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**PREPARED TESTIMONY OF
THOMAS J. LONG**

**ON
PG&E's QUANTITATIVE RISK MODELS;
PG&E's DEFERRAL OF WORK BASED ON REPRIORITIZATION;
AND
GAS DISTRIBUTION RECORDKEEPING**

Submitted on Behalf of

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TABLE OF CONTENTS

I.	Introduction and Summary	1
II.	PG&E’s Quantitative Models Fall Far Short of Enabling Prioritization (Let Alone Optimization) of Risk Mitigations.....	2
A.	Goals of Quantitative Risk Models.....	4
B.	Limitations of PG&E’s Quantitative Modeling	5
C.	Calculation of Risk Reduction Is Achievable Now and Should Be Required	12
D.	Conclusions and Recommendations.....	14
III.	Concerns with PG&E’s Practice of Delaying or Deferring Work Based on Reprioritization.....	14
A.	Description of the Practice	14
B.	PG&E Needs to Show That Its Reprioritizations Are Necessary and Reasonable; Limiting Spending to Authorized Levels Is Not a Valid Justification	20
C.	The Commission’s Identified Concerns Are Present With Respect to Much of the Deferred Work for Which PG&E is Now Requesting Funding a Second Time.....	23
D.	Ratemaking Adjustments or Forecast Reductions Are Warranted for Work Deferred As a Result of Unnecessary or Unreasonable Reprioritization	27
E.	TURN’s Recommendations Regarding Deferred Gas Distribution Work....	28
IV.	GAS DISTRIBUTION RECORDKEEPING.....	31
A.	Scoping Ruling and PG&E’s Supplemental Testimony	31
B.	PG&E’s Supplemental Testimony Is Inconsistent With PG&E’s Response in the Distribution Recordkeeping Investigation and Information Provided in PG&E Reports to the Commission.....	32
C.	TURN’s Recommended Disallowance.....	35
	Appendix A.....	36

1 the Safety Model Assessment Proceeding (“S-MAP”) (A.15-05-002 et al.), actively participating
2 in five workshops, the Risk Lexicon Working Group, and the Metrics and Reporting Working
3 Group. Most recently, he participated in the Safety and Enforcement Division (“SED”)-led
4 March 25, 2016 workshop in this proceeding concerning PG&E’s risk assessment and planning
5 process. A summary of Mr. Long’s qualifications is attached as Appendix A.

6 **II. PG&E’s Quantitative Models Fall Far Short of Enabling Prioritization (Let Alone**
7 **Optimization) of Risk Mitigations**

8
9 PG&E states that it uses risk assessment and integrated planning processes that produce
10 “risk-informed” prioritization and budgeting for the projects and programs in its GRC forecasts.¹
11 “Risk-informed” is a vague term that would presumably apply to any of the methods and
12 processes PG&E has used to address safety in its GRC requests for decades and thus, in itself,
13 does not signal a major change in how GRC requests are determined.

14 However, a key development in recent years has been PG&E’s use of quantitative
15 modeling as part of its risk assessment and planning processes. The two main quantitative tools
16 PG&E used in connection with developing its forecast in this case are the Risk Evaluation Tool
17 (“RET”)² and Risk Informed Budget Allocation (“RIBA”) scoring.³ PG&E claims that its
18 relatively new processes built around these quantitative tools “help[] to ensure that the projects
19 having the greatest impact on system safety and reliability are included in the portfolio of work
20 put forth by the core operating LOBs [lines of business].”⁴ In its Gas Distribution testimony,
21 PG&E claims that it engages in “portfolio-level optimization across all assets and programs,”
22 describing the goal of such optimization as “invest[ing] in [Gas Operations’] higher risks with

¹ Ex. PG&E-2, pp. 3-1, 4-1, and 4-8.

² Ex. PG&E-2, p. 3-3.

³ Ex. PG&E-2, p. 4-6.

⁴ Ex. PG&E-2, p. 4-7 (emphasis added).

1 the most effective mitigation programs given constraints including compliance obligations,
2 obligations to serve, resources, system availability, executability and cost.”⁵

3 Statements such as these would suggest that, with the benefit of its new quantitative
4 models, PG&E is now able to “prioritize” and “optimize” its GRC requests like never before and
5 is able to rank competing projects and programs based on their impact on system safety and
6 reliability and their effectiveness in mitigating risk. It is understandable that PG&E would want
7 to make such claims for its new models because such ranking, prioritization, and optimization is
8 precisely what is needed in GRCs, as the Commission has made clear in its decisions.

9 Unfortunately, as discussed below, PG&E’s quantitative models do not enable calculation
10 of the safety benefits or effectiveness of competing mitigations and thus cannot be said to be
11 using those models to produce a prioritized or optimized portfolio of projects and programs.
12 Thus, at this point, PG&E’s risk models are much less informative and useful to the GRC
13 process of determining the optimal portfolio of risk mitigations than PG&E’s rhetoric would lead
14 one to believe.

15 Before addressing the shortcomings of PG&E’s approach, this testimony will discuss
16 the important role that quantitative modeling can and should play in developing GRC requests
17 and the Commission’s expectations for such models.⁶

18
19
20
21

⁵ Ex. PG&E-3, pp. 3-9 to 3-10 (emphasis added).

⁶ As PG&E’s presentation shows, with respect to PG&E’s risk assessment efforts, there is considerable overlap between PG&E’s Safety Model Assessment Proceeding (S-MAP) application and this case. In fact, PG&E includes its S-MAP testimony as part of its direct showing in this case. (Ex. PG&E-2, pp. WP 3-9 to 3-36 and 4-1 to 4-16.) Just as PG&E has presented its view of the virtues of its quantitative modeling approach in both S-MAP and this case, TURN also has presented (and by this testimony is presenting) its views regarding the limitations and shortcomings of PG&E’s approach in both cases. Unlike S-MAP, which is reviewing the utilities’ risk models without reference to a specific utility rate request, this case offers an important opportunity to evaluate PG&E’s approach in the context of the requirements and expectations of a specific rate case.

1 **A. Goals of Quantitative Risk Models**

2
3 It is generally recognized, including by PG&E, that it is not possible to eliminate all
4 safety risks associated with the operation of an energy utility.⁷ The challenge then is deciding
5 which risk mitigation activities to implement with the limited resources -- particularly limited
6 ratepayer funds -- available to the utility. As the Commission stated in the decision on PG&E's
7 last GRC:

8 Virtually everything a utility does [has] some nexus to safety and can
9 be deemed to have some safety impact, but the emphasis should be on
10 those initiatives that deliver the optimal safety improvement in relation
11 to the ratepayer dollars spent.⁸

12
13 In other words, a work effort cannot be justified simply by asserting that it would reduce risk.
14 The utility needs to demonstrate that it is proposing that its limited resources be used in a way
15 that would produce “optimal safety improvement in relation to the ratepayer dollars spent.”⁹

16 Quantitative risk modeling can be enormously useful to achieving this goal, as the
17 Commission has recognized. In D.14-12-025, the Commission set forth its objectives for
18 quantitative risk analysis, including requiring utilities in the future Risk Assessment and
19 Mitigation Phase (“RAMP”) of GRCs to present a “prioritization of risk mitigation alternatives,
20 in light of estimated mitigation costs to risk mitigation benefits (Risk Mitigated to Cost Ratio).”¹⁰
21 “Risk mitigation benefits” and “risk mitigated” are other ways of saying risk reduction. In
22 addition, D.14-12-025 requires utilities, after the conclusion of GRCs, to submit annual Risk
23 Mitigation Accountability Reports that will “compare the utility’s GRC projections of the

⁷ PG&E Response to DR TURN 46-1; Ex. PG&E-2, p. WP 3-22 (“With limited resources – PG&E cannot do everything and must decide at what point it is okay to not mitigate the risk further – tradeoff decisions must be made”).

⁸ D.14-08-032, p. 28.

⁹ D.14-08-032, p. 28.

¹⁰ SED Report at 73; D.14-12-025 at 32.

1 benefits and costs of the risk mitigation programs adopted in the GRC to the actual benefits and
2 costs, and to explain any discrepancies between the projected risk mitigation and the actual risk
3 mitigation.”¹¹ This report effectively requires a comparison of achieved risk reductions with
4 forecasted risk reductions and therefore necessitates the calculation of risk reduction.

5 In short, quantitative models can make a critical contribution to the prioritization and
6 optimization of risk mitigation activities that a GRC requires. Calculation of risk reduction is
7 necessary to enable such prioritization and optimization. In addition, as D. 14-12-025 expects,
8 calculation of risk reduction will be a key tool to making the utility accountable for the results of
9 its spending to control and reduce risks.

