Ex Parte Sanctions Decision* adopted a disallowance for the five-month delay in this proceeding caused by PG&E's unlawful ex parte contacts, which was to be calculated at the conclusion of the proceeding.[108] While the PD quantifies a proposed disallowance of $164 million, the PD's directive appears to have been misapplied in the utility's rate calculations in Appendix G.

D.14-11-041 explained the maximum amount of penalty that could be applied in the final decision in this proceeding:

> *The amount of the ratemaking disallowance is to be calculated at a maximum of all of the revenues, as authorized in a final Commission decision in this proceeding, that would have been amortized (collected from ratepayers) during the five-month period of the delay.*[109]

The PD quantifies the delay disallowance adopted in the *Ex Parte Sanctions Decision* as $164 million.[110] The PD's value appears to be the five-month amortized portion of the revenue *increase*, rather than all 2015 revenues, proposed by the PD over 2014 authorized revenues.

While the rate tables also focus on the revenue increase, the calculations do not comport with the text of the PD. Table G-3 shows a delay disallowance of only $102 million.[111] This error appears to be a consequence of substituting a revenue requirement for 2015 of $960 million, rather than $1,108.196 million.[112] The rate tables appear to have calculated the revenue requirement by first offsetting operating expenses with $158 million of the expense-committed portion of the $850 San Bruno Penalty disallowance.[113]

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[108] D.14-11-041 at 15-16.
[109] *Id*. at 16.
[110] PD at 272.
[111] PD, Appendix G, Table G-3, line 37, column (d).
[112] *Id*., Table G-3, line 36, column (d).
[113] *Id*., Table G-3, line 17, column (d).

By applying the San Bruno Penalty disallowance before calculating the delay disallowance, the delay allowance is reduced from the $164 million directed by the PD to $102 million. The impact is to increase the revenue requirement for 2015 for which ratepayers will be responsible by an equal amount. Effectively, this allows PG&E to profit from the PD's inclusion of the $850 million in the PD rather than in two separate decisions. Allowing PG&E to profit from the San Bruno Penalty, while its ratepayers face extreme rate shock, is inconceivable. If the Commission permits resolution of the $850 million San Bruno Penalty in this decision, it must at a minimum direct how to calculate and apply the delay disallowance prior to applying the $850 million to its revenue requirement.

XI. AMORTIZATION

The rate tables provided by PG&E reflecting full amortization of the 2015-2016 revenue shortfall in the next 18 months demonstrate that this case will result in unreasonable rate shock.[114] The Indicated Shippers have offered alternatives necessary to mitigate that rate shock, including: additional disallowances, application of the entire $850 million San Bruno disallowance to 2015-17 expenses, and proper sequencing of the delay and San Bruno Penalty disallowances. Recognizing that the likely rate impact will still be unreasonable, the Commission should extend the amortization period for the remaining 2015-16 shortfall period to 48 months to further emolliate the effects of the impending rate shock.

XII. CONCLUSION

For all of the foregoing reasons, the Indicated Shippers request both that the Commission further mitigate the severe rate shock that would result from adoption of the PD and that the Commission correct the errors in the PD regarding Burden of Proof and characterization of Risk Management. Specifically, the Commission should (1) adopt the further disallowances specified in Attachment A; (2) apply the $850 million San Bruno Penalty to 2015-17 expenses; (3) properly sequence the application of the

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[114] *See supra* note 4.

San Bruno Penalty and delay disallowances to maximize their benefit to ratepayers; and (4) extend the amortization of the 2015-16 revenue shortfall for 48 months.

Respectfully submitted,

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Counsel to Indicated Shippers

May 25, 2016.

