Decision **PROPOSED DECISION OF ALJ BUSHEY** **(Mailed 10/12/2012)**

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.	Rulemaking 11-02-019 (Filed February 24, 2011)

(See Attachment A for Appearances)

DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, IMPOSING EARNINGS LIMITATIONS, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ONGOING IMPROVEMENT IN SAFETY ENGINEERING

TABLE OF CONTENTS

Title **Page**

DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, IMPOSING EARNINGS LIMITATIONS, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ON-GOING IMPROVEMENT IN SAFETY ENGINEERING 1
Summary 2
1. Background 4
2. Description of PG&E's Proposed Natural Gas Transmission Pipeline Pressure Testing Implementation Plan 14
2.1. Pipeline Modernization Program 14
2.2 Pipeline Records Integration Program 18
2.3. Costs of the Pipeline Modernization and Pipeline Records Integration Programs, Including Management and Contingency 20
3. Positions of the Parties 25
3.1. Division of Ratepayer Advocates (DRA) 25
3.2. The Utility Reform Network (TURN) 30
3.3. City of San Bruno 36
3.4. City and County of San Francisco (San Francisco) 38
3.5. Black Economic Council, National Asian American Coalition, and the Latino Business Chamber of Greater Los Angeles 39
3.6. Northern California Generation Coalition 39
3.7. Northern California Indicated Producers (NCIP) 39
3.8. Southern California Edison Company (EDISON) 40
3.9. SDG&E and SoCalGas 40
3.10. Dynegy, Inc. 41
4. Burden and Standard of Proof 41
5. Discussion 42
5.1. Next Steps on the Safety Journey 43
5.1.1. Why we must make the safety journey 43
5.1.2 Learning From the Past 44
5.1.3. A Promising Start 47
5.1.4. Going Forward 50
5.2. Specific Orders 51

TABLE OF CONTENTS (Cont'd.)

Title **Page**

5.2.1. Comprehensive Disallowance of All Implementation Plan Costs 51
5.2.2. Adopted Amounts for PG&E's Implementation Plan 56
5.2.3. Pipeline Records Integration Program 87
5.2.4. Contingency and Escalation Rate 97
5.2.5. Shareholders Return on Equity 102
5.2.6. Cost Allocation and Rate Design 106
6. Assignment of Proceeding 109
7. Comments on Proposed Decision 109

ATTACHMENT A - Appearances
ATTACHMENT B – List of Recommendations from Report of the Independent Review Panel
ATTACHMENT C – Decision Tree Flow Chart
ATTACHMENT D - Specifications for PG&E Implementation Plan Compliance Reports
ATTACHMENT E - Authorized Revenue Requirement Increases
ATTACHMENT F - Table F – 1 Implementation Plan Rate component by Function
Table F – 2 Illustrative Class Average Present and Proposed Rates
Table F – 3 Implementation Plan Rate Component by Customer Class

DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, IMPOSING EARNINGS LIMITATIONS, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ONGOING IMPROVEMENT IN SAFETY ENGINEERING

Summary

This decision requires Pacific Gas & Electric Company (PG&E) to continue its work towards becoming a safe natural gas transmission system operator. The specific actions we authorize and direct today are essential steps on a permanent safety journey that PG&E, its officers, employees, and shareholders, must internalize as a part of every action they will take over the decades that the natural gas pipeline system will be in place. The inherent danger to the public created by a natural gas transmission and distribution system requires a profound and unwavering commitment to safe operations. As described in detail below, the record shows evidence that, at one time, PG&E had the corporate ability and focus to go beyond nominal regulatory compliance to propose and create a long-term engineering-based safety program for the Commission's consideration. The current challenge to PG&E, and this Commission, is that attaining the goal of future decades of safe operations will require detailed, repetitive, and often seemingly unnecessary actions, which are likely to be expensive, with the overall goal of no significant incidents. Ensuring public safety requires that PG&E meet this commitment, and today's decision lays the groundwork for this Commission to oversee and supervise PG&E's safety operations.

Specifically, this decision grants PG&E authority to increase its annual revenue requirement for 2012, 2013, and 2014 for Implementation Plan projects:

	2012	**2013**	**2014**	**TOTAL**
Requested Revenue Requirement Increase	$247,279	$220,833	$300,641	$768,753
Authorized Revenue Requirement Increase	$2,913	$115,343	$180,958	$299,214
% Authorized	1.2%	52%	60%	39%

This decision mandates pressure testing of 783 miles of pipeline, replacement of 186 miles of pipeline, installation of 228 automated valves, and upgrades to 199 miles of pipeline to allow for in-line inspection.[1] Interim safety measures are also required, pending completion of these needed safety improvements. PG&E shareholders will bear the costs of pressure testing pipeline for which pressure test records are missing. PG&E is required to continue its record management improvement project; however, due to past deficiencies in document management, the costs of this project and its computer data base may not be recovered from ratepayers. We approve PG&E's cost forecasts for pressure testing and replacement, but require that PG&E's shareholders bear the risk of cost overruns because PG&E's past management decisions led to the need to undertake this massive project on an expedited schedule. We also mandate that PG&E scrutinize and evaluate its internal

corporate operations as well as external events, such as trenching work by other entities, to capture cost-effective safety improvement opportunities. We will require PG&E to demonstrate that its proposed safety investments provide good value to California's families and businesses. We also require PG&E to update its Pipeline data base after the conclusion of its Maximum Allowable Operating Pressure validation and record search effort.

Today's decision evaluates the projects PG&E proposes in its Implementation Plan and establishes forward-looking rates for PG&E's natural gas system operations. Our upcoming decisions in Investigations (I.) 11-02-016, I.11-11-009, and I.12-01-007 will address potential penalties for PG&E's actions under investigation. We do not foreclose the possibility that further ratemaking adjustments may be adopted in those investigations; thus, all ratemaking recovery authorized in today's decision is subject to refund.

1. Background

Pursuant to Pub. Util. Code § 451, each public utility in California must "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities, . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Ensuring that the management of investor-owned gas utility systems fully performs its duty of safe operations is a top priority of this Commission,

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[1] As set forth below, these amounts will be updated in accordance with today's decision.

and the California Legislature has recently confirmed this critical function of the Commission.[2]

To meet this obligation with added urgency after the tragic and catastrophic San Bruno events, the Commission expanded its safety efforts in the following areas: (1) natural gas rate cases, (2) this Rulemaking, and (3) enforcement proceedings.

We initiated this Rulemaking to consolidate and coordinate our efforts, obtain public input, and propose rule and policy changes as necessary. We set forth the following primary objectives of this proceeding, as well specific plans to achieve each objective:

A. Provide the public with a means to make their views known to this Commission.

B. Provide the public with the Independent Review Panel's expert recommendations regarding the technical explanation for the San Bruno explosion, assessment of likelihood that similar events may occur, and recommendations for preventive measures and other improvements.

C. Develop and adopt safety-related changes to the Commission's regulation of natural gas transmission and distribution pipelines, including requirements for construction, especially shut-off values, maintenance, inspections, operation, record retention, ratemaking, and the application of penalties.

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2 Pub. Util. Code § 963(b)(3) finds that: It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

D. Consider ways that this Commission can undertake a comprehensive risk assessment for all natural gas pipelines regulated by this Commission, and possibly for other industries that the Commission regulates.

E. Consider available options for the Commission to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the "nuts and bolts" details of prudent utility operations.

F. Consider the appropriate balance between the Commission's obligation to conduct its proceedings in a manner open to the public with the legitimate public safety concerns that arise from unlimited availability of certain utility information.

G. Consider if we need further rules or other protection for whistleblowers to inform the Commission of safety hazards.

H. Expand our emergency and disaster planning coordination with local officials.

On September 23, 2010, the Commission created an Independent Review Panel of experts to conduct a comprehensive study and investigation of the September 9, 2010, explosion and fire. The Commission directed the Panel to make a technical assessment of the events, determine the root causes, and offer recommendations for action by the Commission to best ensure such an accident is not repeated elsewhere. The Commission encouraged the Panel to make such recommendations as necessary. Such recommendations could include changes to design, construction, operation, maintenance, and replacement of natural gas facilities, management practices at Pacific Gas and Electric Company (PG&E) in the areas of pipeline integrity and public safety, regulatory changes by the Commission itself, and statutory changes to be recommended by the

Commission. The Commission offered the following questions to guide the Panel:

- What happened on September 9, 2010?
- What are the root causes of the incident?
- Was the accident indicative of broader management challenges and problems at PG&E in discharging its obligations in the area of public safety?
- Are the Commission's current permitting, inspection, ratemaking, and enforcement procedures as applied to natural gas transmission lines adequate?
- What corrective actions should the Commission take immediately?
- What additional corrective actions should the Commission take?
- What is the public's right to information concerning the location of natural gas transmission and distribution facilities in populated areas?

The Independent Review Panel issued their final report on June 8, 2011.[3] The Independent Review Panel's full set of recommendations are reproduced in Attachment B to today's decision. We have adopted from the Panel's recommendations the description of safety as a journey to reflect our perspective on the multiple decade duration of the natural gas system and consequent need for extraordinarily long-term thinking on this topic.

Specifically, the Panel found numerous deficiencies in PG&E's data collection and management, with resulting defects in Integrity Management, that undermine the safety of PG&E's gas system operations. The Panel's

[3] The entire Independent Review Panel report is found at http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm.

recommendations include instituting state-of-the-art risk analysis to evaluate the likelihood of various possible failures and to establish a culture of pipeline integrity. The Independent Review Panel's recommendation 5.4.4.5 captures the comprehensive and long-term perspective needed, and is the source of our description of safety as journey:

> PG&E should develop and adopt a maturity framework that reflects the importance and advancement of thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise, where progress is transparent and measurable, and is consistent with the best thinking on pipeline integrity and process safety management.

The Independent Review Panel declared that the goal of natural gas pipeline engineering design is zero significant incidents. To attain this goal, the pipeline operator must consistently practice the following:

1. Identify pipeline segments and threats; assume threats to exist until demonstrated otherwise;
2. Inspect and assess the segments;
3. Mitigate and/or remediate identified threats; and
4. Generate new data and analysis, then repeat entire process.[4]

The Independent Review Panel Report concluded that PG&E's Integrity Management Program lacked effective executive leadership, and that "perpetual organizational instability," including corporate bankruptcy, had undermined PG&E's ability to meet its integrity management responsibilities.[5] The Panel found that PG&E had excessive levels of management, comprised largely of

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[4] Independent Review Panel Report at 65-66.

[5] Independent Panel Report at 50, 73.

non-engineering personnel including telecommunications, legal and finance executives, who primarily focused on financial performance.[6] The Panel found that PG&E lacked robust data and document information management systems that impeded the needed quality assurance/quality control to accurately characterize pipeline threats and risk.[7] Addressing multiple threats to a particular pipeline and monitoring third-party activities were also noted as deficiencies.

Maintaining PG&E's focus on its safety journey toward the goal of zero significant incidents is the long-term objective of this proceeding. As noted elsewhere in today's decision, emergency circumstances brought about this Implementation Plan but the needed improvements in corporate culture, Integrity Management, and pipeline operations are permanent requirements.

The National Transportation Safety Board (NTSB) issued its report on August 30, 2011. The NTSB made many recommendations related to the investigation of the San Bruno explosion.[8]

The NTSB report concluded that the Commission should do the following:

- With assistance from the Pipeline and Hazardous Materials Safety Administration, conduct a comprehensive audit of all aspects of Pacific Gas and Electric Company operations, including control room operations, emergency planning, record-keeping, performance-based risk and integrity management programs, and public awareness programs. (P-11-22.)

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[6] Id. at 54.

[7] Id. at 64.

[8] The entire NTSB report is at http://www.ntsb.gov/investigations/summary/PAR1101.html.

- Require PG&E to correct all deficiencies identified as a result of the San Bruno, California, accident investigation, as well as any additional deficiencies identified through the comprehensive audit recommended in Safety Recommendation (P-11-22.), and verify that all corrective actions are completed. (P-11-23.)

Among the many recommendations for PG&E, the NTSB issued this comprehensive directive regarding PG&E's integrity management program and risk analysis:

- Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum, (1) a revised risk model to reflect PG&E's actual recent experience data on leaks, failures, and incidents; (2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed; (3) a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and (4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment. (P-11-29.)
- Conduct threat assessments using the revised risk analysis methodology incorporated in your integrity management program, as recommended in Safety Recommendation (P-11-29), and report the results of those assessments to the California Public Utilities Commission and the Pipeline and Hazardous Materials Safety Administration. (P-11-30.)

Since opening this rulemaking, our primary efforts have been focused on ensuring that California's natural gas transmission system operators are properly

calculating the Maximum Allowable Operating Pressure for each segment of the natural gas transmission system.

In Decision (D.) 11-06-017, this Commission declared an end to historic exemptions from pressure testing for natural gas transmission pipeline and ordered all California natural gas transmission pipeline operators to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans (Implementation Plans) to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test.[9] As set forth in that decision, the Commission found that 1970 federal and 1961 California requirements for pressure testing natural gas transmission pipeline applied only to new pipeline and exempted all existing in-service pipeline from the pressure test requirement. Accordingly, all pipeline installed after those dates was pressure tested, with the result that some of the oldest in-service natural gas pipeline has not been subjected to pressure testing to determine its MAOP. Instead, the MAOP for these untested pipeline segments is set by the highest recorded operating pressure on the segment.[10] Consequently, the operational records for the exempted pipeline segments are critical to determining MAOP.

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[9] The Commission's General Order (GO) 112, which became effective on July 1, 1961, mandated pressure test requirements for new transmission pipelines (operating at 20% or more of Specified Minimum Yield Strength (SMYS) installed in California after the effective date. Similar federal regulations followed in 1970, but exempted pipeline installed prior to that time from the pressure test requirement. Such pipeline is often referred to as "grandfathered" pipeline, because pursuant to 47 CFR 192. 619(c), pressure testing was not mandated.

[10] 47 CFR 192.619(c).

In D.11-06-017, the Commission also described the natural gas system records examination project set in motion by the NTSB upon discovering that PG&E's records for Line 132 were inconsistent with the actual pipeline found in the ground in Line 132. This Commission adopted the NTSB's recommendation to require natural gas system operators to obtain "traceable, verifiable, and complete" records and, with reliably accurate data, calculate a dependable MAOP.[11] In response, PG&E and Southern California Gas Company (SoCalGas)/San Diego Gas & Electric Company (SDG&E) explained that such records were often not available, especially for the older vintage pipelines.

After review of the detailed record both in this proceeding and before the NTSB regarding the records and vintage pipeline, the Commission concluded that the historic exemption and the utilities' record-keeping deficiencies had resulted in circumstances inconsistent with the safety, health, comfort, and convenience of utility patrons, employees, and the public. The Commission ordered all natural gas transmission pipelines in service in California to be brought into compliance with modern standards for safety, and that all California natural system operators file and serve a proposed Implementation Plan to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c).

The Commission required that the Implementation Plans include interim safety enhancement measures, and that the analytical focus be a list of all transmission pipeline segments that have not been previously pressure tested,

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[11] Commission Resolution L-410; NTSB Safety Recommendation P-10-2 and -3 (Urgent) and P-10-4 (January 3, 2011).

with pipeline that must run at or near operating pressures that result in hoop stress levels at or above 30% SMYS to receive prioritized designations for replacement or pressure testing. The Commission required the operators to also give high priority to pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing.[12] The operators were required to set forth the criteria on which pipeline segments were identified for replacement instead of pressure testing.

The Commission also required each operator to include in the Implementation Plan a priority-ranked schedule for pressure testing all pipeline not previously so tested, and to provide for pressure reductions where necessary. The Implementation Plan also must address retrofitting pipeline to allow for in-line inspection tools and, where appropriate, automated or remote-controlled shut-off valves.

While emphasizing the importance and need to make these safety improvements in California's natural gas transmission systems, the Commission also stressed that it will closely scrutinize the costs to be imposed on ratepayers. In D.11-06-017, the Commission required that the Implementation Plans explicitly analyze cost and demonstrate that the proposed expenditures obtain the greatest safety value for ratepayers. The Commission stated its commitment to ensuring that California's working families and businesses pay only for

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[12] The Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations define the four class locations by number of human-occupied buildings located within 220 yards of the pipeline: Class 1, 10 or fewer buildings; Class 2, 10 to 45 buildings; Class 3, 46 or more buildings, or with a place of public assembly; and, Class 4, where buildings with four or more stories are prevalent. (49 CFR § 192.5.)

necessary safety improvements, and the Commission encouraged customers to participate in the process for reviewing the Implementation Plans.

In today's decision, we only consider PG&E's Implementation Plan.[13]

2. Description of PG&E's Proposed Natural Gas Transmission Pipeline Pressure Testing Implementation Plan

On August 26, 2011, PG&E filed and served its Implementation Plan. The Implementation Plan is comprised of two major programs, the first focused on pipeline segments and a second program to improve pipeline records.

The first program, PG&E's Pipeline Modernization Program, provides for testing, replacing, reducing operating pressure, conducting in-line inspections as well as retrofitting to allow for in-line inspection, and adding automatic or remotely-controlled shut-off valves. The second program, the Pipeline Records Integration Program will enable PG&E to finish its records review and establish complete pipeline features data for the gas transmission pipelines and pipeline system components, and the Gas Transmission Asset Management Project, a substantially enhanced and improved electronic records system.

Each of the two major Implementation Plan programs are described below, followed by discussion of the cost for each program.

2.1. Pipeline Modernization Program

As part of its August 26, 2011, filing, PG&E included its Pipeline Modernization Program to comply with the Commission's requirement that all California natural gas transmission pipeline be pressure tested or replaced. PG&E's Pipeline Modernization Program provides for two phases. Phase 1

[13] In D.12-04-021, the Commission transferred consideration of SoCalGas and SDG&E's Implementation Plans to A.11-11-002.

addresses pipeline segments located in highly populated areas, with now-unacceptable types of vintage seam welds or that had not been previously pressure tested. PG&E plans to accomplish this work during 2012, 2013, and 2014. PG&E contemplates beginning Phase 2 in 2015 to pressure test pipeline segments in less populated areas or to retest pipeline that has not been pressure tested to modern standards.

PG&E stated that it had developed a consistent methodology to identify and prioritize recommended actions based on pipeline threat categories. PG&E organized this methodology into a decision tree to identify actions such as performing pressure tests, replacement of pipe, and in-line inspection, to address specific risks.[14]

PG&E used three unique threats as the analytical framework for its decision tree – manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats.[15] Each threat is summarized below as well as PG&E's rationale for the recommended actions:

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[14] The Decision Tree Flow Chart is reproduced at Attachment C to this decision.

[15] PG&E asserts that weather, human error, equipment failure and third-party damage were addressed either in its Integrity Management Program or operating procedures. PG&E stated that Stress Corrosion Cracking has never been found in its system, and if it is, federal regulations specify measures to be taken.

Manufacturing Related Threats

With pipeline manufactured from the 1930's to the present, PG&E states that its pipeline segments were fabricated using the manufacturing technology available at the time. Federal regulations adopted in 1971 improved safety standards for manufacturing and testing. Generally, pipeline manufactured before 1971 with certain types of longitudinal welds is considered to have a manufacturing threat. The decision tree requires replacement of all pipeline segments that have not been pressure tested in accord with current federal regulations that operate at or equal to 30% SMYS, and are located in urban populated areas. Segments operating below 30% SMYS and in urban populated areas are slated for pressure testing. Untested pipelines located in rural settings will be pressure tested in Phase 2, unless found to be susceptible to fatigue induced crack growth; then such pipeline segments will be tested in Phase 1.

Fabrication and Construction Threats

For fabrication and construction threats, PG&E uses 1960 as the date when industry standards and Commission regulations significantly improved fabrication and construction standards. Pipeline segments from before 1960 are subject to further review in the decision tree. First, pipeline segments with certain types of bends, couplings, nonstandard fittings, or an excessive number of short pieces of pipeline joined together, will receive an Engineering Condition Assessment to determine whether to replace the pipeline segment. Second, pipeline segments operating at or above 30% SMYS and with specific types of welds, will be removed from service or pressure tested and in-line inspected. Third, pipeline segments that have not been pressure tested and are operating at more than 30% SMYS in densely populated areas will be pressure tested and

in-line inspected. If in-line inspection is not feasible, the pipeline segment will be replaced.

Corrosion and Latent Mechanical Damage

PG&E's decision tree treats internal and external corrosion and latent third-party or mechanical damage as universal threats equally probable for all pipeline segments. The decision tree results are that all pipeline segments that have not been pressure tested, are located in High Consequence Areas or Class 2- 4, and are operating at greater than or equal to 30%SMYS will have operating pressures reduced and be pressure tested in Phase 1. Pipelines with these characteristics will be in-line inspected or replaced in Phase 2. Pipelines that have not been tested and are located in High Consequence Areas or Class 2- 4, but that are operating at less than 30% SMYS, will be pressure tested or in-line inspected and subjected to a Close Interval Survey in Phase 2.

The overall results of the decision tree methodology are that PG&E is proposing to: (1) replace at least 186 miles of pipeline, with additional segments added based on inspection and testing results, (2) pressure test 783 miles of pipeline, and (3) retrofit 199 miles to allow for in-line inspection and inspect a total of 234 miles of pipeline with in-line inspection tools.

As also required by D.11-06-017, PG&E's Phase 1 Plan calls for increasing the number of automated or remotely controlled shut-off valves and interim safety measures for the expected multiple year duration of the Implementation Plan. PG&E plans to replace, automate and upgrade 228 existing gas shut off-valves between 2011 and 2014. PG&E will prioritize pipelines in high population areas, and larger diameter pipelines operated at higher pressures. PG&E primarily plans to use remote controlled valves where a PG&E operator will trigger the valve from the Gas Control Center. PG&E will

use fully automated valves that are independently triggered by controls at the valve site only in highly populated areas where the pipeline crosses an earthquake fault. Both types of valves can be easily converted from one type of operation to the other.

PG&E proposes to adopt interim safety enhance measures while it puts in place the measures called for in the Implementation Plan. PG&E currently has in place pressure reductions on approximately 380 miles of pipeline in high consequence areas, and 1,300 miles of pipeline in non-high consequence areas. The decision tree in the Pipeline Modernization Program also calls for additional pressure reductions.

PG&E has increased leak inspections and patrols. PG&E will conduct leak surveys six times per year on all gas pipeline segments included in the Implementation Plan and which lack pressure test records. PG&E will continue patrolling its backbone transmission system on a monthly basis, and the local transmission pipelines will be patrolled 6 times per year.

2.2 Pipeline Records Integration Program

As noted above, the Records Integration Program provides for continuing the document collection, review and verification process underway since the January 3, 2011, pursuant to the NTSB directives. PG&E proposes to assemble these records in a new electronic records management system called the Gas Transmission Asset Management Project. PG&E states that the goal of this project is to provide improved access to detailed pipeline component information for the 6,761 miles of its gas transmission system, of which over 72% was installed prior to 1970.

PG&E states that it will begin by entering critical pipeline information into its existing Geographic Information System from source documentation.

Then, PG&E will validate the piping systems information, and upgrade the system to allow users to access supporting original source records. PG&E explains that much of the source drawings and specifications necessary to develop pipeline features lists for the high consequence areas of its system have been collected. The next step consists of compiling an electronic data set containing key information for each pipeline. To compile the electronic data set, PG&E will (1) code documents by type, such as as-built drawings or pressure test results, (2) identify missing items, and then (3) scan, code, and upload the records into the electronic data base. PG&E's engineers will then review the resulting data set and, where records are missing, make conservative engineering-based assumptions. The entire resulting pipeline features list data set will then be reviewed by PG&E's engineers for quality control and quality assurance. PG&E will then use the ultimate data set to calculate the design-basis MAOP for the segment, which is then compared to the pressure test results based on PG&E's requirements, and PG&E's listed MAOP for the pipeline segment. PG&E will then choose the lowest of these three pressure levels as the new MAOP.

PG&E proposes to use the document collection and analysis efforts for the MAOP as the input to its Gas Transmission Asset Management Project. For this project, PG&E proposes to substantially upgrade its asset management records system. PG&E states that the new system will consolidate existing record management systems into a central, integrated system that will enable PG&E to:

1. Capture, track, update, and manage specification and maintenance data as well as all location and connectivity in two core systems;

2. Improve traceability and verification of asset data by providing links to source documents;
3. Improve integrity and risk analysis, as well as better schedule inspection and maintenance;
4. Provide the field work force with mobile tools that allow remote access to existing asset information, and to update electronically new maintenance and inspection information; and
5. Offer a data management platform capable of addressing any new recordkeeping obligations in the future.

PG&E plans to do this work in four distinct phases over approximately 3.5 years and expects tangible improvements over the entire time frame. PG&E expects to complete the project in early 2015.

2.3. Costs of the Pipeline Modernization and Pipeline Records Integration Programs, Including Management and Contingency

Requested Revenue Requirement Increases

PG&E requests the following increase over its existing authorized revenue requirement for Implementation Plan costs to be recovered from ratepayers:

2012	2013	2014	TOTAL
$247,279,000	$220,833,000	$300,641,000	$768,753,000

PG&E proposes to use currently authorized cost allocation to allocate these costs among Local Transmission, Backbone Transmission, and Storage, in place pursuant to the Gas Accord V Settlement in D.11-04-031.

