BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms. U 39 G	R.11-02-019 (Filed February 24, 2011)

PACIFIC GAS AND ELECTRIC COMPANY'S REPLY BRIEF

WILLIAM V. MANHEIM
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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MISCELLANEOUS

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I. INTRODUCTION

PG&E's Pipeline Safety Enhancement Plan ("PSEP") is an unprecedented, multi-year program to implement new gas transmission safety regulations established by the Commission that are unparalleled in the United States. Phase 1 of the PSEP includes several complementary initiatives that are intended to meet the Commission's new gas safety regulations, including: (1) Pipeline Modernization; (2) Valve Automation; (3) the Pipeline Records Integration Program; and (4) Interim Safety Enhancement Measures. PG&E supported its August 26, 2011 PSEP filing with a thorough engineering analysis and detailed cost estimates.

Several parties to this proceeding—including the Division of Ratepayer Advocates ("DRA") and The Utility Reform Network ("TURN")—claim that PSEP is necessary to remedy PG&E's historic mismanagement, and therefore rate recovery should be largely disallowed. Their arguments are premised on an incorrect implication that the Commission in Decision ("D.") 11-06-017 has merely ordered the utilities to comply with pre-existing regulatory mandates. DRA, TURN and the other intervenors diminish the significance of the new safety enhancements that the Commission has adopted for California gas transmission pipeline operators. The new requirements surpass existing and anticipated gas transmission pipeline regulation at the federal level, and are a clear departure from the grandfathering of pre-1970 vintage pipelines under current federal regulations. As PG&E demonstrates in the body of this Reply Brief, regulations in place prior to Commission Decision 11-06-017 did not require PG&E to: (1) hydrotest pipelines that were installed prior to July 1, 1961; (2) validate the Maximum Allowable Operating Pressure ("MAOP") of all gas transmission pipelines through traceable, verifiable, and complete records; or (3) install automated shut-off valves. However, in instances where hydrotesting or other work must be done to comply with pre-existing regulations, PG&E has committed that such work will be ineligible for cost recovery in the PSEP.

Nor was the PSEP intended to be a panacea to cure all alleged deficiencies noted in the National Transportation Safety Board ("NTSB") report or the Independent Review Panel ("IRP") report, as some intervenors suggest.[1] PG&E has accepted the recommendations in these reports and is working to implement them across many coordinated work streams. The PSEP, however, was developed to comply with Commission Decision 11-06-017, which required PG&E to submit a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan to: (1) comply with the requirement that all in-service natural gas transmission pipelines in California that have not been previously pressure tested be strength tested or replaced; (2) complete the MAOP determination based on pipeline features; (3) include interim safety enhancement measures that will enhance public safety during the implementation period; (4) consider retrofitting pipelines to allow for in-line inspection ("ILI") tools; and (5) consider the use of automated shut-off valves.[2] PG&E's PSEP was not designed to address other recommendations of the NTSB or the IRP.

It is important to keep in mind that the PSEP was a first step in an Order Instituting Rulemaking ("OIR") that will continue to evaluate safety issues, such as emergency response and the gas safety plans. Many of the recommendations made by parties, such as the City of San

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1 For example, the City of San Bruno argues that the Commission should require PG&E to develop a more "comprehensive" PSEP that implements the NTSB recommendations and establishes a comprehensive emergency response procedure. City of San Bruno Opening Brief, pp. 3-4.

2 D.11-06-017, Ordering Paragraphs 1, 4, 5, 8.

Bruno's recommendation to improve emergency response procedures, could be addressed in the context of the broader, ongoing rulemaking, should the Commission deem that to be appropriate. The parties' recommendations that the PSEP be resubmitted to address issues outside of Decision 11-06-017, however, are misplaced.

The parties make several proposals with respect to the technical aspects of the Pipeline Modernization Program and the Valve Automation Plan. In particular, intervenors claim that some changes should be made to the Pipeline Modernization and Valve Automation Decision Trees, that PG&E should not vary from the raw decision tree results based on engineering judgment, that PG&E should choose different mitigation for certain pipeline segments, that PG&E's hydrotesting procedures should be modified, and that PG&E should rely more on automatic, rather than remote-control valves. The parties' technical proposals—discussed in the body of this Reply Brief—do not withstand scrutiny, and should be rejected.

Finally, the parties' arguments regarding PG&E's cost estimates (primarily made by DRA) are based on incorrect assumptions and expert testimony that is not credible. PG&E's cost estimates were supported by PG&E's extensive experience constructing and operating gas transmission pipelines in California, and detailed in volumes of work papers. DRA's cost estimates—which it asks the Commission to adopt in the event that the Commission finds that cost recovery is appropriate—are based on inapposite industry averages and cost estimates from a consultant whose industry experience is derived primarily from off-shore, sub-sea pipelines.

PG&E's PSEP is an aggressive program to implement the Commission's new safety regulations, and its cost estimates are well-supported. The PSEP should be approved.

II. PARTIES' ARGUMENTS THAT PG&E SHOULD NOT RECEIVE ANY COST RECOVERY FOR PSEP ARE WITHOUT MERIT

A. The PSEP Implements Significant New Safety Standards Established By The CPUC In June 2011 And Is Not Designed To Correct Past "Errors And Omissions"

Parties repeat the mantra that the PSEP is necessary to remedy PG&E's historic mismanagement and therefore rate recovery should be largely disallowed. These parties would have one believe that there are no new safety standards adopted in D.11-06-017 and that the Commission has merely ordered the utilities to comply with pre-existing regulatory mandates or industry practices that have been in place for several decades. This "spin" misstates the facts and improperly diminishes the significance of the new safety enhancements that the Commission has adopted for California. The PSEP is a plan to comply with significant new safety standards ordered by the Commission to modernize and establish a safety margin for every gas transmission pipeline. The new requirements are unparalleled in the country and a clear departure from grandfathering of pre-1970 pipelines under current federal regulations.[3]

There are two fundamental changes in regulatory requirements that the PSEP implements. First, in D.11-06-017, the Commission ordered that every untested gas transmission pipeline must be pressure tested or replaced under the PSEP to establish a safe operating margin or "MAOP." Under the prior regulatory requirements, MAOP could be determined by methods other than pressure testing for pipelines installed prior to 1970 (under federal grandfathering regulations)[4] or 1961 (under General Order ("GO") 112). D.11-06-017 has eliminated the use of methods other than pressure testing for determining MAOP—this is clearly a significant change in regulatory requirements and not something PG&E or any other California gas utility was previously required to do as part of its historic operations. Second, the Commission has ordered PG&E and the other California gas utilities to have "traceable, verifiable and complete records readily available" for all gas transmission pipelines (High Consequence Area ("HCA") and non-HCA) at the completion of the implementation period.[5] This change in standard (for HCA pipelines) is also being considered on a national level. As described below, this entails far more than having a pressure test record for a gas pipeline and requires a massive MAOP Validation project to gather existing documents, verify them and fill in any data gaps. In addition, PG&E will require a new data management system and process to complete this validation effort

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3 Exhibit ("Ex.") 21, PG&E Rebuttal, p. 1-2, lines 18-33.

4 PG&E Opening Brief, pp. 72-74.

5 D.11-06-017, Ordering Paragraph 1; Conclusion of Law 1; pp. 18-20.

effectively and ensure that records are managed to the traceable, verifiable, and complete records readily available standard on a going forward basis. The PSEP work scope is designed to meet these new safety standards. Where work is required due to PG&E's failure to comply with past regulations, PG&E has agreed in its customer/shareholder allocation principle number 2 that such costs are ineligible for recovery in the PSEP.[6]

Below we walk through the elements of PSEP that are the focus of the parties' "remedial" arguments (primarily Pipeline Modernization and Pipeline Records Integration Program) to show that PG&E is not performing this work (or seeking cost recovery for work) that is necessary to comply with pre-existing regulatory requirements.

1. The Parties' Claims That All Pipeline Modernization Work Under The PSEP Is Remedial In Nature Miss The Mark

The parties put forth the following arguments to further their claim that all PSEP work is being done to remedy past utility mismanagement or imprudence: (1) industry standards have required hydrotesting since 1955 (or 1935 as DRA asserts); (2) PG&E should have done more hydrotesting under the Transmission Integrity Management Program ("TIMP"); (3) PG&E was planning to do Pipeline 2020 before D.11-06-017 was issued, showing that PG&E believed this work was necessary to meet existing requirements; (4) PG&E deferred work on the transmission system originally proposed under the Gas Pipeline Replacement Program ("GPRP"); and (5) there is no reason to treat cost responsibility for pipeline replacements differently than hydrotesting. Each argument is addressed below.

a. PG&E Had No Obligation To Hydrotest Transmission Pipelines Until 1961

DRA and TURN argue that PG&E had an obligation to follow and implement non-binding industry guidelines prior to Commission adoption of hydrotesting regulations in 1961, and that PG&E's failure to follow such guidelines was either imprudent or a violation of general statutory requirements to charge just and reasonable rates. The parties argue that failing to

6 PG&E Opening Brief, pp. 61-63.

follow voluntary industry guidelines should result in the wholesale disallowance of any hydrotesting on transmission pipelines installed prior to 1961. DRA argues that this disallowance should extend back to pipelines installed on or after 1935 when initial industry standards were under development (although there was no hydrotesting or record retention requirements in such guidelines) and TURN argues that the disallowance should extend to pipes installed in 1955 or later (when the industry guidelines adopted more modern standards for hydrotesting and recordkeeping).

PG&E addresses the pre-1961 industry guidelines on pages 71 to 79 of its Opening Brief and demonstrates therein that: (1) it was not imprudent for a utility to decline to follow voluntary guidance when there was no requirement to do so, particularly in the earliest stages of development; (2) prior to 1955 there was not a general requirement in the industry guidelines to hydrotest gas transmission pipelines and where there are testing recommendations in the guidelines, the technical standards (e.g., 50 psi above operating levels) are not even remotely close to modern Subpart J requirements; (3) until 1955 there were no requirements in the industry guidelines to keep hydrostatic pressure test records; and (4) CPUC General Order 28 requires the retention of documents necessary to support the cost of utility plant. A hydrostatic pressure test record (particularly where there was no obligation to conduct a pressure test) is not needed to prove the cost of a pipeline asset. TURN, in restricting its disallowance recommendation to pipelines installed from 1955 (not 1935), concedes there is no basis under DRA's argument for disallowance of hydrotesting costs all the way back to 1935.[7]

PG&E first addresses TURN's disallowance argument based on 1955 ASA guidelines. Starting in 1955 the ASA guidelines recommended post-installation hydrotesting technical standards that are close to modern requirements and included requirements to retain documentation of such pressure test records. PG&E began to follow the guidelines on a

[7] TURN Opening Brief, pp. 107-108. "The 1935 standard did not require post-installation pressure testing. . . . This '50 psi' requirement continued until adoption of the 1955 revision to B31.8, which adopted the more modern location classification with corresponding pressure test ratios ranging from 1.1 to 1.4 times the maximum operating pressure."

voluntary basis in 1955. However, the ASA standards remained voluntary until 1961 when they were largely incorporated in GO 112. Under PG&E's proposed customer/shareholder cost sharing principle number 2, the costs of PSEP hydrotests on pipelines installed from 1955 to 1960 would be ineligible for cost recovery in the PSEP only if PG&E would have been required to conduct the hydrotesting work on these pipelines if D.11-06-017 had never been issued. There is no pre-existing legal or regulatory requirement to hydrotest pipelines installed from 1955 to 1960. The ASA standards are voluntary guidelines. When the Commission adopted GO 112 it did not apply the hydrotest requirements retroactively; the Commission expressly decided that the GO 112 hydrotest requirements to establish maximum allowable operating pressure would not apply to pipelines installed prior to 1961. Similarly, in 1970 when federal pipeline regulations were adopted, the Department of Transportation ("DOT") did not institute retroactive pressure testing to establish a pipeline's MAOP. Pipelines placed into operation prior to 1970 could establish an MAOP based on the highest recorded operating pressure over a 5 year period (1965-1970) known as the grandfather rule. This confirms that a utility does not need to have a documented pressure test on a pre-1961 pipeline to be in compliance with existing regulations.

TURN argues that Public Utilities Code Section 451 incorporates prudence principles; failing to follow the 1955 ASA guideline for hydrotesting, in TURN's opinion, is imprudent and would result in a violation of Public Utilities Code Section 451.[8] This is an overreaching interpretation of the statute. Section 451 states that "all charges demanded or received by any public utility . . . for any product or commodity furnished . . . or any service rendered shall be just and reasonable. Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." This is a general statute that requires rates for services to be just and reasonable and utilities to provide services as are necessary to promote the safety, health and convenience of its customers and the public. The statute does not

[8] TURN Opening Brief, pp. 62, 75-76.

state that any utility act or omission found to be imprudent by the Commission violates section 451. Thus, even if failing to consistently follow the 1955 ASA were an "imprudent act" (an assumption that PG&E contests), it would not automatically rise to the level of a violation of law. The Commission would have to additionally determine that the "imprudent act" resulted in unjust and unreasonable rates or service under Section 451 at the time the act was performed.

TURN does not present any evidence proving that PG&E failed to comply with the 1955-1960 ASA. As part of its 2011 records search, PG&E was unable to find complete hydrostatic pressure test records for some of the pipelines installed in the 1955 to 1960 period. However, that does not mean that the tests were never conducted or documented in conformance with the ASA standards during this period. Some of the test records from this period are not "complete" under current standards but were in compliance with the recordkeeping standards at the time. Some of the pressure test records may have been lost, destroyed, or misplaced in the intervening years but, despite the loss of such records, PG&E could have remained in compliance with regulatory requirements by using alternative methods for calculating MAOP under the federal "grandfathering" rules. It does not follow that in any instance where PG&E could not locate a complete pressure test in 2011 (as part of MAOP records validation) for a pipeline placed in service during the period 1955 to 1960 that PG&E acted imprudently.

b. Parties' Claims That PSEP Hydrotesting Projects Should Have Been Done In The Past Under TIMP Are Without Basis

TURN and the City and County of San Francisco ("CCSF") argue that PG&E improperly managed its TIMP program in the past by relying on direct assessment rather than hydrostatic pressure testing or ILI to assess manufacturing threats and that if PG&E had conducted hydrotesting as part of TIMP, it would not be necessary to do so again in the PSEP. On this basis, TURN and CCSF propose disallowance of costs for several hundred miles of PSEP pressure tests, pipeline replacements and ILI retrofits projects.[9] There are a number of flaws to

[9] TURN Opening Brief, pp. 84-90; CCSF Opening Brief, pp. 39-44.

this argument which PG&E addresses below, but first it is important to explain how PG&E proposes to resolve the overlap between TIMP compliance and PSEP cost eligibility.

PG&E has agreed as part of its customer/shareholder principle number 2 that any PSEP work that is required to comply with TIMP regulatory requirements is ineligible for PSEP cost recovery and will not be charged to customers. As indicated at the evidentiary hearings, the 2012 TIMP plan now includes a number of hydrotesting projects as part of PG&E's TIMP compliance program (this was not the case when PG&E prepared and filed the PSEP in August 2011). All 2012 to 2014 TIMP hydrotesting work will be removed from PSEP cost eligibility.[10] Because at the time of the evidentiary hearings PG&E was not able to compare the 2012 TIMP plan for hydrotesting to the PSEP hydrotesting, PG&E could not quantify the reduction in scope of hydrotesting that will be charged to the PSEP program.[11] PG&E proposes the Commission adopt an annual audit procedure that will review hydrotest costs included in the PSEP balancing account for eligibility under PG&E's customer/shareholder principle number 2. As part of this annual review, PG&E will verify that none of the costs of hydrotesting or any other assessment under the TIMP program are recorded in the PSEP balancing account. Commission adoption of principle number 2 and this audit procedure will ensure that no TIMP costs are recovered in PSEP rates. This should fully address TURN's and CCSF's concerns about the TIMP program.

The detailed allegations raised by TURN and CCSF challenging the adequacy of PG&E's historic TIMP and whether PG&E used the right methods to assess pipelines under the program have all been raised in the San Bruno OII and will be addressed by the Commission in that proceeding. PG&E has not yet had an opportunity to present its testimony in that proceeding addressing its implementation of TIMP. If the Commission determines that penalties, disallowances or other remedial actions are required to address deficiencies in PG&E's TIMP program, such remedies will be adopted in the OII. It would deny PG&E its right to due process for the Commission to adopt additional disallowances in the PSEP proceeding without giving

[10] Transcript ("Tr.") (Bottorff), p. 944, line 7—p. 945, line 11.
[11] See PG&E's Opening Brief, pp. 62-63.

PG&E an opportunity to respond to the substance of these allegations.[12] It would also duplicate the efforts in the OII and potentially punish PG&E a second time for the same conduct. The only potential cross-over issue to this proceeding is resolved by PG&E's proposal to have an annual audit reviewing implementation of principle number 2 to confirm PG&E has removed TIMP compliance costs from the PSEP. If PG&E's historic TIMP assessments are determined to be inadequate and new assessments must be done to comply with TIMP requirements, these new assessments will not be charged to the PSEP ratemaking balancing account.

The heart of TURN's and CCSF's TIMP disallowance argument goes to a technical issue of TIMP compliance that they either misunderstand or are not fully explaining. TURN and CCSF argue that "manufacturing threats" should be assessed under TIMP regulations through pressure testing or ILI and that PG&E's general use of direct assessment runs contrary to this requirement.[13] TURN and CCSF overlook a critical additional consideration in making this argument. Under the TIMP rules and PG&E's Risk Management Procedures ("RMP") implementing its program, a manufacturing threat is considered "stable" and does not need to be assessed <u>unless there has been some type of event that activates the threat</u>.[14] For example, TURN raised the issue of pressure exceedences on gas pipelines.[15] If there is a pressure exceedence <u>above</u> the regulatory limit, the TIMP regulations would require PG&E to evaluate[16] and, in such a case, ILI tools or pressure testing may be appropriate to evaluate the whether a manufacturing threat has been activated.[17] But that doesn't mean that every time PG&E's TIMP Baseline Assessment Plan lists "manufacturing threat" in a data field that there has been an event

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12 California Constitution, Art. XII § 2; *People v. Western Air Lines, Inc.*, 42 Cal.2d 621, 632 (1954).

13 CCSF Opening Brief, p. 40; TURN Opening Brief, pp. 84-86.

14 The TIMP regulations state "An operator may consider **manufacturing and construction related defects to be stable defects** if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence areas. 49 C.F.R. §192.917(e)(3). (Emphasis added)

15 TURN Opening Brief, pp. 89-90.

16 49 C.F.R. §192.917(e)(3) states "If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. (i) operating pressure increases above the maximum operating pressure experienced during the preceding five years."

17 49 C.F.R. § 192.921(a)(2).

that would activate a potential manufacturing threat, as TURN and CCSF have assumed.[18] PG&E does not take the position that direct assessment is appropriate to assess an active manufacturing threat. None of the evidence cited by TURN or CCSF establishes that PG&E improperly used direct assessment to evaluate an active manufacturing threat. There is accordingly no basis for disallowing hundreds of miles of PSEP hydrotesting projects on the grounds that TIMP should have assessed these pipelines using a hydrotest. PG&E reviews all pressure exceedences (i.e., where operating pressure exceeded the regulatory limit) to evaluate whether a manufacturing threat has been potentially activated and to determine if additional pressure testing or use of ILI tools is warranted.[19] In all such cases where additional assessments are required under the TIMP regulations, this work will not be charged to the PSEP under PG&E's customer/shareholder principle number 2.

Finally, in considering this issue of TIMP/PSEP overlap, one must recognize that the PSEP complements but does not replace the existing TIMP requirements under 49 CFR 192 Subpart O. The PSEP work scope is incremental to work done today under TIMP and it exceeds federal requirements by mandating strength testing or pipe replacement for all non-strength tested pipelines regardless of class location or HCA. In its testimony, PG&E described three significant distinctions between the PSEP and TIMP[20]:

1. Integrity management requires an assessment of certain pipeline threats with a risk-based probabilistic approach for pipelines in HCAs. Decision 11-06-017 calls for pressure testing or pipe replacement on all gas transmission lines (not just HCAs) where complete records of a prior test are not available. Decision 11-

[18] Tr. (Hogenson), p. 1566, lines 5-28 (indicating that the Integrity Management Baseline Assessment Plan database does not indicate if a potential manufacturing threat is "active and we need to address it.")

[19] This does not mean that in every case where there is a pressure exceedence above MAOP that a new pressure test must be conducted to assess whether a manufacturing threat has been activated. For example, if a pressure test has already been done on the pipeline which would effectively evaluate the potential manufacturing threat and the operating pressure exceedence was lower than the test level, there would not be a need to conduct an additional pressure test. TURN's argument that shareholders should pay for every PSEP pressure test where there has been a "spike test" is also in error. (TURN Opening Brief, p. 90). A spike test that does not exceed MAOP does not have the potential to activate a manufacturing threat and would not require a follow-up pressure test.

[20] Ex. 2, PG&E Direct, p. 3-32, line 5—p. 3-33, line 16.

