UNITED STATES OF AMERICA
BEFORETHE
FEDERALENERGYREGULATORYCOMMISSION

CAlifornians for Renewable Energy, Inc., (CARE); Michael E. Boyd; and Robert M. Sarvey Complainant, v. Pacific Gas and Electric Company, Respondents.	Docket No. EL

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COMPLAINT OF CALIFORNIANS FOR RENEWABLE ENERGY

Pursuant to the Natural Gas Act, 15 U.S.C. §§ 717-717z, and Rule 206, 18 C.F.R. 385.206 (2012) of the Rules of Practice and Procedure ("Rules") of the Federal Energy Regulatory Commission ("FERC"), CAlifornians for Renewable Energy, Inc. ("CARE"), Michael E. Boyd, and Robert M. Sarvey Individually hereby file this Complaint against Pacific Gas and Electric Company ["PG&E"], for violation of the terms and conditions of their blanket certificate[1] through a failure to meet requirements to maintain its natural gas transmission system [18 C.F.R. § 157.14(a)(9)(vi)] in the events that lead up to, including the events following the fire that proceeded the explosions that destroyed 35 homes and killed 8 individuals [including an alleged CPUC pipeline safety whistleblower[2]]; and the subsequent response and cover up by the CPUC and NTSB following the San Bruno pipeline explosion. The explosions occurred on

[1] *See* Letter Order Pursuant § 375.307 Pacific Gas and Electric Company Docket No. PR10-72-000 Issued: July 18, 2011, Accession Number: 20110718-3048

[2] "Jacqueline Greig, a CPUC employee who is listed on the commission's telephone directory as part of its Division of Ratepayer Advocates. Greig and her 13-year-old daughter Janessa were killed in the fire." Source: *See* http://sfappeal.com/news/2010/09/san-bruno-fire-ca-puc-seeking-reports-from-those-who-smelled-gas-in-area.php
"What are the odds that Jacqueline Grieg, a whistle blower advocating for customers of PG&E, was at home in San Bruno at the epicenter of the "explosion" and died that day, along with her 13 year old daughter. She had previously exposed PG&E for proposing a cost for pipeline upgrades at a rate increase of $4.2 billion, which her research revealed was exaggerated by $3.2 billion. What are the odds of her house being "ground zero" for that blast?" Source: *See* http://www.henrymakow.com/whats_behind_the_gas_pipeline.html

September 9, 2010, involving the rupture of Line 132, a 30-inch natural gas intrastate transmission line operated by the Pacific Gas and Electric Company and regulated by CPUC. The root cause of the fire and resulting explosions remains undetermined.

I. INTRODUCTION

As this complaint establishes in more detail below there is ample evidence to demonstrate that Pacific Gas and Electric Company ["PG&E"]; enabled by California Public Utilities Commission; miss-appropriated ratepayers' funded maintenance funding intended for CPUC approved PG&E pipeline maintenance programs and pipeline replacements that never occurred; but where paid for by ratepayers anyways, as authorized through CPUC ratemaking; before the San Bruno explosions occurred. Once the blasts occurred; the response by the CPUC and NTSB is also discussed in more details below. [3] Finally we discuss the results of the investigation by NTSB and CPUC in concert with PG&E and our attempts to get to the root cause of the explosions by filing a petition for modification of PG&E advanced metering infrastructure ["AMI"] program that had recently integrated wireless electric and gas PG&E SmartMeters ™ in the San Bruno neighborhood; where the explosions occurred [under CPUC Application 10-09-012] a specifically identified external threat whose investigation efforts where thwarted by the FCC, NTSB, PG&E and the CPUC. CARE also provides as further evidence supporting our claims against PG&E; PG&E SmartMeterTM installation contractor Wellington Energy Whistleblower disclosed that an arc flash event could have sparked the San Bruno fire; Application 10-09-012 submission of National Transportation Safety Board January 21, 2011 preliminary report provides evidence to support arc flash event; February 7, 2011 e-mail to

[3] Of note: the lead investigator in the NTSB investigation was a former PG&E employee. "Ravi Chhatre is the investigator-in-charge for the four-member team from the NTSB. Chhatre, who has been with the board for almost 13 years, previously worked at PG&E as a material scientist in its research department. He was employed there from 1978 to 1998." Source: *See* http://www.baycitizen.org/san-bruno-explosion/story/san-bruno-blast-investigator/

Congress member Speier identifies NTSB investigator Mr. Ravi Chhatra as former PG&E employee and CPUC Chief Counsel Frank Lindh as former PG&E employee and father of the American Taliban while no risk analysis performed for external threats by CPUC and NTSB; a record transcript to CARE's April 11, 2011 Oral Arguments; an April 12, Motion to provide exhibits in Rulemaking 11-02-019; and in CPUC Investigation 12-04-010 SmartMeter opened in April 2012 a senior director of PG&E's SmartMeter Program, William Devereaux, admitted to infiltrating CARE's online smart meter discussion groups in order to spy on their activities and discredit their views; PG&E senior management knew of Mr. Devereaux's deceit; Devereaux was actively involved in intelligence gathering and he performed this task using a false identity; and CPUC Staff aided and abetted Devereaux's deceit.

Also provided is a discussion of the possible motives for such an opaque investigation outcome for PG&E's bottom line as discussed. Under California Public Utilities Code Section 328(b) "No customer should have to pay separate fees for utilizing services that protect public or customer safety." As discussed in more detail CPUC recently issued Decision 12-12-030 [4] issued on December 28, 2012; their purported *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering*; which does the exact opposite of the statutory mandate under Section 328(b); making PG&E's customers pay separate fees for utilizing services that protect public or customer safety while recognizing knowingly PG&E's "shareholders have reaped profits of over $500 million above the authorized return on equity, deferred maintenance of system facilities, and neglected safety improvements" as reported by the CPUC's own Division of Ratepayer Advocates ["DRA"].[5]

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[4] [Exhibit 1] to Complaint *See* http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=40630686
[5] Rulemaking 11-02-019 Decision 12-12-030 P. 25.

Therefore CARE respectfully requests the Commission conduct their own investigation of the events and circumstances leading up to, during, and after the San Bruno pipeline explosion of September 9, 2010 that killed 8, and suspend or revoke PG&E's blanket certificate it has issued, until such time as PG&E demonstrates compliance with the terms of its blanket certificate.[6]

II. STATEMENT OF FACTS

PHMSA,[7] not the Commission, has jurisdiction for promulgating and enforcing pipeline safety standards.[8] PHMSA, through the pipeline safety standards in Title 49 of the Code of Federal Regulations,[9] regulates the design, materials, operating pressure, and amount of ground cover of interstate natural gas pipelines, as well as many other elements, in order to "provide adequate protection against risks to life and property posed by pipeline transportation and pipeline facilities . . . ."[10] The Title 49 safety regulations "are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures."[11]

While the Commission assures that pipelines will comply with PHMSA's guidelines,[12] the primary responsibility for pipeline safety resides with PHMSA. Although the Commission may not promulgate and enforce pipeline safety standards, it may exercise authority over the

[6] *See* 18 C.F.R. § 157.14(a)(9)(vi) and 18 C.F.R. § 380.12(i)(5).
[7] The Department of Transportation's Pipeline and Hazardous Materials Safety Administration [PHMSA].
[8] *See Tennessee Gas Pipeline Co*., 93 FERC ¶ 61,100, at 61,262 (2000) ("Further, the [Department of Transportation], not the Commission, has exclusive authority to promulgate and enforce pipeline safety standards for natural gas pipelines."), *order on reh'g,* 95 FERC ¶ 61,169, at 61,551 (2001) ("The Commission is mindful of the safety issues; however, . . . [DOT] has exclusive jurisdiction over the safety of gas pipelines."), *Williams Gas Pipelines Central, Inc.,* 96 FERC ¶ 61,084, at 61,361 (2001) (stating that the DOT "has exclusive jurisdiction over the safety of gas pipelines").
[9] 49 C.F.R. Part 192 (2012).
[10] Pipeline Safety Laws, 49 U.S.C. § 60102(a)(1) (2006).
[11] *See Tennessee Gas Pipeline Co*., 136 FERC ¶ 61,173, at P 71 (2011) and *Transcontinental Gas Pipe Line Corp.,* 119 FERC ¶ 61,039, at P 46 (2007).
[12] *Tennessee Gas Pipeline Co., L.L.C.,* 139 FERC ¶ 61,008, at P 16 (2012) ("As part of the Commission's review of applications for the construction and operation of natural gas pipeline facilities, the Commission must ensure that the applicant will comply with the DOT safety regulations.").

natural gas company's maintenance of the pipelines covered under that company's blanket certificate.

When the Commission authorizes a natural gas company to construct and operate pipeline facilities, the authority must necessarily include authority to *maintain* the pipeline. 18 C.F.R. § 157.14(a)(9)(vi) which requires that an *applicant* for a certificate of public convenience and necessity *shall* certify in its application, among other things, that it will "*maintain the facilities for which a certificate is requested in accordance with Federal safety standards*." Further, the eminent domain authority at NGA section 7(h) gives the certificate holder the right to "construct, operate, and *maintain* a pipe line."[13] But the eminent domain authority under NGA section 7(h) can only be as broad as the Commission's certificate authorization.

The record presented [herein] demonstrates beyond any reasonable doubt that PG&E failed to "*maintain the facilities for which a certificate is requested in accordance with Federal safety standards*."