The following is a breakdown of the components of PG&E's revenue requirement increase request.

Pressure Testing

PG&E states that it used the decision-making process depicted in its decision tree to determine that 546 miles of pipeline segments should be pressure tested in Phase 1. These pipeline segments, however, are not always contiguous and can be located throughout PG&E's system. In some instances, testing the identified segments requires that additional pipeline be tested as well. For example, when two segments need testing but are separated by a segment not requiring testing, conducting one pressure test of the entire three-segment length is less expensive but increases the mileage tested. Thus, to accomplish the needed testing in an efficient manner consistent with sound engineering principles, PG&E proposes to pressure test 783 miles of pipeline. PG&E's expects to spend a total of $271.9 million in 2012, 2013, and 2014. PG&E also spent $117.0 million in 2011 on pressure testing but will not seek rate recovery for these costs. All pressure test costs are expenses.

Pipeline Replacement and In-line Inspection Retrofits

PG&E proposes to replace 185.5 miles of mostly older pipeline at a total cost of $818.7 million during 2012, 2013 and 2014. PG&E proposed to capitalize all of these costs.

PG&E estimates that it will spend $38.8 million for pipeline retrofits to enable in-line inspection in 2012, 2013, and 2014. Of this amount, $29.2 million will be capitalized and $9.6 million will be expensed.

Document Collection, Review and Verification Process

PG&E estimates that it will spend a total of $271.9 million in collecting, reviewing and verifying the documents related to determining the MAOP of the its gas transmission pipeline segments. PG&E states that its shareholders will fund all document costs related to pipeline installed after 1970, and costs

incurred in 2011. PG&E is seeking Commission authorization to include in revenue requirement a total of $107. 1 million for recovery from ratepayers for costs related to 2012 and 2013 records validation.

Gas Transmission Asset Management Project

PG&E estimates that during 2012, 2013, and 2014, it will spend $115.7 million for this computer data base system upgrade, which it proposes to include in revenue requirement. PG&E is not seeking recovery from ratepayers for $7.9 million expended in 2011.

Valves

PG&E estimates that its valve automation program will cost a total of $143.6 million in 2011 through 2014. Of that amount, PG&E shareholders will fund $15.3 million. The remaining $128.3 million which PG&E requests authorization to include in revenue requirement is comprised of $118.8 million in capital and $9.5 million in expenses for 2012, 2013, and 2014.

Interim Measures

In D.11-06-017, the Commission directed PG&E to take interim measures to enhance safety. Those measures include pressure reductions and increased patrols of pipeline. PG&E estimates that these measures will cost $1.0 million in 2012, and $1.1 million in each of 2013 and 2014. All of the costs are expenses.

Contingency

PG&E presented testimony calculating a risk-based contingency cost forecast for its entire Implementation Plan programs. PG&E requested Commission approval of a total of $380.5 million as a risk-based allowance. This amount covers costs expected to be incurred in 2011, 2012, 2013, and 2014. Of the total, $247.3 million is capital costs and $133.2 million is expense.

PG&E states that it performed a detailed assessment of each component of its Implementation Plan projects and assigned a contingency percentage based on industry guidelines for work elements with a similar risk profile and extensive engineering experience on historical data for similar projects. The contingency amounts vary from 10% to 28% for different components of the Plan due to risk profiles and level of design completion. For example, emergency replacements due to pressure testing are assigned a 10% contingency and the capital costs for the document system upgrade (GTAM) receives a 26% contingency. Overall, the total Implementation Plan contingency allowance is 21% of the total costs.

Program Management Office

PG&E states that it has established a Program Management Office to manage the overall execution of the Implementation Plan and to coordinate the inter-related projects and work streams. PG&E estimates that the office will incur the following costs:

	2012	**2013**	**2014**
Expense	$3.5 million	$3.4 million	$3.4 million
Capital	$6.6million	$6.7million	$6.6 million
TOTAL ($millions)	$10.1 million	$10.1million	$10.0 million

PG&E states that it has hired an experienced project management firm to help manage the overall Implementation Plan construction and testing. The office is comprised of four primary sub-teams: (1) Project Controls will be responsible for cost, schedule, scope, quality, change control, resource management and reporting, (2) Project Support will coordinate procurement, human resource management, customer outreach, and component standards, (3) Quality Assurance/Quality Control, will monitor and evaluate test results to

ensure compliance with applicable standards, and (4) PG&E Business Planning and Coordination will provide end-user input and operational advice, including specific business requirements for component projects.

Shareholder Cost Responsibility

As required by D.11-06-017, PG&E included a proposal for shareholders to absorb a portion of the Implementation Plan costs. PG&E proposed that shareholders pay the costs associated with activities in 2011, $222.1 million, and the costs of validating the MAOP or pressure testing pipeline segments installed after 1970, $97.7 million. PG&E also added in $215.4 million in 2010 and 2011 expenses related to document review, answering information and data requests, and responding to investigations by the NTSB, this Commission and the Independent Panel. Although PG&E proposes that shareholders fund the 2011 revenue requirements associated with 2011 capital costs, PG&E proposes to allocate the future revenue requirements for these capital costs to ratepayers. PG&E's tabulation of the total amount to be absorbed by shareholders is $535.2 million. PG&E states that a one-time upfront shareholder assessment is preferable to an on-going disallowance because it reduces the uncertainty about the ultimate cost of the disallowance.

PG&E's Rationale for Revenue Requirement Increase

PG&E argues that its Implementation Plan will make the gas system safer and more reliable for years to come, support future growth, and keep energy costs reasonable.[16] PG&E states that its plan meets all the Commission's requirements, and does so in the most economical, least disruptive, and safest manner.

[16] PG&E Opening Brief at 2 – 4.

PG&E supports its pipeline modernization plan as drawn from three decision trees used to prioritize pressure testing and replacement based on known threats to the pipelines. PG&E explains that its valve modernization program complies with the Commission's requirement to expand the use of automated valves. Upon completion of the valve program, PG&E states, it will have substantially decreased the time required to isolate a pipeline segment in the event of rupture for the majority of the gas transmission pipeline in populated areas of its service territory.

PG&E argues for approval of its record integration program as a cost-effective and efficient means of validating MAOP based on traceable, verifiable, and complete records.

PG&E contends that it has presented detailed cost forecasts for each element of its Implementation Plan, including specific information on each of the 350 projects in the pipeline modernization portion. Three volumes of work papers provide detail on each of these projects.

3. Positions of the Parties

3.1. Division of Ratepayer Advocates (DRA)

DRA recommends that the Commission disallow ratemaking recovery for any of the costs associated with the Implementation Plan. DRA implores the Commission to stop PG&E's mismanagement of the natural gas system when the shareholders have reaped profits of over $500 million above the authorized return on equity, deferred maintenance of system facilities, and neglected safety improvements. DRA contends that the logical consequence for PG&E's mismanagement and excess profits is that shareholders should reasonably bear the cost of this initial phase of the Implementation Plan.

DRA begins with the fundamental premise of test year ratemaking that revenue requirement is not adjusted after the test year has been adopted, regardless of whether costs turn out to be higher or lower than adopted in the test year. DRA points out that the Overland report[17] found that PG&E enjoyed several years where its profits were higher than anticipated in the test year revenue requirement, which PG&E shareholders retained, and that the unanticipated costs of the Implementation Plan should similarly be borne by PG&E shareholders without an increase in rates. DRA concludes that PG&E bears the burden of justifying its proposed rate increase as just and reasonable, and that it has not.

Turning to specific costs in the Implementation Plan, DRA argues that PG&E shareholders should be responsible for the costs of pressure testing all pipeline installed after 1935. DRA argues that pressure testing pipeline prior to placing it in service has been industry standard practice since 1935, and that PG&E should have complied with this practice and retained the records of such tests. DRA contends that even though the 1961 Commission and 1970 federal pressure testing directives did not require testing of pipe already in service, this exclusion did not override the industry practice of testing. DRA states that PG&E has agreed that it began in 1955 following industry standards for pressure testing pipeline prior to placing the pipeline in service. Consequently, DRA recommends that where pipeline installed prior to 1955 must be replaced due to

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[17] Hearing Exh. 42: Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures For the Period 1996 to 2010, Overland Consulting (December 30, 2011), which concluded that PG&E's gas and storage operations have been very profitable since March 1998, and that PG&E's gas revenues have exceeded the amount needed to earn the authorized rate-of-return by $430 million.

absent pressure test documentation, the shareholders should bear the costs of such replacement. DRA further recommends that where pipeline installed prior to 1955 must be replaced or tested, PG&E shareholders should receive a 200 basis points reduction in return on equity, and bear 20% of the expenses associated with the capital investment.

DRA next turns to PG&E's gas pipeline record improvement proposal. DRA explains that PG&E seeks over $200 million to comply with the purportedly "new" requirement to maintain accurate records of its natural gas transmission pipeline system. DRA cites to reports which conclude that PG&E's inadequate records have resulted in a "dysfunctional pipeline integrity management system so that PG&E does not know enough about its pipeline system to prioritize inspection, repair, and replacement."[18] DRA argues that PG&E has a long-standing obligation to maintain complete, accurate and accessible records, and that it has received substantial funding from ratepayers over the decades for just that purpose. DRA concludes that all costs for PG&E's record correction programs should be allocated to shareholders.

DRA next challenged the specifics of PG&E's Implementation Plan, focusing on the decision tree and the data used. DRA's outside expert reviewed PG&E's decision tree analysis and concluded that with improved decision-making protocols and procedures, rather than relying on practical judgment, the number of pipeline segments requiring replacement could be reduced, with the number of segments to be pressure tested increased, and overall Phase 1 mitigation costs reduced. DRA also contended that PG&E's

[18] DRA Opening Brief at 25, *citing* Hearing Exh. 45 at 49 and NTSB Report at xi.

Implementation Plan included unnecessary upgrades in pipeline diameter (37% of the replaced pipeline has an increased diameter) and excessive modifications for in-line inspection tools.

DRA challenges as too high PG&E's cost forecasts for pressure testing. DRA explains that PG&E used estimated fixed and variable costs to forecast the total costs for its hydrotesting projects. DRA analyzed each cost component and concluded that PG&E had not adequately justified a majority of the proposed costs. DRA particularly challenged PG&E's forecast of fixed costs as being without evidentiary support. DRA compared PG&E's mobilization/demobilization surcharge of $500,000 for each pressure test, for which DRA contended PG&E provided no supporting calculations, to its own specific calculations based on actual PG&E cost data which resulted in a cost forecast of between $85,600 and $139,400, depending on the size of the pipeline to be tested. DRA similarly challenged PG&E's indirect cost calculations, 31% of direct costs, and found little support for the assumptions used by PG&E. For example, DRA shows that PG&E added a 5% construction management fee plus a 2.5% project management fee, all in addition to the requested $415 million for the Program management office. Overall, DRA recommended that the Commission adopt substantially reduced fixed and variable hydrotest cost forecasts for the PG&E Implementation Plan.

DRA further recommends a cost escalation rate of 1.1% to 1.5%, rather than PG&E's 3.12%.[19]

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[19] Hearing Exh. 147 at 1-16 to 1-17.

DRA next attacked PG&E's forecast of the cost to replace pipeline. DRA's consultant tabulated pipeline per-foot total replacement cost forecasts to be about 30% lower than PG&E's. The consultant also found that PG&E's pipeline replacement cost forecasts were over 20% higher than similar forecasts prepared by the University of California at Davis and the Pacific Northwest National Laboratory. In its brief, DRA pointed out that these cost comparisons do not include, among other things, incremental "adders" for pipeline on the San Francisco peninsula, customer outreach, project management, and inflation escalation. With these adders, plus the 20% explicit contingency factor included, DRA concluded that PG&E's replacement cost estimates are 75% higher than the cost estimates in the Davis and Pacific Northwest studies.

DRA then turned to PG&E's 20% contingency factor, which PG&E adds on to the entire Implementation Plan project for $380.5 million in additional costs. DRA showed that PG&E relied on professional judgment, without supporting calculations, to largely predetermine that the contingency rate for pipeline replacement would be at least 17% and for hydrotesting at least 20%. DRA also showed that PG&E only considered scenarios where costs were higher than expected and ignored the possibility of actual costs being lower than expected. DRA concluded that PG&E should update its costs and contingency amounts annually throughout the years in which PG&E will be performing its Implementation Plan, and that an overall 8% contingency factor appeared to be a reasonable starting point for the time being.

DRA opposed including in-line inspection projects as part of Phase 1. DRA contended that PG&E had not justified the $9.6 million in expense and $30.3 million for eight in-line inspection projects as a high priority to be included in Phase 1. Similarly, DRA opposed PG&E's proposed valve automation

program because the valves are not required by the Commission's 2011 decision and the costs are highly speculative.

DRA's final recommendations include putting all Implementation costs into a memorandum account pending further review of the Commission, several directives for the record review process, and denying PG&E's request to use a Tier 3 advice letter for any cost overruns.

3.2. The Utility Reform Network (TURN)

Like DRA, TURN recommended that the Commission issue a comprehensive disallowance from recovery in rates of all costs in the Implementation Plan Phase 1. TURN argued that Pub. Util. Code § 463(a)[20] requires the Commission to disallow costs when PG&E cannot produce adequate competent records, and that disallowances for imprudently incurred costs serve the important purpose of deterring imprudent management actions. TURN argues that the standard of prudence for natural gas transmission system operators is a high standard due to the inherently dangerous nature of natural gas. TURN also notes that public utilities are not entitled to a presumption of prudence but rather, PG&E bears the burden of proving that all of its actions were prudent. TURN also opposed final ratemaking treatment for any of the costs included in the Implementation Plan before the Commission issues final

[20] Pub. Util. Code, § 463(a) provides that: "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."

decisions in its three investigation proceedings related to the San Bruno tragedy,[21] and offered as an alternative that all authorized ratemaking recovery should be subject to refund pending the outcome of those proceedings.[22]

TURN challenged PG&E's contention that the Commission's 2011 decision created a new regulatory compliance obligation for PG&E. TURN explained that prior to the 2011 decision, PG&E had planned to take many and possibly most actions ultimately brought forward in the Implementation Plan. TURN argues that PG&E's proposed pipeline testing and replacement projects in the Implementation Plan were required by pre-existing regulatory obligations, and that PG&E had imprudently failed to comply with those obligations. TURN concludes that PG&E's imprudent failure to comply with existing regulatory requirements obligates the Commission to disallow rate recovery for all costs of the Implementation Plan.

TURN also presented an issue-by-issue analysis of the Implementation Plan. TURN recommends that shareholders fund all pressure testing for pipeline installed after 1955 for which PG&E cannot produce a valid pressure test record. TURN explained that PG&E accepted that industry standards starting in 1955 required pressure testing and that PG&E's claimed practice was to follow those standards. Thus, PG&E should have both tested and retained records for all pipelines installed after 1955.

TURN takes issue with PG&E's determination that pressure test records for 1961 to 1970 are inadequate if such records include only the three required

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[21] Investigation (I.) 11-02-016 (record keeping); I.11-11-009 (pipeline classification); I.12-01-007 (San Bruno rupture).

[22] TURN Opening Brief at xix.

elements - test medium, duration, and pressure - but do not show the test operator's name. PG&E proposes to have ratepayers fund pressure testing for pipelines with pressure test records that lack the operator name but do have all three required elements. TURN contends that the rules in effect at the time for pressure tests, G.O. 112, only required test medium, duration, and pressure, and not operator name. Thus, shareholders should fund any hydrotests for pipeline installed in that time frame for which PG&E does not have the required elements. TURN comments that any re-testing required to bring such pipeline up to current standards (i.e., with operator name and an eight hour duration) should be included in Phase 2.

TURN also challenges PG&E's assumption that when PG&E lacks a valid pressure test record for pipeline which was required to be pressure tested prior to being placed in service, and the decision tree action plan is pipeline replacement, the ratepayers should fund the replacement. TURN contends that the missing record moves the pipeline into the decision tree as requiring action, and therefore PG&E should not be exculpated for its missing records solely because the logical outcome is replacement rather than pressure testing.

TURN recommends a series of changes to the Implementation Plan to re-prioritize segments and to increase the use of hydrotesting instead of replacement. TURN states that Class 2 non-High Consequence Area segments should be moved from Phase 1 to Phase 2. TURN advocates for pressure testing rather than replacing pipeline operating at over 30% SMYS, and questioned the 237 miles of pipeline being included for pressure testing due to engineering efficiencies. TURN supports exempting from the Commission's 2011 test or replace requirement all pipeline operating at less than 30% SMYS. TURN

reasons that such pipeline will likely fail as a leak and not as a far more destructive rupture.

TURN supports expanding PG&E's proposed Valve Automation Program to include more automated shut-off valves rather than remote controlled valves, and to focus on placing valves in 24-inch diameter pipelines.

TURN asks the Commission to disallow $40 million for in-line inspection costs, $120 million for hydrotesting, and $279 million for pipeline replacement due to PG&E's imprudent integrity management. TURN explains that federal integrity management rules require PG&E to perform a baseline assessment of the pipeline and that PG&E decided to use in-line inspection or corrosion assessment for the baseline assessment, and to only use pressure testing "where pressure testing is the only feasible option."[23] TURN finds that PG&E's baseline assessments were flawed because PG&E did very little in-line assessment and relied almost exclusively on corrosion assessment for 239 miles of pipeline with identified manufacturing defect threats. TURN argues that PG&E violated the federal integrity management rules and should have performed the proper assessment, i.e., inline inspection or pressure test, for these pipelines in 2009, and concludes that PG&E shareholders should be responsible for the now-belated testing or replacement of these pipelines.

TURN offers the historic narrative of PG&E's Gas Pipeline Replacement Program to illustrate that PG&E had lost its focus on safety, turning to financial performance as its primary corporate value. TURN explains that in 1985, PG&E started a 25-year program to replace 2,467 miles of natural gas distribution and

[23] TURN Opening Brief at 85 *quoting* PG&E RMP-06, rev.7 (8/13/11).

transmission pipeline, with about 500 miles of transmission pipeline. The Commission routinely approved the ratemaking requests for this program from 1985 to 2000, and PG&E replaced an average of 24.1 miles of transmission pipeline each year. In 2000, however, the remaining 212.3 miles of transmission pipeline were transferred out of the Gas Pipeline Replacement Program into the Risk Management Program, where about 4.4 miles per year were replaced through 2010, leaving a pipeline replacement deficit of about 160 miles, including lines 109 and 132.[24] TURN finds this as strong evidence of imprudent system management caused by PG&E prioritizing cost cutting. TURN concludes that PG&E shareholders should absorb the $720 million for replacing these pipelines or, at a minimum, the Commission should use this evidence of imprudent management to reduce PG&E's return on equity.

TURN next addresses PG&E's two-part Pipeline Records Integration Program, and recommends that the Commission disallow rate recovery for the costs of both parts. TURN explains that PG&E's record review process to ensure that its pipeline records are complete and accurate originated with the NTSB report on the San Bruno tragedy which found that PG&E's records were factually inaccurate for the pipeline involved. TURN concludes that PG&E's program to restore accuracy and reliability was needed to remedy record-keeping deficiencies that PG&E should not have allowed to happen.

TURN disputes PG&E's claim that the traceable, verifiable, and complete standard set forth by the NTSB and adopted by the Commission is a new regulatory requirement. TURN argues that accurate and reliable records of

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[24] Lines 109 and 132 are located on the San Francisco peninsula, and a segment of Line 132 ruptured in San Bruno.

natural gas system components were at all times essential for safe operation of the system and thus were required for all natural gas transmission system operators in California pursuant to Pub. Util. Code § 451.[25]

The second component of PG&E's Pipeline Records Integration Program is the Gas Transmission Asset Management, a computer data base for document management. TURN also opposes ratemaking recovery of the $95.2 million of capital and $20.5 million in expenses for this component of the Program. TURN states that PG&E has failed to show that the costs of the Gas Transmission Asset Management data base are not remedial in nature because the purpose of the data base is to cure the PG&E's serious and imprudent record-keeping deficiencies.

TURN concludes its ratemaking recommendations with a request to reduce PG&E's return on equity to the cost of debt, remove incentive compensation from the overhead loadings added to Implementation Plan costs, and require the use of PG&E internal funding before increasing rates. TURN also recommends increasing the depreciation life of transmission pipeline from 45 years to 65 years, due to the much longer service life expected for natural gas pipe installed today as compared to over 40 years ago.

TURN recommends moving pressure testing or replacing pipeline in Class 2 locations to Phase 2 of the Implementation Plan absent clear operational efficiencies or realistic potential to become high consequence areas. TURN

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[25] Pub. Util. Code § 451 provides, in part: "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in § 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

explains that PG&E offered little supporting rationale for its decision to include Class 2 locations in Phase 1 of its Implementation Plan, in light of the Commission's 2011 directive to prioritize Class 3 and 4 areas, and only high consequence areas of Class 1 and 2. TURN concludes that postponing the Class 2 areas that are not high consequence areas to Phase 2 could save about $162 million in current pipeline replacement costs and $71 million in testing costs.

TURN opposes PG&E's decision to determine that pressure test records which lack the name of the operator should be considered incomplete and re-tested. TURN seeks either shareholder funding for these re-tests due to lack of records or accepting the records without the signature.

TURN takes issue with PG&E's decision to replace rather than hydrotest all pipeline operating at high pressures.[26] TURN argues that the default assumption in PG&E's decision tree that all pipeline which has not been pressure tested and is or is expected to operate at high pressure must be replaced, leads to unnecessary replacement capital costs of $427.5 million. TURN recommends requiring PG&E to put forward a location-specific justification for replacement, rather than assuming all such locations will be replaced rather than pressure tested.

3.3. City of San Bruno

The City of San Bruno challenges the Commission to bring renewed and meaningful regulatory oversight to PG&E to restore badly damaged public

[26] Such pipeline would operate at or over 30% of its Specified Minimum Yield Strength (SMYS), or about a third of the pressure expected to cause the pipeline to become permanently deformed.

confidence in the public utility system and this Commission. The City of San Bruno forcefully states that the Commission must require PG&E to improve its emergency planning, training, and response, along with improved community outreach and communication in the event of a disaster.

Specifically, the City of San Bruno recommends that PG&E greatly expand its Implementation Plan to address all the recommendations from the NTSB. The City contends that the relationship between the Commission and PG&E is too close and has led to the Commission condoning practices, policies, and safety protocols based more on PG&E's convenience than on science and technology. The City specifically requests that the deficiencies in PG&E's public awareness and emergency response programs should be addressed in a formal Commission proceeding.

The City requests that the Commission order PG&E to install automatic shut-off valves on the natural gas transmission pipeline in San Bruno. The City explains that such valves would have greatly decreased the 93 minutes it took PG&E to stop the flow of gas to the rupture, and would have similarly lessened the severity of the property damage and life-threatening risks to the residents and emergency responders.[27]

The City takes issue with several aspects of the Implementation Plan seeking greater specificity for decisions made, as well as proposing the preparation and distribution of annual revisions to the plan. The City also recommends that the Commission require PG&E to use qualified personnel to carry out the construction projects in the Implementation Plan and adopt a

[27] City of San Bruno Opening Brief at 7.

definition of quality control and quality assurance that goes beyond mere compliance.

The City implores the Commission to exercise stronger oversight over PG&E's management and execution of the Implementation Plan. The City emphasizes the critical role of CPSD to ensure that PG&E adheres to the Plan, and it makes needed program reporting to all municipalities and counties where residents are affected by timely completion of the work. The City concludes that PG&E and the Commission must take specific steps beyond the Implementation Plan to improve emergency preparedness and community outreach.

3.4. City and County of San Francisco (San Francisco)

San Francisco contends that PG&E's Implementation Plan needs technical improvements because it is unclear that the most pressing work will be performed first. San Francisco points to the decision tree as based on inaccurate data and lacking the best analysis available. San Francisco recommends that the Commission reject the Implementation Plan, order PG&E to start testing or replacing 630 miles of pipeline in high consequence areas, and re-run all decision tree analyses with updated data from the records review.

San Francisco opposes allowing PG&E any rate recovery for its record review or new computer data base program, as PG&E has always had an obligation to keep accurate records. San Francisco strenuously objects to PG&E's cost sharing proposal as unfairly burdening ratepayers with PG&E's costs of coming into compliance with the pre-exist regulatory requirements.
San Francisco contends that PG&E should pay for testing or replacement of the all pipeline installed after 1955, and that any revenue the Commission authorizes PG&E to recover from ratepayers should be subject to refund.

3.5. Black Economic Council, National Asian American Coalition, and the Latino Business Chamber of Greater Los Angeles

These parties jointly renewed their call for a ratepayer confidence fund to restore community trust in the Commission and PG&E. They also recommend that ratepayers bear only 25% of the cost of any needed safety upgrades and that PG&E be ordered to engage in greater customer outreach and communication.