06-017 thus prescribes actions PG&E must take to establish a safe operating margin and eliminate unknown strength testing information in the gas transmission system.

2. The TIMP program requires PG&E to complete an assessment of approximately 1059 miles of HCA pipe by December 17, 2012 and requires reinspection approximately every seven years. The PSEP assesses the entire 5,786 miles of PG&E's gas transmission pipeline system one time in accordance with pipeline modernization decision trees to determine if the pipelines should be hydrotested or replaced.
3. The TIMP regulations require that each new line must be capable of ILI but they do not mandate retrofitting of existing lines. The PSEP proposes that every transmission line operating above 30 percent Specified Minimum Yield Strength ("SMYS") would be modified to accommodate ILI devices.

As discussed in PG&E's Opening Brief,[21] PG&E was transparent in filings to the Commission about how it intended to assess pipelines under TIMP. Direct assessment and ILI, two legally authorized assessment methods under Part 192 Subpart O regulations, were identified as the primary means of assessment in PG&E's TIMP Plan. PG&E clearly notified the Commission and parties of its TIMP implementation strategies and its rate authorization in the GT&S rate cases reflected the costs of implementing these approaches. The Commission approved PG&E's TIMP implementation strategies and funding request in the GT&S rate cases. If PG&E had proposed more extensive TIMP hydrostatic testing as parties assert it should have, customers would have paid for this work and GT&S rates would have been significantly higher in the past.

[21] PG&E Opening Brief, pp. 80-82.

c. Parties' Arguments About Pipeline 2020 Are Misplaced

TURN argues that because PG&E announced the Pipeline 2020 plan before the Commission issued D.11-06-017, the safety enhancements initially conceptualized in Pipeline 2020 (such as strength testing, pipeline replacements and ILI retrofits) are remedial in nature and would have been undertaken by PG&E even if D.11-06-017 had never been issued.[22] TURN makes an illogical leap in this argument stating that because PG&E proposed the Pipeline 2020 concept before D.11-06-017 was issued that PG&E must have been <u>legally required</u> to undertake the Pipeline 2020 activities by pre-existing regulation. This misstates the purpose and scope of Pipeline 2020. Shortly following the San Bruno accident, PG&E announced that it intended to propose at the CPUC a plan to enhance pipeline safety and go above and beyond current regulatory requirements through a program that it called Pipeline 2020. This program was to be submitted to the Commission in an application for its consideration and was contingent upon Commission approval and ratemaking authorization.[23] PG&E never described Pipeline 2020 as something it was obligated to do under then-existing regulatory requirements. To the contrary, PG&E's aspiration was to enhance pipeline safety on its system by proposing new measures to go above and beyond existing regulatory requirements. Many of the concepts that PG&E proposed for inclusion in Pipeline 2020 were ultimately endorsed by the Commission and included in D.11-06-017 as new regulatory requirements to enhance gas system safety. Pipeline 2020 was proposed by PG&E to raise the bar on safety requirements in California, not to comply with pre-existing regulatory requirements.

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22 TURN Opening Brief, pp. 70-73.

23 Comments of Pacific Gas and Electric Company on Order Instituting Rulemaking, R.11-02-019, April 13, 2011, p. 16. ("If the Pipeline 2020 Program is approved by the Commission, PG&E expects by the end of 2014, it will . . . [complete numerous incremental strength testing, ILI retrofit and pipeline replacement projects].")

d. The Commission Approved Discontinuation Of The Gas Pipeline Replacement Program In Order To Transition To Risk Management And Integrity Management

TURN proposes that the Commission disallow PSEP costs or reduce the return on equity for PSEP pipeline replacement projects because the transmission portion of the GPRP was discontinued as part of the transition to Integrity Management. In making this argument, TURN does not point to a single PSEP pipeline replacement project that was funded under the GPRP and is being asked for a second time in the PSEP. TURN's own brief indicates that in each successive GRC decision after the GPRP program was adopted the Commission reviewed PG&E's progress under the GPRP and did not find fault with how PG&E was implementing the transmission portion of the program. The vast majority of the GPRP was focused on the replacement of distribution pipes, which constituted roughly 2500 of the 3000 mile program.[24] Transmission pipe segments were removed from the GPRP when PG&E transitioned to the Risk Management Program in 1998, over 14 years ago. The Risk Management program expanded the scope of transmission pipelines to be assessed and "increased the number of threats the program would mitigate, widened the consequence analysis to consider impacts to system reliability and the environment, and expanded mitigation options to reduce system risks."[25] The Risk Management Program evaluated pipeline risk by assessing the probability or likelihood of failure and the local consequence of failure. Under the program, the techniques to reduce pipeline risk included pipeline replacement, strength testing, smart pigging, pipeline rehabilitation or recoating, erosion mitigation, external corrosion direct assessment, and internal corrosion management.[26] This model was later adopted on a national level through the implementation of Transmission Risk Management in 49 CFR Part 192 Subpart O. PG&E's 2000 GPRP Annual Report states that the Chief of the Commission's Utilities Safety and Reliability Branch on

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24 TURN cites to PG&E's 1996 GRC decision which did not adopt PG&E's request to increase its forecast for replacement of distribution pipe in high cost neighborhoods. (TURN Opening Brief, p. 94). The decision rejected a TURN disallowance recommendation and notes that PG&E's progress under the program was "on target" but that actual costs were less than forecast. It is clear from the discussion quoted in TURN's brief that its concern was about PG&E's spending on the gas distribution portion of the program.

25 Ex. 2, PG&E Direct, p. 2-12, line 18—p. 2-14, line 8.

26 Id.

April 20, 2000, approved PG&E's Gas Transmission Risk Management Program and authorized the removal of all remaining gas transmission pipelines from the GPRP to the Risk Management Program.[27]

The evidence shows that: (1) the Commission approved the reasonableness of the GPRP in numerous GRC decisions, rejected TURN's disallowance recommendations and did not find PG&E's implementation of the program to be imprudent; (2) the transmission portion of the GPRP was transitioned to the Risk Management Program, which was a more sophisticated assessment program with a broader scope and that considered more threats and evaluated additional mitigative actions, such as assessment and testing of potential threats; (3) the Commission Safety Branch reviewed and approved the transition of transmission pipes from the GPRP to the new Risk Management Program; and (4) there is no evidence that PG&E received funding for transmission replacements that as of 14 years ago were not completed under the GPRP.[28]

e. It Is Reasonable For Customers To Pay For Pipeline Replacements Since The Decision To Replace Rather Than Hydrotest Is Driven By The Safety Objective Of Addressing Known Manufacturing Or Construction Threats On Vintage Pipelines

DRA and TURN have proposed disallowance of pipeline replacement projects for pipes installed in the 1955 to 1969 time period. The common thread in these arguments is that for those time periods where PG&E's shareholders are found to be responsible for hydrotesting costs due to a lack of hydrotest records, it follows that shareholders should also be responsible for replacement of pipes. The problem with this position is that it ignores the long-term safety benefit and value to customers associated with eliminating known manufacturing and

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27 Id.

28 CCSF states that PG&E identified the three San Francisco Peninsula lines (Line 101, 109 and 132) as being within the scope of the GPRP. (CCSF Opening Brief, p. 45). Portions of these lines were replaced during the GPRP program and the remainder of the lines were transferred to the Risk Management Program. There is no evidence that PG&E sought and received funding for replacement of the entirety of these pipelines in GRC decisions prior to their transfer to the Risk Management Program.

construction hazards on vintage pipelines and replacing them with new transmission pipeline manufactured and constructed to modern safety standards.

In D.11-06-017, the Commission directed PG&E and the other respondent gas utilities to hydrotest or replace every gas transmission pipeline on its system without records of a modern pressure test and to develop a criteria specifying when it is appropriate to test and when it is appropriate to replace. DRA and TURN take the position that it is never appropriate under the PSEP to replace a pipeline installed after 1955. PG&E, on the other hand, addressed this question in a more safety conscious manner. PG&E's recommendation to replace rather than test a pipeline is driven by the safety objective of addressing a known manufacturing, fabrication or construction threat in vintage pipe. In other words, it is not the lack of a pressure test record that is driving the decision to replace rather than test.[29] PG&E is proposing to replace certain vintage pipelines with characteristics that carry a significantly higher risk of failure because replacing old, at risk vintage pipes that are approaching the end of their useful lives with modern pipe enhances safety for the long term. In some cases, it just does not make sense to incur the cost to test a pipe that will need replacement in the near future and which, if tested, may fail and require replacement anyway. In such cases, hydrotesting, even at shareholder expense, is a shortsighted approach and may end up costing customers more over time.[30]

PG&E describes its rationale for when pipelines should be replaced rather than tested in Chapter 3 of its prepared testimony.[31] In the decision trees, PG&E proposed replacement of vintage pipelines that are more likely to contain manufacturing, fabrication and/or construction flaws. PG&E proposes to replace pipe subject to the following *manufacturing* processes:

> Pipe manufactured by processes generally thought to be susceptible to produce weld seam anomalies or weld seams with poor fracture toughness, including pre 1970, low frequency ERW,

29 Tr. (Hogenson), p. 1415, lines 4-11.

30 If a vintage pipeline is tested now and needs to be replaced, for example, in five years, the replacement would be fully eligible for cost recovery as part of a future GT&S rate case. From a customer cost perspective, it makes no sense to hydrotest a pipeline now and have customers pay to replace it at the end of its useful life a few years later.

31 Ex. 2, PG&E Direct, p. 3-22, line 28—p. 3-24, line 14.

> flash welded, SSAW, furnace butt welded, lap welded, and hammer welded pipe.[32]

PG&E asked TURN witness Kuprewicz if he agreed that pipe with these manufacturing characteristics warrants replacement[33]:

> Q Would you agree that these are all types of pre-1970 vintage pipe that are considered inferior as compared to today's modern pipeline standards?
>
> A Yes.
>
> Q Would you say that the pipes that have this type of manufacturing characteristics are significantly inferior to modern pipe?
>
> A [omitted text] Some of this, most of this would be significantly inferior. Some of it, especially low frequency ERW if you properly tested it, is more than adequate to last for long times.
>
> Q Would you agree that pipes with these manufacturing characteristics pose a higher risk of failure as compared to modern pipe?
>
> A Yes, if they were not properly managed.

PG&E proposes to replace pipelines with the following *construction* characteristics:

> Pipelines constructed with welding techniques generally thought to produce low toughness or inferior designed girth welds, such as oxygen acetylene welds, bell-bell chill ring welds, bell and spigot welds, and pre-1940 arc welds.[34]

PG&E asked TURN witness Kuprewicz if he agreed that pipe with these construction characteristics warrants replacement[35]:

> Q Would you agree that pipelines constructed with these characteristics are significantly inferior to modern pipe?
>
> A Yes.

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32 Ex. 2, PG&E Direct, p. 3-23, lines 12-16.
33 Tr. (Kuprewicz), p. 2216, line 6—p. 2217, line 12.
34 Ex. 2, PG&E Direct, p. 3-23, lines 17-20.
35 Tr. (Kuprewicz), p. 2217, line 13—p. 2218, line 3.

> Q Would you agree that there is a significantly higher risk of failure with pipes constructed with these techniques as compared to modern pipe?
>
> A Yes, in general. Also depends on the threat.

PG&E also explained in its testimony that while hydrotesting can be used in most cases to assess manufacturing and construction threats, there are three reasons why replacement is a better, safer option than hydrotesting for these types of manufacturing and construction flaws:

> 1. Strength testing will confirm a margin of safety at the time of the test, but it is unable to identify and address compounding threats to the long seam such as wall loss, pipe deformation, external stresses, and loading.
>
> 2. Strength testing is not an effective means of proving a margin of safety for girth welds where the frequency of welding anomalies or additional external loading conditions are suspected concerns for the pipe's integrity. Hydrostatic testing primarily produces a hoop stress, while a girth weld's typical stress induced failure mechanism is a result of axial or lateral stresses.
>
> 3. Strength testing a line does not make a line piggable. Older vintage pipelines are difficult and often impossible to adequately in line inspect based on their complex geometrical configured girth welds and long seams, often outdated diameters, and use of back to back fittings.

TURN witness Kuprewicz was asked about these limitations in strength testing and he agreed that each of the above statements is correct.[36]

Clearly, there is an additional safety benefit associated with replacement rather than hydrotesting pipelines with these manufacturing and construction characteristics. A new pipeline, built to modern manufacturing, fabrication and construction standards and fully "piggable" will be significantly safer and less susceptible to failure for fifty years or more into the future. From a customer perspective, there are clear, long term safety benefits resulting from the decision to replace the vintage pipelines targeted by PG&E's Pipeline Modernization decision trees.

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[36] Tr. (Kuprewicz), p. 2218, line 7—p. 2219, line 12.

In its report summarizing its technical review of the PSEP, CPSD states "[t]he decision tree framework makes an appropriate assessment of risks and logically identifies when to replace versus pressure test segments . . . CPSD's review found that PG&E's PSEP provides a consistent, repeatable, and well defined mechanism for identifying, planning and estimating projects to test or replace segments which have not been adequately pressure tested to current safety testing standards . . . [T]he decision trees properly select segments for replacement versus pressure testing and establish a logical prioritization of that work . . ."[37]

There is some confusion about PG&E's ratemaking proposal for pipeline replacements. As a general matter, PG&E proposes that the costs of Phase 1 pipeline replacements are recoverable in PSEP rates, subject to three provisos:

1. The pipeline replacement project must pass the test under PG&E's customer/shareholder allocation principles 1 and 2. The project must be incremental to existing GT&S rates under principle 1 and must not be required to comply with a pre-existing regulatory requirement under principle 2.[38]
2. For post-1970 pipeline replacements (without pressure test documentation), the revenue requirement for these capital projects will not be recovered in PSEP rates through the end of 2014.[39] Post-1970 capital projects will be eligible for inclusion in rate base as part of PG&E's next GT&S rate case for the period commencing January 1, 2015.
3. Under PG&E's shareholder/customer allocation proposal, for capital projects that go into service in 2011, PG&E will not recover the 2011 revenue requirement.[40] The

[37] R.11-02-019, Technical Report of the Consumer Protection and Safety Division Regarding Pacific Gas and Electric Company's Pipeline Safety Enhancement Plan (filed Dec. 23, 2011), pp. 2-3.

[38] See, PG&E Opening Brief, pp. 58-63. For example, under principle number 1, PG&E removed the costs of nine pipeline replacement projects that had already been forecast in the GT&S rate case. Ex. 149, DRA Direct (Sabino), p. 30, lines 1-12.

[39] PG&E Opening Brief, p. 62, footnote 270.

[40] Ex. 2, PG&E Direct, p. 8-9, lines 23-26. PG&E forecasts that the revenue requirement for 2011 capital projects will be approximately $1.4 million. Ex. 2, PG&E Direct, p. 8-11, Table 8-5, line 3.

revenue requirement for these projects will be eligible for recovery in PSEP rates starting in 2012.

TURN argues that shareholders should pay for all post-1961 replacement projects because this outcome is consistent with PG&E's concession that shareholders will pay for post-1961 pressure testing where there are no records of a pressure test.[41] TURN also points to a discrepancy between the testimony of PG&E witnesses Bottorff and Hogenson at hearings on this topic.[42] First, to clarify, PG&E's position is that customers should pay for the costs of pipeline replacements installed in the period 1961 to 1970. Mr. Bottorff misspoke at hearings and apparently did not understand that the question was referring to shareholder responsibility for pipeline replacements rather than hydrotests.

Having clarified PG&E's position, the next question is why is it reasonable to have customers pay for replacements of pipes installed in the 1961 to 1970 time period when PG&E has agreed that under customer/shareholder principle number 2, shareholders should bear the costs of hydrotests during this period? As discussed above, the manufacturing and construction threats associated with vintage pipe still occurred in the 1961 to 1970 time period and the long-term safety benefits associated with replacement of these pipes is the same as with prior periods. In the 1970's modern pipeline manufacturing, fabrication and construction practices were largely in place so these factors are not driving the decision in the few instances where PG&E is proposing to replace post-1970 pipelines. PG&E drew the line at 1970 because the 1970 federal pipeline safety regulations established new modern standards for construction and operation of pipelines (in addition to establishing standards for determining MAOP). PG&E also believes that pipe making practices had improved to modern standards by 1970.[43] Pipelines installed prior to 1970 were "grandfathered" from the new manufacturing, fabrication and construction standards; there was thus no regulatory requirement for pre-1970 pipes to meet these modern

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41 TURN Opening Brief, pp. 78-82.
42 TURN Opening Brief, pp. 79-80.
43 Ex. 2, PG&E Direct, p. 3B-9.

pipeline standards. The replacement of 1961 to 1970 pipelines is not driven by a failure to comply with regulatory requirements in place at the time but, rather, by an objective to enhance safety by addressing vintage pipe manufacturing and construction threats that are not up to modern standards.

If the Commission nonetheless decides that 1961-1970 pipeline replacements should be partially allocated to shareholders, the same allocation method that PG&E has proposed for post-1970 pipeline replacements should apply. Under this approach, the capital revenue requirement for the 1961 to 1970 pipeline replacements for the period 2012 to 2014 would be allocated to shareholders. However, these capital projects would be eligible to be added to rate base starting in 2015 in conjunction with the rate base true-up in PG&E's next GT&S rate case. This is the normal rule that would apply to all capital additions above forecast that are completed during the current GT&S rate case cycle.

DRA recommends that replacements of pipelines installed *before* 1955 should be recoverable in rates, subject to a reduction in rate of return of 200 basis points for such projects.[44] DRA concedes that customers receive a benefit from replacement of vintage pipelines and that they should pay for these replacements since "pipelines installed in 1955 will be more than 60 years old by 2015" and these transmission pipelines will be "replaced with a new transmission pipeline constructed using modern materials and construction techniques."[45] DRA also asserts that customers should pay for a share of the pre-1955 replacements due to the "acceleration of pipeline replacement that may occur pursuant to the plan relative to the status quo average annual pipeline investment." The factors that led DRA to support partial recovery of pipeline replacements prior to 1955 apply equally to the replacements in the period 1955 to 1969.[46]

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44 DRA Opening Brief, pp. 20-21.

45 Id.

46 DRA argues that the reduced return on equity is appropriate because these pipes should have been hydrotested under industry standards from 1935 to 1955. PG&E responds to the "industry standards" argument in its Opening Brief and demonstrates that this argument has no basis. PG&E Opening Brief, pp. 74-79.

2. MAOP Validation And GTAM Are Not Remedial

The parties assert that none of the costs of PG&E's MAOP Validation and Gas Transmission Asset Management ("GTAM") Projects should be recovered in rates because both programs are necessary to cure PG&E's alleged prior recordkeeping deficiencies. In support of this claim, the parties rely on two arguments: (1) that the obligation to validate the MAOP of gas transmission pipelines by reference to traceable, verifiable, and complete records is not a new obligation; and (2) MAOP Validation and GTAM are necessary to remedy alleged past record keeping deficiencies that have been noted by this Commission and other regulatory bodies. The intervenors rely on a fundamental misunderstanding of the new traceable, verifiable, and complete standard and the work PG&E must do to meet that standard today and into the future. Even if it were true that PG&E has failed to keep "complete, accurate, and accessible records" (as DRA articulates it), not a single party has demonstrated that the obligation to validate MAOP for gas transmission pipelines by referencing traceable, verifiable, and complete records existed prior to January 3, 2011.

a. The Parties' Argument That Traceable, Verifiable, And Complete Is Not A New Standard Is Not Credible

Several parties argue that the obligation to validate MAOP through traceable, verifiable and complete records is merely a different articulation of general record keeping standards in the industry. DRA, for example, claims that "PG&E has had an obligation to maintain complete, accurate, and accessible records, which is the same as maintaining 'traceable, verifiable, and complete' records."[47] DRA cites no evidence in support of this assertion. Similarly, the Northern California Indicated Producers ("NCIP") claim (also with no evidentiary basis) that the "traceable, verifiable, and complete" standard is simply a new "articulation" of a preexisting standard.[48] TURN argues that PG&E was required by the general "prudence" requirement to meet this heightened standard of recordkeeping.[49]

47 DRA Opening Brief, p. 23.
48 NCIP Opening Brief, p. 9.
49 TURN Opening Brief, p. 103.

The intervenors cite a panoply of pre-existing general obligations to maintain records. DRA, TURN and NCIP reference Public Utilities Code Section 451, GO 28 and GO 112.[50] DRA also claims that the TIMP regulations (in place since 2004) imposed a record keeping requirement on PG&E.[51] The parties' arguments depend on equating general, pre-existing obligations to maintain records, to a specific requirement to validate the MAOP of gas transmission pipelines through the use of traceable, verifiable, and complete records.[52] Even assuming a general obligation to keep "accurate, complete and accessible records" (in DRA's words), that is not the same as validating MAOP through the use of traceable, verifiable, and complete records. DRA and the other parties cite not one single document that supports their argument that the obligation to validate MAOP through traceable, verifiable, and complete records is not a new standard.