Indicated Shippers Recommended Additional Disallowances 2015 Expenses (in millions $)				
Program	PG&E Forecast	PD Forecast	Indicated Shippers Recommended Forecast	Additional Disallowance from PD
Transmission Pipe				
Hydrostatic Testing	181.792	148.390	58.8	89.59
Shallow Pipe	3.073	3.073	0	3.073
Facilities				
ECA Phase 1	15.633	15.633	2.345	13.288
ECA Phase 2	8.682	8.682	1.302	7.38
Hydrostatic Testing	5.926	5.926	.889	5.037
Critical Documents	11.573	11.573	1.73	9.837
Corrosion Control				
Corrosion Investigations	5.455	5.455	0	5.455
DC Interference	2.552	2.522	2.023	.499
Casings	48.504	38.390	4.896	33.494
Internal Corrosion	8.784	8.784	0	8.784
Atmospheric Corrosion	20.437	20.437	16.143	4.294
TOTAL				180.731

PD Adopted 2015 Expenses: $572.739 million[1]

Indicated Shippers Proposed 2015 Expenses: $392.008 million

[1] PD at Appendix D, Table 1.

Indicated Shippers Recommended Additional Disallowances 2015 Capital Expenditures (in millions $)				
Program	PG&E Forecast	PD Forecast	Indicated Shippers Recommended Forecast	Additional Disallowance from PD
Transmission Pipe				
Vintage Pipe Replacement	193.624	164.534	126.033	38.501
Shallow Pipe	21.571	17.228	0	17.288
Corrosion Control				
AC Interference	10.350	10.350	5.750	4.6
DC Interference	.802	.802	.401	.401
Casings	21.039	16.991	1.93	15.061
TOTAL				75.851

PD Adopted 2015 Capital Expenditures: $710.635 million[1]

Indicated Shippers Proposed 2015 Capital Expenditures: $634. 784 million

1 PD at Appendix D, Table 2.

Changes to Existing Findings of Fact

1. The Natural Gas Pipeline Safety Act requires gas utilities to prioritize safety. ~~Since PG&E's last GT&S application, there have been significant legislative and regulatory changes mandating a greater priority on safety.~~

4. PG&E's risk management program is not new ~~evolving~~.

19. PG&E ~~has confirmed ratepayers will not bear the costs of testing the post-1961 miles of pipe for which PG&E~~ does not have strength test records for 97 miles of pipe installed after 1961.

24. ~~PG&E expects to~~ A reasonable pace for ~~replace 60 miles of~~ vintage pipe replacement during the Rate Case Period is 46 miles, focusing on the areas with the greatest population density.

81. PG&E's forecast expenses for its Corrosion Investigation excludes some costs to perform corrective work associated with remediating past compliance issues.

88. Corrosion is a time dependent threat and consequently ~~There is no testimony to conclude that the~~ corrosion problems with the 335 contacted casings would have been less severe ~~smaller~~ if PG&E had remediated them sooner.

89. There is sufficient record evidence to conclude that ~~some of~~ the proposed mitigation work is the result of PG&E's failure to originally perform the work properly.

91. ~~PG&E's NCR06 found that "10% of pipe inspections made during corrosion leak repairs were performed by individuals who were not Operator Qualified for the task."~~

New Findings of Fact:

1. Affordability is a consideration when determining the reasonableness of a revenue requirement.

2. The rates proposed by PG&E would result in undue rate shock for several customer classes.

3. Rates must be affordable to be found just and reasonable.

4. Well-designed risk management programs will assist a utility to identify the risk mitigation program that provides the greatest risk reduction at any given budget.

5. Without quantifying the benefits of a proposed risk mitigation it is impossible to determine that it is a cost-effective program.

6. PG&E does not measure the risk reduction benefits of proposed programs.

7. PG&E has previously measured the risk reduction of proposed mitigation programs.

8. PG&E lacks data on the condition of many of its assets.

9. Asset condition data is a required input for assessing risk effectively.

10. PG&E has implemented a relative risk approach to risk management.

11. PG&E has not identified key constraints.

12. PG&E relies on ill-defined and inconsistent scales to evaluate risks.

13. PG&E does not rely on optimization techniques.

14. Transparency is required to properly assess a risk management proposal.

15. Transparency requires readily identifiable data, clearly delineated decision making process and the ability to replicate results.