10 **B. Limitations of PG&E’s Quantitative Modeling**

11 *1. Prevents Comparison of Cost Effectiveness of Risk Mitigations*

12 PG&E states for the “operational LOBs,” it uses the RIBA process to prioritize project
13 and and program expenditures.¹² With respect to one LOB, gas operations, PG&E claims that it
14 used the RIBA scores included in its workpapers¹³ to “prioritize funding at the portfolio level for
15 the 2017 GRC forecast.”¹⁴

16 However, as PG&E acknowledges, none of the quantitative modeling it used to develop
17 the 2017 GRC forecast included calculation of risk reduction from any risk mitigations under
18 consideration in the portfolio selection process.¹⁵ As a result, PG&E’s RIBA scores do not

¹¹ D. 14-12-025 at 44, 46.

¹² Ex. PG&E-2, p. 3-10.

¹³ Ex. PG&E-3, p. WP 3-20.

¹⁴ Response to TURN DR 30-16.c.

¹⁵ Response to TURN DR 46-3 (Supp O1) (The RIBA score “does not directly represent a measure of risk reduction achieved by the subject project or program.”); Ex. PG&E-2, pp. 3-10 to 3-11 (describing determining the risk reduction value of risk mitigations as a “difficult” future goal). Below, we will show that calculation of risk reduction can be done now.

1 allow the kind of prioritization of risk mitigations that the Commission has said that it wants.
2 The fundamental problem is that PG&E’s current quantitative efforts, detailed and complex as
3 they are, do not rank or prioritize competing mitigation efforts based on risk reduction per dollar
4 spent.

5 The shortcomings of RIBA in the absence of measuring risk reduction is shown by
6 PG&E’s response to a recent TURN data request. TURN asked if “the RIBA score would be the
7 same for two projects to address the exact same risk if one project were half as effective in
8 reducing the targeted risk.” PG&E responded that “the RIBA score is not a measure of risk
9 reduction” and that the scores for the two projects “may or may not” be the same.¹⁶ A scoring
10 process that does not *necessarily and always* give a higher score to a project that is twice as
11 effective in mitigating the targeted risk as a half-as-effective project cannot be described as
12 providing meaningful or useful information in an effort to prioritize mitigations.

13 PG&E’s Gas Distribution request in this case provides two examples in which calculation
14 of rate reduction would have been extremely useful to PG&E’s – and the Commission’s –
15 decision-making about the best use of limited ratepayer funds.

16 First, as analyzed in the accompanying testimony of John Sugar for TURN, PG&E
17 proposes to shorten the interval for leak surveys for most of its distribution assets from 5 years to
18 4 years. Mr. Sugar shows that PG&E’s other, considerable ratepayer-funded efforts in the area
19 of risk management appear to be succeeding and that PG&E has failed to demonstrate that there
20 are sufficient incremental benefits from shortening the survey interval to justify the cost.¹⁷ If
21 PG&E had calculated risk reductions for the various mitigations under consideration, it would
22 have been possible to measure the incremental benefits of shortening the risk survey interval and

¹⁶ Response to TURN DR 70-1.

¹⁷ Testimony of John Sugar, Section III.

1 to compare the cost-effectiveness of that particular mitigation to other risk mitigations under
2 consideration – not just in the area of gas leak management or even limited to gas distribution,
3 but even across other lines of business.

4 Second, as also discussed in Mr. Sugar’s testimony, PG&E has unwisely adopted a policy
5 of replacing gas services in response to leaks even when, in the majority of cases, the problem
6 could be effectively addressed by a much less expensive tee cap repair.¹⁸ In considering its
7 policy change, if PG&E had calculated the risk reduction that would be achieved by repairing tee
8 caps when they are the cause of the leak, and compared that calculation to the risk reduction
9 from replacing services in such situations (and if PG&E knew that such calculations would be
10 part of the record in the GRC), the relative cost effectiveness of tee cap repair would have been
11 underscored. And PG&E would have avoided an imprudent use of large amounts of ratepayer
12 money for which TURN is now recommending a permanent disallowance from rate base.¹⁹

13 **2. No Prioritization of Mitigations Based on Effectiveness in Reducing**
14 **Risk**

15 In light of PG&E’s assertion that the portfolio of projects included in its 2017 GRC
16 request have “the greatest impact on system safety and reliability,”²⁰ one would expect that
17 PG&E ranked the projects it considered for this case based on their effectiveness in reducing
18 risk. PG&E has no such ranking.

19 To explore this issue, TURN asked PG&E, for each of major LOBs, the following
20 hypothetical: Assume PG&E wished to reduce the cost of its non-mandatory forecast spending
21 in 2017 by 25%. Which projects or programs would be eliminated or modified (e.g., reduced in

¹⁸ Testimony of John Sugar, Section I.
¹⁹ Testimony of John Sugar, Section I.
²⁰ Ex. PG&E-2, p. 4-7 (emphasis added).

1 pace or scope), such that risk reduction would be maximized? And how would RET, RIBA, or
2 any other model be useful in this analysis? PG&E’s response began:

3 PG&E is unable to make the determinations requested in these questions.
4 PG&E’s methodology is not intended to reasonably calculate, or
5 maximize, risk reduction by re-sorting portfolios of projects or programs
6 in the manner that this question indicates.²¹
7

8 The response went on to indicate that, to answer the question, PG&E would need to “revisit its
9 entire prioritization of work across the line of business portfolio” and that RIBA scores would be
10 considered as part of that process.²²

11 PG&E’s response highlights the problems that result from the failure to calculate risk
12 reduction. There is no ready way for PG&E, intervenors, or the Commission, to adjust PG&E’s
13 chosen portfolio of projects in response to a change in the budget, either up or down. Although
14 PG&E claims that it has chosen the most effective projects for reducing safety risk, PG&E
15 cannot back up that claim by a list that shows how it made that determination, or which projects
16 were at the bottom of the list and should be the first to drop out of the portfolio in the event of a
17 reduced budget.

18 Without calculating risk reduction, PG&E and other utilities are squandering a key
19 benefit of quantitative models, a benefit that (as shown above) the Commission expects such
20 models to yield. By including in their rate case presentations a prioritization of risk mitigation
21 projects based on calculation of risk reduction, utilities could provide the parties and
22 Commission an extremely useful analytic tool that could assist in speeding the resolution of rate
23 cases.

²¹ Response to TURN DR 70-15.

²² Response to TURN DR 70-15.

1 3. ***PG&E Chooses Its Portfolio of Projects Through an Opaque Process***

2 The process by which PG&E decides which projects to propose in a rate case is not
3 transparent to the other parties or the Commission. In its testimony, PG&E summarizes its
4 Integrated Planning Process, which involves the generation of numerous and voluminous
5 documents that are considered in a series of meetings and discussions throughout the year.²³
6 PG&E may find these processes useful, and TURN is willing to accept PG&E's statements that
7 they are an improvement over PG&E's past processes for choosing portfolios of risk mitigation
8 projects.

9 But they do not lend themselves to enabling the Commission or intervenors to gain
10 transparency into how PG&E chose its particular portfolio. As the data request responses
11 discussed above show, PG&E's process yields no document or set of documents that shows how
12 PG&E prioritized the mitigations it was considering. At first blush, the RIBA scores would
13 seem to hold that promise, but, as shown, they have significant limitations and are just one factor
14 that PG&E considers in its extensive decisionmaking process.²⁴ Ultimately, at the end of its
15 Integrated Planning Process, PG&E doesn't explain for the benefit of those of us who were not
16 part of it: (1) what mitigations the company considered and rejected; (2) what criteria it used to
17 decide which mitigations to pursue; (3) and why the chosen mitigations are superior to other
18 potential mitigations.

19 A ranking of mitigations based on risk reduction per dollar spent that is presented as part
20 of the rate case showing would be a major advance in focusing the utility's decisionmaking

²³ Ex. PG&E-2, Chap. 4.

²⁴ See, for example, PG&E's response to TURN DR 48-1 (included in response to TURN DR 48-1 Supp 01), in which PG&E makes the point that RIBA scores are not the sole factor in deciding the portfolio or work in the Integrated Planning Process and that consideration is also given to other factors such as "classification of work, system constraints, resources constraints, work optimization, and financial constraints."

1 process and improving transparency. TURN is not suggesting that utilities or the Commission
2 should slavishly adhere to such a ranking in choosing portfolios of mitigation. But transparency
3 and GRC streamlining would benefit if the utility’s showing including such a list and, as
4 necessary, explained what factor(s) caused it to deviate from the ranking.