In contrast, the weight of the evidence shows that operators (including PG&E) have never before been required to validate the MAOP of gas transmission pipelines through a pipeline features analysis using traceable, verifiable, and complete records. As discussed on pages 40-41 of PG&E's Opening Brief, prior to January 3, 2011, federal regulations allowed operators to establish MAOP using any one of four possible methods: (1) calculated based upon the design of each of the components of the pipelines; (2) through a strength test; (3) the highest actual operating pressure during the five years preceding July 1, 1970; or (4) the pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.[53]

The January 3, 2011 NTSB recommendation and subsequent Commission order materially altered how an operator could establish the MAOP of its pipelines. Now, a strength test is the *only* permitted means to establish the MAOP of a pipeline. In addition, although the

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50 DRA Opening Brief, pp. 32-35; TURN Opening Brief, pp. 103-104; NCIP Opening Brief, pp. 14-18.

51 DRA Opening Brief, p. 35.

52 Arguments regarding GO 28 are misguided. GO 28 is a document preservation requirement concerning the original cost, and "depreciation and replacement" of property equipment and plant. See PG&E Opening Brief, p. 78.

53 49 C.F.R. § 192.619 (2011); Tr. (Howe), p. 1218, line 26—p. 1220, line 13.

only permitted means for establishing MAOP is through a strength test, the Commission has nonetheless ordered PG&E to complete its MAOP Validation Project to validate the MAOP of its pipelines as an interim measure, until pipelines without a documented pressure test can be pressure tested or replaced. CCSF concedes that the 1970 federal regulations permitted operators to operate gas transmission pipelines at the highest pressure to which the pipeline had been subjected during the five years preceding July 1, 1970.[54] The leap from that concession to the conclusion that, despite grandfathering, PG&E nevertheless should have validated MAOP through pressure testing or a design-basis calculation based on pipeline features, is without merit.[55] Similarly, many parties argue that the federal regulations did not view a lack of historical diligence in record-keeping as a reason for adopting grandfathering.[56] It is not relevant, however, why existing pipelines were grandfathered. The indisputable fact is that, prior to the NTSB guidance and Commission Decision 11-06-017, PG&E was permitted to establish the MAOP of its pipelines through reference to the highest operating pressure for the five years preceding July 1, 1970. Now, it is not.

Recent activity at the federal level underscores PG&E's argument. On May 7, 2012, the Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued an Advisory Bulletin (ADB-2012-06) informing gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP. As explained in the Advisory Bulletin:

> On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Act), which requires PHMSA to direct each owner or operator of a gas transmission pipeline and associated facilities to provide verification that their records accurately reflect MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in High Consequence Areas (HCAs). . . . Owners and operators should consider the guidance in this advisory for all pipeline segments and take action as appropriate to assure that all

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54 CCSF Opening Brief, p. 33.
55 CCSF Opening Brief, p. 33.
56 CCSF Opening Brief, p. 32; TURN Opening Brief, pp. 107-109.

> MAOP and MOP are supported by records that are traceable, verifiable and complete.[57]

Moreover, the PHMSA Advisory Bulletin includes a lengthy discussion of the terms "traceable," "verifiable," and "complete." For example, the Advisory Bulletin provides that:

> Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or asbuilt documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.[58]

None of the parties addresses why PHMSA would issue a bulletin regarding "anticipated changes" to federal regulations if, as the parties suggest, this standard is already in place. In addition, there would have been no need for PHMSA to define the words "traceable, verifiable, and complete" if those words mean the same as "complete, accurate, and accessible." The ineluctable conclusion to be drawn from the record evidence is that transmission pipeline operators are entering a new world in which they cannot rely on historical operating pressures to establish MAOP, but must confirm MAOP through the use of traceable, verifiable, and complete records.

b. MAOP Validation And GTAM Are Not Being Done To Remedy Prior Alleged Recordkeeping Deficiencies

Several parties claim that MAOP Validation and GTAM are necessary to cure alleged record-keeping deficiencies and that therefore PG&E shareholders should pay for these efforts. Intervenors cite a litany of alleged record keeping failures that have been noted by this Commission and other regulatory bodies in other proceedings. DRA for example, cites to the NTSB report on the San Bruno accident, the January 12, 2012 CPSD report on the San Bruno accident issued in the San Bruno OII (I. 12-01-007), and reports issued by Duller & North, and

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[57] May 7, 2012 PHMSA Advisory Bulletin 2012-0068, Federal Register, Vol. 77, No. 88.

[58] <u>Id.</u>

Margaret Felts in the Recordkeeping OII (I.11-02-016).[59] TURN similarly argues that GTAM is remedial, and is intended to address alleged problems with PG&E's recordkeeping noted in the IRP and NTSB reports.[60] TURN also references a report prepared by an outside consultant retained by PG&E (PwC).[61]

The allegations regarding historical recordkeeping practices, even if they are true,[62] do not prove that the MAOP Validation Project or GTAM are remedial measures. As explained above, both of these projects are necessary to meet the Commission's mandate to validate the MAOP of all gas transmission pipelines using traceable, verifiable, and complete records. MAOP Validation is necessary to allow PG&E to meet that standard today; GTAM will provide an efficient means for PG&E to meet that standard going forward. MAOP Validation and GTAM were not intended to "fix" any of the alleged record keeping problems that parties discuss in their briefs. TURN argues that rate recovery for GTAM should be denied because GTAM will help PG&E implement some of the improvements suggested in the IRP and NTSB reports.[63] While it may be true that GTAM will "establish the infrastructure that will help PG&E address past gas transmission recordkeeping deficiencies if they are identified in the future,"[64] the mere fact that it may help PG&E improve recordkeeping is not sufficient to justify disallowing any rate recovery.

B. Parties Misconstrue Section 463

Several parties misconstrue the meaning and scope of Public Utilities Code Section 463.[65] These parties assert that Section 463 compels the Commission to review the prudence of PG&E's gas operations over the past 75 years to determine any PG&E "errors or omissions" in

59 DRA Opening Brief, pp. 26-29.
60 TURN Opening Brief, p. 111; see also CCSF Opening Brief, pp. 28-29.
61 TURN Opening Brief, pp. 101-103.
62 It bears noting that PG&E has not had an opportunity to respond to the findings made in the San Bruno OII or the Recordkeeping OII. It would compromise PG&E's due process rights to make any findings regarding PG&E's recordkeeping practices before PG&E has had an opportunity to respond to those allegations.
63 TURN Opening Brief, pp. 111-114.
64 Ex. 2, PG&E Direct, p. 5-3, lines 17-19.
65 DRA Opening Brief, pp. 7-8; CCSF Opening Brief, p. 4; NCGC Opening Brief, p. 3, TURN Opening Brief, p. 62

PG&E's historic practices over this period and assess disallowances to PSEP costs for any historic imprudent behavior.[66]

This is simply not what the statute requires. Section 463 was added to the Public Utilities Code in 1985. The statute applies to additions of capital plant in excess of $50 million and requires the Commission to review the reasonableness of a utility's management of and expenditures on the project and disallow, if applicable, project expenditures that result from "unreasonable error or omission related to the planning, construction, or operation" of the project "including any expenses resulting from delays caused by any unreasonable error or omission." The statute thus requires the Commission to review how effectively the utility has developed and constructed a capital asset over $50 million and if there have been errors and omissions in planning, operation or construction of the asset that resulted in cost overruns or excessive delays, the Commission should disallow the increased costs.[67]

Each of the key terms in the statute is clearly defined to pertain strictly to the development and construction activities associated with a capital asset over $50 million.

> (c) For purposes of this section:
>
> (1) "Planning" includes, but is not limited to, activities related to the initial and subsequent assessments of the need for a plant construction project; the selection of contractors and the negotiation of contract provisions; certification; project organization; and site selection, including the investigation and interpretation of environmental factors such as seismic conditions and other external factors affecting the construction, operation, and safety of the plant.

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66 Pub. Util. Code § 463 is addressed on page 86 of PG&E's Opening Brief.

67 Pub. Util. Code § 463(a) states "For purposes of establishing rates for any electrical or gas corporation, the commission shall disallow expenses reflecting the direct or indirect costs resulting from any unreasonable error or omission relating to the planning, construction, or operation of any portion of the corporation's plant which cost, or is estimated to have cost, more than fifty million dollars ($50,000,000), including any expenses resulting from delays caused by any unreasonable error or omission. Nothing in this section prohibits a finding by the commission of other unreasonable or imprudent expenses. This subdivision is a clarification of the existing authority of the commission, is not intended to limit or restrict any power or authority of the commission conferred by any other provision of law, and applies to all matters pending before the commission. This section does not prohibit the commission from establishing rates for an electrical or gas corporation on a basis other than an allowed rate of return on undepreciated capital costs."

> (2) “Construction” includes, but is not limited to, activities related to engineering such as the development and use of specifications, drawings, and procedures; the preparation and use of construction plans, including blueprints; procurement activities; repairs, replacement, redesign, or repositioning of equipment and facilities; startup activities; and quality assurance and quality control activities.
>
> (3) “Operation” includes, but is not limited to, activities related to decisions affecting the timing and nature of the use of the plant; dispatch and control activities and decisions; and plant operation, fuel loading, and maintenance.

In addition, “error” and “omission” are defined so as to be specifically related to construction and development factors that resulted in increased costs for the capital asset or delays in the expected operations date.

(c) For purposes of this section:

*   *   *

> (4) “Error” includes, but is not limited to, any action or direction which causes an avoidable (i) increase in the time required to bring the plant to full commercial operation, (ii) change in the number or types of personnel or firms required to bring the plant to full commercial operation, (iii) increase in the number of worker hours required to complete any portion of the plant construction project, or (iv) change of equipment, configuration, design, schedule, or program.
>
> (5) “Omission” includes, but is not limited to, any failure to act or to provide direction which causes an avoidable (i) increase in the time required to bring the plant to full commercial operation, (ii) change in the number or types of personnel or firms required to bring the plant to full commercial operation, (iii) increase in the number of worker hours required to complete any portion of the plant construction project, or (iv) change of equipment, configuration, design, schedule, or program.

The prudence review of capital assets required under this section is thus limited to the “development, construction and operation” of the capital assets themselves if there has been a significant cost overrun or significant delay due to errors or omissions in project management. This statute does not require the Commission to review the prudence of past utility actions that are unrelated to the "planning, construction, and operation" of a capital asset over $50 million.

In this case, Section 463 applies to the capital projects in PG&E's PSEP (i.e., pipeline replacements), not expense projects, such as hydrotesting, and would require the Commission to conduct an after the fact reasonableness review if a PSEP capital project is subject to a cost overrun or extensive delay to determine if there was an unreasonable "error" as narrowly defined in section 463(c)(4) or "omission" as narrowly defined in section 463(c)(5). The Commission cannot conduct a "Section 463" prudence review of PSEP costs until the capital assets are completed. This is a very different prudence review than the 75 year historical operations review contemplated by TURN.

TURN seizes upon the phrase in Section 463(b)—"fails to prepare or maintain records"—in an attempt to encompass historic recordkeeping issues within the scope of the Section 463 review. However, it is clear from the face of the statute that this "records" section is similarly narrowly drafted only to pertain to records documenting the planning, construction or operation, of the specific capital asset over $50 million that is under review.

> (b) Whenever an electrical or gas corporation fails to prepare or maintain records sufficient to enable the commission to completely evaluate any relevant or potentially relevant issue related to the reasonableness and prudence of any expense **relating to the planning, construction, or operation of the corporation's plant,** the commission shall disallow that expense for purposes of establishing rates for the corporation. This subdivision does not apply where the commission determines that a reasonable person could not have anticipated either the relevance or potential relevance, to an evaluation of costs incurred on the project, of preparing or maintaining the records or the extent of recordkeeping required to adequately evaluate those costs. (Emphasis added)

This provision clearly applies to documents necessary to evaluate cost overruns or delays in the development or construction of a capital project over $50 million. PG&E's historic gas pipeline pressure test records are not relevant to the management of potential PSEP cost overruns or construction delays for future pipe replacements. In addition, as specified in the last sentence of this section, this subdivision does not apply if a reasonable person could not have anticipated the relevance of the documents to an evaluation of the costs of the project over $50 million. There is no evidence to suggest that a reasonable person in the 1930's, 1940's, and 1950's could have anticipated that historic gas transmission pressure test documents would need to be developed and maintained (when there was no requirement to do so) because the documents might be relevant to the review of the construction of gas transmission pipelines in 2012 and beyond.

Importantly, Public Utilities Commission Section 463.5 was added two years later to clarify the requirements under Section 463. It states:

> 463.5.(a) Section 463 does not require the commission to undertake a reasonableness review of recorded costs to determine the reasonableness of the costs of each item of any electrical or gas corporation's plant which costs, or is estimated to have cost, more than fifty million dollars ($50,000,000) where the commission either has established a maximum reasonable cost pursuant to Section 1005.5 or has adopted an estimate of the reasonable costs in any proceeding. The establishment of the maximum costs or adoption of an estimated cost does not limit or restrict the discretion of the commission in considering the reasonableness of plant-related costs in subsequent proceedings.

PG&E has proposed that the Commission adopt an "estimate of the reasonable costs" of the PSEP pursuant to this section, which eliminates any legal requirement for the Commission to conduct an after the fact reasonable review of PSEP construction overruns or delays under Section 463 (as long as actual costs are less than or equal to the estimate.)

Contrary to TURN's argument, there is no legal obligation under Public Utilities Code Section 463 for the Commission to conduct a duplicative reasonableness review of PG&E's past recordkeeping "errors and omissions" in the PSEP proceeding.

C. PG&E's Request For Cost Recovery Is Not Inconsistent With Gas Accord V

DRA argues that PG&E's ratemaking proposal "disrupts the bargain struck in the Gas Accord V." DRA asserts: (1) the Gas Accord V Settlement Agreement precludes parties from making rate changes; (2) in D.11-06-017, the Commission ordered PG&E to file the PSEP and propose rates but it didn't require PG&E to raise rates; and (3) PG&E knew it would incur significant costs when the Gas Accord V was entered into that it should have made clear to the settling parties that it intended to argue that these "new" costs would be added to rates. [68]

First, as discussed in PG&E's Opening Brief, the Gas Accord V settlement clearly states that "Nothing in this Settlement Agreement shall prevent PG&E from making adjustments to . . . rates . . . in order to comply with Commission orders in other proceedings."[69] The Commission in D.11-06-017 directed PG&E to propose rates associated with the costs of implementation of new safety standards adopted in the decision. PG&E submitted the PSEP to comply with the Commission's order in "another proceeding." The potential for PG&E to propose rate changes associated with new developments in other proceedings was clearly considered and authorized by the settling parties. In fact, other than DRA, no other Gas Accord V settling party has taken the position in testimony or opening briefs that PG&E's ratemaking proposal is prohibited by the Gas Accord V Settlement Agreement, even though several of those settling parties are active participants here.

Second, DRA is incorrect about the timing of the Gas Accord V settlement. The Gas Accord V settlement agreement was executed on August 19, 2010 and submitted to the Commission on August 20, 2010. The San Bruno accident occurred in September, 2010. PG&E did not know and could not have anticipated in August 2010 that the Commission would order it in June 2011 to incur close to $2 billion during the 2011-2014 time period in new expenditures to hydrotest and replace gas transmission pipelines and implement other safety enhancements.

On September 20, 2010, in comments filed by PG&E in response to an Assigned Commissioner Ruling in the Gas Accord proceeding to evaluate whether the proposed settlement was adequate to fund pipeline safety, integrity and reliability efforts, PG&E said:

> The settlement determination was made *before* the San Bruno incident occurred. . . . the funding level reflected in the settlement does *not* include sufficient funds to do the thorough safety

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68 DRA Opening Brief, pp. 10-12.

69 Ex. 21, PG&E Rebuttal, p. 1-20, lines 24-27.

inspection of PG&E's entire gas system referred to in the Ruling. Nor does the funding level in the settlement include sufficient funds for any specific additional work the Commission may direct PG&E to perform. . . . PG&E believes that any additional requirements the Commission determines should be imposed on PG&E arising out of the San Bruno incident . . . should be the subject of a separate proceeding, which would establish the work to be done and the appropriate cost recovery for any such additional work the Commission directs. And nothing now pending before the Commission should be interpreted as barring cost recovery for any such work directed by a future Commission ruling.[70]

In these comments, PG&E expressly put settling parties and the Commission on notice that the Gas Accord V settlement did not contain sufficient revenues to fund any "additional work that the Commission may direct PG&E to perform" following the San Bruno accident and that the Gas Accord V settlement agreement pending before the Commission would not bar "cost recovery for any such work directed by a future Commission ruling." None of the settling parties filed any comments disagreeing with this interpretation of the Gas Accord V settlement agreement.

D. It Is Reasonable Under Commission Criteria To Authorize PG&E To Change Rates During the GT&S Rate Case Period Because The New Safety Measures Ordered In D.11-06-017 Could Not Have Been Forecast By PG&E In The GT&S Rate Case And Are Not "Normal Day To Day" Expenses That Should Be Absorbed As Part Of Traditional Test Year Ratemaking

DRA argues that PG&E should be barred under principles of traditional test year ratemaking from proposing rate changes during the term of the GT&S rate case (2011 to 2014) and that PG&E is responsible for controlling costs and managing risks between rate cases.[71] PG&E briefed this issue in its Opening Brief (pages 66-70) and has nothing further to add.

E. The Parties' Arguments For ROE Adjustments Should Be Rejected

TURN, NCIP, and DRA recommend that the Commission reduce the authorized return on equity on PSEP capital projects. This is a fallback position to the parties' primary argument

70 A.09-09-013, Comments of Pacific Gas and Electric Company In Response to September 15, 2010 Assigned Commissioner and Administrative Law Judge's Ruling To Address Whether Proposed Settlement Is Adequate in Terms Of Pipeline Safety, Integrity, and Reliability Efforts. (September 20, 2010).

71 DRA Opening Brief, pp. 9-10; 12-13.

that capital projects should be disallowed in their entirety. PG&E has viewed the issue of potential ROE reductions as an examination of how disallowances adopted by the Commission should be implemented to best align ratemaking and safety policy objectives. For example, if the Commission decides to disallow $100 million in PSEP costs, is it better policy to implement this disallowance on a one time, lump-sum basis as a reduction in authorized PSEP revenues, or should the disallowance be applied as an ROE reduction over the life of the capital assets? PG&E discussed in its Opening Brief the policy reasons why an ROE reduction is a poor policy choice for implementing disallowances.[72] What is striking is that NCIP, TURN and DRA see this issue very differently; they think that ROE reductions should be applied as an additional penalty measure to capital assets that pass through disallowance reviews unscathed and are otherwise recoverable in rates. In considering their proposals, the first question the Commission should ask is what conduct is PG&E being punished for through adoption of an ROE reduction and has this conduct already been accounted by other actions taken in the OIIs or in this proceeding? The second question is how much will the ROE reduction cost PG&E, i.e., what is the equivalent disallowance? It appears that none of the parties has quantified the financial impact of their ROE reduction recommendations. The third question is, if the Commission decides to implement a disallowance through an ROE reduction, will there be an impact on the utility's ability to attract debt and capital and should the Commission care if there is an adverse impact?

First, what is the basis for applying an ROE reduction to a gas safety project that is prudent and otherwise eligible for cost recovery under the parties' disallowance recommendations? The parties don't have a good answer to that question other than to suggest that even more punishment is warranted for general reasons. The Commission is reviewing the circumstances of the San Bruno accident and will determine in the San Bruno OII the appropriate fine, penalties or disallowances to which PG&E should be subject. The same is true with respect

[72] PG&E Opening Brief, pp. 82-85.

to PG&E's historic recordkeeping and the results of the Recordkeeping OII and the Class Location OII. In this proceeding, the Commission is reviewing whether there is a sufficient record to conclude whether alleged imprudent historic gas errors or omissions resulted in the need to conduct remedial PSEP work and, if so, which work should be disallowed from PSEP rate recovery. The parties ignore the overlapping nature of these inquiries and suggest that any presumably "prudent" capital costs that remain eligible for cost recovery after surviving these disallowance reviews should suffer a further ROE reduction just because there have been allegations of mismanagement in the OIIs. By advocating both lump sum disallowances of capital projects in this proceeding and punitive measures in the OIIs, and advocating a further ROE reduction penalty to punish for the same circumstances, the parties are unreasonably doubling and tripling disallowances and punitive measures for the same core set of facts. There is simply no factual or policy basis for applying an additional ROE reduction on top of all their other disallowance recommendations.