3.6. Northern California Generation Coalition

Each member of the Coalition is a local publicly-owned electric utility that purchases natural gas transportation services from PG&E for the member's natural gas-fired electric generation facilities. The Coalition explains that, under PG&E's proposed ratemaking, the gas transportation rates paid by members will increase 91% because of the Implementation Plan. The Coalition recommends that the Commission defer its determination on costs to be absorbed by shareholders until the Investigations are completed. Any costs to be recovered from ratepayers should be primarily allocated to core customers, and not transportation customers such as the Coalition members, because the safety improvements will directly benefit core customers who are more likely to be located within the Potential Impact Radius of PG&E's transmission pipelines. The Coalition opposed using the existing cost allocation methodology adopted in Gas Accord V to allocate Implementation Plan costs because it was a settlement that should not be used as precedent.

3.7. Northern California Indicated Producers (NCIP)

NCIP states that both the reason for and the cost of PG&E's Implementation Plan requires the Commission to assign greater cost responsibility to PG&E's shareholders and to reduce the return on equity. NCIP describes the Implementation Plan cost as staggering and states that in 2014 the

Implementation Plan costs alone will comprise 52% of PG&E's gas transmission and storage revenue requirement.[28] NCIP recommends disallowing all remedial costs, such as record-keeping, and reducing the return on equity by 500 basis points to the cost of debt, i.e., from 11.35% to 6.35%.[29] NCIP supports an end-user surcharge as the most appropriate means to recover the Implementation Plan costs because the purpose of the Implementation Plan is to enhance the safety of the public with regard to natural gas facilities. NCIP also put forward a cost allocation proposal which would allocate more costs to noncore customers than the current allocation methodology, and argues that overly allocating to gas transportation customers, such as electric generators, will lead to increased rates for electricity.

3.8. Southern California Edison Company (EDISON)

Edison argues that the proposals to reduce PG&E's return on equity or disallow capital cost recovery will harm ratepayer interests by increasing the cost of borrowing capital to make the needed safety enhancements. As a natural gas customer of SDG&E and SoCalGas, Edison also emphasizes that the cost allocation adopted for PG&E should not be regarded as precedent for the other gas utilities' Implementation Plans.

3.9. SDG&E and SoCalGas

These natural gas system operators ask the Commission to refrain from ruling on whether the NTSB description of traceable, verifiable, and complete is a new recordkeeping standard, and that the Commission should consider historic recordkeeping and pressure test standards and practices in the industry. These

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[28] NCIP Opening Brief at 1.

[29] Hearing Exh. 123 at 25.

operators contend that they should be afforded a full and impartial opportunity to litigate these issues with regard to their Implementation Plan.

3.10. Dynegy, Inc.

Dynegy states that it owns two large gas-fired electric power plants served by PG&E natural gas transmission lines and will see up to an 86% rate increase if PG&E's Implementation Plan is adopted as proposed. Dynegy opposes PG&E's cost allocation methodology, which is based on the existing methodology adopted in D.11-04-031 (Gas Accord V settlement). Dynegy supports the cost allocation proposal put forward by SDG&E and SoCalGas, which allocates the Implementation Plan costs on an equal percentage of authorized margin basis. This methodology allocates more costs to core customers, who, Dynegy contends, will see more service improvement from the Implementation Plan than the large noncore customers. Dynegy also recommends that the Commission avoid large disruptive rate changes during the transitional period between now and PG&E's next general rate case.

4. Burden and Standard of Proof

Pursuant to Pub. Util. Code § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified." (§ 454.) The Commission requires that the public utility demonstrate with admissible evidence that the costs which it seeks to include in revenue requirement are reasonable and prudent. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable.

PG&E must meet the burden of proving that it is entitled to the relief sought in this proceeding, and PG&E has the burden of affirmatively establishing the reasonableness of all aspects of the application.[30]

With the burden of proof placed on PG&E, the Commission has held that the standard of proof PG&E must meet is that of a preponderance of evidence. Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth'"[31] In short, PG&E must present more evidence that supports the requested result than would support an alternative outcome.

We have analyzed the record in this proceeding within these parameters.

5. Discussion

Our evaluation of PG&E's proposed Implementation Plan requires that we address broad policy issues as well as specific project cost issues. In the first section below, we analyze the overarching safety challenges confronting PG&E and our assessment of PG&E's current operations and set a course for future PG&E natural gas system operations. In the second section below, we address the specific project proposals in PG&E's Implementation Plan.

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[30] See generally Application of Southern California Edison Company for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009, And to Reflect That Increase In Rates (D.09-03-025, *mimeo*. at 8) (March 12, 2009) and Decisions cited therein.

[31] In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

5.1. Next Steps on the Safety Journey

5.1.1. Why we must make the safety journey

Among all public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. Unlike more common public utility facilities, gas pipelines carry flammable gas under pressure - in transmission lines, often at high pressure - and these pipelines are typically located in public right-of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems, including the pace at which death and life-altering injuries can occur, are far more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.

In the context of an unending obligation to ensure safety, we must also realize that in practical terms safety is exacting, detailed, and repetitive. It is also expensive, so ensuring that high value safety improvements are prioritized and obtaining efficiencies wherever possible is also essential. And, in the end, if the goal of safe operations is met, the reward is that absolutely nothing bad happens. In short, safety is difficult, expensive and seemingly without reward.

This is why today's decision must be only the beginning of a permanent change in operations, attitude, and perspective, for both PG&E and this Commission. Institutionalizing the needed change will require permanent operational and functional changes. For the future, we must ensure that safety remains PG&E's top priority.

5.1.2 Learning From the Past

As discussed above, following the tragic events in San Bruno, the Commission appointed an Independent Review Panel of experts to gather and review facts and make recommendations to the Commission to best ensure that such events are not repeated. The Panel found numerous deficiencies in PG&E's data collection and management, with defects in Integrity Management that undermine the safety of PG&E's gas system operations. We adopt the Panel's recommendation for "thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise" and use the safety journey as the description of the long-term regulatory model[32] we require for PG&E.

Maintaining PG&E's focus on its safety journey toward the goal of zero significant incidents is the overall objective of this proceeding. As noted elsewhere in today's decision, pipeline pressure testing and replacement, as well as record-keeping improvements are immediate and necessary actions; but the needed radical changes in PG&E's corporate culture, its Integrity Management, and its pipeline operations are permanent non-negotiable requirements.

In considering the safety journey ahead of us, we look back at PG&E's pipeline safety approach in the mid-1980's, presented in the record by TURN. During that era, we see evidence that PG&E met the Panel's objective of going beyond nominal regulatory compliance and displaying corporate initiative to "analyze whether more or different investments could be appropriate to strengthen public safety."[33] PG&E's 1985 plans for its older pipeline that had not been pressure tested illustrate that *at that time* PG&E was capable of exercising

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[32] Independent Review Panel Report at 75.

[33] Id. at 10.

initiative to recognize the need for, develop, and present engineering-based safety programs for the Commission's consideration.

In 1985, PG&E implemented its Gas Pipeline Replacement Program, a 25-year plan to replace about 2,467 miles of aging distribution and transmission pipelines.

> PG&E states that it has historically had an ongoing program for continually replacing its gas transmission and distribution pipelines based on age and safety considerations, and on economic analysis of the relative cost of leak repair versus replacement for individual line segments. However, as PG&E's system has aged, the need to replace pipelines has increased. In response, in 1984, PG&E established a major program to eliminate, under a systemwide schedule, the deteriorating gas piping systems.
>
> PG&E's program calls for the replacement of over 2,000 miles of steel transmission and distribution lines and over 800 miles of cast iron distribution main over a 20-year period. According to PG&E, the replacement of these lines will enhance the safety and reliability of the gas piping system and will reduce leak repair expenses as high-maintenance piping is eliminated.
>
> PG&E's 20-year program is designed to dovetail with sewer and water system replacement programs underway or planned by the City and County of San Francisco. The program has also been designed to conform to meet manpower and training constraints to ensure that the work can be accomplished in a safe, efficient, and yet timely manner.[34]

The only staff objection to the proposal came from the Safety Division, seeking an expedited 15-year timetable. The Commission approved the

[34] Re Pacific Gas and Electric Company, 23 CPUC2d 149, 198-9 (D.86-12-095).

20-year plan, finding that the longer plan would not compromise public safety and would allow the gas line program to dovetail with the sewer and water replacement.[35]

In 1992, the Commission again considered PG&E's Gas Pipeline Replacement Project and determined that, heavily influenced by the 1989 Loma Prieta earthquake, natural gas pipeline replacement was an essential safety improvement. DRA raised objections that PG&E had consistently recovered greater amounts in rates for pipeline replacement costs than it had actually spent, but the Commission overruled DRA and authorized the full amount requested by PG&E:

> On this program we must agree with PG&E as to both the importance and necessity of moving forward with the gas pipeline replacement program as quickly as possible. . . . By authorizing the dollars PG&E requests for all of the accounts that deal with the gas pipeline replacement program, it is our fervent hope that PG&E actually spends the money on this program. We agree that this program is an important element of seismic safety improvement and urge PG&E to exercise due diligence in not only keeping the program on its targeted time line, but where feasible speeding up the program. Therefore, we will authorize all dollars related to the [Gas Pipeline Replacement Program] which PG&E has requested in this proceeding.[36]

The decision-making and priorities driving PG&E's pipeline safety actions in 1985 and 1992 show a different PG&E than the PG&E of the early 2000's. The 1985 plan showed PG&E thinking ahead, coordinating with local

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[35] Id. at 276.

[36] Re Pacific Gas and Electric Company, 47 CPUC2d 143, 234 (D.92-12-057).

authorities planning similar trenching work, updating meters and associated system components as part of a comprehensively planned, orderly approach to making economically sound upgrades as part of an overall system improvement plan. PG&E included "manpower and training" among its considerations, showing that it was planning to use its own employees and not outside consultants. In this way, PG&E staff would study its system and actually perform pipeline tests and replacements, thus retaining the knowledge within the organization for long-term operations and planning.

In contrast, as the Independent Review Panel pointed out, more recently PG&E's field operations and integrity management efforts were not coordinated. In 2008, the City of San Bruno undertook a project that included trenching near the location of the 2010 rupture. Properly assessing the potential threat to the natural gas pipeline from the sewer project should have revealed to PG&E that its records were inaccurate, potentially leading to further review and analysis of threats to that pipeline segment.[37]

Coordination within PG&E, awareness of outside actions, and systematically recognizing and capturing cost-effective safety enhancing opportunities is a monumental task. That task, however, is what lies before PG&E executives and employees at every level to achieve the goal of zero significant incidents.

5.1.3. A Promising Start

PG&E's analytical presentation for its Implementation Plan shows a promising start at developing a coherent engineering-based analysis and decision-making process for pipeline safety improvement. This type of analysis

is an essential foundation for bringing PG&E to the level of organization and forward-thinking safety management necessary to meet today's standards for safe natural gas transmission system operations.

In D.11-06-017, the Commission found that historic exemptions to the pipeline pressure testing requirement must end and required all California natural gas system operators to file Implementation Plans to either pressure test or replace all natural gas pipeline for which pressure test records are not available. The Commission specifically ordered that such Plans:

- Start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing.
- Reflect a timeline for completion that is as soon as practicable, and include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near MAOP values which result in hoop stress levels at or above 30% of Specified Minimum Yield Stress, and other such measures that will enhance public safety during the implementation period.
- State criteria on which pipeline segments were identified for replacement instead of pressure testing.
- Include a priority-ranked schedule for pressure testing pipeline not previously so tested, and may provide for MAOP reductions.

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[37] Independent Review Panel Report at 11 – 12.

- Consider retrofitting pipeline to allow for in-line inspection tools and, where appropriate, improved shut off valves.
- Include best available expense and capital cost projections for consideration of the improvement of safety for amount expended must be considered in prioritizing projects.

To comply with the Commission's analytical requirements, PG&E prepared its Implementation Plan Pipeline Decision Tree (Decision Tree) as well as many other supporting documents. The goals of the Decision Tree were to: establish a demonstrated margin of safety for each pipe segment with verifiable pressure test records, pipe replacement, or strength testing; have all upgraded pipelines and those operating at over 30% SMYS capable of in-line inspection; and, confirm that all existing margins of safety have not been compromised by pipe damage or degradation.[38] As described above, the Decision Tree identifies manufacturing defects, fabrication and construction defects, and corrosion and latent mechanical damage as the pipeline integrity threats to be addressed. The Decision Tree then uses the threats as a means of grouping, phasing, and prioritizing pipeline segments. PG&E's Decision Tree Flow Chart is reproduced at Attachment C.

The Decision Tree Flow Chart begins with "All PG&E Pipeline" and clearly articulates decision points to create paths for all pipelines to ultimately end up in an "action box" where specific actions are required. For example, the F2 Action Box prescribes immediate pressure reductions and replacement for pipeline constructed prior to 1960, containing certain types of now-suspect

[38] Hearing Exh. 2 at 3B-2.

components, located in a high consequence area, and operating at greater than 30% SMYS. Less urgent actions are prescribed in Action Box C1 – Phase 2 pressure testing or in-line inspection, along with close interval surveying - for pipeline that has not been previously pressure tested but is not located in a highly populated area.

PG&E's Decision Tree analysis is a promising beginning of a comprehensive decision-making process based on safety concerns related to historical pipeline manufacturing, fabrication, and testing practices. PG&E's remaining challenges, however, include bringing this level of engineering analysis to all other safety concerns, and then translating the analysis to its on-going gas system operations. This will require a long-term commitment of corporate resources to create and implement a permanent plan putting safety at the core of gas system operations, with continuous improvement and initiative.

5.1.4. Going Forward

PG&E's safety journey will require a lasting commitment to decision-making based on sound engineering analysis with implementation across all aspects of PG&E's natural gas system operations. While PG&E has presented a promising beginning, this Commission will require that PG&E diligently proceed toward the goal of zero significant events.

The record in this proceeding has brought to light three operational areas where significant and immediate action is required – PG&E's quality control, field oversight, and integration of information from on-going operations into the Integrity Management Program. Ensuring that natural gas system management is meeting quality standards and translating corporate directives into actionable information for field personnel are essential components of a safe

natural gas system. PG&E's presentation indicates that it is pursuing improvement on these topics, and others.

The record also shows serious deficiencies in PG&E's Integrity Management programs, some of which may be caused by the unreliability of its quality control and field oversight. The testing and replacement actions we order today should provide substantial and dependable input to the Integrity Management program baseline assessments. We also order PG&E to comply with the Independent Review Panel's and NTSB's recommendations for improving its Integrity Management programs.

5.2. Specific Orders

In this section, we address each project component of PG&E's Implementation Plan. We authorize an increase in PG&E's gas operations revenue requirement by granting PG&E's request to revise its tariffs to add a new rate component to the customer class charge for gas transportation for all core and noncore customers. The forecasted amounts to be recovered are: $14,019,000 in 2012; $103,801,000 in 2013; and $159,984,000 in 2014. The total for the three-year period is $277,805,000.

5.2.1. Comprehensive Disallowance of All Implementation Plan Costs

As set forth above, DRA and TURN recommend that the Commission comprehensively disallow all Implementation Plan costs, and specifically: (1) order PG&E to complete its Implementation Plan, with some modifications, and (2) disallow ratemaking recovery of all costs PG&E incurs for completing the Plan. DRA's objections to cost recovery center on the theory of test year ratemaking; that is, between general rate cases shareholders bear any unexpected costs. TURN presents a different argument to support its recommended comprehensive disallowance. TURN contends that the

Implementation Plan costs are the result of PG&E's imprudent operation of its natural gas transmission system, and that shareholders should bear these costs. TURN points to Pub. Util. Code § 463 as requiring the Commission to disallow all costs associated with the Implementation Plan.

PG&E opposes both these recommendations and contends that the new safety measures ordered in D.11-06-017 could not have been forecast by PG&E in its last Gas Transmission and Storage General Rate Case, which covered gas system costs from 2011 through 2014 and was approved by the Commission in D.11-04-031.[39] PG&E explains that the new safety measures are not routine costs that a public utility would be expected to absorb between rate cases as part of traditional test year ratemaking.[40] PG&E noted that the factors the Commission considers when evaluating a request for a post-test year ratemaking adjustment all focus on whether the utility could and should have included the cost in the test year forecast. Here, PG&E contends, it did not and could not have anticipated the substantial new safety investments required by D.11-06-017 when finalizing the gas rate case settlement. PG&E offered as an example the Commission's treatment of the costs for a new program to install advanced electric metering as a post-test year revenue requirement adjustment that is similar to the costs of the Implementation Plan.[41]

We find that the evidentiary record does not support DRA's request for a comprehensive disallowance of all Implementation Plan costs. While DRA

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[39] This decision is referred to as the Gas Accord V decision and approves a settlement agreement among the parties.

[40] PG&E Opening Brief at 66 - 70.

[41] Id.

correctly recites the general rule that post-test year ratemaking is inconsistent with our ratemaking principles, the scope and magnitude of the costs at issue here sufficiently justify deviation from the general rule, and we, therefore, deny DRA's global request. TURN's prudence argument warrants a more detailed analysis.

It is beyond dispute that the Commission has the authority to disallow ratemaking recovery for costs imprudently incurred by California's public utilities. As set forth above, Pub. Util. Code § 451[42] requires that all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate except upon a showing before the commission and a finding by the commission that the new rate is justified.

Here, TURN contends that PG&E has failed to meet its burden of demonstrating the reasonableness of the Implementation Plan because a prudent natural gas system operator would have previously made the improvements contained in the Plan. TURN does not argue that PG&E has previously received ratepayer funding for the activities contemplated by the Implementation Plan and not preformed the approved tasks. Similarly, TURN does not contend that PG&E's Implementation Plan proposed expenditures are completely unnecessary, although TURN does take issue with certain expenditures. TURN's argument here is that PG&E should have made these improvements previously, and TURN does not contest that such costs would likely have been included in revenue requirement at that time. Because PG&E had a pre-existing obligation to

[42] Unless otherwise stated, all citations are to the Public Utilities Code.

institute these improvements, TURN concludes that PG&E's proposal for ratepayers to fund these improvements now is unreasonable.

We do not agree that the Public Utilities Code or Commission precedent support the proposition that due to belated timing, the cost of safety improvements by a public utility become unreasonable and subject to ratemaking disallowance.

TURN argues that PG&E's imprudence and managerial failure was the decision *not* to make these needed safety improvements at an earlier date. We find no case law or statute supporting the assertion that such a failure to act timely could render the currently proposed expenditures unreasonable. As discussed below, however, such management imprudence does provide an evidentiary basis for a reduction in Return on Equity due to management ineptitude. From a ratemaking perspective, PG&E's ratepayers have not been subject to unreasonable costs; rather, as a result of needed but not performed safety improvement projects, ratepayers ended up paying rates lower than may have been reasonable due to the absence of the needed projects. The public utility code standards for rate recovery, i.e., just and reasonable, and the disallowance concept reflected in § 463 do not combine to provide an analytical basis for disallowing reasonable costs on the basis that the utility should have made the expenditures at an earlier date.[43]

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[43] In D.94-03-048, 53 CPUC 2d 452, 477, the Commission disallowed rate recovery for costs stemming from the catastrophic 1985 accident at the Mohave Power Plant. If, hypothetically, Edison had owned a second similar plant and sought Commission authorization and ratemaking approval to make the needed safety improvements at the second plant, the reasonableness standard would not support a disallowance of those costs. Those needed safety measures, although belated, would have met the standard of a just and reasonable expense and would not be subject to disallowance based on the

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As set forth above, section 451 of the public utility code requires that public utility rates be just and reasonable, and section 463 states that costs associated with an "unreasonable error or omission relating to planning, construction, or operation" of utility plant be excluded from revenue requirement. For example, where PG&E had an obligation to test pipeline and has lost records of such pressure test records, PG&E must remedy the missing records by retesting. The cost of such retesting is unreasonable because ratepayers funded the first test, and PG&E unreasonably failed to retain the records.

In contrast, TURN is correct that PG&E's request for ratemaking recovery of its document management expenses offends the just and reasonable standard because PG&E had not only a pre-existing obligation to maintain records of its facilities but it also had sought and obtained ratemaking authorization to recover from ratepayers the costs associated with the record maintenance. PG&E is now seeking cost recovery for remedial document management costs that stem from its previous failure to prudently perform its document management duties. These current costs are unreasonable because PG&E should not have had to incur them, not because they should have been done at an earlier date. We discuss in more detail below our rationale for disallowing PG&E's proposed document management costs.

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objection that the measures should have been taken at an earlier date. In contrast, a different result would occur if the hypothetical were changed to have Edison previously obtaining ratepayer funding to make the safety improvements but not performing, and then later seeking ratepayer funding for second time.

Therefore, for the reasons set forth above, we deny DRA's and TURN's requests for a comprehensive disallowance of all Implementation Plan costs.

5.2.2. Adopted Amounts for PG&E's Implementation Plan

In the following subsections, we address each significant component of PG&E's Implementation Plan. As explained in this section, we approve PG&E's Implementation Plan subject to the following:

- PG&E's request to include the costs for pressure testing post-1955 pipelines in revenue requirement is denied;
- PG&E's request to include the costs for the gas system records integration program in revenue requirement is denied,
- The risk of cost overruns is assigned to shareholders,
- PG&E's return on equity is reduced to the incremental cost of debt for capital costs incurred as part of the Implementation Plan for five years.

5.2.2.1. Pipeline Modernization Program

In this section we address the issues related to the Pipeline Modernization Program, which includes pressure testing, replacement, inline inspection, and valves. We find that costs to pressure test pipeline installed between 1956 and 1961 should not be included in revenue requirement, that pipeline segments located in Class 2 areas should be delayed to Phase 2, and that PG&E's proposed pressure testing program is reasonable.[44]

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[44] We also note that projects approved today may displace projects planned and authorized as part of PG&E's Integrity Management Program in the Gas Accord V

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Pressure Testing

PG&E requests a total of $271.9 million in 2012, 2013, and 2014 to pressure test 783 miles of pipeline. The parties have raised three significant issues with regard to PG&E's proposed pressure testing: (1) cost responsibility for 1956 to 1961 pipeline with missing pressure test records, (2) excessive forecasted pressure testing costs, and (3) failing to test to 90% SMYS.

DRA opposes ratepayer responsibility for pressure testing transmission pipeline installed after 1935. DRA argues that industry standards in effect since 1935 required any prudent natural gas transmission system operator to pressure test pipelines before placing the lines in service and to retain records of construction, testing, and maintenance on those lines. DRA concludes that all pressure testing costs for lines installed after 1935 should be assigned to shareholders.

TURN agrees with DRA's proposition that PG&E's responsibility to pressure test and retain records begins well before PG&E's proposed date of 1961, but TURN contends that the cut-off date is 1955. TURN points to American Standards Association Code for Pressure Pipeline (ASA B31.8) as establishing in 1955 the industry standard of pre-service pressure testing for natural gas pipeline. TURN explains that PG&E's avowed practice was to follow this industry standard from 1955 on, but that PG&E now cannot find records of those tests.[45] TURN concludes that the cost of pressure testing now needed to bring PG&E pipeline installed in or after 1955 into compliance with the 1955 standard

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decision. That decision provides for a one-way balancing account for unspent Integrity Management costs, which will thereby be returned to ratepayers.

[45] Hearing Exh. 31 at 75 - 77.

should be assigned to shareholders. TURN estimates that pressure testing approximately 90 miles of 1956 to 1961 pipeline accounts for $45 million of testing expense. TURN applies a similar rationale for pipeline of that vintage which PG&E's proposed decision tree determines should be replaced, and recommends disallowance of $81 million in costs for replacing 18 miles of 1956 to 1961 pipeline.

PG&E states that while it began to follow the industry guidelines in 1955, it did so on a voluntary basis rather than due to a legal or regulatory requirement. Because it was not required to perform pre-service pressure tests from 1955 to 1961, PG&E posits that ratepayers should fund pressure testing for any pipeline placed into service during that time for which PG&E cannot locate pressure test data. PG&E summarizes its position: even though it may have "lost, destroyed, or misplaced" some of its records, it was able to prudently operate its natural gas transmission system by relying on the historical exemption in subpart J, thus the newly required pressure testing or replacement should be at ratepayers expense.[46]

We find that where PG&E undertook or stated that it undertook to comply with industry standards but no longer possesses the records of such compliance, the costs of retesting required by the missing records is a result of an error in PG&E's operation of its natural gas transmission system. Where PG&E's record retention errors have led to re-testing pipeline installed between 1955 and 1961, the costs of such re-testing is not a just and reasonable cost of providing

[46] PG&E Reply Brief at 8.

public utility service. Such costs, therefore, should be excluded from authorized revenue requirement to be recovered from ratepayers.