According to the NTSB report[14] [P-11-008-020] on the San Bruno events provides ample evidence of violations by PG&E in concert with CPUC issued September 26, 2011 stating [P. 5] "***The NTSB concludes that the 95 minutes that PG&E took to stop the flow of gas by isolating the rupture site was excessive."***

> ***This delay***, which ***contributed to the severity and extent of property damage and increased risk to the residents and emergency responders***, in combination with the failure of the SCADA center to expedite shutdown of the remote valves at the Martin Station, ***contributed to the severity of the accident***....

[13] (Emphasis added.)
[14] Exhibit 2.

Federal regulations prescribe, at Title 49 *Code of Federal Regulations* (CFR) 192.179, the spacing of valves on a transmission line based on class location. However, other than for pipelines with alternative maximum allowable operating pressures (MAOP),[15]6 the regulations do not require a response time to isolate a ruptured gas line, nor do they explicitly require the us of ASVs or RCVs. The regulations give the pipeline operator discretion to decide whether ASV5 or RCVs are needed in HCAs as long as they consider the factors listed under 49 CFR l92.935(c). [16]7

Therefore, ***there is little incentive for an operator to perform an objective risk analysis***, ***as illustrated by PG&E's June 14, 2006, memorandum-which was issued after the CPUC 2005 audit identified PG&E's failure to consider*** the issue and does not directly discuss any of the ***factors listed in section 192.935(c)***. Rather, it cites industry references to support the conclusion that most of the damage from a pipeline rupture occurs within the first 30 seconds, and that the duration of the resulting fire "has (little or) nothing to do with human safety and property damage." The memorandum concludes that the use of an ASV or an RCV as a prevention and mitigation measure in an HCA would have "little or no effect on increasing human safety or protecting properties." In the case of the San

[15] Under 49 CFR 192.620, "Alternative Maximum Allowable Operating Pressure for Certain Steel Pipelines," issued in 2008, an operator is allowed to operate a pipeline at up to 80 percent specified minimum yield strength (SMYS) in class 2 locations as long as it meets a very specific and stringent set of criteria. Section 192.620(c)(3) states that an RCV or ASV is required for such pipelines if the response time to mainline valves exceeds 1 hour under normal driving conditions and speed limits.

[16] Those factors are (I) the swiftness of leak detection and pipe shutdown capabilities; (2) the type or gas being transported; (3) the operating pressure; (4) the rate of potential release; (5) the pipeline profile; (6) the potential for ignition; and (7) the location of nearest response personnel.

Bruno transmission line break, nearby RCVs could have significantly reduced the amount of time the fire burned, and thus the severity of the accident...."

This shows that as far back as June 14, 2006 the CPUC recognized that for PG&E "there is little incentive for an operator to perform an objective risk analysis".

Knowing this fact the CPUC knowingly authorized, through rates; PG&E's on going maintenance and pipeline replacement programs without any objective risk assessment, enabling PG&E to violate the terms and conditions of their FERC authorized blanket certificate's "authority to *maintain* the pipeline [18 C.F.R. § 157.14(a)(9)(vi)] which requires that "an *applicant* for a certificate of public convenience and necessity *shall* certify in its application, among other things, that it will " *maintain the facilities for which a certificate is requested in accordance with Federal safety standards*.""

On April 28, 2011 CARE attempted to request CPUC provide a proper risk assessment [17] of PG&E's maintenance programs, pressure testing methodology and plans, and pipeline replacement activities to be conducted, along with an assessment of PG&E's entire natural gas transmission system explaining "PG&E's motion itself provides incontrovertible evidence that PG&E does not have any Quality System, Process validation, Installation qualification, Process performance qualification, Product performance qualification, Prospective validation, Retrospective validation, or a Validation protocol in place to allow the determination of "whether its validation methodology is acceptable to the Commission".[18] Further explain the importance of such measures CARE further explained "The Quality System (QS) defines process validation as establishing by objective evidence that a process consistently produces a result or product

[17] Rulemaking 11-02-019 CARE response to Pacific Gas and Electric's (PG&E's) April 21, 2011 Motion asking the Commission make a finding regarding "whether its validation methodology is acceptable to the Commission"
See http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RESP/134297.PDF
[18] *Id.* P. 4

meeting its predetermined specifications.[[19]]2 The goal of a quality system is to consistently produce products that are fit for their intended use. Process validation is a key element in assuring that these principles and goals are met."[20]

When the Commission authorizes a natural gas company to construct and operate pipeline facilities, the authority must necessarily include authority to maintain the pipeline. Indeed, section 157.14(a)(9)(vi) **requires that an applicant** for a certificate of public convenience and necessity shall certify in its application, among other things, that it **will "maintain the facilities for which a certificate is requested in accordance with Federal safety standards."** Further, the eminent domain authority at NGA section 7(h) gives the certificate holder the right to "construct, operate, and *maintain* a pipe line." [21] The eminent domain authority under NGA section 7(h) can only be as broad as the Commission's certificate authorization.

The certificate obligation to maintain a pipeline is embedded in the Commission's regulations. Rule 380.15(b) of the Commission's regulations, for example, provides: (b) Landowner consideration. The desires of landowners should be taken into account in the planning, locating, clearing, and maintenance of rights-of-way and the construction of facilities on their property, so long as the result is consistent with applicable requirements of law, including laws relating to land-use and any requirements imposed by the Commission.[22]

[19] REFERENCES
1. Guideline on General Principles of Process Validation, May 1987, FDA, CDRH/CDER
2. Journal of Validation Technology, Vol. 1, No. 4, August 1995
[20] Rulemaking 11-02-019 CARE response to Pacific Gas and Electric's (PG&E's) April 21, 2011 Motion P. 4
[21] (Emphasis added.)
[22] 18 C.F.R. § 380.15(b) (2012).

Further, section 380.12(i)(5) of the Commission's regulations [23] requires an applicant for an NGA section 7(c) construction certificate to explain how its construction plan provides environmental protection equivalent to or greater than that found in Commission staff's Upland Erosion Control Plan. The Commission staff's Upland Erosion Control Plan and Wetland and Waterbody Construction and Mitigation Procedures represents the minimum expectations for pipelines operating and maintaining their facilities in perpetuity for all future activities.

III. VIOLATIONS & ARGUMENT

1. Pacific Gas and Electric Company ["PG&E"]; enabled by California Public Utilities Commission; miss-appropriated ratepayers' funded maintenance funding intended for CPUC approved PG&E's pipeline maintenance programs and pipeline replacements that never occurred.

As stated by the CPUC's own Division of Ratepayers Advocates "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*. ...*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.... ...

[23] 18 C.F.R. § 380.12(i)(5) (2012). Section 380.12(i)(5) of the Commission's Rules and Regulations require an NGA application to:

> (5) Describe proposed mitigation measures to reduce the potential for adverse impact to soils or agricultural productivity. Compare proposed mitigation measures with the staff's current "Upland Erosion Control, Revegetation and Maintenance Plan", which is available from the Commission Internet home page or from the Commission staff, and explain how proposed mitigation measures provide equivalent or greater protections to the environment.

"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."*[24] 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 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.*"

According to Blanket Certificates §157.208(d)[25] Construction, acquisition, operation, replacement, and miscellaneous rearrangement of facilities. **Limits and inflation adjustment.** The limits specified in Tables I and II shall be adjusted each calendar year to reflect the "GDP implicit price deflator" published by the Department of Commerce for the previous calendar year. The Director of the Office of Energy Projects is authorized to compute and publish limits

[24] DRA Opening Brief at 25, *citing* Hearing Exh. 45 at 49 and NTSB Report at xi.
[25] *See* http://www.ferc.gov/industries/gas/indus-act/blank-cert/facilities.asp

for future calendar years as a part of Tables I and II, pursuant to 18 CFR §375.308(x)(1) of this chapter.

Year	Limit	
	Automatic project cost limit	Prior notice project cost limit
2012 PDF	$10,800,000	$30,800,000
2011 PDF	$10,600,000	$30,200,000

According to DRA however "PG&E seeks over $200 million to comply with the purportedly "new" requirement to maintain accurate records of its natural gas transmission pipeline system..."

2. Response by the CPUC and NTSB and the results of their purported investigation in concert with PG&E

Regarding CPUC purported investigation "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." [Decision 12-12-030 at P. 6] "The Independent Review Panel issued their final report on June 8, 2011... ... 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 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.[26]

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*.[27] The Panel found that *PG&E had excessive levels of management, comprised largely of non-engineering personnel including telecommunications, legal and finance executives, who primarily focused on financial performance*.[28] 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*

[26] Independent Review Panel Report at 65-66.
[27] Independent Panel Report at 50, 73.
[28] Id. at 54.

and risk.[29] *Addressing multiple threats to a particular pipeline* and *monitoring third-party activities* were also *noted as deficiencies*." [Decision 12-12-030 at Pp. 7-8]

NTSB chooses to focus on the CPUC's **risk assessment** "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.

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.)

- 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

[29] Id. at 64.

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.)" [Decision 12-12-030 at Pp. 8-9]

But neither CPUC; nor the NTSB; ever assessed external threats in PG&E integrity management program as identified in *CARE's Motion to provide supplemental information to CARE's Application 10-09-012* filed January 28. 2011[30] with CPUC.