Second, the parties fail to quantify the disallowance associated with their ROE reduction recommendations or explain why this level of ROE reduction is the right amount versus a larger or smaller reduction in ROE. DRA proposes a 200 basis point reduction on replacements of pipelines installed prior to 1955, which would apply for 10 years, but doesn't quantify the dollar impact of this adjustment.[73] NCIP proposes a 500 basis point reduction which would reduce the revenue requirement by $67.7 million from 2012-14 but NCIP does not quantify the reduction in revenues associated with implementation of its proposal in 2015 and beyond.[74] TURN proposes to reduce PG&E's ROE 540 basis points to its cost of debt (currently 6.05 %) or, alternatively, reduce the ROE by 105 basis points to the low end of the range considered in PG&E's last cost of capital case.[75] TURN also doesn't quantify the reduction in revenues over the life of the assets that shareholders would absorb, or explain why the disallowance it recommends is just and

73 DRA Opening Brief, p. 20.
74 NCIP Opening Brief, p. 26.
75 TURN Opening Brief, pp. 121-22.

reasonable. The only guidance on what the right level of ROE reduction should be was submitted by NCIP, which relies upon an erroneous characterization of a 1982 Southern California Edison ("Edison") general rate case decision. In D.82-12-055, the Commission ruled that Edison had violated a prior Commission decision requiring it to offer full avoided cost pricing to Qualifying Facilities ("QFs") and the Commission adopted a penalty of $8 million for this violation.[76] NCIP mischaracterizes this decision in its brief; the Commission did not "decrease SCE's entire rate base by 10 basis points for two years" as NCIP asserts.[77] The 16% ROE adopted for Edison in the decision was not reduced. Rather, the Commission characterized the $8 million penalty as "the revenue equivalent of 10 basis points on Edison's return on equity" for two years. The Edison decision does not establish precedent for adopting an ROE reduction to punish a utility for violation of a prior Commission decision; it does, however, create a benchmark of an $8 million one time, lump sum penalty (10 basis point, two year ROR reduction equivalent) for a clear violation of a Commission decision. The parties' 200 to 500 basis point reduction recommendations are clearly excessive and unreasonable when compared to this precedent.

Third, there is ample evidence that adopting a reduced ROE will adversely affect PG&E's ability to attract capital in the debt and equity markets. The reality of the capital markets is that investors place their capital in investments that offer them the opportunity to make market returns. As Edison points out in its Opening Brief, "Ratepayers need those investors . . . a Commission decision to reduce the return shareholders can earn or denial of cost recovery altogether would make PG&E stock more risky and thus a less attractive investment."[78] If the returns PG&E offers are diminished, this will hamper its ability to attract financing at a reasonable cost.[79] Financing the billions of dollars of investment in Phase 1 and Phase 2 of the

76 *SoCal Edison Co*., D.82-12-055, 1982 Cal. PUC Lexis 1209, pp. *208-*209. In the decision, the Commission concluded that by offering only non-standard contracts at less than avoided cost, Edison violated Commission orders and impeded the development of QF resources.

77 NCIP Opening Brief, p. 27.

78 Edison Opening Brief, p. 2; Ex. 130, Edison Rebuttal, p. 5, lines 8-10.

79 Ex. 21, PG&E Rebuttal, p. 2-16, lines 15-20.

PSEP will require PG&E to finance large sums through the equity and debt markets. PG&E can only raise funds if investors think they can earn a competitive rate of return on capital and lenders/creditors have high assurance the company will be strong enough to repay in full what it has borrowed.[80]

In the Cost of Capital proceeding, the Commission sets the cost of capital at a level that allows a utility to compete successfully in capital markets to obtain the funds required to meet needed investments, and provide a sufficiently sound financial footing for the company to maintain its credit quality and take on debt at a reasonable price. The return on PG&E's equity set in the Cost of Capital proceeding must reflect market realities and establish a return that reflects the returns offered by other investments with corresponding risks. It is in the customers' interest to set rates at levels that allow the utility to sustainably attract capital necessary to provide service at least-cost to customers.[81] The Cost of Capital proceeding for PG&E is currently underway. That is the proper forum for evaluating the returns necessary for PG&E to attract equity and debt at the lowest possible cost to customers. The Commission should not interfere with or impede that process by introducing ROE reductions on a piecemeal basis in this proceeding driven by extraneous factors that have nothing to do with PG&E's ability to compete with other investment opportunities to attract capital or debt necessary to fund safety investments on a cost-effective basis.

When the Commission initiated this proceeding, it raised the question of whether a rate of return reduction would be a preferred method for implementing a disallowance of PSEP costs as opposed to a one-time, upfront shareholder funding amount. PG&E has demonstrated that a one-time disallowance aligns ratemaking and safety policies and is preferable to an on-going disallowance, such as an ROE reduction:

> Imposing an ongoing disallowance to all capital spending on gas system safety enhancements would not result in an alignment of ratemaking and safety goals. Under PG&E's proposal, . . . there is

80 Ex. 21, PG&E Rebuttal, p. 1-15, line 21—p. 1-16, line 6.
81 Ex. 21, PG&E Rebuttal, p. 2-26, lines 4-17.

> no ongoing financial loss that would be applied to gas safety investments in 2012 and beyond . . .[which] reduces uncertainty about the future impact of disallowances on utility rates and investments. Removing this financial uncertainty will strengthen PG&E's ability to attract capital and financing at the lowest possible cost to customers.[82]

Edison has intervened in this proceeding because it is alarmed at the precedent the intervenor ROE reduction proposals would have for all of the utilities in California:

> The Commission should utilize long-standing ratemaking practices that provide clear signals to utilities, investors, customers, and the public that it supports investment in safe and reliable operations. Punitive measures work in the opposite direction . . .[83]

Reducing a utility's rate of return is not an effective means of implementing a disallowance or sharing of PSEP costs. Adoption of these proposals would send the wrong message to the financial community, discourage investment in California utilities and increase market risk premiums, and ultimately impede the Commission's goal of implementing significant new gas safety enhancements in California in a manner that is as affordable to customers as possible.

F. TURN's Argument That PG&E Should Exhaust Other Sources Of Funding Completely Unrelated To The PSEP Prior To Seeking Ratepayer Cost Recovery Of PSEP Costs Is Unreasonable And Without Justification

TURN identifies three sources of "funding" that it suggests should be used to offset the costs of PSEP work prior to authorizing customer rate recovery of PSEP costs: (1) bonus depreciation; (2) past "overearnings" from GT&S rates for the period 1999 to 2012; and (3) incentive compensation authorized in PG&E's last General Rate Case decision.[84]

None of these proposed disallowances is characterized as imprudent PSEP costs. Nor does TURN suggest that these three sources of funds are linked to allegations of past imprudent conduct in PG&E's gas operations. As discussed below, all of these "sources of funds" were authorized by prior Commission ratemaking decisions, which TURN seeks to selectively reopen. TURN brazenly admits it is "cherry-picking" and its only justification for selective reopening of

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82 Ex. 2, PG&E Direct, p. 1-15, lines 7-23.
83 Edison Opening Brief, p. 3.
84 TURN Opening Brief, pp. 127-132.

these prior decisions is that shareholders should pay more.[85] In criticizing the level of incentive compensation for utility management authorized by the Commission in the past, TURN fails to present a rational basis for disallowing PSEP costs (on top of all of TURN's other disallowance recommendations, which taken together, appear to exceed PG&E's entire PSEP budget). Still worse, TURN has not quantified the value of any of its recommendations; if the Commission were to accept these recommendations, it would do so blindly without any sense of how much an additional disallowance would reduce PSEP costs. PG&E briefly addresses each of these recommendations below.

1. The PSEP Already Reflects Bonus Depreciation And Is Not Eligible For The Treatment Proposed By TURN

The Commission has already decided how the tax benefits associated with bonus depreciation will be handled in Resolution L-411/411A.[86] The PSEP is in full compliance with Resolution L-411, which adopted a memorandum account to track the use of tax benefits to fund incremental projects above and beyond those authorized in PG&E's 2011 GRC and 2011 GT&S Rate Case. All of the additional spending under the Resolution has already occurred or has been committed to incremental utility projects.[87] Finally the PSEP already reflects bonus depreciation as applicable to PSEP projects and for this reason, it is ineligible for tracking in the L-411/411A memo account. This exclusion was added to the resolution at TURN's insistence.[88] TURN's proposal would improperly and unreasonably reopen Resolution L-411/411A and change the rules of the game after funds have been fully committed.

2. Management Compensation Approved In The 2011 GRC Should Not Be Relitigated

The Commission approved management compensation, including incentive pay, in the 2011 GRC decision. In the 2011 GRC decision, the Commission approved a settlement funding

85 TURN Opening Brief, p. 130.
86 Ex. 21, PG&E Rebuttal, p. 18-1, line 23—p. 18-3, line 9.
87 Id.
88 Id.

approximately fifty percent of the short term incentive pay. Long term incentive pay for senior officers was excluded from the application.[89] The Parties to the GRC settlement have already agreed on partial recovery in rates of short-term pay and have addressed the issue of executive compensation funded (or not funded) through the GRC. TURN proposes to modify the reasonable level of management compensation approved in the 2011 GRC decision, reallocate these funds to the PSEP, and require shareholders to fund any incentive pay to PG&E officers or managers until the next GRC. Most of this incentive pay is directed to PG&E management employees in electric operations, which has no connection to gas operations and would result in an improper cross subsidy of gas revenues by electric customers. TURN argues that "facts in the record warrant offsetting the amounts ratepayers pay for top executive and manager bonuses" but TURN doesn't identify any facts in the record to support the recommendation. If TURN is referring to the allegations raised in the OIIs about PG&E's past recordkeeping and San Bruno related-findings (which it cites in several other portions of the brief to support findings of past imprudence and disallowance of PSEP costs), then it would be <u>triple counting</u> to disallow incentive pay to address these facts which are already being evaluated 1) in the OIIs for possible disallowances or fines and 2) in this proceeding for disallowances of PSEP costs associated with allegations of imprudence in PG&E's historic gas operations. TURN's proposal is unsupported, improper, duplicative and unreasonable.

3. TURN's Proposal To Modify Gas Accord V To Eliminate The Negotiated Upside For At Risk Revenues Is Unreasonable

TURN proposes to modify the Gas Accord V settlement agreement, which includes a revenue sharing mechanism for at risk revenues, by requiring that 100 percent of PG&E's upside under the sharing mechanism be reallocated to offset PSEP costs. Under the current Gas Accord V, the parties agreed that PG&E would be at risk for throughput, meaning if PG&E doesn't sell enough gas transmission service to the market, it is at risk for recovery of its costs and if it sells more service than forecast, it shares in some of the excess revenues. For Backbone transmission

[89] D.11-05-018, Settlement Agreement, § 3.6.1, p. 1-12.

revenue, any overcollection or undercollection is shared 50 percent to customers and 50 percent to shareholders. For Local Transmission, any undercollection or overcollection is shared 75 percent to customers and 25 percent to shareholders. For gas storage (the service that is most variable and at risk), 100 percent of the undercollections are borne by shareholders and overcollections are shared 75 percent to customers and 25 percent to shareholders.[90] This sharing mechanism is a carefully negotiated revenue sharing approach that puts PG&E at risk for most of the shortfalls in market revenues and provides the lion's share of the upside to customers. TURN's proposal would take back any upside that PG&E earns and credit it to PSEP rates. This would leave PG&E exposed to shortfalls but would take away all opportunities for revenue sharing, which could help offset undercollections in the at risk areas. This would unfairly rebalance the package of risk and reward that was approved by the Commission in the Gas Accord V Settlement decision. TURN provides no rationale for why the Gas Accord V should be modified, other than it presents a source of revenue that can be taken away.

The revenue sharing approach in the Gas Accord V is reasonable and TURN has not provided a basis for changing it. It should be pointed out that the revenue sharing approach in Gas Accord V does not allow PG&E to "profit" by reducing spending on reliability investments. There is a balancing account for the Transmission Integrity Management Program that does not authorize PG&E to reallocate funds to other uses (and any unspent funds are returned to customers).[91] In addition, PG&E committed to the Commission that it will spend all the funds budgeted in Gas Accord V for pipeline safety, reliability, and integrity projects and activities. The Commission found when it approved the Gas Accord V Settlement that the funding levels for these activities in the settlement and PG&E's assurances that this work will be performed will "ensure safe and reliable service."[92]

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90 Ex. 21, PG&E Rebuttal, p. 17-6, lines 10 to 32.
91 Ex. 21, PG&E Rebuttal, p. 17-7, lines 1-25.
92 D.11-04-031, p. 69, Findings of Fact 46 – 49.

G. PG&E's Cost Recovery Proposal Should Be Adopted

1. PG&E's Request for Memorandum Account Should Be Granted

Both TURN and DRA in their opening briefs support adoption of a memorandum account if the Commission does not decide to disallow 100% of the PSEP costs in its decision.[93] DRA states that the memorandum account should take the same form, and apply the same procedures, as the memorandum accounts adopted for the Sempra utilities in D.12-04-021. Both TURN and DRA would defer any recovery in rates of PSEP costs until a future CPUC proceeding conducts further review of the costs and another decision is issued by the Commission. For DRA this future proceeding would review whether the costs are "reasonable and incremental" and for TURN the future proceeding would address the results of the three OIIs.[94] At this stage, it appears that no party opposes the authorization of a memorandum account and the only question is what purpose it will serve.

As discussed in PG&E's Opening Brief, PG&E still needs a memorandum account for two reasons: 1) to track PG&E's actual 2011 PSEP costs so that total PSEP program costs can be calculated and PG&E's actual shareholder contribution for 2011 costs can be determined; and 2) to establish the PSEP rates for 2012 following the issuance of the Commission's decision in this proceeding.[95] Under PG&E's ratemaking proposal, it proposes a binding budget for capital and expense for the four year period 2011 to 2014. The four year, Phase 1 budget for PSEP expense is $750.5 million and the four year, Phase 1 budget for capital is approximately $1.4 billion.[96] While 2011 costs would be allocated to shareholders, these costs still are counted toward the four year binding budget. In order for PG&E to count 2011 expenditures against this budget, the Commission needs to authorize a memorandum account to track these costs for later reconciliation. If there is no official tracking of 2011 costs allocated to PG&E's shareholders, PG&E will be unable to track its progress toward the four year program budgets for expense and

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93 DRA Opening Brief, pp. 129-130; TURN Opening Brief, pp. 138-139.
94 Id.
95 PG&E Opening Brief, pp. 95-97.
96 Ex. 2, PG&E Direct, p. 1-16, Table 1-2, line 7; Table 1-3, line 7.

capital. Authorizing the tracking of 2011 costs in a memorandum account is limited to this purpose.

Second, the memorandum account is needed to authorize PG&E to recover in rates its 2012 expenditures (to the extent they are found to be recoverable in rates by the Commission). Since the Commission's decision on the PSEP is likely to be issued in the third or fourth quarter of 2012, a memorandum account is required to track and record PSEP expenditures starting on January 1, 2012. Otherwise, recovery of costs incurred prior to the PSEP decision may not be recoverable under the rule against retroactive ratemaking. As discussed in the Opening Brief, the Commission has clear legal authority to authorize PG&E to record PSEP costs as of January 1, 2012, for later recovery in rates and there are many Commission precedents for doing so.[97] Not authorizing the memorandum account would have the effect of allocating all 2012 PSEP expenditures incurred prior to the Commission decision date on the PSEP to shareholders, an unfair and arbitrary outcome given PG&E's good faith decision to commence hydrotesting, pipeline replacement, MAOP validation, automated valves, interim safety measures and GTAM development immediately rather than wait for a Commission decision before beginning work in earnest.

DRA recommends that the Commission approve for PG&E the exact same advice letter procedure that it did for Sempra, including requiring PG&E to file a new Tier 2 advice letter that includes cost estimates for 12 months of expenditures. This does not make sense for PG&E since 1) PG&E already submitted a draft memorandum account letter with its PSEP filing (which the Commission can approve in its decision on the PSEP[98]); 2) PG&E has already provided its estimates of PSEP costs in the filing; and 3) the purpose of the Sempra memo account is to track costs <u>prior to</u> a decision on its PSEP and the purpose of PG&E's memorandum account, as explained above, is to enable it to implement its ratemaking proposal <u>after</u> the Commission's

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97 In D.12-04-021 the Commission authorized the Sempra utilities to retroactively track costs for the first 12 months of their PSEP program. This is essentially the same relief that PG&E is requesting – authorization to record and track PSEP costs as of the start of the program on January 1, 2011.

98 Ex 2, PG&E Direct, Attachment 8D.

decision on the PSEP. DRA also suggests that costs tracked in the memorandum account would be reviewed in a later proceeding to determine if they are "incremental and reasonable." This second proceeding contemplated by DRA is not necessary since PG&E has already demonstrated in this proceeding that its costs are reasonable and incremental. The second proceeding would merely duplicate a review that is occurring in this proceeding.

2. PG&E's Tier 3 Advice Letter Proposal Should Be Adopted

As described in the Opening Brief, PG&E has requested a Tier 3 Advice letter process be authorized for PG&E to seek expedited changes in the PSEP budget if circumstances lead to a change in Phase 1 project scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital. The objective is not, as TURN alleges, to allow PG&E to defer work or, as DRA speculates, to drive up returns on capital projects. Rather, the objective of the advice letter process is to provide a timely mechanism to address the need for a mid-course correction if unanticipated circumstances make it impossible for PG&E to complete Phase 1 work at the adopted budget. This process provides a forum for collaborating with the Commission and stakeholders on a real time basis on how best to respond to the changed circumstances. The process by no means is a guarantee of cost recovery; parties will have a full opportunity to review and comment on the advice letter and the Commission may reject the request, modify it or set it for hearings if it determines that additional process is required to evaluate the request.

The point here is that it is fair and reasonable to have some mechanism in place to address changed circumstances. For example, PG&E witnesses testified about the unexpected circumstances surrounding additional "cleaning runs" that were required as part of the hydrotesting process in 2011.[99] While PG&E assumed that it would have to conduct one or two pipeline cleaning runs prior to a hydrotest, PG&E was required to run dozens of additional cleaning runs to address new clean water standards or the presence of mercury in certain

[99] Ex. 21, PG&E Rebuttal, p. 4-2, line 25—p. 4-4, line 14; Tr. (Campbell), p. 1817, lines 22-28; Tr. (Caletka), p. 2130, lines 17-27; Tr. (Marre), p. 1976, line 24—p. 1977, line 10.

pipelines. This required PG&E to store, transport, filter and dispose of significantly more water than was contemplated and was the major driver in a $110 million cost overrun in the hydrotesting program. Since this cost overrun occurred in 2011, under PG&E's shareholder allocation proposal, these costs will be borne by shareholders. PG&E will not use the Tier 3 advice letter process to seek recovery of these 2011 costs.[100] However, if this scope change continues for the remainder of the program and, for example, would result in a $300 million cost increase to PG&E's $750 million cost estimate, it is reasonable to have a process to evaluate if this unanticipated circumstance was beyond PG&E's control, whether PG&E reasonably and prudently managed the issue, and whether additional cost recovery is warranted.

There are other ways to address changed circumstances of this nature. For example, the Commission could authorize PG&E to file an application at the conclusion of Phase 1 for an after the fact reasonableness review of any costs that are in excess of the approved expense and capital for the PSEP Phase 1. A second option would be for PG&E to file a petition for modification of the decision approving the PSEP and raising the issue this way. These alternatives would ultimately provide the same opportunity to address changed circumstances but because these applications or petitions would take at least 12 to 18 months for the Commission to process, the review would be done on an after the fact basis. The benefit of the Tier 3 advice letter process proposed by PG&E is that it would allow stakeholders and the Commission an opportunity to join in, recommend and authorize course corrections or changes in scope during Phase 1 rather than reviewing the utility's conduct after the fact. PG&E believes this method of proactive regulatory oversight is one of the cornerstones of how the Commission can better align safety and ratemaking objectives. This process, together with PG&E's proposed procedures for enhanced reporting and transparency of the project, will facilitate active regulatory oversight of the PSEP safety enhancements.

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[100] Tr. (Marre), p. 1979, lines 23-26.

TURN expresses concern that the 20 day comment period for an advice letter may be inadequate to respond to a request for a potentially large rate increase.[101] The Commission can always grant more time for parties to review and comment on the utility submittal if it raises complicated issues that require more time to evaluate. Or the Commission can convert the advice letter to an application if it decides this is the right path. This concern is easily addressed at the time any advice letter is filed in response to the issues raised and scope of relief requested. TURN's concern does not warrant rejection of the concept.

TURN and NCIP raise an additional concern about PG&E's proposed Tier 3 Advice Letter process. In the event the Commission denies a request for additional funding in a Tier 3 Advice Letter request, PG&E has asked the Commission to authorize it to manage the remainder of the Phase 1 work scope within the approved forecast.[102] NCIP and TURN assert that reserving the option of deferring work from Phase 1 to Phase 2 as a way of managing cost overruns is a "loophole" that could put customers at risk for excessive cost overruns. NCIP recommends that any change in work scope from Phase 1 to Phase 2 should have to be approved by the Commission, presumably under the Tier 3 Advice letter process.[103] PG&E witness Marre clarified a few features of PG&E's proposal. First, in any advice letter filing, PG&E will present a detailed description of the issue driving the change in scope, schedule or cost and present PG&E's proposed course correction. There will be alternatives, including the changes in scope that would be necessary (and potential deferral of work) if the request for additional funding is requested.[104] While this is not exactly NCIP's proposal, it is close. PG&E will put the Commission on notice of the options available, including potential changes in Phase 1 work scope and will implement whatever course the Commission directs PG&E to take.