The evidentiary record supports the factual finding that from 1956 on, PG&E's practice was to comply with then-applicable industry standards for pre-service pressure testing, and that retaining records of such testing was part of the industry standard. As it was PG&E's practice to incur these pre-service test costs, we would expect that absent unusual circumstances such costs would be included in revenue requirement and recovered from ratepayers. No evidence has been presented to suggest that the cost of the 1956 to 1961 testing was excluded from revenue requirement. We, therefore, find that the preponderance of the evidence supports the findings that from 1956 to 1961: (1) PG&E's practice was generally to pressure test natural gas pipeline before placing the pipeline into service, with record retention being part of the practice, and (2) the costs of such pressure testing were included in revenue requirement recovered from ratepayers. We further find that if PG&E had competently retained the pressure test records for pipeline installed from 1956 to 1961, we would have evidence that such pressure tests did, in fact, occur and this pipeline would not be included in the Implementation Plan.[47]

Now, in response to D.11-06-017, PG&E is required to pressure test or replace all applicable natural gas transmission pipeline in its system. PG&E is unable to locate records of some of its previous testing for the 1956 to 1961 pipeline, and requests Commission authorization to include the cost of re-

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[47] See Conclusion of Law 3 in D.11-06-017 defining pre-1961 pressure test requirements. Notwithstanding compliance with historic standards, PG&E should evaluate these pipeline segments in later Phases of the Implementation Plan.

testing this pipeline in revenue requirement. PG&E argues that because it was not legally required to pressure test these pipeline segments previously, even though it did so in compliance with industry practices, the directive in D.11-06-017 justifies allocating the cost of the re-testing to ratepayers.

We do not agree that the change from an industry practice to regulatory mandate somehow excuses PG&E's failure to retain the pressure test records. As noted above, the record supports the finding that PG&E stated that from 1956 on, PG&E's practice was to pressure gas system test pipeline prior to placing it in service and that the costs of such testing was passed on to ratepayers. As required by industry practice and prudent natural gas transmission system operations, PG&E should have created and maintained records of those pressure tests. The absence of the records for the 1956 to 1961 pipeline now brings these pipeline segments into the Implementation Plan for re-testing or replacement. Having paid for such testing once, the ratepayers should not be required to pay for re-testing due to PG&E's failures in document management.

For pipeline determined to be in need of replacement, ratepayers should similarly be relieved of the obligation to pay for retesting, but not for complete replacement. That is, absent PG&E's poor document management, ratepayers would not have been required to pay for retesting the 1956 to 1961 pipeline. Certain pipeline segments, for reasons unrelated to PG&E's poor document management, require replacement, rather than just re-testing.[48] PG&E

[48] As discussed in more detail below, some pipeline segments have features, such as now-suspect welds, that when combined with age of the pipeline and operating

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shareholders should be held to their obligation for re-testing costs, but not extended to replacement costs. Shareholders should not be excused from their duty to pay the costs of re-testing, and ratepayers should not receive a new pipeline at no cost. Thus, shareholders will be allocated the costs of retesting pipeline installed in 1956 to 1961; and where such pipeline is scheduled for replacement, the estimated cost of pressure testing will be recorded as an equitable adjustment to reduce the replacement costs included in revenue requirement and recovered from ratepayers. In this way, PG&E's shareholders meet their obligation caused by management's protracted failure to retain the missing records while ratepayers fund the remaining pipeline replacement costs. We order similar treatment for pipeline installed after 1961, lacking pressure test records, and scheduled for replacement, rather than pressure testing, in Phase 1.

In conclusion, we hold that for pipeline segments installed after 1955 or for which PG&E does not know the installation date, and where PG&E cannot produce pressure testing documentation, the cost of pressure testing these segments now is not a just and reasonable cost of providing public utility service and we deny PG&E's request to include these costs in revenue requirement for recovery from ratepayers. Where such segments, and any segments installed after 1955 similarly lacking pressure test records, require replacement, rather than pressure testing, we grant PG&E's request to include in revenue requirement for recovery from ratepayers replacement costs but only to the extent the replacement costs exceed the estimated cost of pressure testing the segment.

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pressure, support replacement rather than pressure testing based on sound safety engineering.

DRA argues that PG&E's forecasted costs for pressure testing are too high.

DRA presented testimony developed by an outside expert setting forth cost estimates for fixed costs per test and variable cost per foot of pipeline tested. As shown below, DRA's cost forecasts were substantially lower than PG&E's:

Cost Item	DRA	PG&E
Variable Cost – 12″ and under ($/ft)	$8	$30
Variable Cost – 14″ to 20″ ($/ft)	$12	$39
Variable Cost – 22″ to 28″ (4/ft)	$19	$45
Variable Cost – 30″ to 42″ ($/ft)	$37	59
Fixed Cost – Fabricate Test Header	$0	$15,000 to $40,000
Fixed Cost – Move Around/Test Section Charge	$44,700 to $76,700	$200,000 to $500,000
Fixed Cost – Mob/demob	$85,600 to $139,400	$500,000

For comparison purposes, set out below are the total costs for a 2,500 foot length pressure test for both a 12″ diameter pipeline and a 36″ diameter using DRA's and PG&E's costs forecasts:

Comparison of DRA and PG&E Pressure Testing Cost Forecasts		
	DRA	**PG&E**
12″ pipeline, 2,500 feet	$150,300	$790,000
36″ pipeline, 2,500 feet	$308,600	$1,187,500

Thus, PG&E's pressure test cost forecasts are more than triple DRA's estimates. TURN also presented pressure test cost estimates per mile of

$29,700 to $40,000.[49] TURN's cost estimates are from 2001, and thus of limited evidentiary value due to the passage of time.

PG&E responded that its pressure testing cost estimates were developed based on actual cost data from pressure tests of its gas system analyzed by experienced engineers. PG&E pointed out that DRA's costs estimates do not include pre-cleaning pipeline, which DRA's expert claimed to be regular maintenance, but which PG&E claims is actually unusual for a natural gas transmission and distribution system.[50] PG&E similarly dismissed DRA's reliance on pressure testing cost estimates in sets of industry data as showing very broad cost ranges and lacking detail on the diameter of pipeline tested, test medium, and average test length.[51]

We agree that DRA's analysis is insufficient to overcome PG&E's actual cost experience of pressure testing natural gas pipeline in its natural gas system. We, therefore, authorize PG&E to include in revenue requirement the forecasted costs of its natural gas transmission pipeline pressure testing projects as requested in the Implementation Plan.

We find, however, that DRA's analysis is sufficient to demonstrate that PG&E's cost forecasts for pressure testing natural gas pipeline are much higher than industry-based estimates. As the two examples above show, PG&E's cost estimates are more than triple DRA's. Therefore, we conclude that the record shows that PG&E's cost forecast for pressure testing natural gas transmission pipeline falls in the high end of the range of

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[49] Hearing Exh. 131 at 81 – 82.

[50] PG&E Opening Brief at 26.

[51] Id. at 27.

reasonableness. We will use this conclusion, and our similar conclusion for PG&E pipeline replacement costs, to inform our analysis of PG&E's request for an overall 20% contingency adder.

TURN also challenged PG&E's determination that a valid hydrotest record from 1961 to 1970 must include the name of the operator. TURN cited to D.11-06-017 as requiring records of a valid pressure test consistent with regulations in effect at the time of the test.[52] PG&E counters that while then-effective pressure test regulations did not require an operator's name, such information is "necessary to ensure accountability" for the test.[53]

We agree with PG&E that the operator name adds value to the pressure test record and is required by current PHMSA regulations.[54] Such information, however, was not required by the regulations in effect at the time for pressure tests performed between 1961 and 1970. Thus, consistent with D.11-06-017, we find that pressure test records for tests performed between 1961 and 1970 need only contain the information required by the then-applicable regulations to be valid pressure test records for purposes of inclusion in PG&E's Implementation Plan.

TURN also proposes that all pipeline segments be pressure tested to 90% Specified Minimum Yield Strength (SMYS)(the pressure level at which the pipe would undergo permanent deformation). PG&E explains that pressure testing to this very high level is not required by federal subpart J regulations for existing pipeline, which require up to 150% of MAOP for that pipeline. PG&E

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[52] TURN Opening Brief at 25.

[53] PG&E Reply Brief at 66.

[54] See 49 CFR § 192.517(a)(1).

states that it uses the 90% SMYS standard for new pipeline, and that this is practical because new pipeline would typically have a uniform SMYS. In contrast, PG&E contends, its existing pipeline often is comprised of pipe with a variety of characteristics with no uniform SMYS. Consequently, PG&E argues, pressure testing to 90% SMYS for each portion of an existing pipeline is impractical and unnecessary, which is why the industry and PG&E pressure testing rules allow existing pipeline to be tested based on its actual maximum allowable operating pressure, plus a margin of safety. TURN acknowledges the practical difficulty with its proposed 90% SMYS standard in its brief.[55] PG&E contends that little safety improvement is gained by increasing the pressure level tested to 90% SMYS, which might be two or three times the maximum operating pressure. PG&E also notes that bringing each pipeline component up to 90% SMYS would greatly increase costs.

We find that federal regulations in 49 CFR subpart J pressure testing protocols provide for a margin of safety based on the MAOP of the pipeline to be tested. The 90% SMYS standard TURN advocates creates serious practical problems, which TURN admits. We find, therefore, that PG&E has established by a preponderance of the evidence that the 49 CFR subpart J pressure testing protocols are reasonable to use in its pressure tests.

TURN recommends deferring from Phase 1 to Phase 2 pressure testing or replacement of pipeline segments located in Class 2 locations.[56] TURN

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[55] TURN Opening Brief at 41.

[56] PHMSA regulations define the four class locations by number of human-occupied buildings located within 220 yards of the pipeline: Class 1, 10 or fewer buildings; Class 2, 10 to 45 buildings; Class 3, 46 or more buildings, or with a place of public

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explains that D.11-06-017 requires PG&E to begin its work with pipeline located in densely populated places, i.e., Class 3 and 4 locations and High Consequence Areas of Class 1 and 2 locations, but that PG&E has also included significant amounts of Class 2 locations that are not High Consequence Areas. TURN recommends that these less densely populated areas be moved to Phase 2.

PG&E responds that when it prepared its Implementation Plan, it included pipeline segments adjacent to segments within the specified scope to determine if cost and construction efficiency could be achieved by doing the adjacent Class 2 segments as part of Phase 1 of the Implementation Plan. PG&E gave particular attention to such pipeline operating at over 30% SMYS. PG&E states that to go back and pressure test or replace these pipeline segments could increase costs and delayed completion of the overall program.[57]

PG&E has presented a valid justification to evaluate Class 2 locations adjacent to Class 3 locations and determine whether including these segments in Phase 1 would be economically more efficient or decrease customer interruptions such that these segments should be included in Phase 1 and not deferred to Phase 2. In rebuttal testimony at 3-15 to 3-17, PG&E states that it looked at "adjacent pipeline segments as well" and explains that going back to pressure test or replace "adjoining pipe segments at a later time" would lead to increased costs.

In D.11-06-017, the Commission directed PG&E to "start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and

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assembly; and, Class 4, where buildings with four or more stories are prevalent. 49 CFR § 192.5

[57] PG&E Reply Brief at 54.

Class 2 high consequence areas, with pipeline segments in other locations given lower priority."[58] Accordingly, the general rule is that pipeline segments in Class 1 or 2 locations will not be included in Phase 1. We recognize exceptions to this general rule where, for sound engineering or economic reasons, pipeline segments not located in the priority locations should nevertheless be included in Phase 1. Pipeline segments adjacent to priority locations logically fit within such exceptions. Thus, we find that to the extent a pipeline segment is located in a Class 1 or 2 area but is adjacent to Class 3 or 4 locations, PG&E properly included the Class 1 or 2 segments in Phase 1. In this way, the priority location drives the project and the lower priority work is only included where efficiency or other engineering rationale supports extending the project beyond the priority location. Pipeline segments in Class 2 or Class 1 locations which are not high consequence areas, or adjacent to Class 3 or 4 locations or high consequence areas, must be deferred to Phase 2 of the Implementation Plan.

5.2.2.2. Pipeline Replacement, In-Line Inspection Retrofits, and Valve Automation

Pipeline Replacements

PG&E proposes to replace 185.5 miles of mostly older pipeline at a total cost of $818.7 million during 2012, 2013 and 2014. All of these costs will be capitalized.

As set forth above, the authorized revenue requirement for replacing pipeline installed after 1956 for which PG&E does not have pressure test records will be reduced by the estimated cost of pressure testing that pipeline. Similarly, pipeline replacements for some Class 2 locations may be

[58] D.11-06-017 at Ordering Paragraph 4.

deferred to Phase 2. This reduction and deferral will reduce the total pipeline replacement costs in the Implementation Plan Phase 1.

DRA and TURN challenge PG&E's proposed pipeline replacement costs as excessive. DRA presented a thorough analysis of PG&E's proposed estimates for pipeline replacement costs, and based on this analysis recommended a 20% disallowance. DRA's and PG&E's pipeline replacement cost estimates priced the pipeline replacement based on the project area's residential and commercial development and divided the project areas into three categories of "congestion." Pipeline replacement projects in open desert or agricultural areas are categorized as "non-congested" and have the lowest cost due to minimal need to dig through or under a road. In small towns or outskirts of larger towns where pipeline is placed in existing right of way, with some road drilling and repair, the area is termed "semi-congested." Finally, areas with extensive residential or commercial development where heavy road drilling and repair, and where pipeline is placed under existing roads or parking lots, are categorized as "heavily congested." Generally, the higher the level of congestion the higher the costs for pipeline replacement.

For comparison purposes, set out below are the costs estimates for the middle level of congestion – "semi-congested" – presented by DRA and PG&E.

COMPARISON OF PIPELINE REPLACEMENT COST ESTIMATES FOR SEMI-CONGESTED AREAS ($/ft)			
Diameter of Replaced Pipe (inches)	DRA[59]		PG&E[60]
	UC Davis Study	Pacific Northwest National Laboratory	
10	$406	$370	$489
16	$492	$494	$618
24	$659	$648	$841
36	$1,007	$1,098	$1,253

DRA emphasizes that its estimates include contingency and management costs, which PG&E separately adds on to its base cost estimates.[61] DRA recommends that PG&E's forecasted pipeline replacement base costs be reduced by 20% before inclusion in revenue requirement.

DRA points to the $22.6 million "Peninsula Adder" which PG&E layers on to six pipeline replacement projects on the San Francisco peninsula as further documentation of PG&E's efforts to over-state its replacement costs. DRA explains that PG&E already categorizes pipeline by location, as described above, and has not justified this additional cost component for the San Francisco peninsula. In rebuttal, PG&E explained that the Peninsula Adder reflects the high cost of pipeline replacement in those areas due to: (1) congestion, (2) lack of third party utility records, and (3) permitting.[62]

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[59] Hearing Exh. 147 at 3 – 8.

[60] Hearing Exh. 2 at 3E-15.

[61] DRA Opening Brief at 95.

[62] Hearing Exh. 21 at 3-32.

PG&E counters the attacks on its cost forecasts by stating that PG&E alone has constructed 940 miles of natural gas pipeline in California over the past 20 years and that its forecasts are based on actual experience, rather than DRA's reliance on academic publications.[63]

We agree that DRA's analysis is insufficient to overcome PG&E's experience with the cost of natural gas pipeline construction. We, therefore, authorize PG&E to include in revenue requirement the forecasted costs of its natural gas transmission pipeline replacement projects as requested in the Implementation Plan. This excludes Class 2 locations deferred to Phase 2 and requires the cost offset for pressure testing post-1956 pipeline with missing records from the requested $818. 7 million in capital costs.

DRA's analysis is sufficient, however, to support a finding that PG&E's cost forecasts fall in the high end of the cost range. On average, PG&E's cost estimates are about 20% higher than DRA's. This cost increment, however, does not account for the different treatment of management and contingency costs in the two sets of estimates. DRA's cost estimates include management and contingency costs, which can be significant, and PG&E's base cost estimates do not include management and contingency costs, which are treated as separate line items in the final revenue requirement analysis. Thus, DRA's cost estimate is much less than PG&E's final total cost for replacing natural gas pipeline. Therefore, we conclude that the record shows that PG&E's cost forecast for replacing natural gas transmission pipeline falls in the high end of the range of reasonableness, and that PG&E has used its experience with natural gas

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[63] Id. at 3-39.

transmission pipeline construction to identify the need for and include allowances for additional foreseeable costs. We will use this conclusion, and our similar conclusion for PG&E pressure testing cost forecasts, to inform our analysis of PG&E's request for an overall 20% contingency adder.

TURN takes a different approach to challenging PG&E's pipeline replacement costs as excessive, and argues that most of the costs should be absorbed by PG&E's shareholders, not recovered from ratepayers due to PG&E's imprudent management. TURN argues that PG&E violated its Transmission Integrity Management Program by relying on direct assessment to evaluate external corrosion and third party damage risk, rather than using in-line inspection or pressure testing to assess manufacturing or construction defects.[64] The City and County of San Francisco similarly argues that federal Integrity Management regulations required PG&E to assess its pipeline for manufacturing and construction defects and that PG&E improperly used direct assessment due to its lower cost rather than in-line inspection or pressure testing.[65]

TURN contends that the costs of replacing 42 miles of pre-1956 pipeline and pressure testing another 177 miles should be assessed to PG&E shareholders due to PG&E's imprudent implementation of the Integrity Management program. TURN argues that PG&E should have pressure tested or in-line inspected these pipeline segments as part of its Baseline Assessment Plan required by federal Integrity Management regulations.[66] TURN concludes that

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[64] TURN Opening Brief at 86.

[65] City and County of San Francisco Opening Brief at 39 – 41.

[66] 49 CFR § 192 Subpart O – Gas Transmission Pipeline Integrity Management.

but for PG&E's imprudent decision to forgo pressure testing or in-line inspection, this work would be completed.

As discussed elsewhere in today's decision, the Independent Review Panel and the NTSB have questioned the efficacy of PG&E's Integrity Management Program. For ratemaking purposes, however, it is not clear how PG&E's failure to perform certain types of pipeline assessment in the past, even if an imprudent decision, justifies disallowing ratemaking recovery for the currently proposed pipeline assessment. TURN is not arguing that PG&E obtained ratepayer funding for the more expensive pressure testing, but opted instead to actually perform less-expensive direct assessment. Delay in implementing needed safety expenditures does not render the current expenditures imprudent and thus subject to disallowance, as we have set forth in detail previously. Therefore, we deny the requested disallowance of TURN and the City and County of San Francisco.

TURN also opposes including $81 million in capital costs to replace 18 miles of pipeline that was installed between 1956 and 1960. TURN argues that this pipeline should have been tested prior to being placed into service and the testing records retained by PG&E. If PG&E had properly retained the records, TURN reasons, these replacements would not be needed now.

TURN also challenges PG&E's proposal to replace, rather the pressure test, all pipeline segments that have certain types of welds and operate at high pressure in heavily populated areas. These pipeline segments end up in

the M2 box on the decision tree flow chart.[67] TURN opposes PG&E's proposed replacement as the default treatment for pipeline in the M2 box on the decision tree. PG&E counters that pipeline segments assigned to the M2 Action Box must be older than 1970, not pressure tested, have welds that do not meet current engineering standards, and operate at or above 30% SMYS in a high consequence area. PG&E concludes that pressure testing is not adequate for pipeline with this cluster of characteristics. The M2 Action Box includes 100 miles of pipeline with an estimated replacement cost $450 million.

The magnitude of PG&E's proposed replacement costs for the M2 Action Box require that we carefully consider TURN's argument that lower-cost pressure testing may be a sufficient treatment for pipeline in this Action Box. PG&E's testimony and decision tree set forth the features that must all be simultaneously present to bring pipeline segments to the M2 Action Box. These segments must have both substandard welds and be operated at high pressures. This means that the probability of manufacturing defects is increased and that if the segment fails, it will fail with a rupture, rather than a leak, in a highly populated area. The increased probability of a manufacturing defect in the now-suspect welds, coupled with the potentially catastrophic failure mode, counsels us that, while expensive, PG&E has justified the cost of replacing these pipeline segments. We, therefore, deny TURN's request that PG&E's proposed decision tree be modified and the costs associated with the M2 Action Box be disallowed.

In-line Inspection Costs

We next turn to in-line inspection costs. PG&E estimates that it will spend $38.8 million for pipeline retrofits to enable in-line inspection in 2012,

[67] The decision tree flow chart is reproduced as Attachment C to today's decision.

2013, and 2014. Of this amount, $29.2 million will be capitalized and $9.6 million will accounted for as expense.

DRA challenges PG&E's analytical process to arrive at the need to perform these retrofits and additional in-line inspection runs, as well as PG&E's cost forecasts. DRA contends that PG&E has presented no justification for including these additional in-line inspection costs in Phase 1 because PG&E's decision tree does not produce any outcomes requiring these actions. DRA also notes that PG&E's cost forecasts are equally unsupported.

PG&E explains that in-line inspection means that a cylindrical-shaped inspection tool is inserted into and passed through the interior of a pipeline segment, and then retrieved at the end of the inspection run. The tool has hundreds of sensors that obtain data on pipeline conditions including indentations, wall loss, pipe strain, metallurgical variations, and various types and shapes of cracks.[68] PG&E explained that in-line inspection is useful to identify, locate, and remove excessive pups, miter bends, and wrinkle bends. PG&E states that its overall objective is that all its gas transmission pipeline operating at 30% SMYS or greater be capable of accommodating in-line inspection. As of the end of 2010, about 17% of PG&E's pipeline operating at that pressure was capable of in-line inspection and PG&E intends to increase that percentage to 22% by the end of 2014. PG&E is also incorporating improvements

[68] These tools are referred to colloquially as "pigs" with the more advanced models described as "smart pigs," and pipelines through which these tools can pass are described as "piggable."

for in-line inspection as part of the pressure testing, valve automation, and replacements in its Implementation Plan.[69]

In D.11-06-017, the Commission addressed in-line inspection and valve improvements as an adjunct to the high priority pressure testing and replacement objectives. Accordingly, DRA is correct that the Commission has not issued an absolute order that PG&E increase its in-line inspection activities. The Commission did, however, recognize that in-line inspection has an important role in the overall operation of a natural gas transmission system, and should be considered as part of a large-scale capital project such as the Implementation Plan. We further note that increased in-line inspection is particularly useful when, as here, the validity of system records is in question. For overall budget comparison, PG&E explained that from 2005 to 2009 it spent over $100 million on in-line inspection retrofitting, and it seeks $38.8 million for three years with this current proposal.

We find that PG&E has justified its proposal to increase its in-line inspection program by $38.8 million. The proposal incrementally expands PG&E's existing in-line inspection program, focuses on the pipeline segments operating at higher pressures, and is consistent with our directive in D.11-06-017 to consider increased use of in-line inspection tools. We approve PG&E's cost forecasts subject to the one-way balancing account requirement and the disallowances elsewhere in today's decision.

Valve Automation Proposal

PG&E proposes to replace, automate, and upgrade 228 valves in Phase 1 of the Implementation Plan. PG&E states that these 228 valves will

[69] Hearing Exh. 2 at 3-26 to 3-29.

improve safety by increasing emergency preparedness, and may reduce property damage and danger to emergency personnel and the public in the event of a pipeline rupture. PG&E pointed to recent California legislation and a long-standing NTSB recommendation for automated valves in urban areas with high-pressure natural gas pipelines.[70]

PG&E states that it will design its automated valves to be capable of operation as either remotely controlled by personnel in the gas system control room, or by automatic control where sensors will set to close the valve without further action by PG&E personnel. PG&E plans to operate most valves by remote control due to concern about a valve automatically but erroneously closing under non-rupture circumstances. PG&E presented detailed testimony on the system and customer impacts from unnecessary gas line closures. PG&E plans to use fully automatic valves only on earthquake fault crossings at this time, but will continue studying fully automated valves and may convert some of the remote controlled valves in the future.[71]

PG&E estimates that the overall valve program for Phase 1 will cost $128.3 million which PG&E requests authorization to include in revenue requirement. This total is comprised of $118.8 million to be capitalized and $9.5 million in expenses for 2012, 2013, and 2014.[72]

The City of San Bruno supports automated valves, with manual override options to forestall unnecessary closures.[73] TURN recommends more

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[70] Hearing Exh. 2 at 4-30 to 4-33.

[71] Hearing Exh. 2 at 4-25.

[72] Hearing Exh. 2 at 4-7.

[73] City of San Bruno Opening Brief at 5.

automatic shut-off valves rather than remote-controlled valves to reduce response time. TURN also took issue with PG&E's approach to prioritizing pipelines for valves, which is based on the potential impact radius from a rupture. TURN, instead, recommended using the diameter of the pipeline, with all pipeline 24 inches or more in diameter being eligible for valves. DRA found PG&E's valve program proposal to lack a sufficiently detailed rationale for immediate implementation and DRA recommends limiting PG&E's valve program to upgrading existing valves and installing new valves only on active earthquake faults.[74]

We find that PG&E has provided detailed analysis of the basis for its proposed valve program and has justified the forecasted Phase 1 expenditures. We share the parties' objective of reliable and automatic shut-off valves. We direct PG&E to continue its review of new designs and operational options to allow for expanded use of automated valves. In its next rate case, PG&E must submit an updated showing of then-current best practices within the natural gas pipeline industry for automated shut-off valves. PG&E must also continue to improve its gas system control room operation due to the critical role it plays in addressing a rupture or functioning as the manual override on automatic valves. PG&E must avoid unnecessarily complicating natural gas system operations with unpredictable technology but obtain all useful safety benefits from technology, and at the same time develop knowledgeable and fast-acting human operational control to enhance system safety. The Independent Panel recognized that remote controlled and/or automated shut-off valves are a

[74] DRA Opening Brief at 124.

major issue for the pipeline industry, with the safety and reliability trade-offs discussed at length in Appendix L to their report.[75] PG&E should monitor the development of this issue in the pipeline industry.