3. CARE's attempts to get to the root cause of the explosions [under CPUC Application 10-09-012]; including external threats whose investigation efforts where thwarted by the FCC, NTSB, and the CPUC.

A. Mr. Boyd's qualifications

Mr. Boyd; CARE's President of the Board of Directors; is qualified as a failure analysis engineer based on his personal experience as a Test Engineer, for QP Semiconductor Inc. [31] from 1993 – 1996 (3 years) which experience included; but is not limited to, he supervised the environmental laboratory to ensure accurate testing and test component development; developed electronic device characterization test fixtures for this QML certified company specializing in qualifying parts for government, industrial and space applications. This included preparation of test plans according to specific military application e.g. MIL-STD-883, 202, UL requirements,

[30] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/130619.PDF
[31] *See* http://www.qpsemi.com/

etc. designing automation software to acquire, log, and report critical data, developing test plans in accordance with military application specifications. Resolved electronic issues and identified root causes, including failure mode testing [including destructive testing]; withstand voltage; high current surge testing, mechanical shock; vibration; temperature extremes; water vapor; and radiation exposure testing of components.

B. Application 10-09-012 to modify Decision (D.) 06-07-027

On September 20, 2010 Mr. Boyd filed CARE's application to modify Decision (D.) 06-07-027; "Decision (D.) 06-07-027 authorized Pacific Gas and Electric Company (PG&E) to deploy an Advanced Metering Infrastructure (AMI)."[32]

"D.06-07-027 should be rewritten to state at 15 "While it may not be required it is within this Commission's discretion to require an analysis of PG&E's AMI deployment pursuant to the requirements of the California Environmental Quality Act (CEQA)."

"As of September 2, 2010 1,378 electric SmartMeter complaints have been filed against PG&E's SmartMeters with the CPUC by PG&E customers. On September 9, 2010 a PG&E gas line ruptured and a towering fireball roared through a San Bruno neighborhood, killing four people, and officials have yet to determine what led to the blast.

[32] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/A/123808.PDF P. 2.

"On September 15, 2010 CARE filed a Complaint[[33]]4 with Federal Communications Commission stating "I wish to file a complaint against Pacific Gas and Electric Company (PG&E) and the California Public Utilities Commission (CPUC) for allowing PG&E to install 5.5 million SmartMeters in its California territories that do not meet FCC regulations 47CFR15.5 b)"Operation of an intentional, unintentional, or incidental radiator is subject to the conditions that no harmful interference is caused and that interference must be accepted that may be caused by the operation of an authorized radio station, by another intentional or unintentional radiator, by industrial, scientific and medical (ISM) equipment, or by an incidental radiator". 1,378 electric SmartMeter complaints have been filed with the CPUC without any actions to stop and on September 9, 2010 a PG&E gas line ruptured and a towering fireball roared through a San Bruno neighborhood, killing [eight] people, and officials have yet to determine what led to a blast. I allege EMF from PG&E's SmartMeters created the ignition source." CARE is seeking the FCC to pursuant to 47CFR15.5 c) "The operator of a radio frequency device shall be required to cease operating the device upon notification by a [FCC] representative that the device is causing harmful interference. Operation shall not resume until the condition causing the harmful interference has been corrected." This Petition seeks therefore that D.06-07-027 be Modify to Order PG&E to stay further deployment of PG&E SmartMeters until PG&E provides the

[33] Filling for: Michael Boyd has been received by the FCC. Thanks for your information. When inquiring about your complaint, be sure to reference this number: 10-C00246969 and, be sure to mention that you filed this complaint over the internet.

Use this page as a Fax Cover Sheet when faxing additional details to the FCC.
Fax Number (866) 418-0232
Date: 09/15/2010
To: Federal Communications Commission
Total Number of Pages: ______
Subject: 10-C00246969(Form 2000 Filed Via The Internet)
Address: 5439 Soquel Dr
Soquel CA 95073
Carrier/Company Name(s): CAlifornians for Renewable Energy, Inc. (CARE)

Commission evidence of compliance with FCC regulation 47CFR15.5 b)...." [A. 10-09-012 Pp. 2-4]

In an attachment to an Exparte Notice CARE filed with CPUC on October 5, 2010 regarding CARE's application to modify Decision (D.) 06-07-027 a copy of an September 28, 2010 acknowledgement letter of receipt of CARE's FCC complaint is provided.[34]

In CARE's October 26, 2010 Reply to Protest of PG&E and Response of DRA to Application 10-09-012 CARE provides as an attachment a copy of an October 20, 2010 FCC response to CARE's FCC complaint against PG&E, stating "This letter is in response to your complaint filed with the Federal Communications Commission (FCC). The matter you have outlines in your correspondence does not come under the jurisdiction of the FCC. Included below is contact information for an agency that may be of more assistance....Contact Information: California Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102-3298..."[35]

C. PG&E SmartMeter™ installation contractor Wellington Energy Whistleblower disclosed that an arc flash event could have sparked the San Bruno fire

Beginning in the fall of 2010 CARE began to act as Stop Smart Meters! fiscal sponsor as reported on CARE's 990A IRS charitable reporting form for 2011. In an interview with Stop Smart Meters! ["SSM"] a Wellington Energy Whistleblower ["WW"] disclosed that an arc flash event could have sparked the San Bruno fire and explosions was reasonable foreseeable stating: "It really doesn't surprise me that they haven't answered questions regarding the smart meters and San Bruno".

[34] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/EXP/124612.PDF

[35] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/REP/126055.PDF

"General Community: Stop Smart Meters! Exclusive: Interview with the Wellington Energy Whistleblower Posted: January 26, 2011.[36]

Wellington Energy is the company that is installing PG&E's new wireless 'smart' meters in California. A former Wellington Energy employee sent us an e-mail late last year offering to speak with us about his experience installing smart meters in the San Francisco Bay Area. He has requested anonymity. Here is the Stop Smart Meters! interview with the 'Wellington Whistleblower' in full:

SSM: Thank you for getting in touch with us. What made you want to come forward?

WW: I'm disgusted by what I've seen. PG&E and Wellington need to make the public aware that there are risks with these things. They need to come clean about the emissions of harmful radio waves, potential arcing etc. No one is taking the steps necessary to protect the public. People need to be aware the risks that are being taken with their homes and with their lives.

SSM: How long did you work for Wellington and where were you based?

WW: I worked at the Capitola yard from June until the beginning of September 2010, when they abandoned the yard following community protests. After that, I worked out of the San Jose yard until the end of September when I was laid off. I primarily installed in the Santa Cruz Mountains.

SSM: What is your opinion of PG&E and Wellington Energy?

WW: The only thing they are concerned with is money. Safety was an afterthought.

SSM: What was your experience with the public? Are people happy to have these devices installed on their homes?

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[36] [Exhibit 3] *See* http://stopsmartmeters.org/2011/01/26/stop-smart-meters-exclusive-interview-with-a-wellington-energy-whistleblower/

WW: Most people who had looked into the issue on their own did not want the meters installed. We were dealing with an increasingly resistant public. Forcing these meters on people makes the job really difficult and stressful. A few of my colleagues reported that the police were called on them multiple times.

SSM: The FCC requires that these devices be installed by trained professional electricians.[1] What kind of training did you receive prior to working as a 'smart' meter installer?

WW: We received only two weeks of training before they sent us out to do the installations. Though the procedure is relatively simple, if you get it wrong this can lead to arcing, shorts-even house fires. The blades on the back of the meter have to be aligned properly with the jaws on the socket the meter gets placed in. I kept hearing one of the managers say, "you guys weren't trained properly."

SSM: What did he mean?

WW: Many of the installers would come back to the yard and report that they had come across meters that were hanging by an electrical wire, or other clearly unsafe conditions. There was a lot of pressure on workers to install as many meters as possible in a day in order to earn bonuses. One employee went out into the Santa Cruz Mountains and I think he is still out there somewhere he got so disoriented. Needless to say, improper training, and being under incredible pressure, there HAS TO be error, especially with new people working in new territory. I overheard numerous times while at work, "you could have burned that goddamned house down."

SSM: Did you personally come across safety hazards? What happened when you tried to report them?

WW: The more you called Wellington, the worse it looked on your record- because you're wasting time. I saw sparks coming from one of the meters on a home. I reported it but am not sure what- if anything- was done.

SSM: Based on your observations while working for Wellington, what are your fears about the risks they are taking with the public's safety?

WW: First off I can only speak about what I personally observed. I believe- based on what I observed- that there is a chance that due to inadequate training some meters were not installed properly. I do feel that Scotts Valley, Boulder Creek, Ben Lomond, Corralitos, to name a few should be informed enough to prepare for what could realistically turn into another San Bruno. (emphasis added)

SSM: Of course at the time of the explosion San Bruno was 100% installed with smart meters. Are you aware that PG&E and the CPUC have not yet responded to questions about what safety precautions they took while installing smart meters adjacent to gas lines? Seems like a fairly reasonable question given that the technology can generate sparks.

WW: It really doesn't surprise me that they haven't answered questions regarding the smart meters and San Bruno. When I asked one of my managers who was in charge of training "is it possible in your opinion that a fire could start from an arc from a meter located above a gas meter" (which always has some blow off gas emitting from it) he would not give me a direct answer! He avoided the question like the plague, quoting some plumber he knew and on and on, avoiding an answer. Could the San Bruno fire have been started by an arc from a meter? I'll let you decide. The definition of an electrical arc is: "a sustained luminous discharge of electricity across a gap in a circuit". The definition of ignition: the process or means (as an electric spark) of igniting a fuel mixture. Gas is a fuel. I'll leave it at that. It doesn't take a rocket scientist to put it all together.