5 **4. The “Flags” that PG&E Assigns to Projects and Programs Can Be**
6 **Questionable**

7 In PG&E’s Integrated Planning Process, a significant factor seems to be how a project or
8 program is “flagged.” Flags refer to a label that shows “other non-risk drivers of the work” and
9 show, among other things, whether PG&E views the work as required. The flags showing
10 required work categories are: Mandatory, Compliance, Work Requested by Others, and
11 Commitment.²⁵

12 One (including PG&E’s senior officials) might believe that a project or program that is
13 assigned a flag for one of these required categories must be performed. However, there is reason
14 to question whether activities that are so flagged are indeed required – particularly at the
15 indicated level of funding.

16 PG&E’s RIBA result tables (for Gas Distribution in this example) show the associated
17 2017 forecast amounts for the project or program in question. TURN asked PG&E to indicate
18 for each such activity that was flagged “mandatory” whether the full funding amount was
19 mandatory, and, if not, which part was non-mandatory. PG&E responded that the “RIBA
20 process does not distinguish between programs that are 100 percent mandatory and those that are

²⁵ Ex. PG&E-2, pp. WP 4-4 to 4-5. A list of the flags is shown at p. WP 4-14)

1 predominantly mandatory.”²⁶ In other words, some funding for a supposedly mandatory project
2 or program may not actually be mandatory.

3 PG&E’s response further showed that two of the programs for below ground Grade 3
4 leak survey and repair, MATs FIG and FIP, together representing \$6 million in expense, were
5 wrongly labeled as mandatory.²⁷

6 In addition, PG&E’s data request response shows that PG&E takes an expansive view of
7 what work is mandatory. Relying on the “best practices” language in PU Code Section 963,
8 PG&E seems to be of the view that any practice it considers to be a best practice is mandatory.²⁸
9 For example, PG&E claims that accelerating the gas distribution leak survey cycle is a best
10 practice and that, therefore its proposal to shorten the leak survey cycle from five to four years is
11 mandatory.²⁹ PG&E made this same argument in the 2014 GRC in support of a similar proposal
12 for a three-year survey cycle. The Commission disagreed with PG&E’s view, pointing out that
13 PG&E was overly focused on one aspect of other operators’ leak management programs and did
14 not consider all of the techniques and strategies operators use to detect and repair leaks.³⁰

15 Thus, by probing just one of the flags associated with RIBA-scored projects and
16 programs for one LOB, gas distribution, TURN learned that the “mandatory” flag was
17 sometimes applied: (1) incorrectly; (2) to the full scope of work when not all of the work

²⁶ Response to TURN DR 70-14.a. In a supplement to this response, PG&E stated that it attempted to quantify “the percentage” of spending on non-mandatory components within mandatory programs and was providing “additional details” in an attachment. Response to TURN DR 70-14.b Supp 01, Attachment 1. However, the attachment does not include any such percentages. However, as discussed below, it does show that some of PG&E’s mandatory designations were incorrect.

²⁷ Response to TURN DR 70-14.b Supp 01, Attachment 1. While in PG&E’s lexicon “mandatory” means that the work must be completed within one year, PG&E states that the below ground Grade 3 leak repairs are not required to be repaired by a scheduled date.

²⁸ As in the 2014 GRC and the 2015 GT&S case, TURN disagrees with PG&E’s legal interpretation of the import of the use of “best practices” in Section 963, but will save that legal discussion for the briefs.

²⁹ Response to TURN DR 70-14.b Supp 01, Attachment 1 (Explanation column).

³⁰ D.14-08-032, pp. 76-77.

1 qualified for that label; or (3) based on a dubious legal interpretation. To the extent that PG&E
2 senior officials relied on such flags in their decisionmaking (which is unknown because the
3 process is opaque), these findings call into question whether portfolio choices were made based
4 on accurate information. For example, if work that addresses relatively lower priority risks was
5 included in the portfolio based on an incorrect view that all of that work was “mandatory”, other
6 work that addressed more significant risks may have been squeezed out.

7
8 **C. Calculation of Risk Reduction Is Achievable Now and Should Be Required**
9

10 In the S-MAP proceeding, TURN has presented a methodology that has been used by
11 many electric utilities for many years that calculates risk reduction in a way that permits
12 meaningful comparison of any mitigations that are under consideration in any and all lines of
13 business in a utility. The methodology and implementing software were developed over a 10-
14 year period, 1998-2008, with the support of the Electric Power Research Institute (“EPRI”) and
15 EPRI-member utilities, including PG&E and California’s other large energy utilities. A full
16 description of the methodology, including an explanation of ways in which it avoids problems
17 with PG&E’s quantitative models, is set forth in a white paper authored by TURN’s experts, one
18 of whom helped to develop the methodology.³¹ The white paper has been made part of the
19 record of the S-MAP case and is attached to this testimony as a supporting document.

20 Before TURN presented this methodology in S-MAP, PG&E had long claimed that it was
21 not able to calculate risk reduction using its quantitative models. However, after we presented
22 our methodology, PG&E admitted that risk reduction could be calculated even using PG&E’s

³¹ *Intervenor Perspective Regarding an Improved Methodology to Promote Safety and Reliability of Electric and Natural Gas Service in California*, prepared for the S-MAP Workshop January 25, 2016 (and revised in response to workshop comments on January 28, 2016), prepared by Charles D. Feinstein, Ph.D and Jonathan A. Lesser, Ph.D on behalf of TURN, Indicated Shippers, and Energy Producers and Users Coalition.

1 current risk models. In a data request response in this case, PG&E stated that it could use its
2 RET tool to calculate a risk reduction score for a program, by running the RET sequentially,
3 modeling the risk with, and without, the program in order to determine the risk reduction.³² The
4 existence of the EPRI-developed methodology and PG&E’s acknowledgement that RET could
5 be used to calculate risk reduction show that PG&E need not wait to begin using risk reduction
6 calculations as part of its process for choosing GRC projects and programs.

7 Now that PG&E has acknowledged that methodologies exist to calculate risk reduction,
8 PG&E presents other roadblocks: “The challenge is to obtain sufficient data -- of integrity -- and
9 have sufficiently robust models through which the calculations can be performed reasonably well
10 and provide a value that is credible, verifiable and repeatable.”³³ However, if before and after
11 RET scores can be used to calculate risk reduction, PG&E needs to explain why RET and RIBA
12 would not meet the above-quoted criteria for purposes of calculating risk reduction but can be
13 advantageously used for the purpose of scoring risks and projects and programs to address those
14 risks. The “challenge” PG&E asserts applies to quantitative risk models used for any purpose.

15 If PG&E’s point is that risk reduction calculations using currently available information
16 should not be considered 100 percent reliable, TURN would not disagree, but would note that the
17 same is true of the scores that PG&E produces with its current models that rely on the same
18 available information. Even if far from perfect, using quantitative models to calculate risk
19 reduction would greatly expand the usefulness of such models in meeting the needs of the
20 Commission and the parties in choosing an optimal portfolio of risk mitigations.

21

³² Response to TURN DR 46-3 Supp 01. Because of problems with the RET scoring methodology discussed in the S-MAP white paper, TURN does not advocate that RET as currently formulated be used to calculate risk reduction. However, as the white paper explains, those problems could be corrected relatively easily if PG&E chose to do so.

³³ Response to TURN DR 46-3 Supp 01.

1 **D. Conclusions and Recommendations**
2

3 Based on the foregoing, TURN offers the following conclusions and recommendations:

4 1. PG&E did not calculate risk reduction for the mitigations it considered in its Integrated
5 Planning Process. As a result and contrary to PG&E’s claims in its testimony, that process did
6 not demonstrably lead to a 2017 GRC portfolio that includes projects and programs that are the
7 “most effective mitigation programs” and “have the greatest impact on system safety.”

8 Accordingly, the portfolio of mitigations that emerged from PG&E’s planning process is not
9 entitled to deference from the Commission.

10 2. PG&E’s opaque process for choosing its portfolio of risk mitigations impedes the
11 ability of parties and the Commission to understand the basis of PG&E’s choices and does not
12 help parties or the Commission make alternative judgments about the best ways to optimize
13 limited ratepayer funds.

14 3. “Flags” on RIBA-scored projects are not necessarily reliable.

15 4. PG&E should be required to include calculation of risk reduction and risk reduction
16 per dollar spent as part of its presentation in all future cases, including its next GT&S
17 application, and should justify any deviations from rankings derived from such measures.