Interim Safety Measures

No party objected to PG&E's proposed interim safety measures of pressure reductions and increased patrols of pipeline, at an estimated total cost of $3.2 million for 2012, 2013, and 2014. Similarly, PG&E's proposed $30.2 million total cost for extra management of the Implementation Plan programs was not disputed as a separate line item. We, therefore, approve these requested elements.

Pipeline Segments Less than 50 Feet in Length

PG&E proposes to capitalize all pipeline replacements, including replacement pipe less than 50 feet in length. PG&E states that where a pipe segment less than 50 feet in length is part of a maintenance project, the pipe is expensed for accounting efficiency.[76] PG&E explains that it considers the entire Implementation Plan to be one project so that all capital portions of the project will be capitalized. DRA contends that PG&E should adhere to its usual accounting rules for the Implementation Plan. We find that PG&E has not justified this deviation from its standard accounting rules. We will, therefore, require PG&E to continue to expense replacement pipe less than 50 feet in length.

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[75] Appendix L is viewable at http://www.cpuc.ca.gov/NR/rdonlyres/5CF0591F-E4B8-4CB4-9325-3DFE1B790A5A/0/AppendixL.pdf.

[76] Hearing Exh. 21 at 17-16.

Capital expenditures should be reduced by $213,000 in 2012, $649,000 in 2013, and $875,758 in 2014, and expenses increased a corresponding amount.[77]

Allowance for Funds Used During Construction

PG&E agrees to correct its error and to remove an allowance for funds used during construction for pressure test job estimates.[78]

Useful Life for Pipeline

PG&E used its existing term of 45 years as the depreciable life for gas transmission mains installed pursuant to the Implementation Plan. TURN recommends 65 years as depreciable life, and states that 68% of PG&E's existing transmission pipeline is older than 40 years, with 47% older than 50, and that the new pipeline can be expected to last substantially longer than the existing.[79] TURN also noted that SoCalGas has proposed to increase its transmission main service life from 55 to 57 years in its current rate case. PG&E objected to the piecemeal approach to service life for gas transmission plant in service, and asked the Commission to require a deprecation study in the next rate case to make an overall determination.[80]

We find that TURN's argument and the record in this proceeding justify increasing the service life of gas transmission mains from 45 years to 65. The new pipeline will be manufactured to higher standards and pressure tested prior to going into service. This supports a conclusion that service life will be extended significantly. While we share PG&E's preference for a depreciation

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[77] Hearing Exh. 21 at 17-17.

[78] Hearing Exh. 21 at 3-47

[79] TURN Opening Brief at 126 – 127.

[80] PG&E Reply Brief at 46.

study, waiting until the next rate case to make this adjustment is not feasible given the scope and magnitude of the Implementation Plan. Therefore, we find that the depreciable life of all natural gas transmission mains installed pursuant to the Implementation Plan shall be recorded as 65 years. To the extent PG&E is required to create a sub-account in its plant records to show this modified amount, we authorize such a sub-account or any other reasonable and auditable mechanism to clearly account for this different service life.

5.2.2.3. Costs Incurred Prior to the Effective Date of Today's Decision

TURN argues that the Commission has no authority to allow PG&E to increase its rates to recover costs incurred prior to the authorization of a memorandum account. TURN explains that the rule against retroactive ratemaking and longstanding Commission doctrine prohibit setting rates that include costs incurred prior to the effective date of a decision, absent an appropriate and authorized memorandum account. TURN states that the Commission and the California Supreme Court have repeatedly found that ratemaking is prospective and the Commission may not increase rates for previously incurred expenses.[81]

PG&E counters that it needs a memorandum account for expenditures already made in 2011 and 2012 for two purposes. The first purpose is to establish an "official tracking of 2011 costs allocated to PG&E's shareholders" because even though these costs will be allocated to shareholders, "the costs still are counted toward the four year binding budget."[82] PG&E's next

[81] TURN Reply Brief at 35.

[82] PG&E Reply Brief at 41.

reason for a memorandum account effective January 1, 2012, is to enable it to recover in rates all 2012 expenditures authorized by the Commission. PG&E admits that, absent a memorandum account, such recovery is prohibited by the rule against retroactive ratemaking.[83] PG&E contends that failing to allow it to recover 2012 costs from its ratepayers would be inequitable because it has been operating in good faith to pressure test, replace pipeline, validate MAOP, and develop its records computer program in advance of the Commission's decision.

We begin with PG&E's first stated objective for a memorandum account – to track 2011 costs. The purpose of a memorandum account is to record current costs for future Commission ratemaking consideration. Tracking 2011 costs for accounting and budget purposes does not require a memorandum account. Tracking 2011 Implementation Plan costs for accounting and budget purposes could be accomplished in any subaccount designated by PG&E. Such a subaccount, of course, must be permanently excluded from revenue requirement. Accordingly, PG&E's first basis for its request is not persuasive.

Second, PG&E states that it has been acting in good faith by starting actions called for in its Implementation Plan prior to Commission ratemaking authorization, and it should be allowed to recover these costs from ratepayers.

As PG&E recognizes, a memorandum account is a recognized exception to the rule against retroactive ratemaking. However, the Commission has not granted PG&E's request for a memorandum account in which to record

[83] Id. at 42.

its Implementation Plan costs incurred prior to Commission approval of the Implementation Plan.

As the Commission said in the Southern California Water Co. Headquarters case, D.92-03-094 (March 31, 1992)43 Cal. P.U.C. 2d 596, 600

> It is a well established tenet of the Commission that ratemaking is done on a prospective basis. The Commission's practice is not to authorize increased utility rates to account for previously incurred expenses, unless, before the utility incurs those expenses, the Commission has authorized the utility to book those expenses into a memorandum or balancing account for possible future recovery in rates. This practice is consistent with the rule against retroactive ratemaking. (Emphasis in original.)

Similarly, it is the Commission's practice not to reduce general rates that have been set on a forecast basis -- to account for costs not incurred -- unless the Commission has previously set up some mechanism to adjust rates for costs not incurred (e.g. a balancing account). This practice is also consistent with the rule against retroactive ratemaking.

The events in San Bruno required that PG&E take immediate action. As DRA and TURN have argued, forecasted test year ratemaking theory generally precludes post-test year revenue requirement adjustments, such as proposed by PG&E here. The Overland Report shows that PG&E enjoyed the protection of the practices described above when, from 1996 to 2010, PG&E consistently underspent Commission-authorized amounts, resulting in approximately $430 million in excess earnings for shareholders. Our ratemaking practices protected PG&E from recaptureof the excess historic profit for ratepayers. Now, PG&E finds itself on the other side of these practices . Rather than unexpected profit, PG&E is now confronting unexpected, and significant,

costs. Under these circumstances, PG&E asks the Commission to set aside these practices and allow PG&E to recover from ratepayers costs that it has incurred prior to the effective date of today's decision.

As set forth above, we find that the scope and magnitude of the Implementation Plan costs provide good cause to set aside the general rule prohibiting post-test year revenue requirement adjustments and consider revenue requirement increases to reflect the projects included in the Implementation Plan. Such a rationale does not, however, overcome the continuing need to follow our standard practices in an even-handed manner.. Here, the need for urgent pre-Commission approval action was caused at least in part by PG&E's own actions, and the record shows that PG&E's management and shareholders used these practices to retain substantial benefits in the past. These circumstances do not justify allowing PG&E to recover Implementation Plan costs incurred prior to the effective date of today's decision.

Therefore, we conclude that PG&E has not met its burden of demonstrating that just and reasonable rates would result if the Implementation Plan or PG&E's proposed memorandum account is retroactively approved as of January 1, 2012. PG&E must exclude from its revenue requirement all expenses incurred prior to the effective date of today's decision.[84]

5.2.2.4. Implementation Plan Post-Approval Requirements

Modifications to Implementation Plan

PG&E requests authority for a Tier 3 Advice Letter process to make expedited changes to the Implementation Plan budget is circumstances

[84] To calculate the revenue requirement for today's decision, the effective date of the decision is assumed to be December 20, 2012.

lead to a change in Phase 1 scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital.[85]

TURN recommends that the Commission "soundly reject" PG&E's advice letter proposal as it creates a "loophole" that could lead to "unlimited amounts of additional revenue."[86] DRA also opposes the proposed Advice Letter process and contends that it will allow PG&E to increase the costs of the Implementation Plan.[87]

We summarily reject PG&E's proposal for Advice Letter treatment for increases and modifications to the Implementation Plan. When directing California's natural gas system operators to file Implementation Plans, we required an orderly and cost-effective plan that would provide safety value to ratepayers. Authorizing piecemeal modifications would substantially undermine those requirements.

Notwithstanding our rejection of PG&E's Advice Letter proposal, the Commission's experience and expertise with large programs that include numerous diverse projects such as the Implementation Plan demonstrates that such plans are subject to revision and updating as new information comes to light. Opportunities for cost reductions must be identified and, where feasible, incorporated into the Plan. New safety engineering information may provide the analytical foundation for revising priorities. While the exact order of specific projects may change, the overall objective, scope, and budget must be retained, absent further Commission action. This is especially true here, due to our

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[85] PG&E Reply Brief at 43.

[86] TURN Reply Brief at 143 – 144 *quoting* Hearing Exh. 123 (Beach, NCIP).

[87] DRA Opening Brief at 131 – 132.

disposition of the risk of cost overruns, discussed below. Therefore, absent further order of the Commission, PG&E must adhere to the objectives, scope, and budget of the Implementation Plan approved in today's decision. We find that improvements, efficiencies, and adjustments to the Implementation Plan based on sound engineering data and that further of the objectives of the Plan are within the scope of the Plan and do not require further Commission review.

Consumer Protection and Safety Division Oversight (CPSD)

PG&E must keep CPSD fully informed of all changes it proposes to make to the program, and must obtain CPSD's concurrence in any proposed change to the Implementation Plan. We delegate authority to CPSD to exercise oversight of all PG&E activities, including those conducted by contractors, pursuant to the Implementation Plan. CPSD is authorized to inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, or plan, of any kind, related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

The Director of CPSD is authorized to order PG&E to take such actions as may be necessary to protect immediate public safety. The Director of CPSD is specifically authorized to issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

The Director of CPSD shall assign staff and allocate resources as may be necessary to perform the duties delegated in today's decision. If the Director determines that additional external expertise or resources are required, the Director shall meet and confer with the Commission's Executive Director to determine the most efficient means of obtaining such expertise or resources. If the Executive Director determines that additional external expertise or staff are required, and that existing Commission funding is inadequate to provide these expertise or resources, the Executive Director is authorized to order PG&E to reimburse the Commission for any contract necessary to carry out the directives in this decision in an amount not to exceed $15,000,000. PG&E may record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery from ratepayers.

Compliance Filings

TURN and DRA have requested that we schedule a formal after-the-fact reasonableness review of PG&E's actions pursuant to the Implementation Plan, and PG&E opposes this request.

At this time, we are not prepared to grant DRA and TURN's request, but we are equally not inclined to foreclose any type of post-construction review. The Implementation Plan represents a massive investment program funded largely by PG&E's ratepayers. Although PG&E has presented sufficient detail of its specific projects currently expected to be performed, substantial amounts of new data on in-service pipeline will be brought to light by the unprecedented number of pressure tests and pipeline replacement construction that will be performed in the upcoming years. In addition, the Commission needs to ensure that project expenditures incurred under the PSEP are clearly distinct from the funding and expenditures that have

already been provided for in D.11-04-031 (in PG&E's 2011 Gas Transmission and Storage Proceeding, A.09-09-013).

To keep the Commission, the parties, and the public informed of PG&E's progress and actual cost experience, we will require PG&E to file and serve compliance reports. Such reports shall include the information and be in form set out in Attachment D. The information required will include comparisons of actual versus authorized cost for each work project as well as explanations of any significant deviations. Schedule and prioritization changes will also be included. Parties may review this information and may request such Commission action by motion as needed.

5.2.2.5. Implementation Plan Conclusion

As set forth in D.11-06-016, we have ordered PG&E to pressure test or replace all natural gas transmission lines for which a pressure test record is not available. We approve PG&E's Implementation Plan, Pipeline Modernization Program and require that PG&E immediately undertake this program, as modified herein.

5.2.3. Pipeline Records Integration Program

PG&E estimates that it will spend a total of $271.9 million in collecting, reviewing and verifying the documents related to determining the MAOP of its gas transmission pipeline segments. PG&E states that its shareholders will fund all document costs related to pipeline installed after 1970, and costs incurred in 2011. PG&E is seeking Commission authorization to include in revenue requirement a total of $107. 1 million for recovery from ratepayers in costs related to 2012 and 2013 records validation.

PG&E forecasts that its Gas Transmission Asset Management Project, a computer data base system upgrade, will cost a total of $115.7 million

during 2012, 2013, and 2014, which PG&E proposes to include in revenue requirement. In total, PG&E is seeking Commission authorization to include $222.8 million in revenue requirement for 2012, 2013, and 2014.

As set forth below, we find that PG&E has not justified including the costs of its gas system records search and organization projects in revenue requirement. PG&E became responsible for its natural gas transmission system the day it installed facilities and equipment for the system. That responsibility includes creating and maintaining records of the location and engineering details of system components. Over the years, PG&E has sought and obtained ratepayer funding for its record-keeping functions. PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies. Having created the need for this remedial work by its imprudent historic document management practices , PG&E has not shown by a preponderance of the evidence that the costs of the current document search and organization projects can be included in revenue requirement and that the resulting rates will be just and reasonable.

DRA opposes PG&E's request for supplemental ratepayer funding for PG&E's record keeping deficiencies. DRA argues that PG&E has failed to properly manage its records, which led to the NTSB directing PG&E to obtain "traceable, verifiable, and complete" records on which to determine MAOP. This directive, DRA explains, was not a new standard but rather an articulation of a long-standing requirement found in existing law, regulations, industry standards, PG&E policies and common sense that gas system operators retain accurate and accessible pipeline records. DRA specifically points to § 451, adopted in 1909, for the requirement that PG&E operate its natural gas transmission system to "promote the safety, health, comfort, and convenience of

its patrons, employees and the public." DRA emphasizes that one need not be a professional engineer to recognize that accurate pipeline records are necessary to safely operate a system that transports explosive material, such as natural gas, for delivery to the public.[88] DRA notes that Commission General Order 28, adopted in 1912, makes explicit the obligation for public utilities to retain records pertaining to public utility property, including improvements. DRA sets out the subsequent history of industry standards and Commission regulations elaborating on the requirement that natural gas system operators create and retain accurate records of their systems.

DRA next turns to ratepayer funding for PG&E's record-keeping efforts. DRA argues that PG&E's historic rate cases have included funding for gas system record-keeping and that PG&E is proposing "nothing but a clean-up of its failed programs" which is prohibited from being passed on to ratepayers by state law and Commission policy.[89] DRA states that the work of collecting and verifying pipeline strength test and features data is "normal, routine, and ongoing" as part of prudent gas system recordkeeping, which is and has been fully funded by ratepayers over the decades that the pipeline has been in place. DRA concludes ratepayers, having paid once for gas system record keeping, should not be charged a second time.[90]

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[88] DRA Opening Brief at 32. DRA also noted that the Commission's safety engineers had similarly concluded that PG&E's gas system records were unreliable and that correcting the database would lead to duplicate costs. (Id. at 48.)

[89] Id. at 42.

[90] DRA Opening Brief at 43.

TURN also opposes any ratepayer funding of PG&E's record review or database upgrade project. TURN contends that the purpose of these projects is to remedy PG&E's past imprudent document management, and TURN focuses on the pressure testing historical exemption found in 49 CFR 192.619(c) and (a)(1)(4) to demonstrate that an accurate and reliable record of key pipeline features is necessary to setting a safe MAOP. TURN explains that for pipeline installed before 1970, the MAOP may be set by maximum operating pressure reached between 1965 and 1970, and that some knowledge of pipeline features would be essential to validating this historic pressure as required by federal regulations. TURN emphasizes that PG&E had an acute need for pipeline features information because an alarmingly high share (70%) of PG&E's pipeline with MAOP set by historical operating pressure had only after-the-fact affidavits by technicians to support the claimed historical operating pressure, rather than any actual pressure recordings.[91] Having needed this information all along to safely operate its natural gas transmission system, TURN concludes that PG&E has no basis to now seek ratepayer funding to bring its records up to the prudent standard.

TURN dismisses as wholly without merit PG&E's argument that the document review and data base projects are necessary to comply with new regulatory requirements.[92] TURN points to D.11-06-017 and contends that the document review for MAOP validation was necessitated by PG&E's unreliable natural gas pipeline records tragically brought to light by the San Bruno rupture. TURN concludes that accurate and reliable records were always necessary to

[91] TURN Opening Brief at 101.

safely operate a natural gas transmission system and the recent articulation of that requirement as "traceable, verifiable, and complete" records is merely a restatement of existing requirements.

TURN similarly finds PG&E's data base upgrade project to be part of PG&E's remedial document management efforts, the costs of which should not be included in revenue requirement because PG&E has a long-standing and apparently unmet obligation to keep accurate and accessible natural gas pipeline records.

PG&E counters that for the first time it must calculate MAOP using traceable, verifiable and complete records and the costs of doing so are new regulatory compliance costs that are properly included in authorized revenue requirement. PG&E explains that its pipeline records integration project is necessary to comply with the new standard for validating MAOP through records as initiated by the NTSB. PG&E states that it is focused on developing a pipeline features list for all high consequence areas from which it will calculate the design basis MAOP for each pipeline component.[93]

PG&E disputes the parties' allegations that its gas records integration program is intended to remedy historical record keeping problems.[94] PG&E argues that both parts of this project, the records review and computer data base upgrade, are necessary to meet the Commission's mandate to validate the MAOP of all gas transmission pipelines using traceable, verifiable and complete records. PG&E contends that prior to the NTSB recommendations and

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[92] TURN Opening Brief at 103.

[93] PG&E's Opening Brief at 42.

[94] PG&E Reply Brief at 26.

the Commission's 2011 decision, it could set the MAOP for a pipeline using historical operating pressure and now it must use a pipeline features analysis. To accomplish this new requirement, PG&E concludes, it must institute its gas records integration program, and the cost of complying with this new regulatory requirement is properly included in revenue requirement.

Pursuant to Public Utilities Code Section 451 each public utility in California must:

> Furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities, … as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

The duty to furnish and maintain safe equipment and facilities is paramount for all California public utilities, including natural gas transmission operators. Furnishing and maintaining safe natural gas transmission equipment and facilities requires that a natural gas transmission system operator know the location and essential features of all such installed equipment and facilities.

The record in this proceeding shows that the NTSB identified "discrepancies" in PG&E's pipeline records and issued recommendations that corrective actions be taken:

> The NTSB's examination of the ruptured pipe segment and review of PG&E records revealed that although the as-built drawings and alignment sheets mark the pipe as seamless API 5L Grade X42 pipe, the pipeline in the area of the rupture was constructed with longitudinal seam-welded pipe. Laboratory examinations have revealed that the ruptured pipe segment was constructed of five sections of pipe, some of which were short pieces measuring about 4 feet long. These short pieces of pipe contain different longitudinal seam welds of various types, including single- and double-sided

> welds. Consequently, the short pieces of pipe of unknown specifications in the ruptured pipe segment may not be as strong as the seamless API 5L Grade X42 steel pipe listed in PG&E's records. It is possible that there are other discrepancies between installed pipe and as-built drawings in PG&E's gas transmission system. It is critical to know all the characteristics of a pipeline in order to establish a valid MAOP below which the pipeline can be safely operated. The NTSB is concerned that these inaccurate records may lead to incorrect MAOPs.[95]

The NTSB was clear that it envisioned its directives as "corrective" measures caused by its discovery of "inaccurate records" in PG&E's natural gas transmission system. The clear purpose of the two urgent recommendations is to address the possibility that "there are other discrepancies between installed pipe and as-built drawings in PG&E's gas transmission system." The NTSB explained that accurate and reliable records are "critical" to setting a safe operating pressure limitation, and that any discrepancies between installed pipe and as-built drawings must be identified and corrected.

The Commission expanded on the NTSB's record correction directives, which the Commission saw as a means to cure PG&E's unreliable natural gas pipeline records:

> As the detailed history set out above shows, this project to validate MAOP was set in motion by the NTSB's justifiable alarm at PG&E's records being inconsistent with the actual pipeline found in the ground in Line 132. The pipeline features data for Line 132 were not missing; the recorded data were factually inaccurate. Records containing inaccurate pipeline

[95] NTSB Safety Recommendation P-10—2, -3 (Urgent) and P-10-4, January 3, 2011, at 2.

> features are fundamentally different from simply missing records. Curing PG&E's unreliable natural gas pipeline records was the obvious goal of the NTSB's recommendation to obtain "traceable, verifiable, and complete" records and, with reliably accurate data, calculate a dependable MAOP.
>
> PG&E and SoCalGas/SDG&E state that such records are not available, especially for the older vintage pipelines. Notwithstanding the utilities' record-keeping challenges, these missing records are particularly needed because the older pipelines were exempted from pressure testing requirements and many have not been pressure tested.
>
> Consequently, the untested pipelines are also some of the oldest in the natural gas transmission system and the more likely to lack a complete set of documents allowing pipeline feature documents to be established without the use of assumptions. We find that this circumstance is not consistent with this Commission's obligations to promote the safety, health, comfort, and convenience of utility patrons, employees, and the public. We conclude, therefore, that all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety. Historic exemptions must come to an end with an orderly and cost-conscience implementation plan.[96]

The Commission went on to require PG&E to complete the records review process because, based on testimony of PG&E's engineering executive, PG&E needed assurance that that its gas system records accurately depicted the pipeline characteristics of segments it was about to pressure test:

> Commissioner Sandoval questioned PG&E's Vice President for Gas Engineering and Operations

[96] D.11-06-017 at 17 -18.

> regarding the use of assumptions in the MAOP validation methodology. PG&E's Vice President explained that for pipeline equipment for which PG&E does not have records, it will make very conservative assumptions based on the era during which the pipeline was constructed, the types of material then available, and the type of material PG&E was purchasing. PG&E's Vice President stated that prior to doing a hydrostatic test it was important to know the components of the pipeline to be tested:
>
> > What you want to know is everything that's in the ground before you start conducting that test so that you don't put yourself in a situation where you've led to unintended consequences by pressuring that pipe up.
>
> The Vice President went on to explain that with regard to seamed pipeline, where adequate records are not available regarding the strength of the longitudinal weld, PG&E would dig up the pipe and verify the condition of the weld. PG&E offered its MAOP validation for its Line 101 as an example of how it intended to approach issues of missing records.[97]

Accordingly, the NTSB, this Commission, and PG&E's own vice-president all agreed that accurate and reliable gas transmission system records are essential to safe operation of the system. Upon discovery that PG&E may have discrepancies in its records, the NTSB and this Commission ordered corrective actions, namely, to aggressively and diligently search for all as-built drawings to compile traceable, verifiable, and complete records. The purpose of accurate records is not limited to calculating MAOP. Among the other uses are safely conducting a pressure test, as PG&E's vice-president's testimony shows.

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[97] Id. at 8 – 9 (citations omitted).

PG&E seems to be arguing that until the NTSB recommendations it had no obligation to maintain accurate and accessible records of the components of its natural gas transmission system because the historical exemption provision of 49 CFR 192.619(c) did not require these records.

We disagree with PG&E's reading of the PHMSA regulations and we want to disabuse PG&E and other California natural transmission gas system operators of the notion that superficial compliance with regulations is acceptable. We require our natural gas transmission system operators to exercise initiative and responsible safety engineering in all aspects of pipeline management. Simply because a regulation would not prohibit particular conduct does not excuse a natural gas system operator from recognizing that such conduct is not appropriate or safe under certain circumstances.

Turning to the specific federal regulation upon which PG&E bases its claimed exemption from a duty to create and maintain accurate and reliable natural gas transmission system records, we find that the regulation presupposes an engaged and evaluating system operator, questioning system operating parameters, examining records, and exercising professional engineering judgment. Specifically, the regulation states:

> (c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding [July 1, 1970].[98]

[98] 49 CFR 192.619(c).

To comply with this provision, a natural gas system operator must undertake four separate affirmative obligations:

1. Examine and determine that the pipeline segment is in satisfactory condition;
2. Obtain and evaluate its operating history;
3. Obtain and evaluate its maintenance history; and;,
4. Determine the highest actual operating pressure during the five year period.

No natural gas system operator can comply with these requirements without creating and preserving accurate and reliable system installation, operating, and maintenance records. Thus, we find that PG&E has failed to demonstrate that long-standing regulations excuse incomplete and inaccurate natural gas system record-keeping.

Therefore, based on the history of PG&E's gas system record improvement project described above, we find that PG&E has not justified including the costs of its gas system record integration projects in revenue requirement, and we disallow PG&E's request. Today's decision addresses PG&E's request to include costs of its gas system record integration project in revenue requirement and we express no opinion on whether PG&E's natural gas system records violated federal or state law or regulations because those questions are pending in I.11-02-016.