16. PG&E has met its INGAA Commitment to address vintage construction and land movement for 90% of the population living in the Potential Impact Radius for the VPR program.

17. PG&E has not completed risk assessment of segments of pipe in its VPR program.

18. Applying the $850 million penalty prior to applying the $164 million delay disallowance would benefit PG&E shareholders to the detriment of ratepayers.

19. Applying the $850 million penalty precisely as specified in D.15-04-024 would unreasonably exacerbate rate shock.

20. Applying the $850 million penalty to 2015-17 expenses, rather than to both expenses and capital, is the best use of the penalty in light of the magnitude of the rate increase customers face in this GT&S.

Changes to Existing Conclusions of Law

2. PG&E's forecast costs are ~~not~~ unreasonable and subject to ratemaking disallowance when ~~simply because~~ its management imprudently delayed or deferred work.

3. Disallowances are warranted when the forecast work is necessary because: (1) PG&E had not originally performed the work properly, or (2) PG&E had failed to comply with regulatory requirements or industry best practices~~that it was previously funded to satisfy~~.

4. PG&E's risk management process does not provide~~s~~ a reasonable and reliable framework for purposes of evaluating the reasonableness of PG&E's forecast revenue requirement in this GT&S proceeding

5. PG&E's proposed ~~risk management approach and~~ asset family categories are reasonable.

19. ~~PG&E's 2015 forecast h~~ Hydrotest ~~capital~~ expenses of $0.~~97~~56 million per mile ~~is~~are reasonable and should be adopted.

24. PG&E's forecast hydrotest expenses for transmission pipeline should be reduced ~~by 1938.2%.~~ to exclude any segment of pipe for which PG&E should have a test record but does not.

27. PG&E's forecast hydrotest ~~capital expenditures~~ expenses for transmission pipeline should be ~~adopted~~reduced to $58.8 million.

58. PG&E's proposed expenses ~~mitigation forecasts~~ in the Shallow Pipe Program are unreasonable.~~are reasonable and should be adopted~~.

61. PG&E's 15% Shallow Pipe Construction Risk Adder is not reasonable.

72. Authorizing a portion of PG&E's requested funding will allow PG&E to perform the scope of work contemplated to ensure that records for its C&P and M&P Stations are traceable, verifiable and complete.

73. ~~PG&E's proposed methodology to proportion cost responsibility between shareholders and ratepayers to perform Hydrotest Station Testing work should be adopted except that,~~ PG&E shall recover from shareholders all costs to address station components installed on or after January 1, 1956 that do not have but were required to have traceable, verifiable and complete records.

74. ~~PG&E should file a Tier 2 Advice Letter to establish a one way balancing account to track the difference between amounts adopted in this decision and the actual costs to perform Hydrostatic Station Testing work during the Rate~~

~~Case Period on stations installed on or before January 1, 1956.~~ PG&E's Hydrostatic Testing forecast should be reduced by 85% to reflect costs more properly paid by shareholders.

77. PG&E's forecast expenses for the Critical Documents Program should be reduced to reflect that it is improper to provide additional funds ~~adopted, costs to be recovered, subject to certain requirements to ensure that the Critical Documents Program is not used~~ to correct past records management deficiencies.

80. ~~PG&E should file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between amounts adopted in this decision and the actual costs of Critical Documents Program work for facilities built before January 1, 1956.~~ PG&E's Critical Documents forecast should be reduced by 85% to reflect costs more properly paid by shareholders.

108. It would be ~~un~~reasonable to conclude that ~~none~~some of PG&E's past corrosion control work had not been timely or properly performed ~~properly~~ and that as a result additional ~~if it had been, no future ongoing~~ corrosion control work is ~~would be~~ needed.

126. PG&E's forecast 2015 expenses for its Corrosion Investigation Program ~~are reasonable and should be adopted~~ unreasonably includes costs to correct prior non-compliance and these costs may not be recovered in rates~~and are disallowed~~.

128. PG&E's forecast capital expenditures and 2015 expenses for the AC Interference Program are not reasonable and 50% of capital expenditures should be ~~adopted~~ excluded from PG&E's revenue requirement.