18
19 **III. Concerns with PG&E’s Practice of Delaying or Deferring Work Based on**
20 **Reprioritization**

21 **A. Description of the Practice**
22

23 Continuing a practice that has drawn unfavorable attention from the Commission in its
24 recent GRCs, PG&E’s request in this case includes several forecasted amounts that are
25 significantly higher than they otherwise would be to make up for work that was deferred during
26 the period prior to the test year. The basic pattern exhibited in this case is as follows:
27

- 1 • In the 2014 GRC, PG&E identified work that it claimed was necessary and which the
2 Commission authorized for 2014-2016. Funding for that work was included in revenue
3 requirement.
- 4 • PG&E decided to forego performing a significant portion of that work in 2014-2016,
5 claiming other work took higher priority.
- 6 • Now PG&E once again says the work in question is important and seeks funding at a
7 level that is significantly higher than it would be if PG&E had simply performed the
8 work as authorized and funded for 2014-2016.

9 PG&E’s use of this practice can be illustrated by three examples from gas distribution, in
10 which several programs were curtailed significantly in the name of reprioritization. The practice
11 was not limited to gas distribution, however. Other TURN witnesses will address other instances
12 of this practice as it relates to programs and projects that are the subject of their testimony.

13 Example #1: Replacement of Plastic (Aldyl-A) Main (MAT 14D)

14 In the 2014 GRC, PG&E made the case for the need to accelerate main replacement,
15 including plastic pipe (primarily Aldyl-A). As summarized in D.14-08-032, PG&E argued that
16 “the pace of replacement must increase, or service quality and safety will decline.”³⁴ PG&E
17 proposed replacing 100 miles of plastic main annually.³⁵ After noting that PG&E had three major
18 distribution pipe explosions in 2009 and 2011 that involved Aldyl-A pipe,³⁶ the Commission
19 agreed with PG&E that acceleration of plastic main replacement was warranted and in fact
20 decided that more safety mitigation results in relation to the costs involved would be achieved by
21 authorizing an even higher level of plastic main replacement – 139 miles per year.³⁷

³⁴ D.14-08-032, p. 95.

³⁵ *Id.*

³⁶ *Id.*, p. 97.

³⁷ *Id.*, p. 98.

1 However, PG&E chose to sharply curtail plastic main replacement and actually only
2 replaced just 32 miles of Aldyl-A main in 2014³⁸ and 63 miles in 2015.³⁹ In 2016, PG&E
3 forecasts replacing 53 miles.⁴⁰

4 PG&E explains in its testimony that the sharply reduced work is due in part to a lower
5 prioritization for the pipeline replacement program within the Gas Operations portfolio based on
6 an updated assessment of relative risk.⁴¹ However, as acknowledged by PG&E's Gas
7 Distribution Pipeline Safety Report ("GDPSR") submitted on March 30, 2015, PG&E's claim is
8 not that it perceived plastic mains to pose a lower risk than presented in the 2014 GRC.⁴² In fact,
9 the GDPSR stated that main replacement "addresses a high risk relative to the overall 2014
10 portfolio."⁴³ The change in relative ranking is because PG&E determined that replacement of
11 services was a higher safety priority.⁴⁴

12 Thus, as explained later in PG&E's testimony, a key reason for the decision to curtail
13 plastic main replacement was because more capital dollars were being spent on service
14 replacement than was forecast in the 2014 GRC.⁴⁵ In addition, PG&E states that its actual unit

³⁸ Ex. PG&E-3, p. 4-22.

³⁹ GDPSR, 2015-2, p. 56.

⁴⁰ Ex. PG&E-3, p. 4-34, Table 4-7.

⁴¹ Ex. PG&E-3, p. 2-15. That discussion also blames the drop-off on the timing of the GRC decision in August 2014. However, the timing of the GRC decision, at most, could only have reduced the miles of replacement in 2014. PG&E could have tried to increase work in 2015 and 2016 to make up for the shortfall in 2014. In fact, PG&E claims that it expects total gas distribution capital spending for 2014-2016 to make up for lower than authorized spending in 2014. However, for plastic main replacement, PG&E made no such effort.

⁴² In fact, in 2015, PG&E calculated an increased risk related to MAT 14D plastic mains, when the estimated likelihood of failure increased to level 4 from level 3 in 2013 and 2014. This assessment of increased risk is reflected in an increase in the RIBA score from 433 in 2014 to 571 in 2015. PG&E response to TURN DR 48-1 Supp 01, which in turn explains the response to TURN DR 4-5.

⁴³ March 30, 2015 (2014-2) GDPSR, p. 12. As required by D.11-05-018, PG&E submits these GDPSRs twice a year, one covering the first 6 months of the year and the other covering the second 6 months. This testimony will refer to the reports by year as follows: the second report in 2014 is 2014-2.

⁴⁴ Mr. Sugar's testimony addresses in detail PG&E's development of its new service replacement policy and concludes, among other things, that: (1) with respect to the majority of service replacements covered by PG&E's new policy, it would be more cost effective to repair the tee cap causing the leak rather than replace the entire service; and (2) PG&E's RIBA score for service replacement failed to exclude tee cap issues from the analysis, leading to an inflated score for service replacements. Testimony of John Sugar, Section I.

⁴⁵ Ex. PG&E-3, p. 4-22.

1 costs to replace main came in above the forecast unit cost in the 2014 GRC and “[a]s a result, the
2 amount of main replaced in 2014 was significantly less than proposed in the 2014 GRC.”⁴⁶

3 Now, PG&E wants to resume replacement of plastic mains at approximately the same
4 100-mile per year level it requested in the 2014 GRC: 95 miles in 2017, 102 miles in 2018, and
5 108 miles in 2019.⁴⁷ In support of this request, PG&E states that this program is needed to
6 mitigate risks associated with mains built with Aldyl-A plastic and similar plastic materials
7 installed before 1985, which is susceptible to cracks leading to leaks.⁴⁸ PG&E asserts that it
8 needs to make “continued progress” on replacing pipelines that pose the greatest risk to system
9 safety, and plans to systematically increase the replacement rate of Aldyl-A year over year.⁴⁹

10 Because there is a finite amount of pre-1985 plastic main in PG&E’s system, each mile
11 that was not replaced in 2014-2016, even though funded by ratepayers, has added to the amount
12 that needs to be addressed in 2017-2019 and later years.

13 Example # 2: High Pressure Regulator Program (MWCI 2K)

14 In the 2014 GRC, PG&E reported a 2011 finding that the majority of leaks on the gas
15 transmission system were on high pressure regulator (“HPR”) facilities and that it therefore had
16 begun an aggressive program to rebuild or replace HPRs.⁵⁰ The 2014 GRC decision approved
17 PG&E’s plan to mitigate risks associated with about 1,000 s HPRs per year in each of 2014 and
18 2015.⁵¹ This work was supposed to conclude the program by the end of 2015.⁵²

⁴⁶ Ex. PG&E-3, p. 4-22 to 4-23. The accompanying testimony of Mr. Sugar (Section II.A) addresses the significant increase in unit costs for plastic main that PG&E has failed to explain or justify.

⁴⁷ Ex. PG&E-3, p. 4-34, Table 4-7.

⁴⁸ Ex. PG&E-3, p. 4-24.

⁴⁹ Ex. PG&E-3, p. 4-35.

⁵⁰ 2014 GRC, Ex. PG&E-3 (Gas Distribution), pp. 8-23 to 8-24.

⁵¹ Ex. PG&E-3, p. 5-16.

⁵² GDPSR 2014-2, p. 11.

1 PG&E’s valve program has two components: replacing valves that are leaking or can no
2 longer be operated and installing new valves, primarily emergency shutdown valves.⁶²

3 The 2014 GRC decision authorized replacing and installing a total of approximately 528
4 valves per year.⁶³ PG&E had actually sought authorization to address even more valves, but in
5 response to concerns raised by TURN and Cycla, the Commission extended the installation of
6 emergency shut-off valves from 3 to 6 years, stating that it wished to mitigate cost impacts on
7 customers and to “alleviate[] pressure on PG&E’s ability to fund competing resources and high-
8 priority programs.”⁶⁴

9 Notwithstanding PG&E’s push in the 2014 GRC to replace and install large numbers of
10 valves, PG&E states that few valves were actually installed. While PG&E’s testimony attributes
11 the curtailment of work in this program to reprioritization of higher priority work,⁶⁵ PG&E’s
12 March 30, 2015 GDPSR states that an increase in unit costs was responsible for curtailing valve
13 replacements.⁶⁶

14 In 2014, PG&E replaced and installed only 83 valves.⁶⁷ In 2015, PG&E replaced and
15 installed only 81 valves,⁶⁸ which is significantly less than the forecast of 118 included in
16 PG&E’s 2017 GRC testimony.⁶⁹ PG&E forecasts replacing and installing 169 valves,⁷⁰ a
17 forecast that is questionable considering PG&E fell far short of its 2015 forecast.