SSM: Why did you stop working for Wellington?

WW: I was let go because I took too much time with each resident. When you are dealing with people's lives, I don't feel that it is proper to hang the door hanger, do your installs, and get out of there. With the reception of these meters I felt people at least needed to be talked to and listened to beforehand. This of course resulted in my dismissal. I talked too much and too long with the customers. As a Wellington employee you must log in to your handheld computer every 15 minutes or it creates a 'red zone' in your day's activities. This is likely to be addressed to you on the phone by your boss the next day as you are trying to get your numbers up that day. A reduction in work force was eventually used as an excuse for my dismissal. Meanwhile a training class for the same position was going on at the same time!

SSM: What do you think is really behind PG&E's 'smart' meter program?

WW: The smart meter has a hell of a lot of potential that they're not talking about. PG&E claims they're not going to use that potential, but who can believe them? Believe me they have plans for these things. They could use it for cell phone reception, broadband, tv services etc.

SSM: As you know, people are desperate. They're suffering headaches, nausea, etc. This has driven some people out of their homes. They're now calling them 'smart meter refugees.' Meanwhile PG&E and the CPUC refuse to remove them even in cases where doctors confirm that health is being jeopardized. Based on your knowledge, can a resident remove the meters themselves? How risky is this?

WW: First of all, about health issues. I was never really concerned about this, because I believed what I was told from Wellington, that the meters only emitted radio waves to send usage to a transponder close by so it could relay it to PG&E...on a short time basis, rarely more than once a month except in the start up, and then not a lot. My manager reiterated that as well, during one of our conversations.

I was surprised to hear that the meters send signals- what- 15 per minute? We all were told they only transmit a few times a month if that, just enough to send the total usage from that account.

As far as a DIY de-installation, I don't advise anyone who hasn't been trained as an electrician to try and remove the meter themselves. However, if you can find a professional electrician to help you, it's not really that big a deal. There is an aluminum ring that holds the meter in place. The ring comes off easy with a pair of wire cutters. Like a watchband or a locking suitcase- you push it in and it pops off easily. You can pull the ring off and then the meter comes right off. There are 4 pins on the back of the meter, and if you have access to an old analog meter, you could just pop it right on. Of course the pins are now essentially live wires so these would be very dangerous to touch.

SSM: The information that I have seen indicates that the new meters can actually be transmitting constantly [2], so it sounds like your managers were not being straight with you. What about the smart meter attachment on the gas meter? How would one go about removing that?

WW: You can remove a smartmeter from a gas meter by removing the screws that attach the module (meter) it to the gas meter itself. It won't interrupt the gas service at all. All the module does is track usage, the index (dial apparatus) has a key on the back which slips onto a key in the meter which has a diaphragm regulating gas pressure and turning the gas index key.

SSM: You were working at the Capitola yard in late August 2010 when the protests were going on. What was the response from PG&E?

WW: PG&E sent a senior security executive out to handle the situation. The protests were effective at informing the public about the risks of smart meters- something PG&E desperately wanted to avoid. They didn't want the situation to escalate so they withdrew from that site, and moved us all to San Jose.

SSM: Thanks for taking the time and being brave enough to speak out. Any last thoughts?

WW: I was never out to hurt people- this was just a job for me. I really feel these days that big brother- in the form of the government and corporations working together- is screwing us big time. I hope we can get regulators to pay attention on this as I believe there is a real chance of more people getting hurt if nothing is done..."

Also, it is important to note that Wellington installers are temporary workers, not professionals. They are not required to have prior experience or electrical education. Installers have only brief training and are paid according to the volume of meters they install. Therefore, it is typical not to report electrical irregularities because this might slow them down. In addition, non-professionals may not recognize irregularities as well as professionals and they may be gone to another place and job before the electrical emergency occurs. This lack of training has raised concerns in other states including Maine [4]. In addition, there are documented cases of gas smart meters being installed without adequate safety certification. [5]

How many homes and neighbourhoods have to burn down before regulators get serious and halt further installations? How many people have to suffer sudden health deterioration before we admit there is a problem? How many suffering people does it take to halt a $2.2 billion project? More than a few apparently.

If you work for PG&E or Wellington Energy and you have inside information you'd like to share with the public, please contact us at info[at]stopsmartmeters[dot]org We will absolutely respect your anonymity.

[1] https://sites.google.com/site/nocelltowerinourneighborhood/home/wireless-smart-meter-concerns/emf-safety-network-finds-smart-meter-fcc-compliance-violations-dec-14-2010

[2] EPRI, 2010. A Perspective on Radio-Frequency Exposure Associated With Residential Automatic Meter Reading Technology, Electric Power Research Institute, Palo Alto, CA.

[3] Advanced Metering Infrastructure; January 2010 Semi-Annual Assessment Report and SmartMeterTProgram Quarterly Report (Updated), Pacific Gas and Electric Company.

[4] http://www.theforecaster.net/content/s-scarsmartmeterforum2-121710

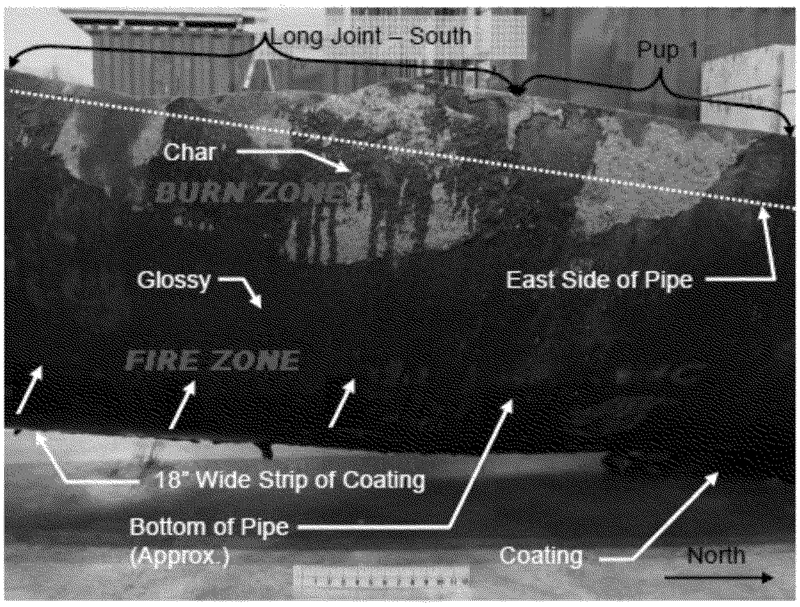
[5] http://www.smartmeters.com/the-news/1472-silver-springs-smart-meter-recall-halted.html"

D. Application 10-09-012 submission of National Transportation Safety Board January 21, 2011 preliminary report provides evidence to support arc flash event

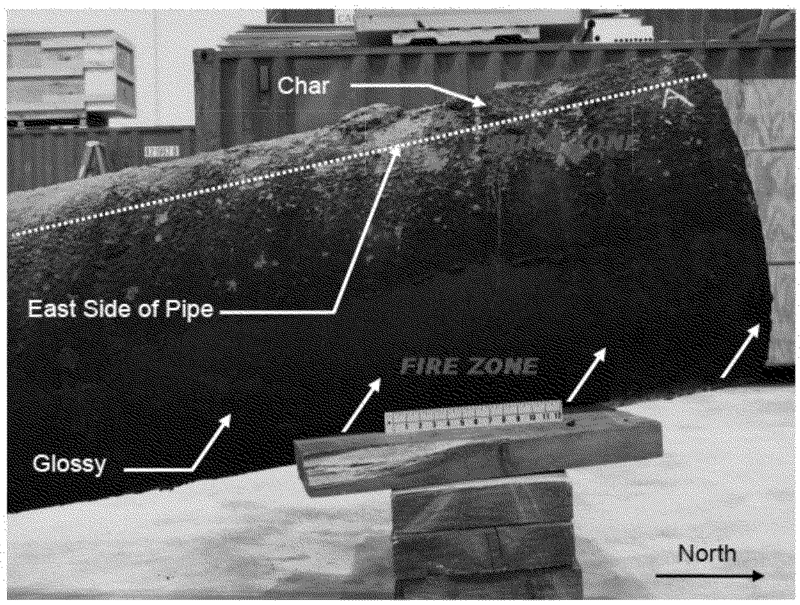
On January 28, 2011 CARE filed a Motion to supplement the record in Application 10-09-012[37] to provide **Supplemental Information supporting an arc flash induced ignition source for fire and explosion** based on information taken from the National Transportation Safety Board January 21, 2011 preliminary report[38] on the San Bruno catastrophe excerpted as follows [Pp. 6-8] "“*The coating on the top and sides of the center section (in its resting position and not as installed) had either a charred or glossy appearance in various locations as shown in*