5.2.4. Contingency and Escalation Rate

PG&E requested Commission approval of a total of $380.5 million as a risk-based allowance. PG&E arrived at this amount by taking the sum of costs expected to be incurred in 2011, 2012, 2013, and 2014 in each chapter of its

testimony,[99] and multiplying each chapter's cost by a risk contingency percentage. The risk contingency percentages vary from 10% to 28%, and average 21%. The sum of each chapter's contingency costs is $380.5 million over the four years, and, of that sum, $247.3 million is capital costs and $133.2 represents expense.[100]

DRA opposes PG&E's request for a contingency as "pre-determined" and based almost exclusively on PG&E's "judgment" and "intuition."[101] In addition, DRA and TURN presented expert analysis showing that PG&E's cost estimates for pressure testing and pipeline replacement, the largest cost components, greatly exceed the national average and are based on unsupported assumptions drawn from a small sample of such work done on an emergency basis.

We find that for both cost forecasting reasons as well as policy reasons, PG&E shareholders should bear the risk of cost overruns and we do not authorize the contingency allowance for inclusion in revenue requirement.

DRA presented testimony developed by an outside expert setting forth cost estimates for fixed costs per test and variable cost per foot of pipeline tested. As discussed above, DRA's cost forecasts were substantially lower than PG&E's, with PG&E's costs forecasts about three to five times DRA's - a substantial margin. PG&E's costs are orders of magnitude greater than TURN's estimates, although we note those estimates are from 2001. PG&E also analyzed its system to identify locations where costs are likely be higher due to population

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[99] See Exh. 2 at 3-6 and 4-7.

[100] Exh. 2 at 7-43.

[101] DRA Opening Brief at 111 – 114.

and determined that conducting pressure tests on pipeline located on the San Francisco peninsula would experience unique expenses due to high population density. To address this, PG&E proposed a location-specific "Peninsula adder" to include costs beyond its typical forecast for testing pipeline on the San Francisco peninsula.

In addition to these already generous cost forecasts, PG&E layers on a Program Management Office that costs about $10 million a year or $34.8 million over the duration of Phase 1.

We find that PG&E's cost forecasts, even without the contingency factor or the program management costs, greatly exceed forecasts presented by other parties. As set forth above, we do not adopt the alternative cost forecasts and approve PG&E's much higher forecasts. Although we find that the preponderance of the evidence supports a finding that the PG&E has justified its cost forecasts and that the resulting rates will be just and reasonable, DRA and TURN have presented credible testimony that PG&E's pressure testing cost forecasts are already biased to the high end of the expected cost range and thus include an implicit allowance for unexpected cost overruns. We find, therefore, that DRA's and TURN's testimony substantially undermines PG&E's request for an additional contingency allowance of $380 million.

This Implementation Plan is a massive expense and capital program, which will be funded largely by ratepayers. To meet our constitutional and statutory duties, we must create powerful incentives for PG&E to manage this program efficiently and to aggressively identify and capture cost savings. Were we to grant PG&E's request for a substantial contingency allowance on top of already generous cost forecasts, PG&E would have no such incentive.

Denying this particular contingency allowance request is appropriate because we find that the record shows that the need to do this amount of testing and replacement on an "urgent" basis has been caused, in part, by PG&E's management of its natural gas transmission system over multiple decades. The majority of the pipeline to be tested or replaced has been part of PG&E's system for decades, and the safety value of pressure testing has similarly been well-known for decades. TURN argues that PG&E's long-standing obligation pursuant to § 451 to operate its system in a safe manner required that PG&E pressure test or replace pipeline and that PG&E's historic failure to do so was imprudent, with significant ratemaking consequences.[102] As set forth above, we disagree with TURN's ratemaking theory analysis; however, the fact that these now "urgent" safety improvements are overdue and caused by years of poor management decisions is a valid rationale to support a ratemaking decision that shareholders should not be shielded from the risks created by the poor management decisions. Having let its natural gas transmission system deteriorate to the point where the Commission was required to order a massive and relatively short-term testing and replacement plan, PG&E cannot now seek protection (in addition to a generous cost forecast) from costs caused by quickly doing work that could and should have been over a much longer time period. Such a longer time period may have allowed PG&E to develop better cost forecasting models as well as to improve efficiency and lower overall costs. We find that having had a role in creating the urgent need for this program, sound

[102] TURN Opening Brief at 69 – 74.

ratemaking policy and the public interest support denying PG&E's request to shift the risk of potential cost overruns to ratepayers.

Therefore, we conclude that PG&E has not shown by a preponderance of the evidence that its generous base cost forecasts require a supplemental contingency cost allowance to be just and reasonable. We deny PG&E's request to include in revenue requirement any additional amounts for Implementation Plan contingency costs.

Escalation Rate

PG&E escalated all costs by 3.12% annually from the time the project is approved to the date that the project will be completed. PG&E explains that its use of the escalation is consistent with past rate cases and necessary for "long-term forecasts."[103] DRA recommends using an annual rate between 1.1% and 1.5% and applying it to the amount from the date of project approval to the date of engineering and procurement. DRA testified that the overall Consumer Price Index is projected to be between 1.1% and 1.5% over the 3-year plan duration, and that steel prices are expected to remain flat through 2016.[104]

We find that PG&E's escalation rate is excessive for the three-year term of Phase 1 of the Implementation Plan. We will adopt the high end of DRA's range, 1.5%, to better account for inflation.

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[103] Hearing Exh. 21 at 3-47.

[104] Hearing Exh. 147 at 16.

5.2.5. Shareholders Return on Equity

PG&E proposes to include $384.3 million in capital investments in 2012, $480.3 in 2013, and $499.9 in 2014.[105] PG&E proposes to include these amounts in plant in service at its existing return on equity, 11.35%.[106]

DRA recommends a 200 basis point reduction in return on equity for capital investments that are part of the Implementation Plan.[107]

TURN presents expert testimony explaining that the Commission considers management efficiency and effectiveness when setting return on equity, and that the very need for PG&E to undertake $10 billion in gas pipeline safety investments to address problems that developed over decades demonstrates that PG&E's management has been neither efficient nor effective.[108] TURN's expert concludes that the current authorized return on equity of 11.35%, which the Commission acknowledged was at the "upper end" of the just and reasonable range would be an entirely inappropriate reward for the investment needed to correct these long-standing safety deficiencies.[109] TURN's two experts

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[105] Hearing Exh. 2 at 1-17.

[106] In Application 12-04-015, et al, the Commission is currently considering the 2013 ratemaking return on common equity and return on rate base for Southern California Edison Company, San Diego Gas & Electric Company, Southern California Gas Company and Pacific Gas and Electric Company. The proposed decision recommends test year 2013 authorized return on equity of 10.40% and return on rate base of 8.06% for PG&E.

[107] DRA Opening Brief at 20. A change of 200 basis points would reduce PG&E's return on equity from 11.35% to 9.35%.

[108] Hearing Exh. 98 at 10.

[109] Id.

recommend a return of equity of no greater than the lower end of the previously recognized range, 10.2%, or to the cost of debt, 6.05%.[110]

The Northern California Indicated Producers argue that PG&E's past mismanagement and the expedited timeline needed for the Implementation Plan merit a 500 basis point reduction in PG&E's return on equity for Implementation Plan investments. Indicated Producers state that even if the rate of return on PG&E's Implementation Plan capital investments is reduced to the cost of debt, these investments represent only about 4% of PG&E's plant in service so that its overall return on equity will only be slightly reduced, which dispels PG&E's argument that the regulatory compact and legal principles impede a return on equity reduction. Indicated Producers explain that the regulatory compact requires PG&E to provide safe and reliable service in exchange for an opportunity to earn a reasonable return on investment, and that PG&E has not kept its end of the bargain with regard to its natural gas transmission system operations.[111]

PG&E responds that the parties' proposals to reduce return on equity are unreasonable and would increase the cost of debt and capital needed for the Implementation Plan investments. PG&E argues that a reduced return on equity will undermine its incentive to make needed investments in safety improvements. PG&E states that one-time disallowances have a more limited negative impact on a utility because disallowances only reduce earnings and overall financial position rather than long-term operating or investment

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[110] Id. at 9; Hearing Exh. 121 at 17.

[111] Northern California Indicated Producers Opening Brief at 26 -30. A 500 basis point reduction would decrease PG&E's 11.35% return on equity to 6.35%.

decisions diminished by adjustments to return on equity.[112] PG&E's witness explained that a "punitive, noncompensatory ratemaking structure" would undermine PG&E's ability to attract capital for needed investments. PG&E also stated that it preferred a one-time cost disallowance to a return on equity reduction because the capital markets will require a higher return for future investments.[113]

When initiating this rulemaking the Commission indicated, at 11-1 2, that adjustments to return on equity would be considered:

> This rulemaking will consider how we can align ratemaking policies, practices, and incentives to better reflect safety concerns and ensure ongoing commitments to public safety. For instance, how do we maintain public and utility management attention to the "nuts and bolts" details of prudent utility operations? How do we foster a culture of commitment to safe utility operations with changing and increasingly competitive energy markets?
>
> The unique circumstances of PG&E's pipeline records and pipeline strength testing program for its pre-1970 pipeline may require extraordinary safety investments. Our ratemaking authority empowers this Commission to impose such ratemaking consequences as the public interest may require. See e.g., Cal. Const. Art. 12; Pub. Util. Code §§ 701, 451 ("every public utility shall…maintain such…equipment and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.") The extraordinary safety investments required for PG&E's gas pipeline system and the unique

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[112] PG&E Opening Brief at 82 - 83.

[113] Id. at 84 - 85.

> circumstances of the costs of replacing the San Bruno line are situations where this Commission may use its ratemaking authority to, for example, reduce PG&E's rate of return on specific plant investments or impose a cost sharing requirement on shareholders. We will consider these, and other ratemaking mechanisms, in this proceeding.

When ordering the natural gas transmission system operators to file Implementation Plans, the Commission directed only PG&E to include in its plan a cost-sharing proposal between ratepayers and shareholders.[114] The Commission found that the unique circumstances of PG&E's pipeline records, the costs of replacing the San Bruno line, and the public interest required that PG&E's rate Implementation Plan include a cost sharing proposal.[115]

We have taken into account PG&E's stated preference for a one-time cost disallowance, rather than a return on equity reduction, in the cost disallowances we made elsewhere in today's decision. As set forth above, PG&E's history of addressing its natural gas transmission pipelines that were installed prior to a pressure testing requirement or for which pressure test records are not available reflects a long-standing avoidance of sound, safety-engineering-based decision-making in favor of financially-motivated nominal regulatory compliance. As also set out above, prudence principles do not support a ratemaking disallowance for the costs of needed safety improvements simply due to belated timing but an adjustment to return on equity can be used to address inefficient or ineffective management.

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[114] D.11-06-017 at 22.

[115] Id. at 28.

The parties recommend downward adjustments between 200 basis points and 500 basis points, which would result in a return on equity of about the cost of debt, 6.05%, as the permanent return on equity for these investments. TURN, particularly, makes a compelling case for not allowing PG&E to earn a "profit" on its overdue safety investments.[116] Equally compelling, however, for the reasons described above, is PG&E's argument that drastically reducing return on equity harms the ratepayers in the long run by increasing borrowing costs and potentially diminishing the financial health of the utility.

We, therefore, decline to adopt an adjustment to PG&E's return on equity for investments made pursuant to the Implementation Plan.

5.2.6. Cost Allocation and Rate Design

Overall, PG&E proposes to follow the cost allocation and rate design principles adopted in the 2011 Rate Case Gas Accord Settlement, approved by the Commission in D.11-04-031.[117] PG&E proposes to allocate its target annual Implementation Plan Backbone Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Backbone Transmission revenue requirement responsibility as established in D.11-04-031. Similarly, PG&E proposes to allocate its target annual Implementation Plan Local Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Local Transmission revenue requirement responsibility adopted in D.11-04-031. The target annual Implementation Plan gas storage-related revenue requirements will also be allocated to core and noncore based on percentages adopted in the 2011 decision.

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[116] TURN Opening Brief at 121.

[117] Hearing Exh. 2 at Chapter 10.

To recover the costs of the Implementation Plan revenue requirements, PG&E proposes to add new rate components to the customer class charges recovered from end-use rates paid by core and noncore customers.

Three parties, Northern California Indicated Producers, Northern California Generation Coalition, and Dynegy, all large noncore customers, recommend that the Commission abandon the 2011 principles and instead use an equal percent of authorized margin methodology. These parties contend that Implementation costs should be allocated among ratepayers based on a potential impact radius analysis, which allocates more costs to core customers, and that costs allocated to noncore electric generators will increase the cost of wholesale electricity.[118]

We find that PG&E has justified its proposal to retain the currently adopted cost allocation and rate design. Such issues are better handled in general rate cases, not a proceeding of limited ratemaking review, such as this one. Accordingly, we are not reopening the rate case adopted cost allocation and rate design and will follow the existing structure. PG&E's proposal comports with existing cost allocation and rate design and we, therefore, approve PG&E's proposed cost allocation and rate design.

Therefore, we authorize PG&E to submit a Tier 1 Advice Letter to revise its Preliminary Statement, Part B, to reflect a new rate component titled the "Implementation Plan Rate" in the customer class charge included in transportation charges as shown in Attachment F to collect the annual increase in revenue requirement as approved herein.

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[118] Northern California Generation Coalition Opening Brief at 4 – 7.

One-Way Balancing Account

PG&E proposes to include capital expenditures for plant as the plant becomes operational and to use actual expenses incurred each year to true up forecasted costs. Thus, PG&E concludes, ratepayers will only pay for Implementation Plan actions that are completed and any unspent funds cannot be diverted to other uses.[119]

No party opposed the use of a one-way balancing account for the Implementation Plan.[120] For administrative efficiency, we will include capital costs in the balancing account as well, rather than to have annual advice letter filings and resultant rate changes. Therefore, we approve a one-way (downward) balancing account to track Implementation Plan costs from the effective date of today's decision through December 31, 2014. Any accumulated balance on December 31, 2014, plus interest, will be returned to customers through the Customer Class Charge in PG&E's Annual Gas True-Up Filing, to be filed shortly prior to the end of 2014. The accumulated balance will be allocated 59.5% to the core class and 40.5 % to the noncore class.

PG&E may only recover from ratepayers the revenue requirements associated with the actual costs and expenses incurred for projects allowed by this decision, and only up to the revenue requirements we estimate here for Phase 1 work. The amounts to be recorded in the balancing account are limited by the adopted expense and capital amounts set forth in Attachment E for each

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[119] Hearing Exh. 2 at 1 -19.

[120] But *see* Independent Review Panel Report at 109 and Appendix Q, finding that one-way balancing accounts, such as PG&E proposes here, create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no more or no less than is authorized for a given activity.

program. To the extent PG&E incurs costs beyond these amounts for projects approved in today's decision, the expense overruns may not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. The amounts in Attachment E are program-based upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the Implementation Plan.

The NCIP expressed the concern that PG&E's proposed one-way balancing account would not adequately safeguard ratepayers from overpaying for projects authorized for Phase 1 of the Implementation Plan. NCIP explains that the proposed one-way balancing account would allow PG&E to overspend on individual projects and shift subsequent projects to Phase II to stay within the authorized total.[121] To address this issue, to the extent specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects, the expense and capital cost limit of the balancing account is reduced by the amounts associated with the project not completed.

6. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Maribeth A. Bushey is the assigned Administrative Law Judge (ALJ) in this proceeding.

7. Comments on Proposed Decision

The proposed decision of ALJ Bushey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3.

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[121] NCIP Opening Brief at 34-35.

Opening comments were filed on November 16, 2012. PG&E supported the Proposed Decision's findings on technical issues but strongly opposed numerous significant disallowances. PG&E contended that disallowing a program contingency is contrary to standard industry practice for estimating program costs. PG&E argued that the failure to authorize rate recovery for 2012 was the result of erroneously failing to grant its request for a memorandum account. PG&E found the proposed ROE reduction to be punitive and contrary to the public interest. PG&E opposed the finding that GTAM project was remedial and should be disallowed. Finally, PG&E argued that the 65-year service life for pipeline and 1.5% escalation rate were both arbitrary and unsupported by the record.

DRA provided extensive and detailed comments contending that the Proposed Decision contained numerous errors. In its comments to the Proposed Decision, DRA asserted that the analysis used to determine the revenue requirement and authorized program budgets was flawed and that more disallowances were warranted. DRA analyzed PG&E's pipeline modernization program database and developed various scenarios for testing and replacement disallowances using different criteria to identify pipe segments without test records. Additionally, DRA recommended using more accurate testing cost values to calculate the disallowance for pipe replacement projects with pipe segments lacking test records. TURN also recommended that PG&E file an advice letter after the decision is issued to remove pipe segments from the Implementation Plan for which the utility found the records. Our evaluation of DRA's and TURN's comments is set forth below.

TURN argued that the Proposed Decision erred by approving without evaluation PG&E's pipeline program. TURN explained that since filing the

Implementation Plan, PG&E has located additional pipeline pressure testing records that obviate the necessity to test or replace these pipes. TURN strongly recommended that PG&E update its Implementation Plan to remove these pipes from the plan, as well as to reassign to Phase 2 pipeline located in Class 2 locations. TURN opposed allowing PG&E any recovery for replacing post-1955 pipeline where PG&E does not possess testing records. TURN focused on Public Utilities Code section 463 as mandating that the Commission assign to shareholders, not ratepayers, all the cost consequences of utility imprudence. TURN also questioned the Proposed Decision's acceptance of PG&E's valve program as relying too extensively on remote-controlled valves rather than automatic valves which can be activated quickly in the event of a pipeline rupture. TURN concluded by supporting DRA's recommended corrections to PG&E's disallowance calculations.

SDG&E and SoCalGas asked the Commission to limit the findings in the Proposed Decision to PG&E, and not extend them to SDG&E and SoCalGas. These two utilities also argued that all pipeline should pressure tested to modern standards and that historic test results with lower standards should not be accepted. SDG&E and SoCalGas contended that the reduction in the return on equity for PG&E's safety enhancement investments would undermine the Commission's safety objectives and increase utility costs statewide.

Edison opposed the return on equity reduction.

San Bruno urged the Commission to go much beyond the actions contained in the Proposed Decision. San Bruno explained that the tragedy in its Crestmoor neighborhood showed that the PG&E gas system was not safe then and it is not safe now. San Bruno stated that PG&E urgently needs to inspect, test, repair, upgrade and modernize the natural gas transmission system.

Rigorous inspection and testing of high pressure gas transmission lines is critical for safety, and in some cases, replacement of high pressure gas transmission lines, especially those installed prior to 1970 and which traverse heavily populated high consequence areas may be necessary. San Bruno also argued for installation of automatic shut off valves and remote controlled shut off valves for gas transmission lines in high consequence areas. San Bruno stated that PG&E's gas control and gas dispatch operations must have internal coordination as well as with local first responders. San Bruno concluded that until all necessary safety measures are implemented, every community in PG&E's service territory remains just as vulnerable as San Bruno was on September 9, 2010.

Specifically, San Bruno recommended that the Proposed Decision be revised to include rigorous evaluation and explanations for each element of Implementation Plan. San Bruno focused on the rejection of the requested total disallowance and the limited 5-year term of the return on equity disallowance. San Bruno sought independent analysis of PG&E's decision tree and the need for automated shut-off valves. San Bruno also supported the Commission obtaining outside assistance in its oversight of PG&E's execution of the Implementation Plan.

San Francisco criticized the proposed decision for failing to clearly state that PG&E does not safely operate its natural gas system. San Francisco explains that the Proposed Decision incorrectly relies on PG&E's flawed decision tree analysis which does not sufficiently address double submerged arc-welded pipe or the effects of pressure-cycle-induced fatigue-crack growth. San Francisco recommended that PG&E update its Implementation Plan with the more recently available accurate information. San Francisco also challenged the Proposed Decision's application of the burden of proof. Finally, San Francisco

recommended that the Commission order an independent monitor to report to the public on PG&E's performance of the Implementation Plan.

The Northern California Generating Coalition opposed the Proposed Decision's determination that the cost allocation and rate design principles for recovery of Implementation Plan costs should be based on the methodology used to calculate Gas Accord V rates in Decision 11-04-031. While supporting the safety and reliability outcomes promised by the PG&E in the Implementation Plan, the Coalition maintained that the cost allocation and rate design aspects of Plan, as adopted in the Proposed Decision were not supported by the record evidence in this proceeding, would result in noncore gas transportation rates that are unjust and unreasonable, and would place gas-fired electric generation facilities located in Northern California at a competitive disadvantage. Dynegy and NCIP also opposed continuing the current cost allocation methodology as it was set by settlement.

The Black Economic Council, National Asian American Coalition and Latino Business Chamber of Greater Los Angeles recommended that the Commission create a working group that focuses on statewide outreach issues resulting from the implementation of gas pipeline safety upgrades, oversee PG&E's full compliance with the directives ordered by the Commission, and conduct a series of workshops ensuring that the audit process is transparent through the process, including selection, progress made, and results.

Reply comments were filed on November 29, 2012, by PG&E, DRA, TURN, San Francisco, San Bruno. SDG&E & SoCalGas, Edison, and, jointly by the Black Economic Council, Latino Business Chamber of Greater Los Angeles, National Asian American Coalition.

PG&E replied that while it continued to oppose the substantial disallowances in the Proposed Decision, it supported the determinations on Public Utilities Code section 463, the burden of proof, approval of the decision tree and scope of Phase 1, the valve automation program approval, oversight and customer outreach, and rate design. PG&E opposed the DRA's recommended calculation of disallowances.

DRA encouraged the Commission to adopt the proposed allocation of costs to shareholders. DRA opposed PG&E's request to allow the balancing account to transfer cost savings from an unnecessary project to offset cost overruns on another project. DRA contended that such an offsetting process would undermine incentives for cost control. DRA supported the disallowance of PG&E's pre-decision costs due to PG&E's mismanagement and neglect, which, DRA argued, distinguished PG&E from SDG&E and SoCalGas, which were granted a memorandum account. DRA supported the PD's disallowance of GTAM and contingency costs. DRA supported the time-limited ROE reduction as striking an equitable balance between shareholders and ratepayers.

TURN supported the corrections put forward by DRA and San Francisco, and recommended that the Commission disregard the attempts by SDG&E and SoCalGas to litigate in this docket issues pending in A.11-11-002. TURN reiterated its recommendation that the Implementation Plan be updated to reflect pipeline for which PG&E has now located pressure test records as well as for non-adjacent Class 2 pipeline.

SDG&E and SoCalGas recommended that the Commission not decide that pipeline installed after 1955 should have been pressure tested. These operators opposed TURN and DRA's argument that section 463 requires that all costs of

implementing D.11-06-017 be assessed to shareholders. SDG&E and SoCalGas also opposed NCIP's interruption credit proposal.

San Francisco noted that San Bruno and DRA joined it in recommending independent oversight for PG&E's Implementation Plan. San Francisco also supported TURN's request for an update to the Plan. San Francisco opposed PG&E's attempts to limit the reporting mechanism in Attachment D to the PD.

Evaluation of DRA's and TURN's Comments: Update Application Requirement

We considered DRA's and TURN's comments in light of the fact that PG&E prepared its database prior to the completion of its MAOP validation and records search work. For some pipe segments, there are indications that a test was conducted, but a final determination cannot be made now as PG&E continued to find records. There are also instances where the database shows that a portion of a pipe segment was tested, but the length of the tested portion was not shown. Furthermore, the database was structured to evaluate pipe segments according to the testing requirements in effect since 1970. This makes it difficult to determine if a pipe segment installed between 1956 and 1969 met the prevailing industry standards or regulatory requirements for testing.

DRA generally disallowed all pipe segments installed after 1955, or those without an installation date, lacking complete evidence of a proper test. Rather than use such a broad brush, we took a more balanced approach given the incomplete nature of the database. Some adjustments were made, but we did not disallow pipe segments where there was a clear indication that a test was performed or if it was shown a portion of a pipe segment was tested. However, we will not know the exact number of pipe segments PG&E lacks the test records for and their associated disallowance until its MAOP validation and records

search is completed. After the MAOP validation and records search are completed, DRA's larger disallowance, or a portion of it, may be appropriate. Therefore, consistent with TURN's recommendation, we shall require PG&E to file an expedited application 30 days after the conclusion of its MAOP validation and records search work that includes an updated pipe segment database. The specific showing that PG&E will be required to provide in its application will be considered in a workshop to be held no later than 90 days from the effective date of this decision. We expect this expedited application to be limited in scope, but we believe that an expedited application will be a more appropriate means to review the submitted data than an advice letter.

We adopted DRA's recommendation to use better testing costs estimates for pipe replacement projects that had pipe segments without test records.

Findings of Fact

1. On August 26, 2011, PG&E filed and served its Implementation Plan required by D.11-06-017.

2. PG&E's Implementation Plan is comprised of: (A) Pipeline Modernization Program that provides for testing or replacing pipelines, reducing their operating pressure, conducting in-line inspections as well as retrofitting to allow for in-line inspection, and adding automatic or remotely-controlled shut off-valves; and (B) Pipeline Records Integration Program where PG&E will finish its records review and establish complete pipeline features data for the gas transmission pipelines and pipeline system components, and the Gas Transmission Asset Management Project, a substantially enhanced and improved electronic records system.