⁶² Ex. PG&E-3, p. 4-25.

⁶³ *Id.*

⁶⁴ D.14-08-032, p. 104.

⁶⁵ Ex. PG&E-3, p. 4-25. Although PG&E claims that reprioritization of higher priority work was the reason for the curtailment, PG&E did not include this program in its list of programs that were curtailed because of a change in PG&E’s risk assessment. Response to TURN DR 48-1.

⁶⁶ GDPSR, 2014-2, p. 11. With respect to new emergency shutdown valves, the GDPSR, like the 2017 testimony, attributes the curtailment to reprioritization.

⁶⁷ GDPSR, 2014-2, p. 68, Table 10-1.

⁶⁸ GDPSR, 2015-2, p. 56, Table 10-1.

⁶⁹ Ex. PG&E-3, p. 4-39, Table 4-9 .

⁷⁰ *Id.*

1 Now, PG&E seeks to ramp up this program again, forecasting replacement and
2 installation of 346 valves per year in 2017 to 2019.⁷¹

3 **B. PG&E Needs to Show That Its Reprioritizations Are Necessary and**
4 **Reasonable; Limiting Spending to Authorized Levels Is Not a Valid Justification**
5

6 In recent PG&E GRC decisions, the Commission has expressed concern about PG&E's
7 practice of deferring work that was requested and authorized in previous GRCs, deferred, and
8 then re-requested in another GRC.

9 Decision 11-05-018

10 In D.11-05-018, the decision in PG&E's 2011 GRC, the Commission went to the trouble
11 of including a full section entitled "Reprioritization and Cost Deferrals," even though most issues
12 in the case had been resolved by a settlement approved in that decision.

13 The Commission began its discussion by acknowledging that the utility should have some
14 flexibility to reprioritize activities in order to manage its operations in a safe and reliable
15 manner.⁷² However, the Commission noted that not everything the utility does in the name of
16 reprioritization is "necessary or reasonable."⁷³ In this regard, the Commission highlighted two
17 concerns.

18 First, the utility has the responsibility to spend what is necessary to ensure safe and
19 reliable service, even if that means spending above authorized levels: "To the extent a utility
20 uses authorized cost levels as a reason for deferring activities, the Commission must be assured
21 that such deferrals are otherwise reasonable especially with respect to safe and reliable
22 service."⁷⁴

⁷¹ *Id.*

⁷² D.11-05-018, p. 27.

⁷³ D.11-05-018, p. 28.

⁷⁴ D.11-05-018, p. 29.

1 Second, the Commission pointed out that reprioritization, “justified or not”, undermines
2 the utility’s accountability for using ratepayer funds efficiently: “Much of what is authorized is
3 based on the utility’s depiction of its needs and associated costs. Those needs and costs are
4 tested by the GRC process. Reprioritized needs and associated costs may not be so tested and
5 may not result in the most efficient use of funds.”⁷⁵

6 The Commission concluded its discussion with the following cautionary language:

7 The Commission will be critical in its evaluation of previously requested
8 activities or projects that were deferred and re-requested keeping in mind
9 that the utility has the obligation to maintain its operations and its plant
10 in the condition to provide efficient, safe and reliable service, even if that
11 condition requires more expenditures than the Commission has
12 authorized.⁷⁶

13
14

15

16

17

18

Decision 14-08-013

19 In the 2014 GRC, PG&E continued its practice of deferring significant expenditures
20 based on reprioritization. In response, ORA submitted policy testimony that is largely applicable
21 to this case and that includes in its attachments to this testimony.⁷⁷

22 D.14-08-013 made several adjustments to PG&E’s request to address problematic
23 deferrals of work. For example, with respect to pole inspections, the Commission made clear

⁷⁵ D.11-05-018, p. 29.

⁷⁶ D.11-05-018, p. 31.

⁷⁷ A.12-11-009, Ex. DRA-7, DRA Testimony on Electric Distribution Capital Expenditures, Part 1 of 2, pp. 11-18. Even though DRA’s testimony was offered in reference to electric distribution capital expenditures, the discussion is generally applicable to any spending, capital or expense, that is deferred based on reprioritization.

1 that the emergence of other higher priority work does not, by itself, justify curtailing other work
2 of ongoing importance:

3 Even assuming that such obligations for higher priority work was of a
4 higher priority, PG&E fails to demonstrate that such obligations for
5 higher priority work forced the postponement of forecasted pole
6 inspections. PG&E voluntarily chose not to perform previously
7 forecasted pole inspections. Obligations to complete unforeseen projects
8 deemed to have a higher-priority does not explain why PG&E shouldn't
9 (or couldn't) also fund lower-priority projects (such as pole inspections),
10 particularly if such projects had been previously found necessary to
11 provide safe, reliable service.⁷⁸

12
13 The Commission further explained that the risk of spending above authorized levels and
14 experiencing reduced earnings did not justify deferred work based on reprioritization:

15 We recognize that PG&E's earned rate of return may have been lower as
16 a result of spending more money on pole inspections in addition to other
17 higher priority work. The risk of earning a lower return, however, does
18 not justify PG&E's choice to allow a pole inspection backlog to develop
19 at ratepayer expense.

20
21 With respect to pole replacements, which are capital expenditures, the Commission again
22 found that PG&E had improperly deferred work based on a supposed need to reprioritize
23 spending:

24 By paying for unanticipated higher-priority expenditures out of ratepayer
25 revenues, rather than out of retained earnings, PG&E's shareholders
26 were protected from the risk that such unanticipated spending would
27 erode profits. To provide this protection to shareholders, PG&E curtailed
28 implementation of the programs which ratepayers had funded. PG&E
29 now seeks similar funding from ratepayers in this subsequent GRC to
30 pay for a program that was curtailed. Utility spending should not be
31 driven simply by the timing of rate relief by deferring pole replacements
32 at levels based on previously adopted forecasts. Accordingly, although
33 we do not expect PG&E to implement its workload in an inflexible
34 manner, we do not believe that ratemaking should provide an incentive
35 to ration projects based upon the timing of rate cases. We thus reduce

⁷⁸ D.14-08-032, p. 190.

1 PG&E’s test year revenue requirement to exclude the effects of capital
2 expenditures for deferred maintenance for pole replacements incurred in
3 2013, as discussed above.⁷⁹

4
5 In this context, the Commission also specifically rejected the notion that authorized
6 spending levels in a GRC should serve as a cap on utility spending: “PG&E bears
7 the risk that, as a result of spending obligations, the earned rate of return may be less
8 than the authorized return. While PG&E has finite funds to meet capital and
9 operational needs, PG&E is not restricted to spending only up to the forecast adopted
10 in a GRC.”⁸⁰

11 The lessons from these two decisions include the following:

- 12 (1) The utility has the responsibility to spend what is necessary to ensure safe and reliable
13 service, even if that means spending above authorized levels;
- 14 (2) The emergence of higher priority work does not, by itself, justify curtailing lower priority
15 projects, particularly if such projects had been previously found necessary to provide
16 safe, reliable service;
- 17 (3) The risk of spending above authorized levels and experiencing reduced earnings, by
18 itself, does not justify deferring work based on reprioritization; and
- 19 (4) Utilities should not ration projects based on the timing of rate cases.

20 **C. The Commission’s Identified Concerns Are Present With Respect to Much of the**
21 **Deferred Work for Which PG&E is Now Requesting Funding a Second Time**

22 Invoking the reprioritization rationale, PG&E has again chosen to defer work that it
23
24 previously indicated was important and was funded to perform. And, again, for this deferred

⁷⁹ D.14-08-032, p. 198.

⁸⁰ D.14-08-032, p. 197 (emphasis added).

1 work, PG&E is requesting funding in this GRC that is higher than it otherwise would be because
2 of the curtailed efforts.