129. PG&E's forecast capital expenditures and 2015 expenses for the DC Interference Program are not reasonable and 50% of capital expenditures and expenses should be excluded from PG&E's revenue requirement ~~adopted~~.

131. ~~Since~~ PG&E's casing mitigation work has not complied with federal regulations.

132. Based on PG&E's previous non-compliance, PG&E's forecast for casings should be limited to $4.895 million in 2015 expense and $1.93 million in capital per year.~~the percentage of non-compliance found in NCR06, 10% of the proposed capital and expense casing mitigation projects for the Rate Case Period should be funded by PG&E shareholders to correct prior work that was performed improperly.~~

133. PG&E should mitigate 94 capital casings during the Rate Case Period and 117 expense casings in 2015, but should only recover the costs for ~~29~~3.58 of the capital mitigation projects and ~~95~~12.75 of the expense casing mitigation per year ~~projects~~ from ratepayers.

134. ~~PG&E's 2015 expense forecast of $1.202 million for casing testing (without test facilities) is reasonable and should be approved.~~

135. PG&E's forecast expenses and capital expenditures for the Internal Corrosion program are not reasonable and should be excluded from PG&E's revenue requirement ~~adopted~~.

136. PG&E's forecast expenses for the Atmospheric Corrosion program are not reasonable and should be ~~adopted~~reduced to $16.143 million.

296. ~~If the proposal for allocation of the $850 million penalty adopted in the *Penalties Decision* contained in Appendix G were adopted, there would not be a need for a second decision to address this allocation and PG&E's rates could go into effect upon the filing of a Tier 1 Advice Letter.~~ As described in the Second Amended Scoping Memo, parties will have an opportunity to comment on application of the $850 million penalty after the Commission has adopted a revenue requirement.

297. ~~Parties should comment on the proposal to allocate the $850 million disallowance as part of their comments on the Proposed Decision.~~

298. ~~Parties advocating for a second decision should include in their comments the specific factual issues that need to be addressed and a proposed schedule.~~

299. The difference between the authorized revenue requirements in this decision and the placeholder revenue requirement incorporated in gas rates PG&E has collected in the Gas Transmission and Storage Memorandum Account should be amortized over ~~1~~48 months to mitigate rate shock.

New Conclusions of Law

1. The reasonableness of PG&E's risk management is a material issue in this proceeding.

2. Since PG&E has not quantified the risk reduction benefit of its proposed investment plan, PG&E cannot assure that its investment plan is reasonable and cost-effective.

3. PG&E failed to properly implement a relative risk approach.

4. Since PG&E's risk management is an unreasonable basis for its proposed forecast, greater ratepayer deference is required in determining reductions in PG&E's revenue requirement.

5. PG&E's proposed rate increases will result in rate shock for some classes of customers.

6. PG&E's vintage pipe replacement program is not supported by proper risk assessment.

7. PG&E's INGAA commitment is not a sufficient basis for PG&E's proposed vintage pipe replacement pace.

8. PG&E has not demonstrated that its vintage pipe replacement program is cost effective.

9. The pace of PG&E's vintage pipe replacement program should be reduced to mitigate only 46 miles over the rate case period.

10. PG&E's ECA Phase 1, ECA Phase 2 and hydrostatic testing forecasts include costs for facilities that should have records but do not.

11. Shareholders should be responsible for the ECA Phase 1, ECA Phase 2 and hydrostatic testing program for facilities lacking records.

12. PG&E's ECA Phase 1 forecast should be reduced by 85% to reflect costs more properly paid by shareholders.

13. PG&E's ECA Phase 2 forecast should be reduced by 85% to reflect costs more properly paid by shareholders.

14. It is reasonable for PG&E to file a separate application to request additional funds required to complete ECA Phase 1, ECA Phase 2 or hydrostatic testing work.

15. PG&E's previous AC interference work has not been executed consistent with industry best practices.

16. PG&E's previous DC interference work has not been executed consistent with industry best practices.