[37] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/130619.PDF
[38] The NTSB report was attached to CARE's January 28, 2011 Motion to supplement *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/130620.PDF

figure 13. In some locations, the coating appeared to be comingled with soil. *On the underside of the pipe (in its resting position) between pup 1 and pup 2 there was a partially attached piece of coating approximately 32 inch in length,* the start of which is indicated by an arrow in figure 13a. There was also an approximately 18 inch wide strip of coating attached to the underside running from pup 1 and continuing south to within 6 foot of the southern fracture, the start of which is also indicated in figure 13a. "



a)



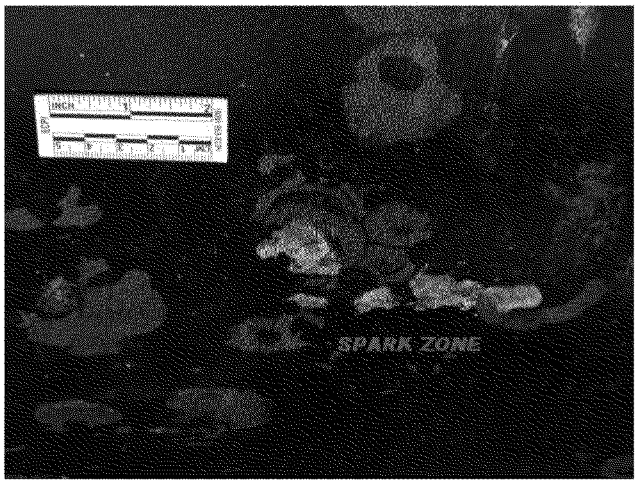
13 b)

The Figure 13 "Glossy" or "Char" regions of the exploded center section demonstrate the fire zone started at the bottom of the pipe since the heat was applied for a long enough period in the "fire zone" to make the tar coating on the bottom portion of the pipe melt and the upper portion to burn since the heat is greatest at the top of the flaming area where there is sufficient temperature and oxygen for the tar to combust leaving a carbon ash residue [noted as the "burn zone" in red text]. The Char area also demonstrates that the fire lasted a significant amount of time [several minutes] before the explosion occurred.

Finally according to the NTSB report "[t]here were also regions on the underside where no coating was observed and the pipe surface was visible. One region on pup 4 near the girth weld fracture is shown in figure 14a. The region was approximately 12.5 inch at its longest and 6 inch at its widest. The visible pipe surface had an orange/brown appearance."

14 a)

"A second region from the underside of the long joint south of pup 1 is shown in figure 14b."



14 b)

"No coating was observed over a cluster of small patches each approximately 2 inch in diameter. The visible pipe surface had an orange/brown appearance. Similar areas of no coating were observed on the undersides of pups 1, 2, and 3."

In Figure 14 b) you can observe newly exposed uncoated metal, that due to the lack of oxidation of the metal exposed [marked in red text as "spark zone"], would have had a lower electrical resistance to electrical arcing than the surrounding oxidized uncoated regions of the underside of the pipe where the explosion pressure was sufficient to throw the pipe 1000 feet."

E. February 7, 2011 e-mail to Congress member Speier identifies NTSB investigator Mr. Ravi Chhatra as former PG&E employee and CPUC Chief Counsel Frank Lindh as former PG&E employee and father of the American Taliban while no risk analysis performed for external threats by CPUC and NTSB?

On February 7, 2011 Mr. Boyd contacted San Bruno's Congressional Representative Jackie Speier[39] by e-mail; with copy to Senator Feinstein; Senator Boxer regarding the inability of CARE to get the purported NTSB investigation to consider external threat risks. "I explained that I had a Application 10-09-012 pending before the CPUC regarding PG&E's SmartMeters in the San Bruno neighbor where the pipeline exploded being the root cause of the fire and

[39] Exhibit 4.

explosions there and therefore wanted to know how to become a Party? Ms. Ward indicted also that the Parties had been pre-selected and there was no opportunity for CARE to be a Party to the investigation....I then asked how I could provide my information on the PG&E SmartMeters in the San Bruno neighbor where the pipeline exploded being the root cause of the fire and explosions and I was directed to mail my information to the Chief NTSB Investigator Mr. Ravi Chhatra...My research reveals that Mr. Ravi Chhatra the "federal investigator leading the National Transportation Safety Board's inquiry into the deadly gas pipeline explosion in San Bruno worked for Pacific Gas & Electric for 20 years." [See article below.] It also reveals that the Frank Lindh the "general counsel for the CPUC... came to the agency from PG&E where he had worked for a decade as an attorney" and that he is the father of the "the so-called "American Taliban"... This left me scratching my head asking myself why such individuals who clearly have a professional if not financial conflict of interest in PG&E why they would have any role what ever in the NTSB investigation of the San Bruno pipeline fire and explosion? For the life of me I can't understand how the Dad of the American Taliban could have any role and this doesn't create a risk to national security as well???"

F. CARE's April 11, 2011 Oral Arguments and April 12, Motion to provide exhibits[40] in Rulemaking 11-02-019.

On April 11, 2011 Mr. Boyd of CARE made the following oral argument on the San Bruno disaster excerpted from the transcript [41] [RT Pp. 404 -408] as follows:

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        ALJ BUSHEY:  Oh, Mr. Boyd, you weren't
here when we signed up.  Okay.
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[40] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/133727.PDF

[41] Exhibit 5

ARGUMENT OF MR. BOYD

MR. BOYD: I guess I'm the newest party, so, new to the party.

My name is Mike Boyd, and I'm the President of Californians for Renewable Energy, Inc., CARE. And I was at your meeting last week and spoke to you, and I have some follow-up information to provide you.

First, on the Stipulation. CARE believes that a stipulation is unlawful, and here's why. First, in order for you to enter into an agreement for compliance you have to have either evidence of compliance or a schedule of compliance. By a schedule of compliance I mean an approved schedule of compliance. You approve the schedule, not CPSD, to my knowledge. So without either, I don't see how you're in a legal position to approve the stipulated agreement because PG&E certainly hasn't provided you that and nor has CPSD.

So without that, I don't see how you can do it. And as I said before at the meeting last week, you're not my only relief. *I can go to the FERC, and the FERC does have* *a million dollar a day fine*. And *I believe this is a federal compliance issue* as well as a state compliance issue. And therefore, *I would ask that you support what CARE is saying and go for the federal standard, a million dollars a day, until they establish compliance through evidence or a schedule that you've approved for compliance*. Okay.

Because we believe Pacific Gas and Electric Company, PG&E, cannot or will not produce the required records to complete the validation of pipeline Maximum Allowable Operating Pressures as well as to complete the pipeline testing and repairs promised by PG&E, Californians for Renewable Energy and CARE hereby submits two Google Earth pictures[[42]] of the site of the San Bruno natural gas pipeline explosion that killed eight of PG&E's natural gas service customers to define the exclusion zone necessary to, quote, "avoid potential high risk for fatalities in future pipeline explosions."

The line pictured in yellow measures a distance of approximately 600 feet. I

[42] See pictures in Exhibits A and B to April 12, 2011 Motion to accept Exhibits in Rulemaking 11-02-019 [Pp. 6 & 7] *See* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/133727.PDF

provided a picture from October 1st, 2009, for the fire to show you the homes that were present there. The next figure shows you after the fire, two days after the fire, that there were some homes there that were destroyed 600 feet from the fire, from the explosion source. And if you look to the south on the road in the picture, you'll see the section of pipeline that exploded is still present there on the 11th sitting there.

Without these necessary records to determine safe operating pressures for PG&E's continued operations of natural gas pipelines in its service territory, the Commission is not in a position to say that any of those pipelines PG&E is operating are safe to the general public and PG&E's customers. But PG&E is not alone in its liability because the local government, the city or county issued building permits for all the homes that burned in San Bruno, likely after the pipeline was built. Where were our elected local leaders then?

I have attached a copy of Robert Sarvey's rebuttal testimony, Exhibit 405, on hazardous materials before the California Energy Commission on the Mariposa Natural Gas Turbine Project in CEC Docket 09-AFC-03 on two other high risk natural gas pipelines at PG&E where Mr. Sarvey states:

> The combination of these two projects and their impact [to degrade] -- to the degraded PG&E Line 002 are not addressed or analyzed in staff's testimony. A significant increase in natural gas volume will occur because of the addition of the MEP and the conversion of the Tracy Peaker Project to combined cycle. Pipeline pressure fluctuation from the cycling of these projects will cause additional stress to Line 002. Given the significant risk of a natural gas line failure as evinced by the recent San Bruno Tragedy,

this impact needs to be addressed. We certainly cannot rely on PG&E's incomplete and inaccurate records and inadequate safety practices.

Mr. Sarvey has provided on page 5 of his testimony a picture of a temporary fence PG&E erected at the site of a proposed sports park in Tracy where apparently PG&E allowed heavy equipment to operate unattended as an offer of proof to PG&E's safety practices or lack thereof.

Therefore, first we need to know what is the safe zone where residential dwellings, parks and recreation facilities and businesses can be built? The City and County then must change its general plans and zoning designations to exclude any development where there is a high risk pipeline where high risk may be based on the lack of recordkeeping by PG&E. PG&E must buy out all those affected landowners along the exclusion zone along the line under eminent domain exercised by authorization of this Commission, if necessary, at fair market value.

In absence of knowing the root cause of the failure that caused PG&E's pipeline to explode, the Commission has no choice but to exclude future development and remove existing developments from the safety exclusion zone. Otherwise, the question will not be if this will ever happen again, but when is the next pipeline explosion going to occur?

Thank you.