3 As was the case in the past, PG&E deferred this reprioritized work in order to limit the
4 amount of spending in excess of authorized levels and therefore to limit the exposure of
5 shareholders to reduced earnings. In response to a TURN data request, PG&E has explained that
6 it uses reprioritization as a response when “emerging issues” arise.⁸¹ Such emerging work could
7 include new work or “unplanned costs” or even, “increases in cost estimates.”⁸² If such an
8 emerging issue arises, PG&E’s lines of business will first try to “fund” the emerging work
9 through reprioritization within the LOB, i.e., by curtailing previously planned work in order to
10 offset the cost of the emerging work.⁸³ If the emerging issues cannot be funded through
11 reprioritization within the LOB, the LOB may seek enterprise-level “reserve” funds to pay for
12 the emerging work.⁸⁴ Such an approach of curtailing work that has previously been found
13 necessary in order to avoid exceeding authorized spending levels runs directly counter to the
14 guidance previously provided by the Commission.

15 The Gas Distribution examples described above illustrate the unreasonableness of
16 PG&E’s deferral of work based on reprioritization. For each program, PG&E asserted in the
17 2014 GRC that the work was important and needed to be funded at the requested level. With
18 respect to Aldyl-A main, the Commission even found that PG&E should do more work. In this

⁸¹ Response to TURN DR 34-4.b and 34.c. See also, Ex. PG&E-2, p. 4-7.

⁸² Response to TURN DR 34-4.b.

⁸³ Response to TURN DR 34-4.c.

⁸⁴ Response to TURN DR 34-4.c. The use of reserve funds is another means by which authorized and ratepayer funded work deemed to be lower priority is deferred in favor of higher priority work. Response to TURN DR 19-3.b.i (reserve is generally funded by reducing expenditures on lowest priority work). As an apparent last resort, PG&E claims that, if the level of available spending, including the targeted reserve amount, is not adequate to fund the needs of the business at the targeted level of earnings, then the earnings target is reduced. Response to TURN 34.f. With respect to the deferred work that is the subject of this testimony, PG&E did not follow the approach of accepting reduced earnings, and instead curtailed certain authorized work to offset the cost of work it perceived to be of higher priority.

1 GRC, PG&E once again claims that the same work is necessary for safety and worthy of
2 funding. As PG&E states at the outset of its Gas Distribution testimony: “Our forecast
3 represents the amount of work PG&E needs to perform to safely and reliably operate our natural
4 gas facilities in a manner consistent with industry best practices.”⁸⁵

5 PG&E chose to curtail these programs in 2014-2016 order to limit its spending above
6 authorized levels, which the Commission has made clear is not an acceptable reason to ask
7 ratepayers to pay again for the same work. As in the two previous GRCs, PG&E has failed to
8 show that it shouldn’t or couldn’t have continued to perform the work it deemed to be lower
9 priority, particularly when in both the 2014 GRC and this case PG&E claims the work is
10 important and needs to be done.⁸⁶

11 As discussed in D.11-05-018, PG&E’s deferrals also undermine the company’s efficiency
12 incentives and its accountability for efficient spending, which is also shown by the Gas
13 Distribution examples. PG&E cut back the Aldyl-A main replacement program and other
14 programs to make room for significantly increased spending for service replacements, based on a
15 new policy that was not reviewed in the 2014 GRC. As a result, consistent with the
16 Commission’s concerns in D.11-05-018, the need for, and efficiency of, that new service
17 replacement policy was not tested before the Commission. As Mr. Sugar explains, it turns out
18 that PG&E’s new policy is not at all cost-effective because the policy results in costly
19 replacement of services when in the majority of cases a much less expensive tee cap repair will

⁸⁵ Ex. PG&E-3, p. 1-16.

⁸⁶ Of the three illustrative programs discussed above, in only the HPR program (MAT 2K) does PG&E claim that it found the program to be less important from a safety perspective. However, as shown above, that assessment was based on risk scoring for only one year, 2013. In the two succeeding years, PG&E found the risks to be higher than it estimated in 2013. The fact that PG&E did not ramp up the program again after its 2014 score significantly raised the risk assessment calls into question how responsive PG&E’s funding decisions were to its risk assessments for this program.

1 fully address the problem.⁸⁷ Furthermore, as noted above, the 2014 GRC decision directed
2 PG&E to replace even more plastic main than PG&E had proposed, precisely to achieve more
3 safety mitigation with the allocated funds, a goal PG&E frustrated by severely cutting back the
4 program.

5 In this regard, it is troubling that PG&E attempts to justify its curtailment of work in part
6 based on cost increases above unit costs that were forecast and adopted in the 2014 GRC. For
7 example, PG&E states that higher than forecast unit costs for replacing main is one of the
8 reasons for curtailing Aldyl-A main replacement.⁸⁸ And it appears that PG&E's inability to
9 control cost increases was a factor in curtailing the HPR program. The 2014 forecast and
10 adopted HPR unit cost was \$51.50,⁸⁹ but PG&E now forecasts 2017 unit costs at \$110.⁹⁰ PG&E
11 says that its earlier HPR work dealt with easy lower cost solutions and future work will be more
12 difficult and more costly.⁹¹ But the 2014 adopted unit cost was to address all remaining HPRs,
13 presumably in all types of locations, so PG&E seems to be trying to spread out the work –
14 rationing the work based on timing of rate cases (to use the phrase from D.14-08-032) -- to
15 obtain higher unit costs from ratepayers than PG&E would if it simply performed the work it was
16 requested and funded to do.

17 A practice of curtailing supposedly lower priority work if authorized work comes in over
18 budget undermines the efficiency incentives that the rate case process is supposed to create. If
19 allowed with impunity, the result of such a practice would be to effectively allow the utility to do

⁸⁷ Testimony of John Sugar, Section I.

⁸⁸ Ex. PG&E-3, p. 4-22.

⁸⁹ GDPSR, 2014-2, Table 10-1, p. 68.

⁹⁰ Ex. PG&E-3, p. WP 5-26.

⁹¹ Ex. PG&E-3, p. 5-17.

1 less work for the authorized funding level, which saps the utility’s incentive to control costs. As
2 the Commission has explained:

3 We know in prospective year ratemaking that our adopted estimates of
4 revenues and expenses may be at variance with actual hindsight
5 experience. But we do not view this as a problem, because we are
6 extending to utility management an opportunity and incentive to find
7 ways to conduct operations for less than projected. When it can do this it
8 flows the benefit to the utility’s bottom line, which means profit. . . .
9 Keeping this incentive for utility management is the cornerstone of
10 ratemaking If ratemaking ever becomes so conceptually upside
11 down that utility management loses the economic incentive to exercise
12 its business acumen, California will be in a sad posture and will suffer
13 under utility management which is lethargic with a ‘cost plus’
14 mentality.⁹²

15
16 When costs between rate cases come in higher than forecast and adopted, the Commission
17 expects utilities to “respond to cost increases in some areas by striving harder to achieve savings
18 elsewhere,”⁹³ not to put off the work until the next case and hope to be awarded more funding, at
19 a higher unit cost to do the same work the utility was already funded to perform.

20
21 **D. Ratemaking Adjustments or Forecast Reductions Are Warranted for Work**
22 **Deferred As a Result of Unnecessary or Unreasonable Reprioritization**
23

24 When the Commission finds that a utility has unreasonably deferred work and seeks in a
25 subsequent rate case to have ratepayers fund the work a second time, the Commission has not
26 hesitated to protect ratepayers by reducing the utility’s forecast to prevent double recovery.

27 A typical approach is to order a ratemaking adjustment (in an appropriate amount under
28 the facts of the case) that makes shareholders responsible for the deferred work, while making
29 clear that the Commission still expects the deferred work to be performed. For example, in
30 D.14-08-032, the Commission found that part of PG&E’s requested pole inspection forecast was

⁹² D.96-12-066, slip op., pp. 4-5, quoting D.85-03-042, 17 CPUC 2d 246, 254.

⁹³ D.96-12-066, slip. op., p. 5.

1 made necessary by PG&E’s past failure to spend authorized funds for this work. The
2 Commission stated:

3 We conclude that timely completion of this level of inspections is
4 appropriate from an operations perspective to promote safe and reliable
5 service. For ratemaking purposes, however, we conclude that the portion
6 of 2014 forecast expense for pole inspections that exceeds the 235,000
7 pole amount constitutes deferred maintenance that should be paid for out
8 of shareholder retained earnings.⁹⁴

9
10 As indicated by this example, this approach is appropriate when the Commission believes that
11 the deferred work is necessary for safe and reliable service.

12 An alternative approach is for the Commission to treat the past curtailment of work based
13 on reprioritization as an indication that the utility has failed to justify its forecast, warranting a
14 forecast reduction. Effectively, the utility’s deferral of previously authorized work undermines
15 the utility’s credibility when it requests funding the same work in the next rate case. Reducing
16 the forecast (by the appropriate amount under the facts of the case) prevents ratepayers from
17 having to pay for the work a second time.⁹⁵

18
19 **E. TURN’s Recommendations Regarding Deferred Gas Distribution Work**

20
21 This section presents TURN’s recommendations regarding the three examples of deferred
22 Gas Distribution work discussed above.