[101] TURN Opening Brief, p. 143.
[102] Ex. 2, PG&E Direct, p. 8-13, line 29—p. 8-14, line 7.
[103] NCIP Opening Brief, p. 35.
[104] Tr. (Marre), p. 1951, lines 16-23.

3. The Depreciable Life For Transmission Mains Should Not Be Increased

TURN recommends that the Commission adopt a depreciable life of 65 years for pipeline replacements, in lieu of the 45 year life PG&E currently uses for transmission mains.[105] This would result in a deviation from the depreciable life of transmission assets adopted in the GT&S rate case decision for non-PSEP pipe replacements.[106] Under TURN's proposal, PG&E would be required to separately book, account for and calculate depreciation for PSEP pipe replacements independent from its accounting practices for the rest of its gas pipeline system. Plant depreciation rates for gas transmission pipes are typically reviewed and established in the GT&S rate case on the basis of a depreciation study. TURN has not presented sufficient evidence (other than citing the average age of PG&E pipes and speculating that new pipes will last longer due to better manufacturing processes) to change current depreciation rates on a piecemeal basis. TURN also fails to mention in its brief that San Diego Gas and Electric Company in its current GRC has proposed a 45 year life for gas transmission assets recorded in FERC Account 367.[107] Depreciation rates for gas transmission pipe should be applied in a uniform and consistent manner. It makes no sense for a new pipe funded under Gas Accord V to have one depreciable life and a new pipeline funded under PSEP to have a different depreciable life. Having two different sets of books to track the different depreciable lives would also unnecessarily complicate the accounting and ratemaking process. The proper forum for reevaluating the appropriate depreciable life of new gas pipelines is PG&E's next GT&S Rate Case, which will set rates effective January 1, 2015. The Commission should defer this issue to the next GT&S rate case, where it can be evaluated on the basis of a formal depreciation study, rather than TURN's unsupported speculation about the potential life of new pipelines.

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105 TURN Opening Brief, pp. 126-127.
106 Ex. 21, PG&E Rebuttal, p. 17-10, lines 11-26.
107 Ex. 21, PG&E Rebuttal, p. 17-10, lines 2-5.

4. An After-The-Fact Reasonableness Review Is Unnecessary

As part of its ratemaking proposal, PG&E has proposed that the Commission adopt an upfront estimate of the reasonable cost to complete PSEP Phase 1. If the actual costs of the program are equal to or less than the estimate, there is no need to conduct an after the fact reasonableness review because PG&E has completed the project at or below the reasonable forecast. This ratemaking approach—adopting an upfront estimate of the reasonable costs of a project rather than conducting an after the fact prudence review of the recorded costs—is fully authorized and set out as an acceptable ratemaking approach in Public Utilities Code Section 463.5. This is the approach the Commission uses when it adopts a "maximum reasonable cost" for utility projects requiring a Certificate of Public Convenience and Necessity under Public Utilities Code Section 1005.5. The Commission has also adopted this "upfront determination of reasonableness" approach for other large capital projects, such as PG&E's Diablo Canyon steam generator replacement project and several of its new power plants.[108]

TURN argues that the Commission should not adopt this approach and should instead conduct an after the fact reasonableness review of the actual costs incurred under the PSEP. TURN states that it may want to argue in the future that PSEP costs are imprudently high because PG&E and Sempra will be competing for the same resources to conduct hydrotesting and pipe replacements and this may drive up costs.[109] TURN is effectively asking the Commission for an opportunity to conduct <u>another duplicative prudence review of PG&E's historic gas operations</u> to evaluate whether PSEP work should have been done earlier. This attempt to reserve the right to litigate once again PG&E's historic gas operations over 70 to 80 years as a basis of a disallowance of current PSEP costs is unreasonable and results in never-ending litigation and wave after wave of overlapping and duplicative disallowances. The purpose of the instant proceeding is to assess the reasonable cost of PG&E's PSEP. TURN and

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108 Diablo Canyon Steam Generator Replacement Project, D.05-11-026, Ordering Paragraphs 2 and 3; Humboldt Bay Generating Station, D.06-11-048, p. 15; Gateway Generating Station, D.06-06-035, Appendix A, p. 5; PV Program, D.10-04-052, p. 25; Fuel Cell, D.10-04-028, p. 38, Conclusion of Law 15.

109 TURN Opening Brief, pp. 139-140.

the other parties have certainly not been constrained from litigating layer after layer of disallowance recommendations and other reductions in the proposed cost estimate. There is no reason to go through this process again after the project is completed to evaluate if the cost of the program was reasonable. Under PG&E's proposal, if it can deliver the project at the forecasted overall program cost, it has performed reasonably, customers have received what was promised and there is no need for another multi-year proceeding to review on an after the fact basis the construction and project management of the PSEP.[110]

H. It Is Not Necessary Or Reasonable To Defer A Decision On The PSEP Revenue Requirement And Rates Until After The OIIs Are Concluded

Several parties recommend that the Commission defer any ruling on the PSEP revenue requirement until after the gas-related OIIs are resolved.[111] TURN proposes a multi-step process for coordinating the OIIs with this proceeding. In TURN's Step 1, the Commission would first address in the current PSEP proceeding the broad disallowance recommendations proposed by TURN and DRA (based on allegations raised but not yet resolved in the OIIs). Next, in TURN's step 2, the evidentiary record in the OIIs would close and TURN would propose a second evidentiary hearing on the PG&E PSEP to evaluate if the facts in the record warrant further disallowances in PSEP costs. TURN's step 3 would wait for the Commission to issue decisions in the three OIIs where it will determine the remedial actions and disallowances that would be applicable to the PSEP. Finally, TURN's step 4 would be to have <u>a third</u> evidentiary proceeding on the PSEP to consider how the PSEP revenue requirement should be further reduced to incorporate the outcomes in the three OIIs. This process recommendation is unworkable, unreasonably duplicative and would result in an unjust and unreasonable delay in cost recovery

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110 If PG&E were to return to the Commission to seek cost recovery of costs in excess of its forecast, it would be reasonable to evaluate why the cost exceeded the forecast and whether 1) PG&E reasonably and prudently managed the project and the cost increase was due to extraneous factors beyond its control or 2) PG&E's management of the project was a contributing factor in the cost increase. But if the project can be delivered at the forecast, such a process is unnecessary.

111 TURN Opening Brief, pp. 116-118; NCIP Opening Brief, p. 21; NCGC Opening Brief, pp. 2-3.

for hundreds of millions of dollars in gas pipeline safety enhancements ordered by the Commission.

PG&E's proposal for coordinating the PSEP proceeding and OIIs is much simpler and effective. First, the Commission in the decision in this proceeding should address 1) the scope of work to be approved in the PSEP, 2) the reasonable cost estimate for the approved scope of work, 3) the customer/shareholder allocation principles that will determine which PSEP costs are eligible for cost recovery; and 4) the ratemaking and rate design features necessary to implement new PSEP rates.[112] The revenue requirement adopted in this PSEP decision would be tracked in the proposed PSEP balancing accounts for potential later adjustment.

Second, the Commission will address the allegations raised in the OIIs in the OII proceedings and decide the appropriate fines, penalties, remedial actions and disallowances in those proceedings. The Administrative Law Judges and assigned Commissioners in those proceedings are quite capable of sorting through the allegations that have been raised and designating any remedial actions that need to occur. The Commission does not need two additional evidentiary hearings in this proceeding to "prelitigate" and "postlitigate" the results of the OIIs as TURN recommends.

Third, after the OIIs are decided, PG&E should be directed to adjust its PSEP rates to reflect the decisions in the OIIs that affect the PSEP. This step involves mere compliance with the OII decisions and can be accomplished as part of the annual true-up of the PSEP balancing account. As discussed above, PG&E supports the notion of an audit, funded by PG&E, to verify: 1) the actual costs of PSEP work; 2) the eligibility of costs under PG&E's customer/shareholder sharing principles; and 3) the adjustment of the PSEP revenue requirement as ordered in the OIIs. This simple annual true-up and audit of the PSEP balancing account will ensure that the results of the OIIs are properly incorporated in the PSEP revenue requirement.

112 Ex. 21, PG&E Rebuttal, p. 1-5, line 6—p. 1-6, line 23.

The annual true-up and audit of the PSEP balancing account will adjust rates in a timely fashion and ensure that rates are implemented in a reasonable way. To illustrate, under PG&E's ratemaking proposal, 2012 rates would be implemented in late 2012 and would be based on PG&E's expense forecast for 2012. The PSEP rates, as tracked in the PSEP balancing account, would be adjusted in 2013 to reflect 1) any adjustments ordered in the OIIs; 2) the 2013 expense forecast; 3) the revenue requirement based on the actual cost of capital projects completed in 2012; 4) the revenue requirement adjustment necessary to amortize any undercollections or overcollections in the PSEP balancing account and 5) any adjustments resulting from the audit of 2012 PSEP balancing account activity. There would be a similar balancing account true-up and audit for PSEP rates and adjustments effective in 2014 and 2015. This process provides an effective and simple way to coordinate the OIIs with PSEP ratemaking and only requires one evidentiary hearing on the PSEP.

As a final matter, Sempra has recommended that the Commission defer making any findings on factual issues that could be precedential to Sempra, such as the content and applicability of voluntary industry hydrotesting and recordkeeping standards or the incremental requirements for recordkeeping under the "traceable, verifiable and complete" requirement adopted by the Commission. PG&E understands and is sympathetic to Sempra's concerns about due process and having an opportunity to address these issues in its separate PSEP proceedings. PG&E believes that the Commission should state that the outcome on these evidentiary issues is non-precedential for Sempra. It would not be reasonable for the Commission to defer the entire decision on PG&E's PSEP until the Sempra decision is issued. The Commission crossed that bridge when it decided to bifurcate the proceedings reviewing the utility PSEPs. PG&E needs to know what work scope will be approved in the PSEP and what modifications to the decision trees or other aspects of the program will be required by the Commission. Delaying a decision on the approved work scope for the PSEP would cause uncertainty and delay and would waste resources.[113]

I. Independent Auditors Are Not An Issue For This Proceeding

The Joint Parties make several recommendations regarding PG&E's use of a third party auditor, including reiterating their request that the Commission compel testimony of PG&E's "financial audit expert."[114] This is not the correct proceeding to explore Joint Parties' concerns about the independence of utility auditors. The Joint Parties have raised the issue of the independence of Deloitte and Touche in multiple proceedings, including at least two other CPUC dockets. As mentioned in the Joint Parties' Opening Brief, they have a pending request for an OIR into this very issue before the Commission.[115] The Petition for Rulemaking is the appropriate forum in which to address this issue. Furthermore, the Joint Parties made a nearly identical request in Sempra's recent GRC (Applications 10-12-005 and 10-12-006) that was denied by ALJ Wong.

It is neither efficient nor practical for the Commission to evaluate essentially the same issue in two different forums. The generic issues raised against Deloitte involve the Sempra utilities as well as PG&E, since those utilities also retain Deloitte as their independent auditor. The Petition for Rulemaking is the more appropriate forum to consider these issues.

III. PG&E'S PROPOSED RATE DESIGN SHOULD BE ADOPTED

A. The Commission Should Not Adopt The Proposed Alternative Rate Design Methodology

PG&E proposes to allocate PSEP revenue requirements between core and noncore customers based upon their annual percentages of revenue requirement responsibility established in Gas Accord V, as an interim step until the next GT&S Rate Case. NCIP, the Northern California Generation Coalition ("NCGC"), and Dynegy Inc.[116] are all large, noncore customers

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113 Ex. 2, PG&E Direct, p. 1-20, line 27—p. 1-21, line 11.
114 Joint Parties Opening Brief, pp. 18-22.
115 Joint Parties Opening Brief, p. 18, citing P.12-02-016.
116 Dynegy is not yet a party to this proceeding, having filed a motion for party status concurrently with its Opening Brief. Nonetheless, PG&E has elected to respond to Dynegy's arguments because they mirror NCIP's proposal for the adoption of the EPAM methodology.

that seek to shift more of the costs of PSEP from noncore customers to core customers through NCIP's proposed equal percent of authorized margin ("EPAM") methodology. The chief argument advanced by these parties is that PG&E's cost allocation method does not reflect cost causation principles.[117] NCIP argues further that the Gas Accord V cost allocation methodology was selected because it was "equitable," not because it was based on cost causation principles.[118] NCIP, NCGC and Dynegy do not cite to any evidence in the record to support their claim that PG&E's proposed rate design methodology conflicts with cost causation principles. In fact, all customers that rely on the PG&E transmission system benefit from a safer system.

Moreover, these parties failed to show that the proposed alternative EPAM methodology better aligns with cost causation principle. These parties note that SoCalGas/SDG&E proposes to design their PSEP rates based upon an EPAM methodology, and rely solely on SDG&E/SoCalGas data indicating that 97% of the premise structures found within the Potential Impact Radius of their transmission pipelines are typically those associated with core residential and commercial customers.[119] While that may be true for SDG&E/SoCalGas, the most these data show is that SDG&E/SoCalGas's proposed EPAM methodology may be a reasonable basis upon which to design *their* PSEP rates. PG&E designed rates in the same manner that base gas transmission rates have been set in all prior GT&S Rate Cases. PG&E has never used an EPAM methodology to allocate costs in prior GT&S Rate Cases.

It is clear that NCIP, NCGC and Dynegy proposed the EPAM methodology because it lowers noncore rates, at the expense of core rates, because rate design is a zero sum game. One need look no further than TURN's Opening Brief to realize that adoption of the EPAM methodology would be detrimental to core customers. As TURN notes, the EPAM methodology is a new and novel cost allocation proposal that is "intended purely to shift costs to core

117 NCIP Opening Brief, p. 39.

118 NCIP Opening Brief, p. 40. It is interesting to note that, in all other respects, NCIP argues that the balances struck in the Gas Accord V Settlement should be preserved, but argues for a departure in this one area of cost allocation because it serves its interests.

119 NCIP Opening Brief, p. 41.

(residential and small commercial) customers."[120] As PG&E has noted on numerous occasions, NCIP seeks to distract from the fact that PG&E's proposed PSEP rates for noncore customers are lower than PG&E's proposed PSEP rates for core customers by focusing the attention on the *percentage* increases.[121] The percentage increase for noncore customers is only higher than for core customers because the gas transportation rates paid by noncore customers are quite a bit lower on a relative basis when compared with core gas transportation rates.[122] Therefore, PG&E urges the Commission not to adopt NCIP's proposed EPAM methodology for PSEP rates, because it would have the effect of shifting costs from noncore customers to core customers.[123]

B. Other Concerns Raised By Large Noncore Customers Are Speculative

The noncore customer intervenors raise the specter of the threat of bypass as support for their proposal to shift more costs to core customers. For example, NCGC criticizes PG&E for failing to analyze the potential for bypass of the PG&E system by electric generator and other large noncore customers.[124] The bypass threat is speculative. If the problem arises, the utilities and the Commission will consider methods to ameliorate the threat of bypass, as has been done in the past. Mere speculation that PSEP rates may lead to bypass is not sufficient to justify rejection of PG&E's proposed rate design.

Similarly, NCIP argues that adoption of the Gas Accord V cost allocation methodology can also lead to significant increases in electric rates because of the impact on gas costs for gas-fired electric generators.[125] While it is true that any time gas transmission prices increase, it may lead to an increase in electric rates because gas transportation costs are one cost for gas-fired electric generators, this truism is not an adequate basis upon which to shift costs from noncore to core customers.

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120 TURN Opening Brief, p. 146.
121 Tr. (Blatter), p. 2021, lines 7-9.
122 Tr. (Blatter), p. 2008, line 22—p. 2009, line 1.
123 Edison asks that the Commission make clear that the cost allocation methodology chosen for PG&E's PSEP will not necessarily be precedent for the cost allocation chosen for SoCalGas/SDG&E's PSEP. SoCalEdison Opening Brief, p. 6. PG&E does not oppose this recommendation.
124 NCGC Opening Brief, p. 6.
125 NCIP Opening Brief, p. 43.

C. TURN's Proposal For Allocation of GTAM Costs Should Not Be Adopted

PG&E elected to allocate all common PSEP costs (including GTAM) by the direct PSEP costs.[126] TURN recommends that GTAM costs allowed to be recovered in rates be assigned to functions by total miles of pipeline, which would assign about 35% of the costs to backbone transmission and about 62% to local transmission.[127] TURN essentially wants to break out a specific portion of the common costs (those associated with GTAM) to perform a different type of allocation.[128] TURN's proposal is inconsistent with the manner in which PG&E allocates common costs in the PSEP, and should be rejected.

IV. THE PIPELINE MODERNIZATION PLAN SHOULD BE ADOPTED

A. Criticisms Regarding The Scope Of Phase 1 And The Level Of Project Definition Are Unwarranted

DRA claims that the Pipeline Modernization Plan "does not define project scope with sufficient accuracy or certainty to support any approval" for cost recovery.[129] In particular, DRA claims that Phase 1 of the PSEP is not accurately defined because the cost estimates for PSEP work submitted in August 2011 were Class 4 estimates, which means that between 5 percent and 15 percent of the projects' scopes were defined.[130] What DRA describes, however, is typical for rate cases in which a utility submits plans for a large-scale capital and expense program, spanning multiple years in to the future. It is certainly not a justification for jettisoning all the planning and engineering work that PG&E has performed for Phase 1 of the PSEP, and requiring PG&E to start over.

DRA and TURN assert that not all Class 2 locations should be included in Phase 1 of the PSEP.[131] While these parties' proposals to eliminate many Class 2 segments that are not adjacent to Class 3 or Class 4 segments may reduce costs in the short-term, it may increase costs in the long-term because PG&E will have to go back and either pressure test or replace Class 2

126 Ex. 21, PG&E Rebuttal, p. 18-3, lines 26-28.
127 TURN Opening Brief, p. 147.
128 Ex. 21, PG&E Rebuttal, p. 18-3, lines 28-30.
129 DRA Opening Brief, p. 49.
130 DRA Opening Brief, p. 51.
131 DRA Opening Brief, p. 55; TURN Opening Brief, p. 22.

and Class 1 pipe segments at a later time.[132] Similarly, CCSF takes issue with prioritizing Class 2 areas operating above 30 percent SMYS over Class 3 and 4 locations with pipelines operating between 20 percent and 30 percent SMYS.[133] PG&E presented sound engineering reasons for prioritizing Class 2 locations operating above 30 percent SMYS over more populated Class 3 and 4 areas operating between 20 percent and 30 percent SMYS, discussed at pages 16 through 18 of PG&E's Opening Brief. In short, untested Class 2 pipeline segments operating above 30 percent SMYS have a greater probability of an uncontrolled rupture and public safety risk than untested Class 3 pipeline segments operating below 30 percent SMYS.[134]

B. Proposed Modifications To The Pipeline Modernization Decision Trees Should Be Rejected

Although no party launches a wholesale attack on the three Pipeline Modernization Decision Trees proposed by PG&E, some parties do suggest changes at the margins. The parties' proposed modifications—discussed below—should not be adopted.

As a threshold matter, DRA retained a consultant to develop modified decision trees that drastically reduce the scope of Phase 1 work. As PG&E argued on pages 14 through 16 of its Opening Brief, DRA's proposed decision trees and resulting reduction in project scope should not be adopted. DRA claims—without any evidence—that its modified decision trees result in "less risk" than the PG&E decision trees.[135] However, it is evident from DRA's testimony that it was focused on cost reductions, not safety.

DRA also suggests that all three of the decision trees should not query whether a Subpart J test has been conducted, but instead the query should include any post-1955 strength test.[136] PG&E does not agree with this recommendation. As the Commission has recognized, pipelines installed prior to July 1, 1961 were exempt from the pressure test requirements of GO 112, and pipelines installed prior to 1970 were not required to be strength tested under federal

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132 Ex. 21, PG&E Rebuttal, p. 3-16, lines 14-19.
133 CCSF Opening Brief, pp. 9-12.
134 Ex. 21, PG&E Rebuttal, p. 3-16, lines 28-32.
135 DRA Opening Brief, p. 57.
136 DRA Opening Brief, p. 54.

regulations.[137] PG&E maintains that it is more appropriate for the decision trees to query whether a GO 112 strength test was conducted for pipelines installed between July 1, 1961 and 1970, or whether a Subpart J strength test was conducted for pipelines installed after 1970.

1. PG&E's Proposed Manufacturing Threats Decision Tree Should Be Approved

The City of San Bruno questions the use of a 1970 vintage date in the Manufacturing Threats decision tree.[138] PG&E witness Mr. Hogenson testified that the 1970 threshold date was selected to reflect improvements in several areas, including: (1) changes in pipe metallurgy, longitudinal welds, the increase of pipe mill test pressures and other pipe inspection criteria; (2) publication in 1970 of federal natural gas transportation safety regulations, which required strength testing of all transmission pipelines installed after that date; and (3) the manufacturing threat is considered present in pre-1970 pipe with a manufactured long seam by low-frequency ERW, spiral weld, Single Submerged Arc Weld, A.O. Smith flash weld, lap weld, hammer weld, or any pipe with a longitudinal joint efficiency factor less than one.[139] The City of San Bruno has submitted no evidence supporting a different date.