ALJ BUSHEY: Thank you, Mr. Boyd.

Other parties that wish to present oral argument?

(No response)

Mr. Sarvey's Exhibit C "Robert Sarvey's Rebuttal Testimony Exhibit 405 on Hazardous Materials before the California Energy Commission ("CEC") on the Mariposa natural gas turbine project in CEC Docket 09-AFC-03 –January 21, 2011 from [California Energy Commission] regarding Tracy Sports Park over PG&E transmission line there are also included in an CARE's April 12, 2011 Motion to incorporate those documents CARE had presented the CPUC at its April 11, 2011 Oral Arguments.

April 11, 2011 is where we can establish we provided advanced notice to PG&E and CPUC that we could and would go to the FERC if PG&E and CPUC under their fiduciary duties to the public did not act immediately to protect the public and ratepayers from PG&E's failures to comply with FERC's authority stating [Mr. Boyd speaking for CARE] "I can go to the FERC, and the FERC does have a million dollar a day fine. And I believe this is a federal compliance issue as well as a state compliance issue. And therefore, I would ask that you support what CARE is saying and go for the federal standard, a million dollars a day, until they establish compliance through evidence or a schedule that you've approved for compliance."

CARE's April 12, 2011 Motion to incorporate documents also included three earlier data requests as follows:

QUESTION 1[43]

Provide a list or chart of all natural gas transportation or storage facilities (facilities) that are included in the scope of OII 11-02-016. A reference to proceedings of the National Transportation Safety Board, California Energy Commission or California Public Utilities Commission websites is sufficient. CARE needs a list of all facilities and a note explaining their ownership.

A. Provide a list of insurance coverage purchased by PG&E or other relevant insurance coverage corresponding to each facility.

B. Provide copies of the insurance documents together with all other relevant documents that will allow CARE to determine whether any of the insurance coverage is still active.

ANSWER 1

PG&E objects to this data request on the grounds that it seeks information that is beyond the scope of this proceeding as described by the Commission in the OII:

By this order, the Commission institutes a formal investigation to determine

[43] See http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/133728.PDF

whether the named Respondent, Pacific Gas and Electric Company (PG&E), violated any provision or provisions of the California Public Utilities Code, Commission general orders or decisions, or other applicable rules or requirements pertaining to safety recordkeeping for its gas service and facilities. This proceeding will pertain to PG&E's safety recordkeeping for the San Bruno, California gas transmission pipeline that ruptured on September 9, 2010, killing eight persons. This investigation will also review and determine whether PG&E's recordkeeping practices for its entire gas transmission system have been unsafe and in violation of the law.

Not withstanding this objection, PG&E responds as follows:

PG&E understands this OII to apply to its recordkeeping policies and practices as they relate to all its gas transmission facilities.

PG&E's general liability insurance policy covers all its gas transmission facilities. In response to CARE's statement at the March 17, 2011, prehearing conference, PG&E's insurance policies cover events that occur during the term of the policies. In the situation referenced by CARE during the prehearing conference regarding the Hazardous Substance Mechanism, insurance coverage was matched with the time in prior years during which the environmental damage occurred. As regards the San Bruno incident, the only insurance policies "active" are those that were in effect on the date of the incident.

QUESTION 2[44]

Please provide copies of documents showing the engineers who signed the drawings or

[44] See http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/133729.PDF

other documents providing final natural gas transportation or storage designs or inspections.

Were these engineers registered or certified by the state licensing authority for the physical location for these facilities?

Were these engineers insured or did they provide bonds or other guarantees for their work?

ANSWER 2

PG&E objects to this data request on the grounds that it is vague and overbroad. Also, it seeks information that is beyond the scope of this proceeding as described by the Commission in the OII:

> By this order, the Commission institutes a formal investigation to determine whether the named Respondent, Pacific Gas and Electric Company (PG&E), violated any provision or provisions of the California Public Utilities Code, Commission general orders or decisions, or other applicable rules or requirements pertaining to safety recordkeeping for its gas service and facilities.
>
> This proceeding will pertain to PG&E's safety recordkeeping for the San Bruno, California gas transmission pipeline that ruptured on September 9, 2010, killing eight persons. This investigation will also review and determine whether PG&E's recordkeeping practices for its entire gas transmission system have been unsafe and in violation of the law.

QUESTION 3[45]

Were the natural gas transportation or storage facilities that are included in the scope of

[45] See http://docs.cpuc.ca.gov/PublishedDocs/EFILE/MOTION/133730.PDF

OII 11-02-016 licensed and permitted by the applicable local licensing authorites (sic)? If not, provide a list of facilities not properly licensed and an explanation of which permits, etc. were omitted.

What insurance coverage would these licensing authorities have that could provide coverage for expenses for natural gas facilities that were improperly installed or that did not conform with the best engineering practices that were applicable at the time that the facilities were installed and inspected by these local authorities?

ANSWER 3

PG&E objects to this data request on the grounds that it seeks information that is beyond the scope of this proceeding as described by the Commission in the OII:

> By this order, the Commission institutes a formal investigation to determine whether the named Respondent, Pacific Gas and Electric Company (PG&E), violated any provision or provisions of the California Public Utilities Code, Commission general orders or decisions, or other applicable rules or requirements pertaining to safety recordkeeping for its gas service and facilities.
>
> This proceeding will pertain to PG&E's safety recordkeeping for the San Bruno, California gas transmission pipeline that ruptured on September 9, 2010, killing eight persons. This investigation will also review and determine whether PG&E's recordkeeping practices for its entire gas transmission system have been unsafe and in violation of the law.

PG&E failed to provide [any] information on their insurance coverage, bonding, and licensing in construction in regards to the section of pipeline that exploded in San Bruno and it was clear at all times that CPUC would not require PG&E to produce the records requested; thereby enabling an opaque investigation of the root cause of the San Bruno disaster.

G. CPUC Investigation 12-04-010 SmartMeter Application Senior director of PG&E's SmartMeter Program, William Devereaux, admitted to infiltrating CARE's online smart meter discussion groups in order to spy on their activities and discredit their views; PG&E senior management knew of Mr. Devereaux's deceit; Devereaux was actively involved in intelligence gathering and he performed this task using a false identity; and CPUC Staff aided and abetted Devereaux's deceit.

In response to CARE's September 2010 San Bruno SmartMeter Application Senior director of PG&E's SmartMeter Program, William Devereaux, admitted to infiltrating CARE's online smart meter discussion groups in order to spy on their activities and discredit their views; PG&E senior management knew of Mr. Devereaux's deceit; Devereaux was actively involved in intelligence gathering and he performed this task using a false identity; and CPUC Staff aided and abetted Devereaux's deceit. According to the April 19, 2012 OII [Pp. 2-3] *Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas & Electric Company regarding Anti-Smart Meter Consumer Groups*: Investigation 12-04-010

> "In early November 2010, several news media sources reported that a senior director of PG&E's SmartMeter Program, William Devereaux, admitted to anonymously joining a couple of anti-smart meter consumer advocacy groups.
>
> "CPSD conducted an investigation into the activities of Mr. Devereaux. CPSD's Report describes Mr. Devereaux as the public face of PG&E's SmartMeter Program from October 2009 through October 2010.[46] Mr.

[46] Public Appearances of William Devereaux Relating to the SmartMeter™ Program, PG&E December 10, 2010, response to DR1 question # 19, Attachment CPSD_001-19-1, page 1 of 1. **(CPSD Staff Report, Attachment 2.)**

Devereaux resigned from PG&E in November 2010. Based on evidence gathered during its investigation, CPSD concluded that:

1. PG&E violated PU Code Section 451 by failing to furnish just and reasonable service when Mr. Devereaux lied about his identity to infiltrate online smart meter discussion groups in order to spy on their activities and discredit their views; and
2. PG&E senior management knew of Mr. Devereaux's deceit before it was reported in the press and failed to prevent and stop his inappropriate behavior.

"PG&E conducted its own internal investigation into Mr. Devereaux's activities beginning November 9, 2010 and concluding on December 17, 2010. Based on the evidence gathered from Mr. Devereaux's PG&E-issued laptop and his internet searches, PG&E concluded that:

1. Mr. Devereaux violated PG&E's Employee Code of Conduct as well as the Company's Core Values and the Expectations of our Leaders;
2. Mr. Devereaux was actively involved in intelligence gathering and he performed this task using a false identity; and
3. Mr. Devereaux provided inappropriate comments and opinions on at least four occasions while using a false identity.[47] "

CARE, EMF Safety Network, and Stop Smart Meters! depend on charitable donations from the public to fund our outreach and educational activities. If the public feels like they

[47] PG&E response to DR1, December 10, 2010, Attachment CPSD_001-01Supp01-1, page 2. **(CPSD Staff Report, Attachment 6.)**

cannot join our groups without their activities also being monitored and scrutinized, they will be less likely to financially contribute. A number of people reported that they did not want their private e-mails to fall into the hands of PG&E or third parties, and no longer felt safe and secure in their organizing efforts. This effect of PG&E's activities represented a significant loss of both volunteer and financial support at a key time in the campaign.