23 Aldyl A Pipe – MAT 14D

24 As noted above, PG&E was funded to replace 139 miles per year in 2014-2016, for a
25 total of 417 miles. In 2014 and 2015, PG&E actually only replaced 95 miles,⁹⁶ and, in 2016,

⁹⁴ D.14-08-032, p. 189.

⁹⁵ TURN’s recommended forecast reduction for Atmospheric Corrosion Mitigation (MWC FH) in Mr. Sugar’s accompanying testimony (Section IV.A) uses this approach in response to PG&E’s request for ratepayers to pay a second time for work that PG&E previously decided was not important enough to perform.

⁹⁶ 2014: Ex. PG&E-3, p. 4-22. 2015: GDPSR, 2015-2, p. 56

1 PG&E forecasts replacing 53 miles,⁹⁷ for a 2014-2016 total of 148. The shortfall between
 2 authorized and funded miles and actual miles replaced, a shortfall of 269 miles or 90 miles per
 3 year. For the reasons provided in this testimony, ratepayers should not have to pay again for
 4 replacement of these 90 miles per year. In 2017-2019, PG&E forecasts replacing an average of
 5 102 miles per year, work that TURN agrees is necessary for safe and reliable service.

6 Accordingly, as a ratemaking adjustment in the 2017-2019 rate case period, shareholders
 7 should pay to replace the 90 miles per year for which ratepayers have already paid, and
 8 ratepayers should pay for the remaining 12 miles per year.⁹⁸ Using the reduced unit cost for
 9 MAT 14D of \$399/foot recommended in the accompanying testimony of Mr. Sugar,⁹⁹ the
 10 resulting ratepayer-funded cost for the 12 miles would be \$27,364,000¹⁰⁰ in 2017, as shown
 11 below.

PG&E 2017 forecast	TURN Recommendation	Difference
\$248,598,000	\$27,364,000	\$221,234,000

12

13 High Pressure Regulators – MAT 2K

14 As shown above, PG&E received funding to rebuild or replace 2,000 HPRs in 2014 and
 15 2015, and thereby complete this program. Accordingly, ratepayers have already paid to
 16 complete this program, and should not have to pay for any work in 2017-2019, all of which
 17 constitutes deferred work.

⁹⁷ Ex. PG&E-3, p. 4-34, Table 4-7.

⁹⁸ In the next rate case, assuming PG&E performs the full amount of forecasted work at reasonable cost, it should be able to add the full amount of its expenditures for this work into rate base.

⁹⁹ Testimony of John Sugar, Section II.A.

¹⁰⁰ 12 miles X \$399/foot X 5,280 feet/mile, plus 12% (90/102) of [\$15,461 (cross bore adder) + \$1,899 (engineering adder)]

1 The same outcome results when one considers the shortfall of work that ratepayers have
 2 already funded, but PG&E did not perform. PG&E only addressed 830 units in 2014-2016,¹⁰¹
 3 a shortfall of 1,170, or 390 per year over the 2017-2019 period. PG&E forecasts rebuilding or
 4 replacing 375 units in 2017, which is less than the amount of deferred work that ratepayers have
 5 already funded.

6 Accordingly, as a ratemaking adjustment in the 2017-2019 rate case period, shareholders
 7 should pay to replace the full forecast amount of work, for which ratepayers have already paid.¹⁰²

PG&E 2017 forecast	TURN Recommendation	Difference
\$41,123,000	\$0	\$41,123,000

8

9

Valves – MAT 50E

10 PG&E was funded to replace and install 528 valves per year, a total of 1,584 from 2014-
 11 2016. PG&E only addressed 164 valves in 2014 and 2015 and forecasts addressing another 169
 12 in 2016,¹⁰³ for a total of 333 valves. This yields a shortfall of 1,251 valves, or 417 per year that
 13 PG&E will be making up in 2017-2019 period. PG&E forecasts replacing and installing 343
 14 valves per year,¹⁰⁴ which is less than ratepayers have already funded. Ratepayers should not
 15 have to pay again for this work in the 2017-2019 rate case period.

16 Accordingly, as a ratemaking adjustment in the 2017-2019 rate case period, shareholders
 17 should pay to replace the full forecast amount of work, for which ratepayers have already paid.¹⁰⁵

PG&E 2017 forecast	TURN Recommendation	Difference
\$15,679,000	\$0	\$15,679,000

¹⁰¹ 410 units in 2014, 120 units in 2015, and 300 units forecast for 2016.

¹⁰² In the next rate case, assuming PG&E performs the full amount of forecasted work at reasonable cost, it should be able to add the full amount of its expenditures for this work into rate base.

¹⁰³ Accepting this 2016 forecast is generous to PG&E in light of how much PG&E fell short of its 2015 forecast.

¹⁰⁴ Ex. PG&E-3, p. 4-39.

¹⁰⁵ In the next rate case, assuming PG&E performs the full amount of forecasted work at reasonable cost, it should be able to add the full amount of its expenditures for this work into rate base.

1 **IV. GAS DISTRIBUTION RECORDKEEPING**

2 **A. Scoping Ruling and PG&E’s Supplemental Testimony**
3

4 In the December 1, 2015 Scoping Ruling in this case, the Commission directed PG&E to
5 provide supplemental testimony that, with respect to Gas Distribution recordkeeping, required
6 PG&E to identify each project or program in this GRC and the 2014 GRC – and the associated
7 costs – that, in whole or in part, include among their purposes correction of inaccurate records,
8 supplying missing as-built information, assessing the accuracy of records of maximum allowable
9 operating pressure, or making inaccessible records accessible. For any such costs that affect the
10 revenue requirement requested in this case and that PG&E has not removed from its request, the
11 Ruling directed PG&E to explain why this outcome is just and reasonable.

12 PG&E submitted its supplemental testimony on January 22, 2016. In summary, the
13 supplemental testimony identified only four expense projects, with 2017 forecast expense
14 amounts totaling \$3.4 million, that meet the Scoping Ruling’s criteria.¹⁰⁶ In PG&E’s view, no
15 capital programs or projects met the criteria.

16 Chapter 3 of the supplemental testimony includes a discussion of the Pathfinder project,
17 which PG&E’s 2014 GRC testimony described as “a project to convert key gas distribution asset
18 and maintenance information from existing legacy and paper-based systems to the SAP and GIS
19 systems.”¹⁰⁷ PG&E recorded \$17.5 million in capital expenditures to this project in 2014¹⁰⁸ and
20 forecast an additional \$16.7 million in 2015.¹⁰⁹ The supplemental testimony asserts that
21 Pathfinder did not meet any of the Scoping Ruling’s criteria, but included it in a list of projects

¹⁰⁶ Ex. PG&E-17, pp. 1-7 to 1-8. In the relevant chapters, PG&E takes the position that it is reasonable for these amounts to be included in revenue requirement. See Chapters 2 and 4.

¹⁰⁷ 2014 GRC, Ex. PG&E-3, p. 11-12. PG&E says Pathfinder was completed in 2015. Ex. PG&E-3, p. 9-15.

¹⁰⁸ Ex. PG&E-17, p. 3-7, Table 3-6.

¹⁰⁹ Ex. PG&E-17, p. 3-6, Table 3-5, showing forecast from the 2014 GRC. At the time of preparing this testimony, TURN did not have the 2015 recorded spending for this project, but will update this testimony when it obtains that figure.

1 that, while not related to making inaccessible records accessible, were designed to improve the
2 accessibility of records.¹¹⁰ PG&E claims that correcting inaccurate was not one of the purposes
3 of Pathfinder, although “enhancing” or “correcting” the mapping data in GIS “was a small
4 portion of the functionality” of Pathfinder.¹¹¹

5 **B. PG&E’s Supplemental Testimony Is Inconsistent With PG&E’s Response in**
6 **the Distribution Recordkeeping Investigation and Information Provided in**
7 **PG&E Reports to the Commission**
8

9 On November 20, 2014, the Commission issued OII 14-11-008 to review and determine
10 whether PG&E’s recordkeeping practices for its gas distribution system have been unsafe and in
11 violation of the law. The OII responded to six separate incidents between 2010 to 2014 creating
12 significant threats to employee and public safety. As detailed in accompanying SED
13 investigative reports, each incident resulted in the release of natural gas into the atmosphere,
14 some resulted in evacuations and service outages, and one caused an explosion that destroyed a
15 house in Carmel.¹¹² A key cause of each of the incident was erroneous or incomplete PG&E
16 records that caused PG&E employees to be unaware of the true location or features of PG&E
17 facilities.¹¹³ The OII ordered PG&E to show cause why it should not be found to have engaged
18 in unsafe practices in violation of various laws and subjected to significant penalties. It also
19 ordered PG&E to submit a report that explained, among other things, what corrective actions
20 PG&E had already taken in response to the recordkeeping failures identified in the SED
21 investigation reports.¹¹⁴

¹¹⁰ Ex. PG&E-17, pp. 3-4 to 3-5.