3. PG&E's Implementation Plan uses a consistent methodology to identify and prioritize recommended actions based on pipeline threat categories and

PG&E organized this methodology into a decision tree to identify actions such as performing pressure tests, replacement of pipe, and in-line inspection, to address specific risks.

4. Natural gas pipelines carry explosive and flammable gas under pressure and are typically located in public rights-of-way, at times amidst dense populations. These facilities must be carefully operated and regulated to protect public safety.

5. The Independent Review Panel found numerous deficiencies in PG&E's operations, including data management and pipeline Integrity Management, and recommended improvements that included modifying its corporate culture and engaging in a progression of activities to address pipeline safety using the image of a journey to a new destination.

6. PG&E's Decision Tree analysis is a promising beginning at a comprehensive decision-making process based on safety concerns related to historical pipeline manufacturing, fabrication, and testing practices.

7. PG&E must improve the safety of its gas system operations, specifically but not only in the areas quality control and field oversight.

8. The Implementation Plan calls for pressure testing 783 miles of pipeline and replacing 185.5 miles of pipeline in Phase 1.

9. PG&E's Decision Tree identifies and prioritizes three unique threats to pipeline integrity – manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats.

10. The Implementation Plan calls for replacing, automating and upgrading 228 gas shut-off valves.

11. The Implementation Plan calls for retrofitting 199 miles of pipeline for in-line inspection and inspecting 234 miles of pipeline with in-line inspection tools.

12. The Implementation Plan calls for pressure reductions and increased leak inspections and patrols.

13. In D.11-06-017, the Commission required PG&E to include in its Implementation Plan a proposed cost allocation between shareholders and ratepayers, and PG&E's Implementation Plan included a discussion of costs to be absorbed by PG&E's shareholders.

14. PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material voluntary cost allocation to shareholders.

15. Generally, post-test year ratemaking is disfavored when a forecasted test year revenue requirement is used to set rates.

16. Adopted in 1955, the American Standard Association Code for Pressure Pipeline (ASA B31.8) required pre-service pressure testing for natural gas pipelines.

17. PG&E admits that it voluntarily complied with American Standard Association Code for Pressure Pipeline (ASA B31.8), beginning in 1955.

18. Since no later than January 1, 1956, PG&E complied with or stated that it complied with industry standards to pressure test pipeline prior to placing it in service. PG&E is unable to produce the records for certain pressure tests that would have been performed in accord with industry standards from January 1, 1956, or for pipeline of unknown installation date. The lack of pressure test records for pipeline placed into service after January 1, 1956, or with an unknown installation date, reflect an error in PG&E's operation of its natural gas system. No evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirement from January 1, 1956.

19. PG&E's cost forecast for pressure testing pipeline is materially higher than DRA's, but is based on actual PG&E pressure test costs and is therefore reasonable.

20. Requiring pressure tests of existing pipeline to attain pressures of 90% SMYS for each pipeline component is impractical, and the margin of safety attained in the 49 CFR subpart J pressure test specifications is calculated based on the MAOP for the pipeline.

21. A valid pressure test record need only comply with the regulations in effect at the time the test was performed, not later adopted regulations.

22. Cost and engineering efficiency may be achieved by pressure testing pipeline segments adjacent to high priority segments.

23. PG&E's cost forecast for replacing pipeline is higher than DRA's, but is supported by actual PG&E operational experience and is therefore reasonable.

24. PG&E's cost forecast for replacing pipeline considered specific locations, as is illustrated by the Peninsula Adder for higher forecasted costs on the San Francisco peninsula.

25. Pipeline segments that end up in the M2 box of the Decision tree have substandard welds and will be operated a high pressure.

26. In-line inspection is a useful means to obtain data on pipeline conditions including indentations, wall loss, pipe strain, metallurgical variations, and certain types of cracks.

27. PG&E's in-line inspection proposal expands its existing in-line inspection program, focuses on segments operating at high pressure, and is consistent with D.11-06-017.

28. PG&E's valve automation proposal will automate and upgrade 228 valves.

29. Transmission main pipeline installed pursuant the Implementation Plan will be manufactured to higher standards than pipe installed 40 or more years ago and will be pressure tested prior to being placed in service.

30. The Commission has not authorized a memorandum account into which PG&E may record its Implementation Plans incurred prior to the effective date of today's decision.

31. The record shows that PG&E retained amounts in excess of its authorized rate of return during years when it did not spend its full authorized budget for gas pipeline improvements.

32. Improvements, efficiencies, and adjustments based on sound engineering practice to the Implementation Plan in furtherance of the objectives of the Plan are within the scope of the Plan and do not require further Commission review.

33. From the date installed, PG&E was responsible for creating and maintaining accurate and accessible records of its natural gas system equipment and facilities.

34. PG&E's failure to possess accurate and accessible records of its gas system caused the NTSB and this Commission to direct PG&E to correct these deficiencies.

35. PG&E's historic gas system revenue requirement has included costs for maintaining gas system records.

36. PG&E's imprudent management decisions to delay pipeline pressure testing and replacement contributed to the need for and timing of the projects needed pursuant to the Implementation Plan, which led to increased risk of cost overruns on projects.

37. An escalation rate tied to the overall inflation rate, as proposed by DRA, is a reasonable escalation factor for Implementation Plan projects.

38. The scope of and timing for the extraordinary capital investment needs of the Implementation Plan were caused, in part, by PG&E's imprudent management decisions regarding pipeline records and pressure testing older pipeline.

39. The amounts in Attachment E are program-based upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the Implementation Plan. To the extent specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects, the expense and capital cost limit of the balancing account is reduced by the amounts associated with the project not completed.

Conclusions of Law

1. In D.11-06-017, the Commission declared an end to historic exemptions from pressure testing for natural gas pipeline and ordered all California natural gas system operators to file Natural Gas Transmission Pipeline Testing Implementation Plans.

2. As required by § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

3. The burden of proof is on PG&E to demonstrate that it is entitled to the relief sought in this proceeding, including affirmatively establishing the reasonableness of all aspects of the application.

4. The standard of proof that PG&E must meet is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.

5. The evidentiary record does not support DRA's request for a comprehensive disallowance of all Implementation Plan costs, and we deny the request.

6. The scope and magnitude of the costs at issue in the Implementation Plan justify deviation from the general rule against post-test year ratemaking

7. The public utility code standards for rate recovery, i.e., just and reasonable, and the disallowance concept reflected in § 463 do not combine to provide an analytical basis for disallowing reasonable costs on the basis that the utility should have made the expenditures at an earlier date.

8. TURN's proposal to disallow all Implementation Plan costs should be denied.

9. PG&E's decision tree for the evaluating manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats should be approved.

10. PG&E's proposal to retrofit 199 miles of pipeline for in-line inspection and inspect 234 miles of pipeline with in-line inspection tools should be approved.

11. PG&E's proposal for pressure reductions and increased leak inspections and patrols should be approved.

12. PG&E's proposal to replace, automate and upgrade 228 gas shut-off valves in Phase 1 of the Implementation Plan should be approved, and PG&E should continue to monitor industry experience with automated shut-off valves for possible revisions to its plans.

13. It is reasonable for PG&E's shareholders to absorb the portion of the Implementation Plan costs which were caused by imprudent management.

14. Because PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material

voluntary cost allocation to shareholders, notwithstanding the Commission's directive to do so, and due to the scope and consequence of PG&E's imprudent management actions, it is reasonable to use exceptional ratemaking measures when considering shareholders' return on equity.

15. It is reasonable for shareholders to absorb the costs of pressure testing pipeline placed into service after January 1, 1956, or for which PG&E has no known installation date, and for which PG&E is unable to produce pressure test records.

16. It is reasonable to impose an equitable adjustment to the replacement cost of pipeline installed from January 1, 1956, to July 1, 1961, for which pressure test records are not available, but which require replacement rather than pressure testing. Such an equitable adjustment shall be equal to the forecasted cost of pressure testing the pipeline and shall reduce the cost of the pipeline replacement included in rate base and revenue requirement.

17. PG&E's cost forecast for pressure testing pipeline is much higher than any other forecast in the record but is reasonable.

18. A valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

19. It is reasonable to require PG&E to comply with 49 CFR subpart J pressure test specifications when conducting pressure tests pursuant to the Implementation Plan.

20. PG&E has justified including pipeline segments located in Class 1 or 2 locations without high consequence areas but adjacent to Class 3 or 4 locations, or with economic or engineering supporting rationale, within Phase 1.

21. PG&E's cost forecast for replacing pipeline is substantially higher than DRA's, but is supported by significant operational experience and is therefore reasonable.

22. The request by TURN and the City and County of San Francisco to disallow pipeline replacement costs for alleged Integrity Management failures should be denied.

23. PG&E's proposal to replace, rather than pressure test, pipeline installed prior to 1970, with weld that do not meet current standards, operated at over 30% SMYS and located in high population areas is reasonable.

24. PG&E's proposal to capitalize replacement pipe less than 50 feet in length is not reasonable and is denied. Such pipe must be expensed, consistent with current accounting practice.

25. It is reasonable to conclude that pipe installed pursuant to the Implementation Plan will have a longer service life than pipe installed over 40 years ago.

26. TURN's proposal to adopt a 65-year service life for transmission main pipe installed pursuant to the Implementation Plan is reasonable, and should be adopted.

27. PG&E has not justified recovering from ratepayers its Implementation Plan costs incurred prior to the effective date of today's decision.

28. Absent extraordinary circumstances, the rule against retroactive ratemaking prevents ratepayer representatives from recovering for ratepayers amounts authorized but unspent by PG&E for gas pipeline improvements.

29. PG&E's request for authority to file Tier 3 Advice Letters to modify the Implementation Plan should be denied.

30. Authority should be delegated to the Director of CPSD, or designee, (CPSD) to oversee all PG&E's work performed pursuant to the Implementation Plan, including:

A. CPSD shall review all changes to the Implementation Plan proposed by PG&E, shall require such modifications as are necessary to ensure public safety, and may concur in such proposals.

B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

C. CPSD may take and order PG&E to take such actions as may be necessary to protect immediate public safety.

D. CPSD may issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety, and PG&E must comply immediately and consistent with any needed safety protocols.

E. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

31. The Executive Director should be delegated authority to order PG&E to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision, not to exceed $15,000,000 and PG&E should be authorized to record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery from ratepayers.

32. PG&E should file compliance reports as specified in Attachment D.

33. It is not reasonable to adopt a cost overrun contingency allowance because PG&E's imprudent management decisions contributed to risk of such overruns and we adopt cost forecasts at the high end of the range of reasonableness with an added layer for program administration.

34. The Commission should impose strong incentives on PG&E to encourage efficient construction management and administration of the Implementation Plan.

35. PG&E's proposal for a 21% contingency adder should be denied.

36. A rate of 1.5% should be adopted to escalate costs from the effective date of today's decision to the date of project completion.

37. A one-way balancing account should be approved for all Implementation Plan projects, subject to the following limitation: To the extent PG&E incurs costs beyond the amounts set forth in Attachment E for projects approved in today's decision, the expense and capital overruns should not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. Similarly, where specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects, the expense and capital cost limit of the balancing account should be reduced by the amounts associated with the project not completed.

O R D E R

IT IS ORDERED that:

1. The Pipeline Safety Enhancement Plan (Implementation Plan) of Pacific Gas and Electric Company (PG&E) is approved. PG&E must expeditiously and efficiently pursue the natural gas system safety improvements as described in the Implementation Plan.

2. Pacific Gas and Electric Company is authorized to increase its natural gas system regulated revenue requirement to be recovered from ratepayers from the amounts authorized in Decision 11-04-031 by the amounts set forth below in the year indicated:

	2012	**2013**	**2014**	**TOTAL**
$ thousands	$2,913	$115,343	$180,958	$299,214

3. All increases in revenue requirement authorized in Ordering Paragraph 2 are subject to refund pending further Commission decisions in Investigation (I.) 11-02-016, I.11-11-009, and I.12-01-007.

4. Pacific Gas and Electric Company is authorized to submit a Tier 1 Advice Letter to revise its Preliminary Statement, Part B, to reflect a new rate component titled the "Implementation Plan Rate" in the customer class charge included in transportation charges to collect the annual increase in revenue requirement adopted in Ordering Paragraph 2, as shown in Attachment F to today's decision.

5. Pacific Gas and Electric Company (PG&E) is authorized to file a Tier 1 Advice Letter to create a one-way (downward) Gas Pipeline Expense and Capital Balancing Account to record the difference between forecast and recorded expenses and capital costs authorized for the Implementation Plan costs from the effective date of today's decision through December 31, 2014, for core and noncore customer classes. Any accumulated balance on December 31, 2014, plus interest, will be returned to customers through the Customer Class Charge in PG&E's Annual Gas True-Up Filing to be filed shortly before the end of 2014. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

6. Pacific Gas and Electric Company (PG&E) must limit the amounts recorded in the balancing account authorized in Ordering Paragraph 5 to the

adopted expense and capital amounts set forth in Attachment E for each program. Expense and capital amounts in excess of adopted amounts may not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. The adopted expense and capital amounts for any program shall be reduced by the cost of any Implementation Plan project not completed and not replaced with a higher priority project. Subject to these limits, PG&E is authorized to collect from ratepayers only the revenue requirements associated with actual expenses and capital costs recorded in the balancing account.

7. Pacific Gas and Electric Company is authorized to file a Tier 1 Advice Letter to create a balancing account to record the amount of revenues collected from ratepayers through the Implementation Plan Rate as compared to the adopted revenue requirement. The balance, if any, as of December 31, 2014, shall be collected from or refunded to ratepayers through the next Annual Gas True-Up filing. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

8. The Director of the Commission's Consumer Protection and Safety Division, or designee, (CPSD) is delegated the following authority:

   A. CPSD shall review all changes to the Implementation Plan proposed by Pacific Gas and Electric Company (PG&E), shall require such modifications as are necessary to ensure public safety, and may concur in such proposals.

   B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

C. CPSD may take and order PG&E to take such actions as may be necessary to protect immediate public safety.

D. CPSD may issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety, and PG&E must comply immediately and consistent with any needed safety protocols.

E. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

9. The Executive Director is delegated authority to order Pacific Gas and Electric Company (PG&E) to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision, not to exceed $15,000,000. PG&E is authorized to record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery from ratepayers.

10. Pacific Gas and Electric Company must submit compliance reports on the schedule and including the information set forth in Attachment D to today's decision. Such reports shall be filed and served in this proceeding, with printed copies to the Directors of the Energy Division and the Consumer Protection and Safety Division.

11. Pacific Gas and Electric Company must file an application within 30 days after the completion of its Maximum Allowable Operating Pressure validation and records search to present the results of those efforts and update its Implementation Plan authorized revenue requirements and related budgets, consistent with this decision.

This order is effective today.

Dated _____, at San Francisco, California

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Attachment A : Appearances

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****

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(END OF ATTACHMENT A)

ATTACHMENT B

List of Recommendations from Report of the Independent Review Panel

No.	***Recommendation***
Section 2 – Background	
None	
Section 3 – The Panel and Its Approach	
None	
Section 4 – San Bruno Incident	
None	
Section 5 – Review of PG&E's Performance as an Operator	
5.1.4.1	*PG&E needs to create a culture of system integrity that enables every employee to recognize and understand how his or her day-to-day actions affect system integrity.*
5.1.4.2	*PG&E needs to streamline the organization, reducing layers of management and rebuilding the core of technical expertise.*
5.2.4.1	*PG&E should acquire and develop a staff of professionals with the skills necessary to do state-of-the-art practical analysis of risk management decisions that concern public health and safety, employee health and safety, environmental consequences, socioeconomic consequences, and financial and reputation implications for the company.*
5.2.4.2	*The Board of Directors of PG&E should require that state-of-the-art risk analysis be conducted on every problem included on PG&E's list of top 10 catastrophic risks. The Board should be assessing the quality of involvement of the members of the top management team in every one of these risk analysis, as all risk management decisions that concern the top ten catastrophic risks should be of direct concern to all top PG&E executives, including the President and CEO, as well as the Board.*
5.3.4.1	*PG&E should conduct a comprehensive review of its data and information management systems to validate the completeness, accuracy, availability, and accessibility to data and information and take action through a formal management of change process to correct deficiencies where possible.*
5.3.4.2	*Upon obtaining the results of the review, PG&E should undertake a multi-year program that collects, corrects, digitizes and effectively manages all relevant*

	design, construction and operating data for the gas transmission system.
5.4.4.1	*The pipeline and distribution integrity management programs should be separated organizationally with dedicated resources to manage and execute both programs.*
5.4.4.2	*PG&E should conduct a staffing and skills assessment of the integrity management group to determine if the organization would be better able to maintain its focus and accomplish its complex mission that would with an alternate structure.*
5.4.4.3	*PG&E should establish a capital program, based on risk criteria, that includes retrofitting existing pipelines, as appropriate, to accommodate ILI tools. ILI surveys provide additional information about the condition of the pipe that enable better decisions regarding remediation, prevention, and mitigation such as monitoring, inspection, repair, replacement, and rehabilitation.*
5.4.4.4	*PG&E needs to establish a culture of pipeline integrity that enable field and staff to encourage self-reporting of deviations from company policies, processes, or practices. CPUC pipeline safety inspectors should view self-reported deviations as nonconformance rather than noncompliance.*
5.4.4.5	*PG&E should develop and adopt a maturity framework that reflects the importance and advancement of thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise, where progress is transparent and measurable, and is consistent with the best thinking on pipeline integrity and process safety management.*
5.5.3.1	*Review and restructure all division, regional and company emergency plans for consistency in presentation and feel, while incorporating best practices observed from Pipeline 2020.*
5.5.3.2	*Conduct a study of SCADA needs to achieve enhanced gas transmission system knowledge that would enable improved shutdown capabilities in the event of a future pipeline rupture. Study to include: (1) the visibility of the transmission operations to system operators, (2) the ability of automation to sense line breaks, (3) the ability to model failure events; and (4) the capability to transmit schematic and real-time information to pipeline field personnel.*
5.5.3.3	*When study of SCADA needs is completed (described in Recommendation 5.5.3.2), establish a multi-year program to make implement the results of the study.*
5.6.4.1	*PG&E should take a fresh look at the budgets for pipeline integrity efforts and make informed judgments about how to address the quality and timeliness of efforts to improve its system.*

5.6.4.2	*PG&E should establish a multi-year program that deals with all the capital requirements to assure system integrity, based on sound risk criteria (i.e., a methodology that addresses the likelihood of various possible failures given competing alternatives). This program would include:* • *Investments to collect, correct, digitize and effectively manage all relevant design, construction and operating data for the gas transmission system.* • *Investments to retrofit existing pipelines to accommodate in-line inspection technology, to test or replace uncharacterized or anomalous pipe has needed, and to reroute pipe in the HCAs where accessed.*
5.7.4.1	*PG&E should restructure the Pipeline 2020 document to enhance effectiveness and assist in monitoring for both PG&E and the CPUC, by incorporating the following:* • *Vision Statement, which will describe "the transmission pipeline system of the future." This should be a clear statement as to how PG&E sees the role of the transmission system of the future. This will facilitate decisions made in the strategic parts of 2020 that can be focused and relevant to more than just compliance. It should demonstrate the asset profile, and how it will support safety, and operational goals. PG&E should identify specific measures to define what an effective program will deliver.* • *Delivery Strategies, which will set out the goals of the strategy and steps to deliver the vision. The delivery strategies should be fully developed based on other recommendations for pipeline integrity management and related improvements.* • *Execution Plan, which will define the tasks to be accomplished, how they will be accomplished, an associated timeframe and projected costs.* • *Analysis of Alternatives, which will document various alternatives considered, complete with costs and consequences. A thorough analysis of alternatives will ultimately result in support of the program.* • *In lieu of or in addition to R&D funding for new technology, entertain reasonable opportunities to serve as a testing ground for improved ILI technology.* *The CPUC or its designated consultant should review the plan and collaborate with PG&E in the development of clear objectives, measures, and schedule.*
Section 6 – Review of CPUC Oversight	
6.2.4.1	*Adopt as a formal goal, the commitment to move to more performance-based regulatory oversight of utility pipeline safety.*

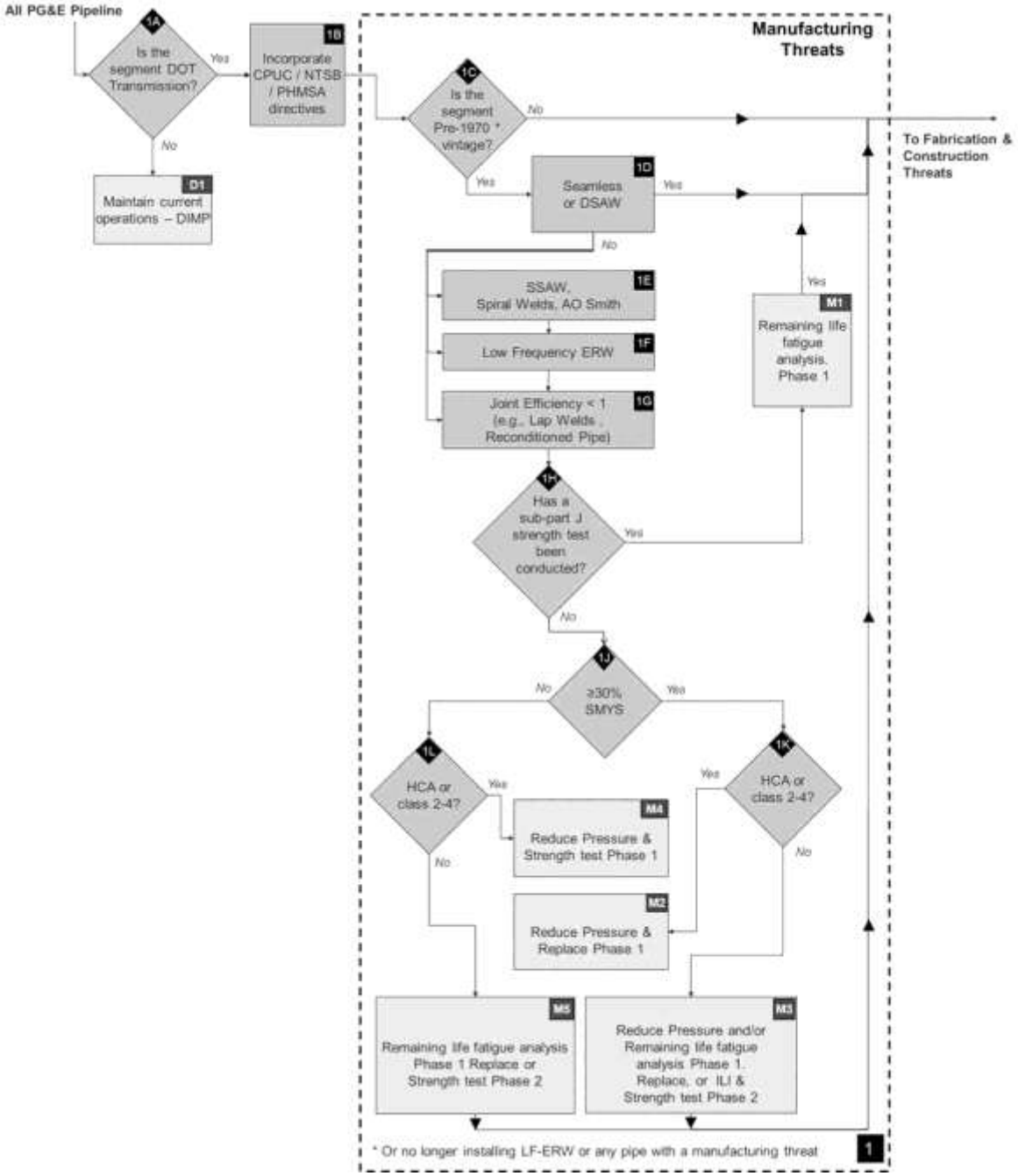
6.2.4.2	*Greater involvement by staff in industry groups such as the Gas Piping Technical Committee (GPTC) will better enable the CPUC staff to keep abreast pipeline integrity management advancements from a technical, process, and regulatory perspective. In addition, the CPUC can, through such forums, gain insight for pipeline operators, utilities, service providers, and professional services firms, as well as other federal and state pipeline safety professionals.*
6.2.4.3	*The CPUC should further divide gas auditing groups to create integrity management specialists.*
6.2.4.4	*Undertake an independent management audit of the USRB organization, including a staffing and skills assessment, to determine the future training requirements and technical qualifications to provide effective risk-based regulatory oversight of pipeline safety and integrity management, focused on outcomes rather than process.*
6.2.4.5	*Provide USRB staff with additional integrity management training.*
6.2.4.6	*Retain independent industry experts in the near term to provide needed technical expertise as PG&E proceeds with its hydrostatic testing program, in order to provide a high level of technical oversight and to assure the opportunity for legacy piping characterization through sampling is not lost in the rush to execute the program.*
6.3.3.1	*The CPUC should develop a plan and scope for future annual California utility initiated independent integrity management program audits. The results of these audits should be used to provide a basis for future CPUC performance based audits on a three-year basis.*
6.3.3.2	*Request the California General Assembly to enact legislation that would replace the mandatory minimum five-year audit requirements for mobile home parks and small propane systems with a risk-based regime that would provide the USRB with needed flexibility in how it allocates inspection resources.*
6.3.3.3	*The CPUC should consider requiring the major regulated utilities operating in the State of California to submit the results of the independent integrity management audits as part of their respective rate case processes.*
6.3.3.4	*The USRB is currently understaffed and will be further understaffed as new programs such as Distribution Integrity Management are added. This understaffing problem must be relieved by a combination of an enhanced recruitment and training program to attract and retain qualified engineers plus a framework of supplemental support by outside consultants.*