PG&E employees who were monitoring the activities of demonstrators and taking photos said in an e-mail dated October 28th 2010:

"Sure. This is fun no one said 'espionage' in the job description"

PG&E obstructed First Amendment Rights to demonstrate publicly. Intelligence obtained through PG&E's "espionage" allowed the company to re-locate utility personnel and equipment to avoid peaceful protests planned by these groups:

"Wellington has established a contingency plan to relocate ~40 Santa Rosa employees….Thursday of next week if requested"

"Sent: Thursday, October 21, 2010 7:59 AM

Subject: Cross-dock serving Sonoma/Marin

Importance: High

Privileged and Confidential

Is our cross-dock in Rohnert Park? If so, it has been found by the insurgents and they are planning a Capitola style blockade for next week or the week after.

Looks like next Thursday 10/28 or Wed. 11/3 may be the days they are targeting.

http://www.doodle.com/fed32kw4vb3car3n **[a private scheduling page]**

Let's put together a plan in the next couple days for this. Where else can we work out of temporarily? Don't we have a large service center in Santa Rosa"?

-(Attachment CPSD_001-13-1of the PG&E internal investigation)

PG&E spied on discussion of legal strategy by their opponents. As included in attachment 16 of the CPSD staff report, William Devereaux forwarded a set of e-mails from the smartwarrior marin group to other PG&E employees, prefacing the discussion of strategy with the following:

"An interesting set of notes from the **insurgents** as they try to find lawyers to help with the cause and get organized better for San Rafael."

Not only is Mr. Devereaux using a term for armed terrorists to describe peaceful protesters defending human health and safety, he is out front in announcing the legal nature of the private discussions he is forwarding. Yet PG&E managers and knowing CPUC staff sat on their hands and did nothing to deter this behavior while the spying continued.

<u>Devereaux not only accessed private e-mail groups using a false identity- he encouraged others to do the same:</u>

"You should add this Google Group to your list- they really are the most active discussion. http://groups.google.com/ group/smartwarriormarin"

-Attachment CPSD_001-13-1 page 169 of 309

As included in document 40, page 1 of PG&E's internal investigative report, it appears that Marzia Zafar, currently Head of Policy and Planning for the CPUC sent at least one e-mail acquired through Devereaux's deceit. (See ten lines from the bottom)

Outlook Header Information

Conversation Topic: [redacted] report from the meeting in Marina last week
Sender Name: [redacted]
Received By: [redacted]
Delivery Time: 10/11/2010 1:44:31 PM
Creation Time: 10/11/2010 1:44:31 PM
Submit Time: 10/11/2010 1:44:27 PM
Importance: Normal
Sensitivity: Normal
Flags: 1 = Read
Size: 21854

Standard Header Information

Microsoft Mail Internet Headers Version 2.0
Received: from exchange158.utility.pge.com ([10.245.211.169]) by exchange17.utility.pge.com with Microsoft SMTPSVC(6.0.3790.4675);
Mon, 11 Oct 2010 13:44:31 -0700
Received: from mail03.comp.pge.com ([10.244.8.21]) by exchange158.utility.pge.com with Microsoft SMTPSVC(6.0.3790.4675);
Mon, 11 Oct 2010 13:44:31 -0700
Received: from maildmz03.pge.com (maildmz03.pge.com [10.252.72.121])
by mail03.comp.pge.com (Sentrion-MTA-4.0.5/Sentrion-MTA-4.0.5) with ESMTP id o9BKiUbZ002819
(version=TLSv1/SSLv3 cipher=DHE-RSA-AES256-SHA bits=256 verify=OK)
for <WFD4@pge.com>; Mon, 11 Oct 2010 13:44:30 -0700
Received: from spam17.calpuc.cpuc.ca.gov (spam17.cpuc.ca.gov [162.15.7.139])
by maildmz03.pge.com (Sentrion-MTA-4.0.5/Sentrion-MTA-4.0.5) with ESMTP id o9BKiSpm003983
(version=TLSv1/SSLv3 cipher=DHE-RSA-AES256-SHA bits=256 verify=FAIL)
for <WFD4@pge.com>; Mon, 11 Oct 2010 13:44:30 -0700
X-DKIM: Sendmail DKIM Filter v2.5.6 maildmz03.pge.com o9BKiSpm003983
X-ASG-Debug-ID: 1286829868-603a28d80001-zfmUj4
Received: from frost.cpuc.ca.gov (frost.cpuc.ca.gov [162.15.5.75]) by spam17.calpuc.cpuc.ca.gov with ESMTP id mRPynoN2CrrAuhqX for <WFD4@pge.com>; Mon, 11 Oct 2010 13:44:28 -0700 (PDT)
X-Barracuda-Envelope-From: marzia.zafar@cpuc.ca.gov
X-Barracuda-Apparent-Source-IP: 162.15.5.75
Received: from wallace.calpuc.cpuc.ca.gov ([162.15.5.7]) by frost.cpuc.ca.gov with Microsoft SMTPSVC(6.0.3790.4675);
Mon, 11 Oct 2010 13:44:27 -0700
X-MimeOLE: Produced By Microsoft Exchange V6.5
Content-class: urn:content-classes:message
MIME-Version: 1.0
Content-Type: multipart/alternative;
boundary="----_=_NextPart_001_01CB6985.1881F3BE"

Confidential - Provided to CPSD pursuant to
Public Utilities Code section 583 Attachment CPSD_001-13-1

Nina's report from the meeting in Marina last week Page 1 of 4

Message1750	
Subject:	Re: Nina's report from the meeting in Marina last week
From:	[redacted]
Date:	10/11/2010 1:44:31 PM
To:	[redacted]

Message Body

Hello,
Any upcoming events scheduled for Smart meter education/inquiry?

Thanks,
[redacted]
Thank You,
[redacted]

From: [redacted]
To: [redacted]
Cc: [redacted]
Sent: Mon Oct 11 11:51:36 2010
Subject: Nina's report from the meeting in Marina last week

From: nbeety@netzero.net
Date: Wed, Oct 6, 2010 at 2:26 PM
Subject: Marina and Monterey City Councils
To: california-emf-safety-coalition@googlegroups.com, emf-safety-network@googlegroups.com

Last night's meetings in Monterey and Marina:

Good news at the Monterey City Council meeting. Two of us spoke in favor of agendizing consideration of an ordinance with a one-year moratorium on Smart Meters. Since I had to leave to go to the Marina meeting, I don't know if anyone spoke during the second section of the meeting (the meeting is held in two sections). The council decided to agendize considering a one-year moratorium ordinance on Smart Meters (moved by Haferman, seconded by Sollecito). Hurray!!!!!!!! The next step will be for staff to research and write up the ordinance. How much time that will take is unknown; it may be on the next council meeting in two weeks or the following one. Will keep you posted.

Marina was a very long meeting with Smart Meters not coming up till 9:30. However, prior to the meeting there was a good group of vocal protestors holding signs and chanting outside, and they were filmed by KION and KSBW TV. Bill Devereux, Wendy Sarsfield, Michael Herz, and one other PGE customer service person were at the meeting, as well as Marzia Zafar (and possibly two others) from the CPUC. Six hours sitting near two cell towers — incredible. It's hard to sit there for hours, too, when you know that the topic you're presenting is so overwhelmingly important that it should be at the top of the agenda. Like, "excuse me, there's an outbreak of cholera, maybe we should talk about it first." I vote for a triage approach to agenda items.

Thus, it can reasonably be stated that top CPUC staff- in addition to PG&E executives- had knowledge of Mr. Devereaux's deceit, but did nothing to report it or prevent it. The evidence implicates CPUC staff, and this information requires a further internal investigation, possibly by an outside third party or the court.

PG&E violations of the law and liability created by Devereaux's activities; include but are not limited to:

a. Public Utility Code 451 It is clear from the CPSD report, and other facts on the record that PG&E violated Public Utility Code 451- the company failed to provide reasonable service every time they read or forwarded a private e-mail of one of their customers.

b. California Business and Professions Code Section 17500 In addition, PG&E violated Section 17500 [48] of the Business and Professions Code prohibiting making misleading statements.

c. CA Constitution Article 1 Section 1: The right of privacy is a primary right under the California Constitution which states:

SECTION 1 All people are by nature free and independent and have inalienable rights. Among these are enjoying and defending life and liberty, acquiring, possessing, and protecting property, and pursuing and obtaining safety, happiness, and ***privacy****.*

d. ***CA Penal Code Section 631:*** The deliberate interception and unauthorized infiltration into communications is criminally prohibited under Penal Code section 631 [49]

[48] **BUSINESS AND PROFESSIONS CODE SECTION 17500-17509**

17500. It is unlawful for any person, firm, corporation or association, or any employee thereof with intent directly or indirectly to dispose of real or personal property or to perform services, professional or otherwise, or anything of any nature whatsoever or to induce the public to enter into any obligation relating thereto, to make or disseminate or cause to be made or disseminated before the public in this state, or to make or disseminate or cause to be made or disseminated from this state before the public in any state, in any newspaper or other publication, or any advertising device, or by public outcry or proclamation, or in any other manner or means whatever, including over the Internet, any statement, concerning that real or personal property or those services, professional or otherwise, or concerning any circumstance or matter of fact connected with the proposed performance or disposition thereof, which is untrue or misleading, and which is known, or which by the exercise of reasonable care should be known, to be untrue or misleading, or for any person, firm, or corporation to so make or disseminate or cause to be so made or disseminated any such statement as part of a plan or scheme with the intent not to sell that personal property or those services, professional or otherwise, so advertised at the price stated therein, or as so advertised. Any violation of the provisions of this section is a misdemeanor punishable by imprisonment in the county jail not exceeding six months, or by a fine not exceeding two thousand five hundred dollars ($2,500), or by both that imprisonment and fine.