¹¹¹ Ex. PG&E-17, p. 3-11.

¹¹² OII 14-11-008, pp. 2-7.

¹¹³ *Id.*

¹¹⁴ *Id.*, p. 9.

1 PG&E’s December 22, 2014 Report in response to the OII, attached in full to this
2 testimony, includes a 12-page section bearing the heading: “PG&E Has Made Substantial
3 Efforts to Enhance Its Gas Distribution Recordkeeping with the Goal of Minimizing Future
4 Events Similar to the Identified Incidents.”¹¹⁵ One of the subheadings in that section is
5 “Accuracy Improvements.”¹¹⁶ That subsection begins: “PG&E has undertaken substantial efforts
6 to improve the accuracy of its gas distribution asset data so that PG&E’s asset management
7 systems incorporate the best and most complete available information.”¹¹⁷ Under a subsequent
8 heading, “The Gas Distribution GIS Makes Asset Information More Accurate and Accessible,”
9 PG&E highlighted the Pathfinder project:

10 PG&E is currently implementing a gas distribution geographic
11 information system (“GD GIS”) as part of its multi-year, multi-million
12 dollar Pathfinder project, which is a foundational effort to make the
13 information that PG&E collects, stores, and manages in relation to its gas
14 distribution pipeline system and its related business processes **more**
15 **accurate, complete, and accessible.**¹¹⁸
16

17 Thus, according to PG&E’s OII response, Pathfinder was a “foundational effort” to
18 increase the accuracy, completeness, and accessibility of PG&E’s records and a key
19 demonstration of PG&E’s “substantial efforts” to improve the accuracy of its records. It would
20 appear that, when PG&E was trying to avoid significant penalties, PG&E was willing to admit
21 what it denies here – that an important purpose of the Pathfinder project was to enable the
22 correction of inaccurate and incomplete records of the type that caused the incidents on which
23 the OII was based.

¹¹⁵ PG&E’s Initial Report in Response to OII, I.14-11-008, December 22, 2014, p. 5.

¹¹⁶ *Id.*, p. 6.

¹¹⁷ *Id.* (emphasis added).

¹¹⁸ *Id.* (emphasis added).

1 PG&E’s GDPSRs provide further evidence that the GD GIS implemented via Pathfinder
2 has served the purpose of improving the accuracy of PG&E’s records, as described in PG&E’s
3 OII response.

4 In the GDPSRs, PG&E is required, in each six-month reporting period, to “identify and
5 explain any discrepancies found with pipeline records and report if no records exist.” PG&E
6 describes the list it provides in response to this requirement as including: “when active facilities
7 are not mapped; the facilities are on the map but not in the field; or when other inaccuracies are
8 found in PG&E’s maps.”¹¹⁹ PG&E has reported huge numbers of discrepancies in these reports.
9 For example, PG&E listed 345 specific discrepancies in 2014-1,¹²⁰ 390 in 2014-2,¹²¹ 510 in
10 2015-1,¹²² and 2,611 in 2015-2.¹²³ In these reports, many of the listed discrepancies are for such
11 potentially dangerous situations as “Facilities in field not on map,” and other include equally
12 dangerous problems such as “Facilities shown in wrong location” and “Wrong size/type of
13 equipment.”

14 In the 2015-2 report, PG&E explains the dramatic increase in the number of reported
15 discrepancies because of a changed method that provides a “more accurate volume and analysis
16 of completed mapping corrections,”¹²⁴ suggesting previous reports may not even have captured
17 all discrepancies. PG&E attributed this improved method to using data from the GIS and SAP
18 systems that were developed in the Pathfinder project.¹²⁵

19 These reports show that PG&E’s efforts to improve the accuracy of its records described
20 in its OII response, including the Pathfinder project, were clearly necessary and have found a

¹¹⁹ See, e.g., GDPSR, 2014-1, p. 53.

¹²⁰ *Id.*, Table 13b-1.

¹²¹ GDPSR, 2015-1, p. 84, Supplemental Table 13B-1.

¹²² *Id.*, p. 72, Table 13B-1.

¹²³ GDPSR, 2015-2, p. 67, Table 13B-1.

¹²⁴ *Id.*, p. 66.

¹²⁵ *Id.*.

1 very large number of problems with PG&E’s records, many of which, if not corrected, would put
2 employee and public safety at risk.

3 **C. TURN’s Recommended Disallowance**

4
5 Contrary to PG&E’s assertions in its supplemental testimony, the Pathfinder project was
6 clearly a key effort by PG&E to remedy its past mismanagement of its gas distribution records –
7 mismanagement that put employee and public safety at risk. As the Commission has repeatedly
8 held, ratepayers should not be required to pay the costs that are necessary to remedy a utility’s
9 imprudence.

10 Recognizing that improving the accuracy of PG&E’s troubled records was probably not
11 the sole purpose of the Pathfinder project, TURN recommends that 50% of PG&E’s 2014 and
12 2015 capital spending be disallowed, as follows.

	2014	2015 ¹²⁶
Expenditures	\$17,530,000	\$16,690,000
50% Disallowance	(\$8,765,000)	(\$8,345,000)

13

14 This concludes my testimony.

¹²⁶ As previously noted, the 2015 expenditures shown are based on PG&E’s 2014 GRC forecast. TURN will update its recommendation based on 2015 recorded spending once it obtains that information.

Appendix A

STATEMENT OF QUALIFICATIONS OF THOMAS J. LONG

Mr. Long is TURN's Legal Director. He has practiced before, or been employed by, the California Public Utilities Commission for almost 30 years and, in that period, has been involved, as an advocate or Commissioner advisor, in numerous important CPUC proceedings in the energy and telecommunications sectors. Since rejoining TURN in September 2011, Mr. Long has served as TURN's lead attorney in several Commission proceedings relating to gas pipeline safety, including PG&E's 2015 Gas Transmission and Storage application (A.13-12-012), PG&E's Pipeline Safety Enhancement Plan ("PSEP") proceeding (R.11-02-019), the Sempra Utilities PSEP proceeding (A.11-11-002), and the enforcement proceedings against PG&E relating to the San Bruno explosion and its causes (I.12-01-007), PG&E's recordkeeping problems (I.11-02-016), and alleged class location violations by PG&E (I.11-11-009). In addition, he has led TURN's efforts in the phase of the Rate Case Plan rulemaking (R.13-11-006) devoted to integrating risk analysis into general rate cases ("GRCs"), including speaking on two panels in multi-day workshops relating to integrating risk assessment and mitigation models into the GRC process. This phase culminated in Decision (D.) 14-12-025. Currently, he represents TURN in the Safety Model Assessment Proceeding ("S-MAP") (A.15-05-002 et al.), actively participating in five workshops, the Risk Lexicon Working Group, and the Metrics and Reporting Working Group.

Other energy cases in which Mr. Long has participated include the Diablo Canyon prudence review, PG&E's Cornerstone application, the Commission's investigation into the 2003 PG&E Mission Substation fire, the Community Choice Aggregation ("CCA") rulemaking,

PG&E's 2011 and 2014 general rate cases, the 2012 Sempra general rate case, and Southern California Edison's 2011 rate design proceeding.

Prior to re-joining TURN as its Legal Director in September 2011, he served as a Deputy City Attorney for the City and County of San Francisco ("CCSF") for over six years. There, among other duties, he represented CCSF in proceedings before the CPUC and advised the City's Public Utilities Commission on its efforts to implement a CCA program. From 2001 through 2004, he served as a policy and legal advisor to CPUC President/Commissioner Loretta Lynch. Before that, he was TURN's Senior Telecommunications Attorney from 1990 through 2000. Mr. Long began his legal career as a Litigation Attorney for the law firm of Morrison & Foerster from 1986 to 1989, after serving as Law Clerk to United States District Court Judge Rudi M. Brewster.

Mr. Long earned his B.A. with High Honors in Economics and Political Science from Swarthmore College and his J.D. *cum laude* from New York University School of Law.