6.3.3.5	*USRB should augment its current use of vertical audits that focus on specific regulatory requirements such as leak records or emergency response plans with: •* • *Horizontal audits that assess a segment or work order of the operator's system through the entire life cycle of the current asset for regulatory compliance.* • *• Focus field audits based on an internally ranking of the most risk segments of the gas transmission system assets in the state, regardless of the operator.*
6.3.3.6	*To raise the profile of the audits among all the stakeholders, add the following requirements to the safety and pipeline integrity audits of the utilities that includes the following features: (1) posting of audit findings and company responses on the CPUC's website; (2) use of a "plain English" standard to be applied for both staff and operators in the development of their findings and responses, respectively; and (3) a certification by senior management of the operator that parallels that certifications now required of corporate financial statements pursuant to Sarbanes-Oxley.*
6.4.3.1	*CPUC should consider seeking approval from the State Budget Director for an increase in gas utility user fees to implement performance-based regulatory oversight for all gas utilities.*
6.4.3.2	*Request the California legislature pass legislation that would replace the mandatory minimum five-year audit requirements with a risk-based regime that would provide the USRB with the needed flexibility in how it allocates inspection resources.*
6.5.3.1	*Adopt as a formal goal, the commitment to move to performance-based regulatory oversight of utility pipeline safety and elevate the importance of the USRB in the organization.*
6.5.3.2	*Develop a holistic approach to identifying pipeline segments for integrity management audits based on intrastate pipeline risk as opposed to simply auditing each operator's pipeline.*
6.6.3.1	*The CPUC should significantly upgrade its expertise in the analytical skills necessary for state-of-the-art quality risk management work. The CPUC should have an organizational structure for individuals doing this work such that they have an equal stature and access to management of the CPUC as those who deal with rate issues or legal or political issues. Although the CPUC's role is to provide oversight of the operator's compliance with federal and state codes, its role should not be to provide management of risk direction to the utilities.*
6.7.3.1	*The CPUC should seek to align its pipeline enforcement authority with that of the State Fire Marshal's by providing the CPSD staff with additional enforcement tools modeled on those of the OSFM and the best from other states.*

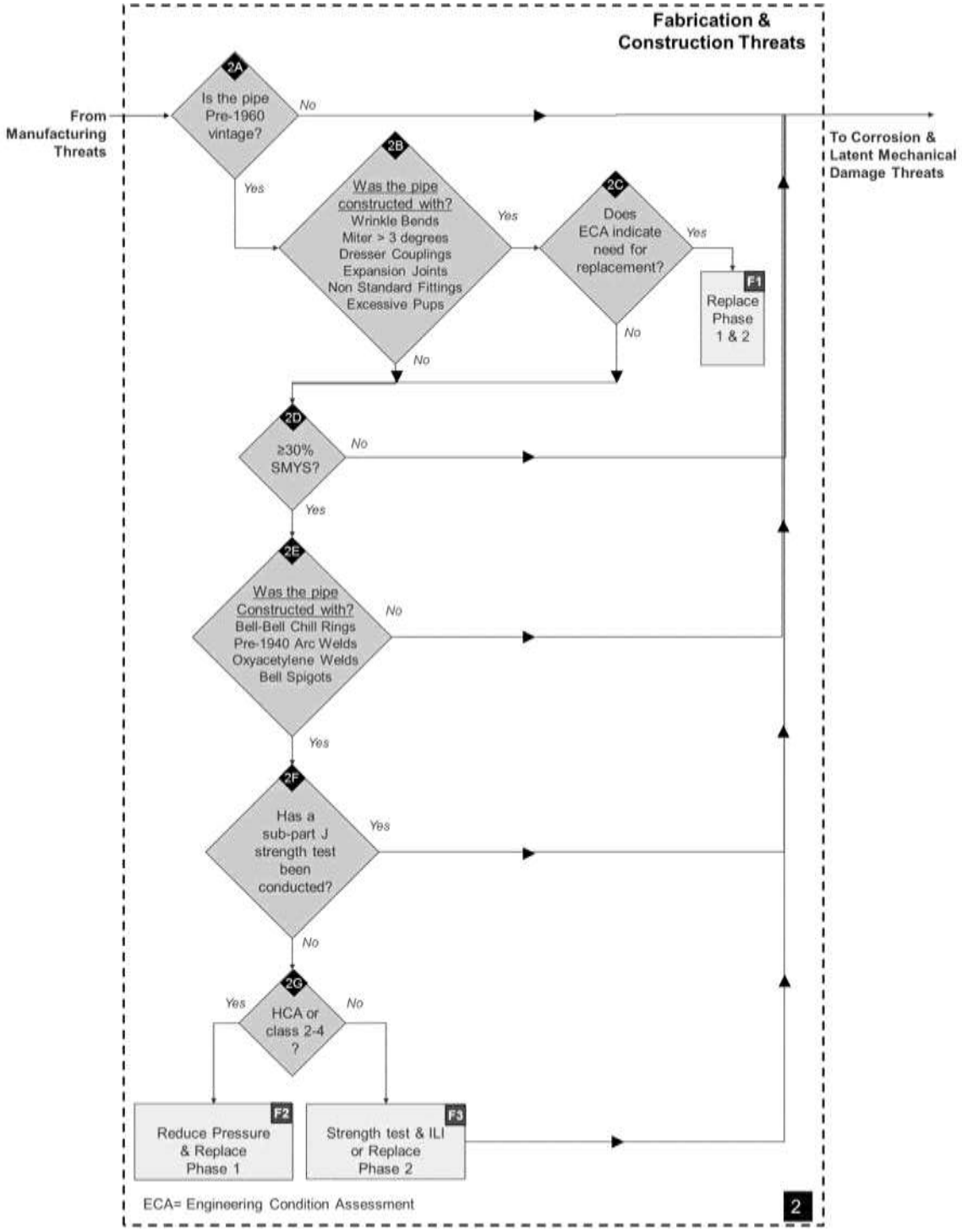
6.8.3.1	*Consider a more proactive role for the safety staff in utility rate filings. Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so there is an enhanced understanding of the costs associated with pipeline safety.*
6.8.3.2	*Consider, as appropriate, transferring the USRB gas safety staff to the OSFM, and with them the responsibility for inspection of gas operator safety and integrity management programs as required by federal and state gas pipeline safety regulations.*
Section 7 – Public Policies in the State of California	
7.4.1	*Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so that there is an enhanced understanding of the costs associated with pipeline safety.*
7.4.2	*Upon thorough analysis of benchmark data, adopt performance standards for pipeline safety and reliability for PG&E, including the possibility of rate incentives and penalties based on achievement of specified levels of performance.*

(END OF ATTACHMENT B)

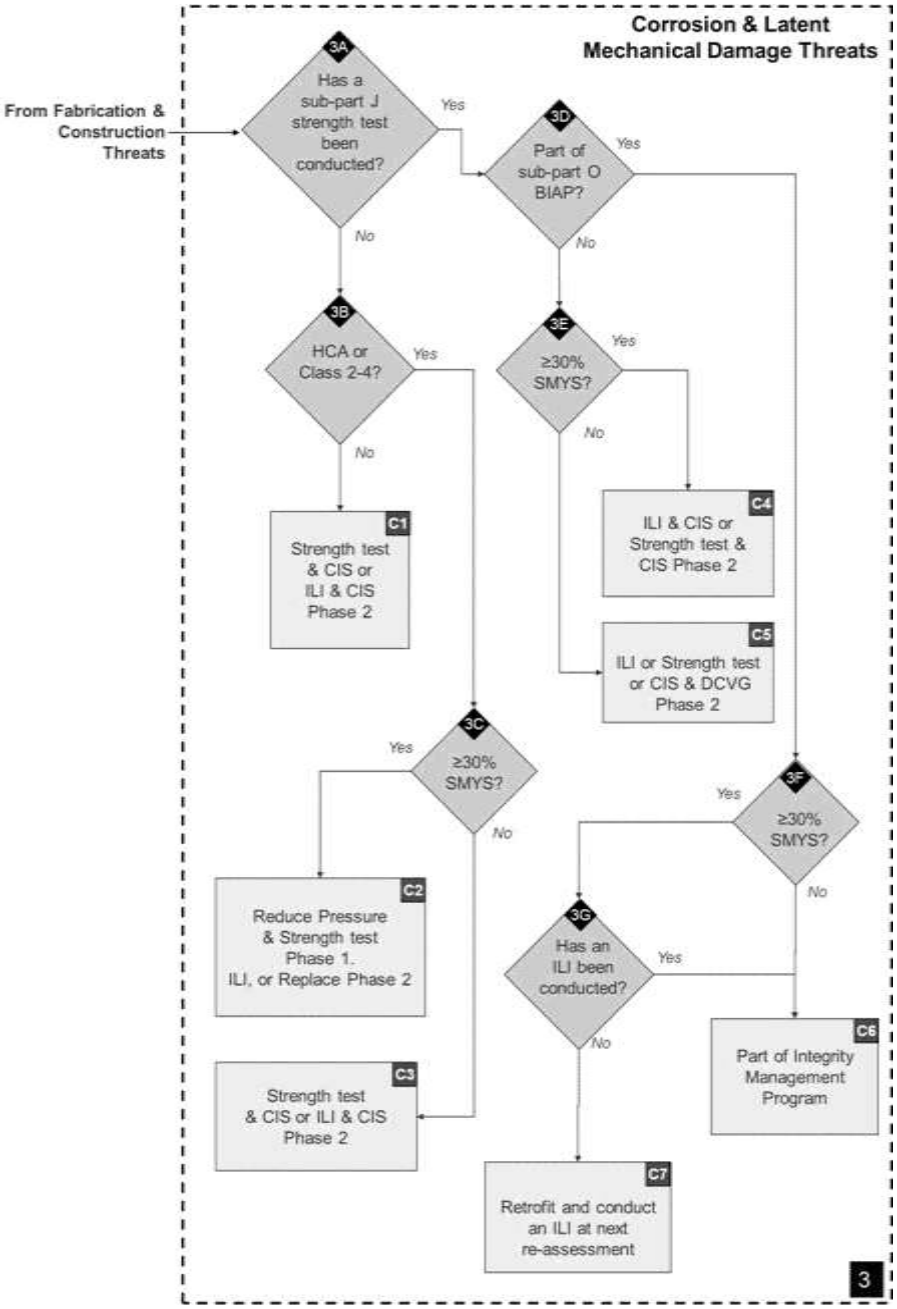
ATTACHMENT C
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
MANUFACTURING THREAT DECISION QUERY



PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
FABRICATION AND CONSTRUCTION THREAT DECISION QUERY



PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
CORROSION AND LATENT MECHANICAL DAMAGE THREAT DECISION QUERY



Attachment D

Specifications for PG&E Implementation Plan Compliance Reports.

Frequency of Filing: No later than 30 days after the conclusion of each calendar quarter.

Availability: Posted on PG&E web site, and served on all parties and Directors of Energy Division and CPSD.

1) Describe PG&E's project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

2) Explain how PG&E decided whether to do the work in-house (e.g, use own employees and equipment) or contract the work out to other parties?

3) For work contracted out to other parties, what criteria did PG&E use to select the contractors and did PG&E use a competitive bidding process to select the contractor(s)? If not, explain why.

4) How does PG&E monitor the quality of work performed by outside contractors? Has PG&E found any instances where a contractor failed to do the work properly? If so, what actions did PG&E take in response?

5) What quality assurance procedures does PG&E have in place to determine whether the project work is being done correctly by its own employees? Has PG&E found any instances where the work was not done properly? If so, what actions did PG&E take in response?

6) Describe the role of the Program Management Office (PMO) (see p. 7-10 of Prepared Testimony) in containing project costs. Provide specific examples where the PMO's recommendations lead to cost savings.

7) Provide the costs incurred by the PMO year-to-date and describe the specific work they did for the benefit of PG&E customers.

8) Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

9) Describe PG&E's procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.

10) What was the disposition (e.g., sold) of replaced pipe and other material. Identify all the amounts earned for the disposition of the material, costs incurred to transport or dispose of the material and regulatory treatment of the incurred costs and revenues.

11) Provide a complete description or a specific reference to proceeding workpapers, of projects completed during this reporting period and those completed Year-to-Date, include the start and finish dates. On a project-by-project basis, provide the amount budgeted for the project and an itemized list of the costs, including labor and material, incurred completing of the project. Identify the amount that a project was over or under-budget. Indicate whether the work was done in-house or by outside contractor(s). Identify the outside contractor(s). Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project. Identify costs that shareholders will absorb.

12) Provide a complete description, or a specific reference to proceeding workpapers, of projects that have begun but are currently unfinished, include the start and anticipated completion dates. On a project-by-project basis, provide the amount budgeted for each project. Explain how the work is being done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project.

13) Provide a complete description, or a specific reference to proceeding workpapers, of projects that were forecasted for Phase 1 that have yet to start, include the anticipated start and anticipated completion dates. Rank the priority of these projects and explain the ranking. On a project-by-project basis, provide the amount budgeted for the project. Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, identify the Decision Tree outcome identifier associated with each project.

14) Describe, in detail, projects that PG&E has completed, are work-in-progress, or have yet to start that were not included in the workpapers submitted in R.11-02-019. Explain why these projects have been included in Phase 1 and whether these projects have lowered the priority of other projects identified in proceeding workpapers and, if so, why. Explain how this work complies with D.11-06-017 and PG&E's Decision Tree and provide the Decision Tree outcome identifier associated with each project.

15) For completed projects that are 10% or more over estimated costs, provide a detailed explanation why the overrun occurred.

16) Provide a list and map of pipelines that are currently piggable, highlighting pipe that was made piggable as a result of projects conducted under the PSEP. Provide the total mileage of transmission pipelines, the total mileage of pipelines that are currently piggable and percentage of the total that is piggable.

17) Describe any lessons learned from undertaking the Phase 1 work that has led to cost efficiencies and quantify any cost savings.

18) How will the work PG&E conducts in Phase 1 influence how PG&E will plan and estimate the costs of its proposed projects for Phase 2

19) What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?

20) Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g, hydrotesting, pipe replacement).

21) Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g, hydrotesting, pipe replacement).

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

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

24) Provide the costs of the public outreach PG&E has incurred year-to-date by month as compared to the amount authorized. Explain in detail what public outreach activities PG&E has engaged in.

25) Describe (e.g., provide date(s), location, Line #) all planned and unplanned service outages PG&E experienced in conducting the project work and explain how PG&E addressed customer needs during the outages. Were customers notified of any outages beforehand?

26) Describe or provide a specific reference to PG&E's work papers of the projects that were not completed or replaced by a higher priority project and show the uncompleted project's associated costs. Compute the corresponding reduction to the Implementation Plan adopted amounts set out in Attachment E, as required by Ordering Paragraph 6.

27) Provide a clear explanation, for each project for which expenditures have been incurred, of how the project is necessary to comply with PSEP requirements rather than being included among projects that are already funded in D.11-04-031.

28) Progress report on record improvement efforts, including report on costs absorbed by shareholders.

29) Any additional relevant information not listed above as specified in hearing Exh. 2 at 8E-1 and 8E-2.

Attachment E – Authorized Revenue Requirement Increases

E- 1 Authorized Revenue Requirement Increases

E- 2 Authorized Program Expenses

E- 3 Authorized Capital Costs

E- 4 Authorized Combined Expense and Capital

		Table E-1				
	Pacific Gas and Electric Company					
	Implementation Plan Authorized Revenue Requirements					
		2011-2014				
	($ in thousands)					
Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	Capital-Only Revenue Requirement	–	$9,191	$41,076	$90,605	$140,872
2	Expense-Only Revenue Requirement		$79,399	$74,267	$90,353	$244,020
3	Total	–	$88,590	$115,343	$180,958	$384,892
4	Disallowance of months in 2012		-$85,678			
5	Decision Increase in Revenue Req.		$2,913	$115,343	$180,958	**$299,214**
	Note (1) - Disallowance based on effective date of decision					

E- 2 Authorized Program Expenses

TABLE E-2 Program Expenses
PACIFIC GAS and ELECTRIC COMPANY
EXPENSES (w/escalation adjustment)
($ IN MILLIONS)

Line No.	Description	2011(a)	2012(b)	2013	2014	Total
1	Pipeline Modernization Program	0.0	2.3	65.9	81.3	149.5
2	Valve Automation Program	0.0	0.1	3.0	3.6	6.7
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	1.1	1.0	2.1
5	Program Management Office	0.0	0.1	3.3	3.2	6.6
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Expenses	$0.0	$2.6	$73.3	$89.2	$165.0

(a) The 2011 expenses will be funded by shareholders.
(b) The 2012 expenses will be funded by shareholders until effective date of decision.

E- 3 Authorized Capital Costs

TABLE E-3
PACIFIC GAS and ELECTRIC COMPANY
Authorized Capital Expenditures (w/escalation adjustment)
($ IN MILLIONS)

Line No.	Description	2011	2012	2013	2014	Total
1	Pipeline Modernization Program	30.5	214.9	290.1	317.0	852.5
2	Valve Automation Program	13.7	38.9	51.6	24.8	129.0
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	0.0	0.0	0.0
5	Program Management Office	3.0	6.5	6.5	6.3	22.3
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Capital Expenditures	$47.2	$260.3	$348.2	$348.0	$1,003.8

Note - Adopted Revenue Requirement includes 2011 and 2012 adjustments associated with authorized capital expenditures

E- 4 Authorized Combined Capital and Expense

Table E-4 - Authorized Combined Expense and Capital
w/Escalation Adjustment
($ IN MILLIONS)

Line No.	Description	2011(a)	2012 (b)	2013	2014	Total
1	Pipeline Modernization Program	30.5	217.3	356.0	398.2	1,002.0
2	Valve Automation Program	13.7	39.0	54.6	28.4	135.7
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	1.1	1.0	2.1
5	Program Management Office	3.0	6.6	9.8	9.5	28.9
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Cost	$47.2	$262.9	$421.5	$437.2	$1,168.8

(a) The 2011 expenses will be funded by shareholders.
(b) The 2012 expenses will be funded by shareholders until effective date of decision.

Attachment F

Table F – 1 Implementation Plan Rate component by Function

Table F – 2 Illustrative Class Average Present and Proposed Rates

Table F – 3 Implementation Plan Rate Component by Customer Class

TABLE F-1
PACIFIC GAS AND ELECTRIC COMPANY
IMPLEMENTATION PLAN RATE COMPONENTS
($ PER THERM)

Line No.		2012	2013	2014
1	**Core**			
2	PSEP - Local Transmission	$0.01492	$0.02024	$0.02953
3	PSEP - Backbone Transmission	$0.00312	$0.00327	$0.00600
4	PSEP - Storage	$0.00010	$0.00033	$0.00113
5	Total GPS Rate	$0.01814	$0.02384	$0.03667
6	**Noncore - Local Transmission/Distribution Level**			
7	PSEP - Local Transmission	$0.00687	$0.00946	$0.01439
8	PSEP - Backbone Transmission	$0.00272	$0.00274	$0.00492
9	PSEP - Storage	$0.00004	$0.00014	$0.00048
10	Total GPS Rate	$0.00963	$0.01234	$0.01979
11	**Noncore - Backbone Transmission Level**			
12	PSEP - Backbone Transmission	$0.00272	$0.00274	$0.00492
13	PSEP - Storage	$0.00004	$0.00014	$0.00048
14	Total GPS Rate	$0.00277	$0.00288	$0.00540

TABLE F-2
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE CLASS AVERAGE PRESENT AND RATES INCLUDING IMPLEMENTATION PLAN COSTS
($ PER THERM)

Line No.	Customer Class	Present April 2012 Rates(a) ($/Th)	2012 Rates(a) With Implementation Plan Costs ($/Th)	Percentage Change
1	Core Retail - Bundled(b)			
2	Residential (Non-Care)(c)(e)	$1.247	$1.265	1.5%
3	Commercial, Small (Non-Care)(e)	$0.966	$0.984	1.9%
4	Commercial, Large	$0.751	$0.769	2.4%
5	NGV Service - Compression on Customer Premises	$0.648	$0.666	2.8%
6	Compressed NGV Service	$1.871	$1.889	1.0%
7	Core Retail - Transportation Only(d)	$0.697	$0.715	2.6%
8	Residential (Non-Care)	$0.436	$0.454	4.2%
9	Commercial, Small (Non-Care)	$0.261	$0.280	6.9%
10	Commercial, Large			
11	Noncore Retail - Transportation Only(d)			
12	Industrial Distribution	$0.189	$0.199	5.1%
13	Industrial Transmission	$0.079	$0.088	12.3%
14	Industrial Backbone	$0.052	$0.055	5.3%
15	Electric Generation - Distribution/Transmission	$0.032	$0.042	30.0%
16	Electric Generation - Backbone	$0.012	$0.015	23.6%
17	Noncore NGV Service - Distribution	$0.174	$0.184	5.5%
18	Noncore NGV Service - Transmission	$0.064	$0.074	15.0%
19	Wholesale - Transportation Only(d)			
20	Alpine Natural Gas	$0.034	$0.044	28.2%
21	Coalinga	$0.035	$0.044	27.8%
22	Island Energy	$0.053	$0.062	18.2%
23	Palo Alto	$0.030	$0.039	32.4%
24	West Coast Gas - Castle(f)	$0.137	$0.147	7.0%
25	West Coast Gas - Mather Transmission	$0.163	$0.172	5.9%
26	West Coast Gas - Mather Distribution(f)	$0.037	$0.047	25.9%

(a) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage. Rates are rounded to three decimal places for ease of viewing. Percentage rate changes are calculated on a 5 digit basis.

(b) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.395 per therm; (ii) a transportation component that recovers Customer Class Charge (CCC), customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a G PPP surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), Low Income Energy Efficiency (LIEE), Customer Energy Efficiency (CEE), Research Development and Demonstration program and State Board of Equalization (BOE)/CPUC Administrative costs. Actual procurement rates change monthly.

(c) CARE customers receive a 20 percent discount on transportation and procurement and are exempt from paying CARE surcharges.

(d) Transportation Only rates include: (i) a transportation component that recovers CCC, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a G-PPP surcharge that recovers the costs of low income CARE, LIEE, CEE, Research Development and Demonstration program and State BOE/CPUC Administrative costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(e) Residential and Small Commercial Classes are 20 percent averaged.

(f) West Coast Gas is allocated 70 percent of its full distribution cost as of January 1, 2012.

Table F-3
Pacific Gas and Electric Company
IMPLEMENTATION PLAN RATES
($ PER THERM)

Line No.		2011 (A)	2012 (B)	2013 (C)	2014 (D)
1	**Core Customer Classes**				
2	Residential	$0.00000	$0.01814	$0.02384	$0.03667
3	Small Commercial	$0.00000	$0.01814	$0.02384	$0.03667
4	Large Commercial	$0.00000	$0.01814	$0.02384	$0.03667
5	Natural Gas Vehicle (Compressed)	$0.00000	$0.01814	$0.02384	$0.03667
6	Natural Gas Vehicle (Uncompressed)	$0.00000	$0.01814	$0.02384	$0.03667
	Noncore Customer Classes				
7	Industrial - Distribution	$0.00000	$0.00963	$0.01234	$0.01979
8	Industrial - Local Transmission	$0.00000	$0.00963	$0.01234	$0.01979
9	Industrial - Backbone Transmission	$0.00000	$0.00277	$0.00288	$0.00540
10	Electric Generation (Distribution/Local Transmission)	$0.00000	$0.00963	$0.01234	$0.01979
11	Electric Generation (Backbone Transmission)	$0.00000	$0.00277	$0.00288	$0.00540
12	Natural Gas Vehicle - Distribution (Uncompressed)	$0.00000	$0.00963	$0.01234	$0.01979
13	Natural Gas Vehicle - Transmission (Uncompressed)	$0.00000	$0.00963	$0.01234	$0.01979
14	Wholesale Customers				
15	Alpine Natural Gas	$0.00000	$0.00963	$0.01234	$0.01979
16	Coalinga	$0.00000	$0.00963	$0.01234	$0.01979
17	Island Energy	$0.00000	$0.00963	$0.01234	$0.01979
18	Palo Alto	$0.00000	$0.00963	$0.01234	$0.01979
19	West Coast Gas - Castle	$0.00000	$0.00963	$0.01234	$0.01979
20	West Coast Gas - Mather Distribution	$0.00000	$0.00963	$0.01234	$0.01979
21	West Coast Gas - Mather Transmission	$0.00000	$0.00963	$0.01234	$0.01979

(END OF ATTACHMENT F)