DRA recommends that replacement be removed as a default Phase 1 action for manufacturing threats.[140] Similarly, TURN argues that PG&E should hydrotest, rather than replace, pipe with manufacturing threats.[141] As PG&E addressed on pages 7 through 8 of its Opening Brief, pipeline segments with the long-seam types listed in the Manufacturing Threats Decision Tree are good candidates for replacement for a number of reasons.

TURN also recommends that DSAW pipe be evaluated for manufacturing threats.[142] As PG&E explained and TURN recognizes, however, this is unnecessary because all untested DSAW pipe will be strength tested or replaced.[143] Under the Corrosion and Mechanical Damage

137 D.11-06-017, pp. 27-28, Findings of Fact 5 and 6.
138 City of San Bruno Opening Brief, p. 8.
139 Ex. 2, PG&E Direct, p. 3-12, lines 4-22.
140 DRA Opening Brief, p. 56.
141 TURN Opening Brief, p. 28.
142 TURN Opening Brief, p. 26.
143 Ex. 21, PG&E Rebuttal, p. 3-4, lines 12-16.

Decision Tree, DSAW pipe without a documented strength test will be strength tested, unless it is replaced due to girth weld fabrication and construction properties.[144]

TURN also asks the Commission to modify Decision 11-06-017 to allow for alternative assessment methods for pipelines operating below 30 percent SMYS, under Steps M4 and M5 of the Manufacturing Threats Decision Tree.[145] According to TURN, it is not necessary from a safety perspective to test these pipelines, because there is general agreement that these pipelines are not likely to rupture at operating levels below 30 percent SMYS.[146] PG&E submitted a PSEP that contemplates testing or replacing all previously untested DOT transmission pipeline, in compliance with Commission Decision 11-06-017. While PG&E agrees that pipelines operating below 30 percent SMYS are more likely to fail as a leak than a rupture, and has used the 30 percent SMYS level as a prioritization tool, not testing or replacing pipelines operating below 30 SMYS would not comply with Commission Decision 11-06-017 as currently crafted.

2. The Commission Should Adopt PG&E's Proposed Fabrication And Construction Threats Decision Tree

The City of San Bruno, again with no citation to the record, questions whether 1960 is an appropriate query date for the Fabrication and Construction Threats Decision Tree.[147] The threshold date of 1960 was selected to reflect fabrication and construction improvements that resulted from: (1) publication and industry use of ASME B31.8 published in 1955 and 1958; (2) the CPUC's enactment of GO 112 in 1961; (3) the widespread use by 1960 of Shielded Metal Arc Welding for gas transmission; and (4) improved construction and quality control practices.[148] The City of San Bruno offers no evidence that would question the selection of a 1960 threshold date for this decision tree.

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[144] Ex. 21, PG&E Rebuttal, p. 3-4, lines 22-26.
[145] TURN Opening Brief, p. 31.
[146] TURN Opening Brief, pp. 31-32.
[147] City of San Bruno Opening Brief, p. 8.
[148] Ex. 2, PG&E Direct, p. 3-15, lines 2-10.

DRA recommends that Decision Point 2F (which queries whether a Subpart J strength test has been conducted) be omitted.[149] DRA contends that a hydrostatic test is not well suited for evaluating manufacturing threats.[150] Similarly, TURN recommends that a Step 2FA should be added to the decision tree after the "no" output to Step 2F to ask whether an "abnormal loading test analysis" has been performed. If the answer is yes, the segment would proceed to the corrosion decision tree.[151] As PG&E explained on page 10 of its Opening Brief, the Subpart J query at Box 2F is a screening tool to ensure that some type of mitigative action is taken on previously-untested pipelines. It does not dictate that the mitigation be hydrotesting, rather than replacement. TURN's recommendation would result in pipeline segments that have not previously been strength tested, but have had an "abnormal loading test analysis," not being tested or replaced. PG&E does not believe this outcome complies with Commission Decision 11-06-017.

TURN also recommends that the Commission should require some technical review of the Engineering Condition Assessment ("ECA") proposed in Step 2C.[152] PG&E does not oppose this recommendation.

3. PG&E's Proposed Corrosion And Latent Mechanical Damage Decision Tree Should Be Approved

PG&E has met its burden of showing that its proposed Corrosion and Latent Mechanical Damage Decision Tree is based on sound engineering principles. TURN's proposed modified Corrosion and Latent Mechanical Damage Decision Tree recommends: (1) Close Interval Survey and Phase 2 ILI for untested pipeline segments operating above 30 percent SMYS; and (2) leak survey and Right of Way Monitoring for pipelines operating below 30 percent SMYS.[153] For the reasons explained on page 12 of PG&E's Opening Brief, TURN's modified decision tree should be rejected because it: (1) does not comply with Decision 11-06-017; (2) would result in

[149] DRA Opening Brief, p. 56.
[150] DRA Opening Brief, p. 56.
[151] TURN Opening Brief, pp. 33-34.
[152] TURN Opening Brief, p. 33.
[153] TURN Opening Brief, p. 36.

no action on some untested pipeline segments; and (3) will not result in the same assurance of safety that would accompany strength testing or replacement.

TURN also states that the results of PG&E's Corrosion and Mechanical Damage Decision Tree needs to be closely scrutinized by the Commission, but does not identify any specific Phase 1 work under this decision tree that should not be undertaken, and defers to DRA.[154] DRA's proposed scope reductions are addressed in Section IV.A.

C. CCSF Misunderstands The Scope Of IRP And NTSB Review Of Pipeline 2020 And The Purpose Of The PSEP

CCSF relies on NTSB and IRP feedback on Pipeline 2020—the precursor to the PSEP—in support of its argument that the PSEP is flawed and needs to be reconfigured.[155] In particular, CCSF points to the IRP's finding that Pipeline 2020 was not supported with solid engineering and economic analysis, and leaps to the conclusion that, because the decision trees were not substantially altered between the infant stages of Pipeline 2020 and the filing of the PSEP in August 2011, the PSEP suffers from the same infirmities.[156] CCSF misunderstands the scope of the IRP's review of PG&E's Pipeline 2020 program. At the time of IRP review, the Pipeline 2020 Program was in its infancy, and was presented to the IRP in a summary fashion. In particular, while the decision trees may have been fairly advanced at the time, PG&E had not created projects or detailed cost estimates for the scope of work contemplated in Pipeline 2020. That the IRP found that Pipeline 2020 was not yet based on solid engineering and economic analysis is not relevant; when PG&E filed the PSEP in August, 2011, it was supported by sound engineering analysis that was validated by outside experts, and detailed cost estimates that spanned multiple volumes of work papers.

CCSF also claims that the decision trees should be revised to incorporate findings by the NTSB Report and the CPSD San Bruno Report.[157] For example, CCSF points to findings by the

[154] TURN Opening Brief, pp. 34-35.
[155] CCSF Opening Brief, pp. 17-18.
[156] CCSF Opening Brief, pp. 16-18.
[157] CCSF Opening Brief, pp. 19-20.

NTSB and CPSD regarding PG&E's threat assessment under its Transmission Integrity Management Program.[158] Again, CCSF does not understand that the PSEP was not intended to be a vehicle to address all of the findings related to San Bruno from all of the various regulatory agencies that are investigating the incident. It was certainly not intended to include any improvements to PG&E's TIMP. Rather, the PSEP was intended to comply with Decision 11-06-017. CCSF's criticism of the PSEP based on the fact that it was not intended to, and does not, incorporate recommendations of the NTSB and CPSD should be ignored.

D. Criticisms Regarding Deviation From Decision Tree Results Are Unwarranted

DRA criticizes PG&E for deviating at times from the raw decision tree results.[159] In particular, DRA argues that: (1) the decision trees allow for engineering judgment in terms of the prescribed mitigation; (2) PG&E accelerates segments to Phase 1 without justification; (3) PG&E plans diameter changes to replacement pipelines to increase piggability; and (4) PG&E relocates lines without justification. Each of these types of deviations from the decision trees is warranted, and does not provide a basis for not approving the scope of PSEP Phase 1.

First, DRA notes that PG&E will sometimes decide that a different mitigation is appropriate for a particular pipeline segment than the raw decision tree results would suggest. DRA uses work on Line 132 as an example. The decision tree would indicate replacement for certain segments of Line 132, but PG&E has elected to hydrotest Line 132.[160] There is good reason for this change. On March 15, 2011, PG&E committed to pressure test 152 miles of Priority 1 pipe segments that had not been hydrotested that were similar to the pipeline segment that failed in San Bruno (e.g., pre-1962, 24-inch to 36-inch DSAW, Class 3, Class 4, or HCA untested pipe).[161] This commitment resulted in 37.01 miles of Line 132 being hydrotested in 2011 and 12.59 miles scheduled to be hydrotested in 2012.[162] When PSEP was developed,

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158 CCSF Opening Brief, p. 20.
159 DRA Opening Brief, pp. 57-66.
160 DRA Opening Brief, p. 59.
161 Ex. 21, PG&E Rebuttal, p. 3-33, lines 30-33.
162 Ex. 21, PG&E Rebuttal, p. 3-33, line 33—p. 3-34, line 1.

PG&E decided that it would be inefficient to replace segments of Line 132 that had already been hydrotested recently, or were slated for hydrotesting in the near future.[163]

DRA also takes issue with accelerating Phase 2 segments into Phase 1 for efficiency reasons.[164] DRA states that it does not oppose "justified" acceleration from Phase 2 to Phase 1, but offers no criteria to distinguish between what DRA would deem "justified" and what it would deem "unjustified."[165] PG&E believes it will reduce long-term costs to accelerate work that would otherwise be done in Phase 2 for efficiency reasons, when Phase 1 work is being performed on adjacent segments, so it does not have to return several years later and perform work on the same pipeline.

DRA also takes issue with PG&E's proposed diameter changes on some pipelines slated for replacement as part of Phase 1.[166] As PG&E explained in direct and rebuttal testimony and on pages 18-19 of PG&E's Opening Brief, the principal reason for replacing roughly 57 miles of pipeline with larger diameter pipe was to improve pipeline piggability.[167] In order to ensure piggability going forward, when PG&E is replacing a pipeline segment, it will look at the diameters of pipelines both upstream and downstream of the proposed replacement.[168] While there are ILI tools on the market today that can accommodate the difference between 24-inch and 30-inch diameter pipe, there are no ILI tools on the market that can handle variations in pipeline diameter greater than 25%.[169]

Finally, DRA alleges that PG&E relocates lines "without justification," and uses the proposed relocations of Line 118A and Line 111 as examples.[170] As PG&E explained in rebuttal testimony, based on project permitting, routing, easement acquisition and construction experience from recent construction, PG&E explored a new pipeline route for Line 118A and

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163 Ex. 21, PG&E Rebuttal, p. 3-34, lines 1-4.
164 DRA Opening Brief, pp. 60-62.
165 DRA Opening Brief, p. 61.
166 DRA Opening Brief, pp. 62-66.
167 Tr. (Hogenson), p. 1598, line 23—p.1599, line 11.
168 Tr. (Hogenson), p. 1379, line 28—p. 1380, line 7.
169 Tr. (Hogenson), p. 1426, lines 12-20; Ex. 21, PG&E Rebuttal, p. 3-23, lines 5-7.
170 DRA Opening Brief, p. 66.

Line 111A that was approximately two miles to the west of the current location, in a more rural area away from an existing high school and residential homes in order to reduce public exposure to the pipeline, minimize property impacts and crop damage.[171] There are many factors that influence pipeline routing, many of which are outside the control of PG&E (such as environmental considerations and landowner impacts). To call line relocations "unjustified" ignores this basic reality.

E. PG&E has Justified The Need For Additional ILI

DRA claims that PG&E has not justified its proposal to perform eight ILI runs, and six upgrade projects to accommodate ILI runs, at an estimated cost of $9.6 million in expense and $30.3 million in capital.[172] In support of this claim, DRA argues that PG&E's decision trees do not produce any outcomes directing ILI to be performed in Phase 1, and that PG&E did not adequately support its ILI cost estimates.[173]

PG&E explained in detail the reasoning behind the scope of ILI in Phase 1. As a complement to the aggressive testing and replacement planned for Phase 1, PG&E plans to ensure that all pipelines operating at or above 30 percent SMYS, and many below 30 percent SMYS, will accommodate inspections using current intelligent pigging technologies.[174] Smart pigging programs are effective in finding near critical and subcritical defects that, once repaired, will increase pipe integrity until the next smart pig inspection.[175] Although PG&E continues to believe that ILI is not a substitute for testing and replacement (as DRA notes), ILI ensures that a margin of safety is preserved going forward.[176] Phase 1 ILI work will also provide valuable input into the ECA process PG&E will use to identify, locate and remove excessive pups, miter bends, and wrinkle bends.[177]

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171 Ex. 21, PG&E Rebuttal, p. 3-33, lines 16-23.
172 DRA Opening Brief, p. 121.
173 DRA Opening Brief, pp. 121-123.
174 Ex. 2, PG&E Direct, p. 3-26, lines 7-11.
175 Ex. 2, PG&E Direct, p. 3-26, lines 12-15.
176 Ex. 2, PG&E Direct, p. 3-21, lines 16-22.
177 Ex. 2, PG&E Direct, p. 3-26, lines 20-23.

As for the cost estimates, PG&E estimated the costs of ILI work according to the following functions: (1) pre-assessment and upgrade (capital); (2) cleaning and inspection (expense); and (3) direct examine and repair (expense).[178] The estimated unit costs for ILI work are based on PG&E's past project experience, and vary from a low of $137,000 per mile to a high of $158,000 per mile for ILI upgrade projects, and from $16,000 per mile to $60,000 per mile for cleaning/inspection and direct examination/repair costs.[179]

PG&E has met its burden of demonstrating that additional ILI work is necessary to ensure a margin of safety on gas transmission pipelines going forward, and has reasonably estimated costs.

F. PG&E Has Outlined A Sensible Approach For Incorporating New Information Into The Pipeline Modernization Work Scope

Several parties raise concerns over the accuracy of the data in GIS upon which the Pipeline Modernization projects were based, and make suggestions regarding CPUC oversight and means to ensure transparency into changes made from the scope of work filed in August, 2011. For example, DRA raises concerns over the accuracy of data in GIS, and suggests that it will be difficult to verify that PG&E is incorporating new information on an ongoing basis.[180] DRA suggests a process by which PG&E would file an Advice Letter within 45 days of a decision in this case that would propose guidelines and procedures to address various changes from the PSEP as filed.[181] The City of San Bruno also asks that the Commission devise a process for communicating changes to PSEP project work scopes to the Commission and interested parties.[182] NCIP suggests that PG&E be required to seek Commission approval of any changes to the PSEP project scopes.[183]

178 Ex. 2, PG&E Direct, p. 3-40, lines 22-25.
179 Ex. 2, PG&E Direct, p. 3-41, lines 2-8.
180 DRA Opening Brief, pp. 51-53.
181 DRA Opening Brief, p. 50.
182 City of San Bruno Opening Brief, p. 7.
183 NCIP Opening Brief, pp. 34-35.

As the parties recognized, PG&E's August 26, 2011 PSEP filing was based on a snapshot of the GIS database in January 2011. The GIS database was the best and most readily available information source PG&E had at the time of the filing.[184] Nevertheless, there will be changes to the PSEP projects based upon new information learned as part of MAOP validation, Class Location studies, or other efforts. In its Opening Brief (pages 19-20), PG&E outlined how it will address concerns about the accuracy of GIS data by incorporating new information learned as part of MAOP validation or the Class Location studies during the detailed project engineering phase. In addition, these changes will be transparent to the Commission and other parties through the semi-annual reporting proposed by PG&E. If the Commission deems that additional or other reporting is necessary to keep the Commission and interested parties fully informed of changes made from the August 2011 PSEP filing, PG&E would support that.

G. TURN's Criticisms Of PG&E's Hydrotesting Program Are Unwarranted

1. Hydrotesting To 90 Percent SMYS Should Not Be Required

TURN recommends that all mainline gas transmission pipe that is strength tested under PG&E's PSEP be tested to 90 percent SMYS.[185] Although PG&E has already addressed TURN's suggestion in detail at pages 20-22 of its Opening Brief, this brief responds to two new arguments raised by TURN: (1) PG&E's own standards require hydrotesting at a minimum test pressure of 90 percent SMYS; and (2) Section 851.12 of ASME B31.8-2007 requires a minimum test "which will cause a hoop stress of at least 90% of the SMYS in the segment with the lowest design or rated pressure in the section tested."[186] Neither argument survives scrutiny.

First, as PG&E witness Mr. Campbell testified, PG&E's Gas Standard A-34 only applies to new pipelines.[187] This would make sense, Mr. Campbell explained, because typically PG&E would have hydrotested new pipe, or when it upgraded a pipeline to a higher pressure.[188] In fact,

184 Ex. 21, PG&E Rebuttal, p. 3-10, lines 7-9.
185 TURN Opening Brief, p. 37.
186 TURN Opening Brief, pp. 37-39.
187 Tr. (Campbell), p. 1835, lines 6-12.
188 Tr. (Campbell), p. 1835, lines 13-25.

Gas Standard A-34 is entitled "Piping Design and Test Requirements," and the stated purpose is to establish "a uniform procedure for designing and testing gas piping systems that will meet the requirements of 49 CFR, Part 192."[189] TURN has offered no contrary evidence that would justify disregarding the testimony of Mr. Campbell that this standard applies only to new pipelines. In addition, Standard A-37, entitled "Hydrostatic Testing Procedure" does not include any requirement for testing existing pipelines to 90 percent SMYS, with the possible exception of a pipeline uprate.[190]

Second, TURN's reliance on ASME B31.8 is misplaced because Section 851.12.1(c) of ASME B31.8 contains an exception to hydrotesting to 90 percent SMYS, which states: "For those in-service pipelines for which the hoop stress percent of the SMYS cannot be accurately determined or those pipelines that operate at hoop stress levels lower than maximum design pressure, the minimum strength test pressure shall be 1.10 times the MAOP."[191] As Mr. Campbell testified, based upon his consultation with a leading industry expert that was on the ASME committee that wrote these standards, this section provides the operator with the opportunity not to test to 90 percent SMYS.[192] And, as Mr. Rosenfeld testified and PG&E explains in its Opening Brief (p. 21), there are good reasons not to hydrotest some pipelines to 90 percent SMYS.[193]

In short, it is neither practical nor necessary to test *in situ* pipelines to 90 percent SMYS. To segment the pipelines and hydrotest for every unique pipeline segment so as to achieve this goal would dramatically increase costs, with no corresponding safety benefit.

2. PG&E Is Using Appropriate Criteria For A Complete Test Record For Pipelines Installed Between 1961 And 1970

TURN argues that PG&E's proposal to add "name of operator" to the criteria establishing a complete test record under GO 112 for pipelines installed between 1961 and 1970 is arbitrary,

189 Ex. 103, PG&E Gas Standard A-34, page 1 of 26.
190 Ex. 103, PG&E Gas Standard A-37.
191 Ex. 102, AME B31.8, Section 851.12.1(c).
192 Tr. (Campbell), p. 1864, lines 13-28.
193 Ex. 21, PG&E Rebuttal, p. 4-10.

and that customers should not have to pay for a hydrotest on a pipeline that has a record of all three elements required by GO 112, but is missing the name of the operator.[194] Pressure tests performed under GO 112 must contain three elements: (1) test pressure; (2) test medium; and (3) test duration.[195] If PG&E has to re-test a pipeline segment because the hydrotest record is missing one or more of these three elements, the re-testing will be at shareholder expense. However, although the "name of operator" is not required under GO 112, PG&E believes it is necessary to ensure accountability of a witness to the test that the test was performed in accordance with the information documented on the pressure test record.[196] It is PG&E's proposal that, if a pipeline must be retested because the record is missing the name of the operator (but the hydrotest record has the elements required under GO 112), the re-testing should be at ratepayer expense.

PG&E met with CPSD staff on February 18, 2011 and walked them through the elements PG&E believes are needed for a traceable, verifiable and complete record, which included the name of the operator.[197] The guidance received from CPSD was reflected in the March 15, 2011 Report which again articulated the elements that PG&E believes are necessary for a complete pressure test record (including name of operator).[198] If the Commission believes that name of operator is not a requisite element of a pressure test performed between 1961 and 1970, that guidance would be helpful in informing a decision regarding whether or not pipelines which have otherwise complete pressure test records (and are only missing the name of the operator) need to be retested.

H. DRA's Proposed Pipeline Modernization Cost Estimates Have No Basis

DRA suggests that the Commission reject PG&E's pipeline modernization cost estimates—developed by engineers who are very experienced with hydrotesting and constructing

194 TURN Opening Brief, p. 78.
195 Tr. (Hogenson), p. 1470, lines 16-24.
196 Ex. 70, PG&E's response to DR_TURN_031-Q01.
197 Tr. (Singh), p. 1674, lines 5-13.
198 Tr. (Singh), p. 1773, lines 8-15.

gas transmission pipelines—in favor of DRA's much lower estimates that were developed by those with little to no experience in the natural gas industry that are based on stale industry averages. DRA's cost estimates are based on unsupported assumptions as described below, and should be rejected.

1. DRA's Hydrotesting Cost Estimates Are Flawed

DRA claims that PG&E did not adequately support its hydrotesting fixed cost estimates.[199] That is not true. As PG&E explained on pages 25-26 of its Opening Brief, PG&E's strength test cost forecasts were based on prior PG&E hydrotesting projects on existing pipelines over the last ten years, and on unit rate input by a California-based pipeline construction company, supplemented by Gulf's experience.[200]

In particular, DRA recommends that the Commission reject PG&E's forecast for Mobilization/Demobilization ("Mob/Demob") costs and move around charges. As PG&E explained in direct testimony, a mob/demob surcharge of $500,000 has been added for each hydrotest project, and a move-around surcharge based on pipe-diameter range has been added for each additional test section within a defined project.[201] These charges cover the costs for moving construction equipment and personnel to and from each site, excavating bell holes at each end of the test section, and returning the site to pre-testing conditions.[202] PG&E's forecasted mob/demob and move-around charges were adequately supported by PG&E's prepared testimony, and Gulf's Estimate Basis Memorandum.[203]

By contrast, DRA's mob/demob and move-around cost forecasts were developed by Mr. Neil Delfino, whose curriculum vitae evidences little experience hydrotesting natural gas transmission pipelines in the United States. In fact, Mr. Delfino's description of hydrostatic testing is very simplistic and the process he described in testimony applies to long-line oil or

199 DRA Opening Brief, p. 70.
200 Ex. 2, PG&E Direct, p. 3-41, lines 10-12.
201 Ex. 2, PG&E Direct, p. 3-41, lines 16-19.
202 Ex. 2, PG&E Direct, p. 3-41, lines 19-22.
203 Ex. 2, PG&E Direct, Appendix 3E.

product pipelines, not natural gas pipelines.[204] In addition, DRA's recommended move around charge is premised on the assumption that "leap frogging" can be used. However, due to the surgical nature of PG&E's hydrostatic testing program to comply with D.11-06-017 (as opposed to testing a long pipeline from one end to the other) it is not feasible for PG&E to simply leap-frog equipment from one test section to another.[205] In short, Mr. Delfino does not support DRA's revised mob/demob or move around charges with anything more than speculation.

DRA also asserts that PG&E has not supported its request for new test heads, and that "tap caps" should be treated as a contingency item.[206] However, DRA's argument is based on an incorrect assumption that a hydrostatic test only involves two test heads on either end of the test. In fact, the need to manage multiple taps in addition to the two test ends requires additional tools and equipment, and must be included in a hydrotest cost forecast.[207] DRA is also incorrect in asserting that tap caps should be a contingency item. The fact that the actual number and location of each test head is unknown at this time is a factor of the level of design detail and in the nature of a Class 4 estimate.

Similarly, DRA continues to argue that pre-cleaning prior to hydrotesting is not necessary, and that pre-cleaning costs should be treated as a contingency item. PG&E addressed DRA's incorrect assumption that pre-cleaning is not a prerequisite to hydrotesting on pages 26-27 of its Opening Brief. In addition, since PG&E was aware that a pre-cleaning run was necessary before each hydrotest, it was properly included in the base estimate, and should not be considered contingency.[208] Even if more than the assumed number of cleaning runs were required for a particular hydrotest, PG&E's witness on contingency explained that contingency was not intended to cover the additional cleaning runs.[209]

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204 Ex. 21, PG&E Rebuttal, p. 4-2, lines 25-28.
205 Ex. 21, PG&E Rebuttal, p. 4-7, line 21—p. 4-8, line 16.
206 DRA Opening Brief, pp. 79-80.
207 Ex. 21, PG&E Rebuttal, p. 4-7, lines 16-20.
208 Tr. (Caletka), p. 2130, lines 17-27.
209 Tr. (Caletka), p. 2130, line 28—p. 2131, line 11.

In fact, DRA asserts without any basis that several items should be considered contingency, such as pipe connection hardware costs. Once again, DRA confuses base estimate assumptions with contingency. The Basis of Estimate prepared by Gulf sets out clear assumptions from which unit costs were derived. PG&E's contingency allowance is required to allow for unforeseeable factors affecting the costs of a defined work scope such as price fluctuations in the required pipe connection hardware. It would be inappropriate (and inconsistent with common estimating practices) to treat scope elements within a base estimate as contingency.

The fact that DRA's hydrotesting cost estimates are unreasonably low is underscored by the actual 2011 costs for hydrotesting, which were $1.412 million per mile. While PG&E expects that it can achieve some cost savings going forward, these actual costs show that DRA's hydrotesting cost estimates are unreasonable on their face, and should be rejected.

2. DRA's Pipeline Replacement Cost Estimates Lack Adequate Support

DRA's cost forecasts for pipeline replacements are based on two sources: (1) industry cost projections for interstate pipelines; and (2) a "bottoms-up" cost forecast performed by Mr. Delfino. Neither source should be afforded any weight.

First, DRA relies on two industry studies—one performed by UC Davis and the other by Pacific Northwest National Laboratory ("PNNL")—in an attempt to show that PG&E's pipeline replacement cost estimates were higher than industry averages.[210] The problems associated with relying on these two studies are well detailed in PG&E's Rebuttal Testimony,[211] and on pages 23-24 of PG&E's Opening Brief. In summary, both studies report cost projections for interstate pipelines primarily in rural areas, many of which were not natural gas pipelines. DRA claims that PG&E failed to support its statement that these interstate pipelines were located in less dense locations.[212] However, the UC Davis study notes specifically that it looked at cost projections

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210 DRA Opening Brief, pp. 97-100.
211 Ex. 21, PG&E Rebuttal, p. 3-37—3-38.
212 DRA Opening Brief, p. 98.

for interstate pipelines traversing primarily rural areas.[213] In addition, both studies analyze cost "projections," not actual costs.

DRA also relies on what it calls a "bottoms-up" pipeline replacement cost estimate developed by Mr. Delfino.[214] As PG&E discussed on pages 24-25 of its Opening Brief, Mr. Delfino's cost models were developed for foreign off-shore pipelines.[215] In fact, Mr. Delfino's examples and estimates appear to be based on sub-sea pipeline projects in Mexico and China.[216] Mr. Delfino makes several assertions in his testimony that demonstrate that he has no experience with engineering, estimating or constructing urban natural gas transmission pipeline projects. For example, Mr. Delfino claims that all work activities are to take place on the surface; therefore, shoring of the trenches is not included in his trenching cost estimate.[217] In fact, shoring and trench plates are likely required for each pipeline replacement project. PG&E's experience shows that a city or county would not typically allow PG&E to cut a 14-foot wide trench down its roadway and allow PG&E to keep the trench open for weeks, resulting in major traffic delays, detours, and safety risks.[218]

In short, PG&E's pipeline replacement cost estimates were developed based on PG&E's historic pipeline construction costs and experience. As stated in rebuttal testimony, PG&E alone has constructed approximately 940 miles of gas transmission pipeline within California over the past 20 years.[219] This experience provides a much better predictor of costs than DRA's proposal to use pipeline construction forecasts from industry journals. DRA's witness's alternative pipeline replacement cost forecasts were based on Mr. Delfino's experience with non-U.S., subsea pipelines. DRA's cost estimates should be disregarded.

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213 Ex. 138, DRA's Response to PGE_DRA_005-Q1, "Summary."
214 DRA Opening brief, pp. 101-102.
215 Ex. 146, DRA Direct (Delfino), p. 1-2.
216 Ex. 21, PG&E Rebuttal, p. 3-39, lines 23-29.
217 Ex. 146, DRA Direct (Delfino), p. 1-11.
218 Ex. 21, PG&E Rebuttal, p. 3-41, lines 1-12.
219 Ex. 21, PG&E Rebuttal, p. 3-39, 9-10.

3. PG&E's Proposed Peninsula Adder Is Justified

DRA also challenges a $200 per foot "Peninsula adder" for projects on the San Francisco Peninsula.[220] The Peninsula adder reflects the high cost of pipe replacement on the Peninsula due to the congestion, lack of third party utility records, and increased costs of permitting.[221] The PSEP Phase 1 project work within the Peninsula will encounter some of the most highly-congested and environmentally-sensitive lands, as well as increased city, county and community concerns when compared to projects in other areas; therefore, the adder is justified.[222]

V. CRITICISMS OF PG&E'S VALVE AUTOMATION PLAN ARE WITHOUT MERIT

PG&E has demonstrated that installing automated valves in highly populated areas and on pipelines that traverse active earthquake faults provides a safety benefit, at reasonable cost. The criticisms of PG&E's Valve Automation Program discussed below lack merit and should be rejected.[223]

A. PG&E Has Demonstrated That Automated Valves Provide A Safety Benefit

DRA claims that PG&E has failed to show that automated valves provide value to customers, or are "necessary for the protection of the public," as required by Public Utilities Code Section 957.[224] In support of this claim, DRA argues that PG&E has failed to perform a traditional cost/benefit analysis.[225] These arguments ignore all of the record evidence that shows that automated valves can increase first responder safety and minimize the effects of a pipeline rupture. In Chapter 4, Section D of PG&E's August 26, 2011 testimony, PG&E detailed the safety benefits of automated valves, including most significantly that automated valves allow

220 DRA Opening Brief, p. 109.
221 Ex. 21, PG&E Rebuttal, p. 3-32, lines 10-15.
222 Ex. 21, PG&E Rebuttal, p. 3-32, lines 22-27.
223 The City of San Bruno argues that automatic valves should be installed in the City of San Bruno. It is unclear whether the City of San Bruno is expressing a preference for ASVs over RCVs, or whether it seeks to confirm that some type of automated valves will be installed in San Bruno. If it is the former, PG&E discusses the debate about whether ASVs or RCVs should be installed below. If it is the latter, PG&E is providing automated pipeline isolation capability on all three major local transmission pipelines (Lines 101, 109 and 132) traversing through San Bruno as part of Phase 1 of the PSEP. The pipelines will have isolation capability at a maximum valve spacing of 8 miles.
224 DRA Opening Brief, pp. 123-127.
225 DRA Opening Brief, pp. 127-128; see also CCSF Opening Brief, p. 27.

first responders to quickly mobilize, evacuate the public, and suppress the fire.[226] PG&E believes that the installation of automated valves on large diameter, higher pressure pipelines traversing heavily populated areas is a key element to emergency preparedness and facilitating emergency response in the event of a major pipeline rupture.[227]

In fact, DRA's valve witness conceded that DRA's (albeit downsized) version of a valve automation proposal is necessary for the protection of the public.[228] DRA offers no explanation for why its own proposal to only automate existing valves is "necessary for the protection of the public," while PG&E's more robust valve automation proposal is not. This inconsistency is again highlighted by DRA's valve witness's testimony at hearing, in which he indicated that tighter automated valve spacing results in a "higher level of safety."[229] In fact, the record demonstrates that DRA was focused on cost, not public safety.

It is true that PG&E has not performed a traditional cost/benefit assessment for automated valves, which would require PG&E to place a value on human life in order to demonstrate that the benefits of automated valves outweigh the costs.[230] It is very difficult to quantify benefits and costs for low probability, high impact events like pipeline ruptures.[231] Moreover, neither Public Utilities Code Section 957, nor the Commission's Decision 11-06-017, requires a utility to demonstrate that the benefits of automated valves outweigh the costs. In light of the strong public sentiment and legislative momentum toward the installation of automated valves, it is not appropriate to delay the automation process by requiring the preparation of a traditional cost/benefit analysis to assess this critical public safety issue.[232]

CCSF criticizes PG&E for not citing the factors in 49 C.F.R. section 192.935(c) when justifying its valve automation proposal.[233] CCSF misunderstands the nature of the federal

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226 Ex. 21, PG&E Rebuttal, p. 6-14, lines 23-24.
227 Ex. 21, PG&E Rebuttal, p. 6-15, lines 18-21.
228 Tr. (Oh), p. 2036, lines 4-16.
229 Tr. (Oh), p. 2041, lines 5-8.
230 Ex. 21, PG&E Rebuttal, p. 6-15, lines 2-5.
231 Ex. 21, PG&E Rebuttal, p. 6-15, lines 5-7.
232 Ex. 21, PG&E Rebuttal, p. 6-15, lines 22-26.
233 CCSF Opening Brief, pp. 26-27.

regulations regarding automated valves. Section 192.935 identifies the use of automated valves as one potential measure for mitigating the consequences of a pipeline failure in an HCA. It discusses the need for operators to evaluate when an automated valve would be an "efficient" means of adding protection to an HCA in addressing a specific pipeline threat.[234] PG&E must comply with this requirement as part of its ongoing TIMP; PG&E is currently evaluating valve automation as part of TIMP.[235] The PSEP Valve Automation Program is a different, complementary approach. It asks: in what situations could the use of automated valves have the greatest impact in facilitating emergency response, reducing property damage, reducing the danger to emergency response personnel and the public in the event of a pipeline rupture?[236] It focuses resources on the pipelines that contain the greatest amount of energy and traverse the most highly populated areas, and works in tandem with the Pipeline Modernization Program that seeks to prevent pipeline ruptures.[237]

B. TURN's Arguments In Support Of Automatic Valves Rather Than Remote Control Valves Are Speculative

TURN recommends that PG&E deploy at least 20 percent ASVs in Phase 1, instead of deploying RCVs and continuing to study ASVs, as PG&E has proposed.[238] In particular, TURN asks the Commission to order PG&E to install at least 20 percent of the automated valves deployed in Phase 1 in ASV mode with "complex algorithms." In addition, if there is "uncertainty concerning the exact nature of what is required to implement this recommendation," TURN suggests that the Commission order a technical workshop, including representatives from federal agencies and other gas operators.[239] TURN makes several assumptions in the course of justifying this recommendation, which should be rejected.

234 Ex. 21, PG&E Rebuttal, p. 6-20, lines 13-16.
235 Ex. 21, PG&E Rebuttal, p. 6-20, lines 16-18.
236 Ex. 21, PG&E Rebuttal, p. 6-20, lines 20-23.
237 Ex. 21, PG&E Rebuttal, p. 6-20, lines 23-28.
238 TURN Opening Brief, pp. 46-58.
239 TURN Opening Brief, p. 58.

TURN claims that PG&E's concerns about false closures of ASVs are "overblown" and can be addressed through proper valve design. PG&E's concerns regarding the risk of false closure are well documented, and are discussed in detail on pages 35 through 36 of PG&E's Opening Brief. TURN's proposal to mitigate the risk of false closure through "complex logic controls" is not without its own risk. As PG&E's valve witness Dan Menegus explained, if an operator sets the controls at such a level as to minimize false closures, it would run the risk of not having the ASV actually identify a rupture.[240] Although one could design the ASV control such that the SCADA system takes information from different points and processes it to allow the ASV to operate using additional information, one would have to install additional SCADA monitoring points, and rely on the SCADA and communication system to be operable.[241] TURN claims that Mr. Menegus admitted that such additional pressure monitoring would "eliminate the false closure problem."[242] Not true. Mr. Menegus testified that even with additional pressure monitoring and more "complex" controls, there is always some risk of false closure.[243]

In addition, if PG&E were to add additional monitoring points and use all of that new information to do a calculation in the SCADA system that will take more data into account, it would also significantly increase the complexity of the controls.[244] Whenever the complexity of the controls is increased, that increases the risk of the automated controls not performing properly, which could defeat the purpose of installing automated valves.[245]

C. It Is More Appropriate To Use PIR, Rather Than Pipeline Radius, As A Criterion For Automated Valves

TURN also recommends prioritizing large diameter pipelines and pipelines susceptible to earth movement, rather than simply using the Potential Impact Radius ("PIR").[246] Instead of relying on the industry-standard PIR, TURN recommends installing automated valves on

240 Tr. (Menegus), p. 1303, line 26—p. 1304, line 1.
241 Tr. (Menegus), p. 1310, line 16—p. 1312, line 27.
242 TURN Opening Brief, p. 54.
243 Tr. (Menegus), p. 1310, lines 16-21.
244 Tr. (Menegus), p. 1314, lines 8-15.
245 Tr. (Menegus), p. 1314, lines 15-18.
246 TURN Opening Brief, pp. 58-60.

pipelines that are 24 inches in diameter or greater. PG&E discussed why it is more appropriate to prioritize based on PIR at pages 37 through 38 of its Opening Brief. TURN witness Kuprewicz claims that the PIR does not accurately define the actual impact zone, especially for larger diameter pipelines.[247] There is no evidence supporting this claim. In fact, the PIR formula is meant to delineate the areas within which the extent of property damage and the chance of serious or fatal injury would be expected to be significant in the event of an ignited rupture failure of a natural gas transmission pipeline; the PIR formula was not intended to delineate the full extent of the area within which minor property damage or injury would be expected to occur.[248] During the development process the PIR formula was validated by comparing calculated impact zone areas and radii to information obtained from actual incident reports.[249] In every studied case, the hazard area calculated using the PIR model is greater than the actual reported area of burnt ground; with the exception of two of the reported incidents, the radius obtained from the hazard formula conservatively overestimates the maximum lateral extent of the burn zone.[250] In all cases, the calculated hazard zone radius significantly exceeds the maximum reported offset distance to injury or fatality.[251] In short, TURN has provided no basis upon which to make a determination that PIR is not a more appropriate criterion than pipeline diameter upon which to prioritize pipe segments for automation.

D. TURN Suggests That PG&E Consider Installing Automated Valves In Class 1 And 2 HCAs In The Next Phase Of PSEP

TURN suggested in its testimony that all large pipelines (greater than 24-inches in diameter) in Class 1 and 2 HCA locations be automated with ASVs.[252] TURN estimated that there are 60 miles of such pipeline in HCAs in class 1 and 2. TURN had assumed that installing automated valves on those pipelines would thus require about ten valve installations.[253] PG&E

247 TURN Opening Brief, pp. 58-59.
248 Ex. 21, PG&E Rebuttal, p. 7-2, line 23—p. 7-3, line 9.
249 Ex. 21, PG&E Rebuttal, p. 7-3, lines 19-23.
250 Ex. 21, PG&E Rebuttal, p. 7-5, lines 4-8.
251 Ex. 21, PG&E Rebuttal, p. 7-5, lines 10-12.
252 TURN Opening Brief, p. 61.
253 TURN Opening Brief, p. 61.

clarified, however, that to automate all 80 miles of Class 1 and 2 HCA pipelines would require over 300 valves to sectionalize 150 pipe segments (because these segments are very short, are not contiguous, and are located on multiple different pipes), at significant cost.[254] Based on this information, TURN does not recommend automating all Class 1 and 2 HCA pipelines, but instead recommends that PG&E provide additional information related to HCAs in Class 1 and Class 2, as some may justify automation in the next phase of PSEP.[255] PG&E is not opposed to investigating automating Class 1 and Class 2 pipelines in HCAs as part of the end of Phase 2 work. These pipeline segments are typically areas of localized population near a large diameter, high pressure pipeline.

VI. THE PIPELINE RECORDS INTEGRATION PLAN SHOULD BE APPROVED

PG&E has met its burden of showing that the MAOP Validation and GTAM Projects are necessary to meet the new regulatory requirement to validate the MAOP of gas transmission pipelines—now and in the future. Parties' arguments to the contrary are discussed in Section II.A.2 of this brief. DRA makes two additional arguments that PG&E addresses below: (1) PG&E has received "ample" funding in the 2011 GRC and Gas Accord V to pay for the Pipeline Records Integration Plan; and (2) ratepayers have paid for several database upgrade projects over the years and should not have to pay for an additional database upgrade project.[256]

DRA's first argument is belied by the facts. The entire GTAM Project forecast is incremental to PG&E's funding in its 2011 GRC and 2011 GT&S Rate Case. The only gas transmission work envisioned in the 2011 GRC was to upgrade the gas transmission GIS system from version 1.0 to version 2.0.[257] This work has been completed and is not duplicated in the GTAM proposal.[258] In fact, GTAM builds on the GIS upgrade by adding Linear Referencing to GIS and SAP, integrating both systems, and providing links to source documentation.[259]

254 TURN Opening Brief, p. 61.
255 TURN Opening Brief, p. 61.
256 DRA Opening Brief, pp. 42-49.
257 Ex. 21, PG&E Rebuttal, p. 11-15, lines 18-20.
258 Ex. 21, PG&E Rebuttal, p. 11-15, lines 20-21.
259 Ex. 21, PG&E Rebuttal, p. 11-15, lines 21-24.

The amounts authorized by Decision 11-04-031 approving the Gas Accord V Settlement Agreement provide for modest system enhancements to the gas accounting/scheduling system (InsideTrack), SCADA, and billing systems.[260] The total amount of IT system enhancements proposed for the GT&S business in 2012 was approximately $2.8 million.[261] In fact, the *entire expense budget* for all gas transmission operations and maintenance in Gas Accord V is $105 million, and would be insufficient to fund the GTAM Project cost of $124 million.[262]

DRA's second argument—that PG&E has included database upgrade projects in prior rate cases and therefore GTAM should not be recovered in rates—fails as well. PG&E recognizes that prior rate cases have included funding for various database projects. For example, as discussed above, the 2011 GRC funded an upgrade from GIS 1.0 to GIS 2.0. That work has been completed; GTAM does not duplicate that work, or any other database projects funded by rate cases over the years. DRA has failed to show that PG&E has asked in the past for ratepayer funding of the GTAM Project, or similar projects. The fact that PG&E has completed other database upgrade projects in the past is irrelevant.

VII. PG&E'S PROPOSED INTERIM SAFETY ENHANCEMENT MEASURES SHOULD BE ADOPTED

No party takes issue with the reasonableness of PG&E's proposed interim safety enhancement measures, which include: (1) pressure reductions on certain pipeline segments until remedial action can be taken; and (2) more frequent leak surveys and patrols. The City of San Bruno, however, mischaracterizes PG&E's plan to implement pressure reductions, claiming that the interim pressure reductions are being "delayed."[263] PG&E's proposal is to *complete* its implementation of pressure reductions called for in the Pipeline Modernization Plan no later than 30 days after CPUC approval of the PSEP.[264] In fact, PG&E began implementing interim pressure reductions even before its PSEP was submitted in August 26, 2011. By the date of the

260 Ex. 2, PG&E Direct, p. 5-30, lines 10-14.
261 Ex. 21, PG&E Rebuttal, p. 11-2, lines 26-28.
262 Id.
263 City of San Bruno Opening Brief, p. 11.
264 Ex. 2, PG&E Direct, p. 6-8, lines 26-31.

filing, PG&E had already implemented interim pressure reductions called for under the Pipeline Modernization Decision Trees on approximately 1,009 pipe segments, covering 249 miles.[265]

In addition, although DRA does not dispute the reasonableness of the proposed pressure reductions per se**,** DRA recommends that the Commission reject PG&E's proposal to hire four Full-Time Equivalents.[266] DRA's stated basis for this recommendation is that "PG&E is already meeting its pressure reduction requirements with its current number of engineering staff," and that, therefore, the additional positions are not necessary.[267] However, the PSEP will significantly increase the number of hydraulic modeling runs that PG&E engineers will be required to perform, as addressed in PG&E's Opening Brief (pp. 47-48), and PG&E will not be able to sustain the increase in engineering work with existing staff. At this point in time, all of PG&E's planning engineers are already 100 percent utilized.[268]

VIII. DRA'S CONTINGENCY ANALYSIS SHOULD BE REJECTED

PG&E has met its burden of demonstrating that its 21 percent contingency request is just and reasonable. DRA claims that PG&E analysis is flawed and should be rejected.[269] DRA's criticisms of PG&E's contingency analysis are unjustified. DRA asserts that PG&E's reliance on professional judgment to guide the level of contingency required for the PSEP program is in conflict with the Association for the Advancement of Cost Engineering ("AACE") International and United States Government Accountability Office ("GAO") guidelines on cost estimating.[270] Not true. The application of experience, expert opinion, and engineering judgment are fundamental aspects of preparing detailed cost estimates and setting appropriate contingency levels for complex programs such as the PSEP, as the workpapers supporting Chapter 7 note. PG&E complied with the guidance provided by relevant industry groups, and industry best practice in establishing its base estimates and required contingency. Workshops were conducted

265 Ex. 2, PG&E Direct, p. 6-8, lines 23-26.
266 DRA Opening Brief, p. 125.
267 DRA Opening Brief, p. 125.
268 Ex. 21, PG&E Rebuttal, p. 12-2, lines 19-20.
269 DRA Opening Brief, p. 110.
270 DRA Opening Brief, p. 113.

in which outside engineering firms (EN Engineering and Gulf) participated.[271] PG&E results were cross-checked with expected contingency requirements. Where professional and engineering judgment were applied, it was informed by the Basis of Estimate prepared for each component project, clearly identified assumptions, exclusions and risks identified in Chapter 7 and throughout the testimony of other witnesses. Although contingency levels of up to 40 percent are suggested in industry guidelines for Class 4 estimates, PG&E's detailed analysis of the component project estimates resulted in a much lower contingency request of 21 percent.

DRA suggests the Commission should adopt a contingency percentage of "no more than 8%" for PSEP, as this is the contingency percentage previously adopted by the Commission for PG&E's Advanced Metering Infrastructure ("AMI") program.[272] DRA supports this suggestion by referencing the rebuttal testimony of PG&E witness Stephen Lechner in Application 05-06-028. DRA's conclusion is not only inconsistent with prior Commission directives,[273] it also misrepresents evidence included in Mr. Lechner's AMI rebuttal testimony. Specifically, in Decision 09-03-026 related to PG&E's SmartMeter™ Program Upgrade Proceeding (A.07-12-009), the Commission concluded that risk based allowances (*i.e.*, contingencies) included in project estimates should be based on the specific risk profile associated with a project rather than simply applying a contingency percentage previously adopted by the Commission on a different project.[274] PG&E's calculation of a contingency amount for PSEP was based on a detailed analysis of the specific risk profiles of the individual elements of PSEP,[275] which is consistent with the prior Commission directive (and common industry practice).

With respect to DRA's misrepresentation of evidence presented in PG&E's AMI proceeding, DRA quotes a reference from Mr. Lechner's rebuttal testimony that highlights a five to seven percent contingency for "standard construction projects" such as road and highway

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271 Ex. 2, PG&E Direct, p. 7-31, line 6—p. 7-32, line 22.
272 DRA Opening Brief, p. 119.
273 Exhibit 21, PG&E Rebuttal, p. 14-14, lines 7-14.
274 Ex. 21, PG&E Rebuttal, p. 14-12, lines 3-22.
275 Ex. 2, PG&E Direct, Chapter 7, Sections F and G.

construction.[276] DRA then inappropriately concludes that PG&E's PSEP is more consistent with a "standard construction project," thus it should carry a contingency value of no more than 8 percent.[277] DRA's citation to Mr. Lechner's AMI rebuttal testimony includes his reference to the California State Administrative Manual ("SAM"), Section 6854.[278] The specific reference out of the SAM section highlighted by Mr. Lechner is:

> Construction contingencies are limited to **5 percent of the construction estimate/bid** for a new facility and **7 percent of the construction estimate/bid** for remodeling/renovation projects [emphasis added].[279]

The five to seven percent figures referenced in the SAM quotation above reflect contingency amounts for projects in a construction phase after awarding a bid (*i.e.*, the "bid check" phase). This is the same as a Class 1 estimate designation included in AACE guidelines. According to AACE tables, the contingency guideline for a Class 1 estimate is 5 percent.[280] In contrast, the projects included in PG&E's PSEP reflect AACE Class 3 and Class 4 estimates, which would typically include a contingency allowance of around 30 to 40 percent according to AACE guidelines.[281] DRA's recommendation that PG&E should apply a contingency amount consistent with the AACE recommendation for a Class 1 estimate to the PSEP estimate, which is composed of Class 3 and Class 4 estimates, is inconsistent with the record in this proceeding, common industry practices and prior Commission directives.

IX. NO PARTY RAISES ANY SIGNIFICANT CONCERNS REGARDING PG&E'S PROPOSED PROGRAM MANAGEMENT APPROACH

PG&E's approach for overall Program Management of the PSEP is sound, and in keeping with industry standards, as demonstrated by the fact that the only intervenor to raise any issue regarding PG&E's Program Management approach was the City of San Bruno, and the issue

276 DRA Opening Brief, p. 119,
277 DRA Opening Brief, p. 120.
278 Ex. 114, Rebuttal Testimony of Stephen P. Lechner in Application 05-06-028, p. 15-5 (footnote 5).
279 State Administrative Manual, Section 6854 (revised 5/98), paragraph 3.a.
280 Ex. 2, PG&E Direct, p. 7-44, Table 7-9.
281 PG&E Exhibit 2, p. 7-44, lines 13-17.

raised by the City of San Bruno is easily addressed. The City of San Bruno claims that if the proposed External Advisory Board ("EAB") coordinates the information flow between the Project Management Office and external parties, that role could undermine the independence of the EAB.[282]

PG&E is currently defining the specific role of the EAB. The scope and charter of the EAB will be solidified once the CPUC issues its final decision regarding PG&E's PSEP. This will allow PG&E to fully incorporate any additional guidance from the Commission that may be articulated during the course of the PSEP proceeding.[283] The City of San Bruno's concern regarding the independence of the EAB is unwarranted. As contemplated by PG&E, the EAB will have no involvement in PSEP execution or oversight. They will have unrestricted access to the PSEP execution team and Program controls and will communicate observations and recommendations directly to PG&E's Program Sponsor and Executive Steering Committee (and external parties, if and as required).[284]

X. PARTIES' ARGUMENTS REGARDING PG&E'S CUSTOMER AND COMMUNITY OUTREACH EFFORTS ARE WITHOUT BASIS

A. PG&E's Proposed Community Outreach Efforts Are Effective And The Costs Should Be Recovered In Rates

PG&E included approximately $30 million in its Pipeline Modernization and Valve Automation cost estimates in order to conduct Customer Outreach for all the projects included in the PSEP. The outreach efforts for gas pipeline projects are designed to ensure that our customers fully understand what PG&E will be doing in their community and how it might impact them.[285] A typical process for a PSEP project will encompass the following efforts for a successful outreach:

- Pre-test project walk to document areas along pipeline segments where there might be impacts to customer property, customer proximity to project noise and

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282 City of San Bruno Opening Brief, p. 11.
283 Ex. 21, PG&E Rebuttal, p. 15-6, lines 10-15.
284 Ex. 21, PG&E Rebuttal, p. 14-7, lines 29-33.
285 Ex. 21, PG&E Rebuttal, p. 8-4, lines 13-15.

odors, and other issues such as proximity to schools and other sensitive public areas where customers will need in-person contact.

- Pre-test letter sent to all customers within 500 feet of the pipeline segment being tested, typically between 900 and 2,000 customers.
- Government Relations up-front contact with Public Officials to:
  - Provide overview of project(s) planned for their communities.
  - Discuss impacts on traffic and needs for access to City/County property.
  - Identify concerns that might hinder the permitting process.
  - Present plans for outreach to residents and businesses in close proximity to work.
  - Provide periodic updates to Public Officials on PG&E's progress.
- Project walk-down to identify:
  - Areas of special impacts to customers (i.e. proximity to project noise, potential for damage to customer property).
  - Sensitive customers who will require special communications (i.e., schools, hospitals, large assigned customers).
  - Customers in close proximity to pipeline test itself or where equipment is to be mobilized.
- Canvass door-to-door:
  - Distribute door hangers informing customers in close proximity to the mobilized equipment and noise about what they will see and hear.
  - In-person visits with customers who are within 50 feet of the pipeline project and facilitating relocation of customer to hotels or other locations, as necessary.
  - In-person visits with customers who will encounter property damage from the pipeline project.

- Facilitate agreements with customers who may not cooperate with PG&E to allow property access to stage equipment or to accommodate the egress and ingress of equipment.
- Send letters to all customers within 500-1,000 feet of the pipeline segment being tested.
- Host at least one customer open house per pipeline project for customer and public official education about the project and public safety.

- 3' X 4' Geographic Information System (GIS) map for each pipeline segment for viewing at open houses.
- Customer personnel on site during critical project periods (e.g., venting, testing, night work) to ensure customers have a contact to ask questions or express concerns and to ensure public safety.
- Project signage for public information and safety.
- Interactive Voice Responses ("IVR") sent to customers in close proximity prior to testing or inspection (900 – 1,500 plus) and prior to venting (5,000 – 20,000 plus).
- Post-Test letter sent to all customers in close proximity to the pipeline segment being tested or inspected (900-1,500 plus) letting them know the results of the test.
- Follow-up report back to public officials on the results of the work.[286]

PG&E has met its burden of demonstrating that the customer and community outreach efforts it has conducted and will continue to conduct are effective and necessary for a program as large as the PSEP. As PG&E witness Greg Hoaglin testified:

> [T]he response has been very positive. The cities – the public officials really appreciate the up-front communication and education so that they know what is going on in their community before we start the work and know what kind of impacts it is going to have. So it's been a positive experience for us, and it has worked very effectively.[287]

[286] Ex. 21, PG&E Rebuttal, p. 8-4, line 15—p. 8-6, line 4.
[287] Tr. (Hoaglin), p. 1886, lines 19-27.

DRA dismisses these customer outreach efforts as mere "public relations."[288] DRA cites to no record evidence to support this assertion, but argues nonetheless that PG&E should not be able to cover any Customer Outreach costs in rates. PG&E's Customer Outreach efforts are not a "public relations" effort, and have nothing to do with polishing "PG&E's tarnished reputation."[289] The focus of PG&E's outreach is about public safety and customer and public official education.[290] While customers and public officials are generally more aware of gas transmission and PG&E's PSEP based on what they read and hear in the press, this is not a basis upon which to deny funding for communicating with specific customers about the work in their communities. Just because PG&E has garnered significant media attention does not mean that customers and local officials will be aware of what is involved with these specific projects in their communities and what the impacts might be when one of these projects comes in close proximity to their homes and businesses.[291]

In fact, the City of San Bruno's Opening Brief underscores the importance of PG&E's customer and community outreach efforts to the success of the PSEP. The City of San Bruno notes that, "effective communication both by PG&E and by the CPUC will be needed so governmental officials and the people whose interests they represent can understand project status, any changes to the initial plan and their justification, and resulting improvements in safety performance."[292] PG&E has submitted a proposal for Customer and Community Outreach efforts that will meet the needs of customers and local officials. The Commission should weigh the needs of customers and cities and counties more heavily than DRA's opinion when it comes to customer outreach.

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288 DRA Opening Brief, p. 120.
289 DRA Opening Brief, p. 121.
290 Ex. 21, PG&E Rebuttal, p. 8-4, lines 6-8.
291 Ex. 21, PG&E Rebuttal, p. 8-4, lines 8-12.
292 City of San Bruno Opening Brief, p. 10, lines 4-6.

B. NCIP's Proposals For Noncore Customer Notice Periods And Associated Fees Should Be Rejected

NCIP requests that the Commission require PG&E to give large Noncore customers a minimum of 30 days' notice for scheduled pressure reductions, and six months' notice for "more complete disruptions in service," and that PG&E provide a service disruption credit of $0.25 per therm when it fails to comply with the proposed notice provisions.[293] NCIP's suggestion should be rejected.

First, there is nothing in PG&E's tariffs that requires the type of notice that NCIP seeks to require. All of PG&E's noncore service is considered to be curtailable.[294] This is in contrast to SoCalGas, which has both interruptible and firm noncore services.[295] The Service Interruption Credit on the SoCalGas system that NCIP cites as a template for what it seeks to impose on PG&E does not apply to interruptible service on the SoCalGas system.[296] It should also not apply to service on the PG&E system, which is interruptible for all noncore customers.

Furthermore, there are many factors that render the type of notice periods that NCIP contemplates impractical for a large-scale program like the PSEP. For example, PG&E has to secure multiple permits from various agencies, the timing of which is at times unpredictable.[297] PG&E also has to schedule engineering and construction resources for multiple projects.[298]

In addition, if PG&E were required to give the lengthy notice that NCIP contemplates, it is likely that PG&E would have to issue a significant number of outage notices that would be cancelled.[299] Many customers would have to make unnecessary arrangements for an outage that may never happen, because PG&E would need to notify customers very early in the planning process of the potential for an outage.[300] In many cases, as PG&E works through the design and clearance process, PG&E finds alternative ways to provide continued service to the customer

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293 NCIP Opening Brief, pp. 47-50.
294 Ex. 21, PG&E Rebuttal, p. 12-6, line 30, citing G-NT Sheet 4 and G-EG Sheet 4 of PG&E tariffs.
295 Ex. 21, PG&E Rebuttal. p. 12-6, lines 30-31.
296 Ex. 21, PG&E Rebuttal, p. 12-7, lines 7-8.
297 Tr. (Berkovitz), p. 1903, line 26—p. 1904, line 2.
298 Tr. (Berkovitz), p. 1904, lines 3-5.
299 Ex. 21, PG&E Rebuttal, p. 12-7, lines 28-29.
300 Ex. 21, PG&E Rebuttal, p. 12-7, lines 29-32.

through the use of alternative back feeds, the construction of cross-ties, and the use of portable Compressed Natural Gas and Liquid Natural Gas Supply sources.[301] That could create confusion and frustration for our customers, and may ultimately be counterproductive because customers may react by ignoring PG&E's initial notifications because there are going to be many changes.[302]

For these reasons, PG&E urges the Commission not to prescribe a notice period for noncore customers and associated interruption credit, as NCIP suggests. Of course, as PG&E explained in its testimony and its Opening Brief at pages 48-50, PG&E has been providing customers with reasonable notice where practicable and providing alternatives when service is disrupted, and will continue to do so.

C. Joint Parties' Suggestions Regarding Customer And Community Outreach Should Be Rejected

The Joint Parties make three proposals concerning customer and community outreach: (1) PG&E should be required to solicit ratepayer views concerning ratepayer satisfaction, customer outreach ratings, cost allocation issues, taxpayers' confidence in the CPUC and PG&E, and gas safety;[303] (2) PG&E should be required to work with Community-based organizations ("CBOs") on gas pipeline issues;[304] and (3) effective communication and outreach should be personally led by PG&E Chief Executive Officer ("CEO") Anthony Earley.[305] All of these proposals should be rejected because they are unnecessary.

First, PG&E should not be required to seek ratepayer input on the highly technical issues in this proceeding, or regarding rate levels. Joint Parties devote several pages to criticizing a survey that PG&E conducted to gauge the effectiveness of its customer outreach regarding PSEP projects in various communities. Joint Parties' criticisms of PG&E's survey miss the mark. As explained several times throughout the course of this proceeding, the purpose of the surveys that

301 Ex. 21, PG&E Rebuttal, p. 12-7, line 32—p. 12-8, line 2.
302 Tr. (Berkovitz), p. 1904, line 25—p. 1905, line 2.
303 Joint Parties Opening Brief, p. 10.
304 Joint Parties Opening Brief, p. 12.
305 Joint Parties Opening Brief, p. 14.

PG&E conducted was limited to obtaining information on the effectiveness of communications with customers regarding PSEP work happening in their communities.[306] In addition, the type of survey Joint Parties suggest will not result in useful information, and may delay these important safety upgrades. DRA and TURN—both representing ratepayers—have been heavily involved in this proceeding, and have retained technical consultants and experts to be able to effectively represent ratepayer interests in this highly technical proceeding. Furthermore, results of a ratepayer survey on whether customers think the cost of safety upgrades should be reflected in customer rates would not be very useful. One would expect that most customers would prefer not to pay for utility service if given the choice. The regulatory compact, however, establishes an essential principle that in return for accepting an obligation to serve all customers, that the utility will be entitled to recover in rates all reasonable incurred costs of service plus a reasonable return on its rate base.[307] Results of a customer survey (either one already conducted by the Joint Parties or a new, PG&E led survey) don't provide a basis for disallowance of costs required to comply with a new Commission compliance obligation designed to enhance gas system safety.[308]

Second, the Commission should not mandate PG&E's collaboration with CBOs when conducting outreach. As PG&E witness Gregory Hoaglin explained, when and where there is a need for assistance with reaching customers where there might be a language barrier or cultural issues to address, PG&E considers collaborating with CBOs for assistance.[309] Requiring PG&E to collaborate with CBOs in all customer outreach, even where no such barriers exist, would add to the cost of PSEP, with little to no corresponding benefit.

Finally, Joint Parties have failed to identify any benefit to requiring PG&E CEO Anthony Earley personally conduct customer outreach. As CEO, everything PG&E does is done at Mr. Earley's ultimate direction. Mr. Earley has communicated in several different forums his vision

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306 Tr. (Hoaglin), p. 1877, lines 17-21.
307 Ex. 21, PG&E Rebuttal, p. 17-16, lines 9-13.
308 Ex. 21, PG&E Rebuttal, p. 17-16, lines 13-16.
309 Ex. 21, PG&E Rebuttal, p. 8-6, lines 26-29.

for the future of PG&E. The Commission should not let the Joint Parties dictate Mr. Earley's management of PG&E.

XI. CONCLUSION

For the reasons explained above and in PG&E's Opening Brief, PG&E respectfully requests that the Commission approve the proposed scope of work for the Pipeline Safety Enhancement Plan, adopt the costs forecasts for performing the work planned for Phase 1, approve PG&E's proposed customer/shareholder cost sharing proposal, and allow PG&E to collect the approved costs through end-use customer rates.

Respectfully Submitted,

WILLIAM V. MANHEIM
KERRY C. KLEIN

By: */s/ Kerry C. Klein*
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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