[49] 631. (a) Any person who, by means of any machine, instrument, or contrivance, or in any other manner, intentionally taps, or makes any unauthorized connection, whether physically, electrically, acoustically, inductively, or otherwise, with any telegraph or telephone wire, line, cable, or instrument, including the wire, line, cable, or

e. Unauthorized Release of Private Communications: In December of 2010, PG&E released a heavily redacted version of their internal investigation to Dana Hull at the San Jose Mercury News and David Baker at the San Francisco Chronicle. This set of more than 100 documents included hundreds of private e-mails sent by individuals associated with anti-smart meter groups, which were left unredacted while e-mails and identities of PG&E and third parties were redacted. The unredacted e-mails were private communications that were sent to the SmartWarriorMarin and other groups with the expectation that they would not be read by PG&E executives, or the CPUC and certainly not distributed to the press. Rather than being transparent about what PG&E management knew and when, PG&E compounded the violations carried out by Devereaux and others by making these private e-mails public without proper authorization from those from whom the e-mails originated. These e-mails discuss legal and practical strategies in the campaign against smart meters and were certainly not intended for public viewing. PG&E's release includes private addresses of individuals:

f. Violations of NGA and FPA: Pursuant to section 4A of the NGA and section 222 of the Federal Power Act (FPA), as added to the statutes by the Energy Policy Act of 2005 (EPAct 2005), the Commission proposed to add a Part 159 under Subchapter E and a Part 47 under Subchapter B to Title 18 of the Code of Federal Regulations. Under the regulations FERC

instrument of any internal telephonic communication system, or who willfully and without the consent of all parties to the communication, or in any unauthorized manner, reads, or attempts to read, or to learn the contents or meaning of any message, report, or communication while the same is in transit or passing over any wire, line, or cable, or is being sent from, or received at any place within this state; or who uses, or attempts to use, in any manner, or for any purpose, or to communicate in any way, any information so obtained, or who aids, agrees with, employs, or conspires with any person or persons to unlawfully do, or permit, or cause to be done any of the acts or things mentioned above in this section, is punishable by a fine not exceeding two thousand five hundred dollars ($2,500), or by imprisonment in the county jail not exceeding one year, or by imprisonment pursuant to subdivision (h) of Section 1170, or by both a fine and imprisonment in the county jail or pursuant to subdivision (h) of Section 1170. If the person has previously been convicted of a violation of this section or Section 632, 632.5, 632.6, 632.7, or 636, he or she is punishable by a fine not exceeding ten thousand dollars ($10,000), or by imprisonment in the county jail not exceeding one year, or by imprisonment pursuant to subdivision (h) of Section 1170, or by both that fine and imprisonment.

adopted, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the Commission, or in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, (1) to use or employ any device, scheme, or artifice to defraud, (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any person.

4. PG&E's threat decision tree fails to assess external threats identifying the possible motive for an opaque investigation outcome for PG&E's bottom line.

According to D. 12-12-030 [P. 15] "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. [50]" But this decision tree is purposely opaque so as to obscure the analysis of three external risks CARE had identified 1) risk of arc flash ignition source for fire proceeding explosions induced from wireless SmartMeters™; 2) a risk of intentional sabotage or terrorist attack; and 3) the risk of intentional use or employment of a device, scheme, or artifice to defraud. None of these reasonably foreseeable external risks where part of the risk assessment adopted by D. 12-12-030.

What motive could PG&E and CPUC have for the opaque investigation outcome found in Decision 12-12-030 that clearly was beneficial for PG&E's bottom line; except to violate California Public Utilities Code Section 328(b) "No customer should have to pay separate fees for utilizing services that protect public or customer safety"; knowing that PG&E had not

[50] 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.

adequately maintain its records regarding the San Bruno pipeline; and knowing that PG&E's entire gas transmission system was in a state of high risk for not maintaining its lines under the terms and conditions of its blanket certificate?

IV. RELATED PROCEEDINGS

The issues presented in this complaint are not before the Commission or another forum in any other current or pending proceeding.

V. RELIEF REQUESTED

1. Complainants respectfully requests the Commission provide PG&E Notice to Show Cause Why the Commission Should Not Revoke its Blanket Certificate PR10-72-000 Issued July 18, 2011.

2. Complainants respectfully requests the Commission provide Complainants' evidence of compliance or a schedule of compliance to the terms and conditions of PG&E's blanket certificate; including but not limited. to the records identified herein as missing or inaccurate; including, but not limited to, proof of insurance, bonding, licensing, for all PG&E natural gas facilities currently operating and/or that where operating at the time of the San Bruno disaster.

3. Complainants respectfully requests FERC staff in cooperation with CPUC staff in the Division of Ratepayer Advocates ["DRA"] develop a proposed PG&E natural gas Quality System (QS) including in the threats decision tree assessment of external threats identified herein which defines process validation so as establishing by objective evidence that a process consistently produces a result or product meeting its predetermined specifications. [51] The Quality

[51] REFERENCES
1. Guideline on General Principles of Process Validation, May 1987, FDA, CDRH/CDER
2. Journal of Validation Technology, Vol. 1, No. 4, August 1995

System should at a minimum include Process validation, Installation qualification, Process performance qualification, Product performance qualification, Prospective validation, Retrospective validation, or a Validation protocol in place to allow the determination of "whether its validation methodology is acceptable to the Commission.

4. Complainants respectfully requests FERC impose civil penalties against PG&E based on fraud and false statements which includes a $1,000,000 per day for such [52] from September 9, 2010 to the date of this instant complaint, or $826,000,000; complainants further request the Commission assess against PG&E the maximum penalties provided for by the NGA, 15 U.S.C. § 717(t): $1,000,000 for willingly and knowingly violating 15 U.S.C. § 717f(h) and $50,000 for each day during which PG&E knowingly and willingly violated 18 C.F.R. § 157.203(d).

5. Complainants respectfully requests the Commission grant any other relief it deems just and proper.

VI. ADDITIONAL REQUIREMENTS OF RULE 206

5. 18 C.F.R. § 383.206(b)(1)-(2)

The price and non-price terms and conditions of the violations challenged herein are unjust and unreasonable and in violation of § 206 of the FPA, and to the extent applicable, are not in the public interest pursuant to § 206.

[52] See Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1284(e), 314 (b)(1)(B), and 314(b)(2), 119 Stat. 594 at 950 and 691 (2005), respectively.

6. 18 C.F.R. § 383.206(b)(3)(5)

Complainant requests FERC impose civil penalties against PG&E based on fraud and false statements which includes a $1,000,000 per day for such [53] from September 9, 2010 to the date of this instant complaint, or $826,000,000. Complainant has reason to believe PG&E is subject to this penalty for each day it operates out of compliance with the terms and conditions of it blanket certificate since September 9, 2010.

Collectively the challenged fraud by PG&E imposes a financial burden on ratepayers which is defined by CPUC in Decision 12-12-030. Non-financial consequences include threats to sound energy policy, as detailed *supra*.

7. 18 C.F.R. § 383.206(b)(6)

While some of the facts and legal arguments relevant to the instant Complaint may have been brought to FERC's attention in other pending proceedings, no pending proceeding provides an adequate opportunity for FERC to address the totality of Respondent's misconduct and fully address the injuries complained of herein.

8. 18 C.F.R. § 383.206(b)(7)

CARE submits that the violations challenged herein must be abrogated as they are unjust and unreasonable. In addition to unreasonable pricing, the non-price terms and conditions of the violations are unjust and unreasonable, and warrant abrogation of the unlawful actions by PG&E. Abrogation of the violations should be implemented in an orderly fashion.

9. 18 C.F.R. § 383.206(b)(8)

In support of the facts in this Complaint, CARE provides the included exhibits:

[53] See Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1284(e), 314 (b)(1)(B), and 314(b)(2), 119 Stat. 594 at 950 and 691 (2005), respectively.

Exhibits Index

Description	Exhibit No.
Notice of Section 206 Complaint	A
CPUC Decision 12-12-030	1
NTSB report [P-11-008-020]	2
E-mail Re: Interview with Wellington Energy Whistleblower January 26, 2011	3
February 7, 2011 e-mail to Congress member Speier	4
Transcript of April 11, 2011 Oral Arguments before CPUC in R.11-02-019	5

10. 18 C.F.R. § 383.206(b)(9)

CARE has not attempted to use any of FERC's alternative dispute resolution procedures, and does not believe that any such procedures could successfully resolve the Complaint.

11. 18 C.F.R. § 383.206(b)(10)

A Form of Notice suitable for publication in the Federal Register is attached hereto as Exhibit A.

VII. SERVICE

The following person should be included in the official service list in these proceedings and all notices and communications with respect to these proceedings should be addressed, by electronic service if available, to:

Michael E. Boyd – President, CARE
5439 Soquel Drive
Soquel, California 95073
(831) 465-9809
(408) 891-9677 (cell)
E-mail: michaelboyd@sbcglobal.net

Robert M. Sarvey

501 W. Grantline Rd., Tracy, Ca. 95375
Phone: (209) 835-7162
E-mail: sarveybob@aol.com

VIII. CONCLUSION

For the foregoing reasons, CARE respectfully requests that FERC grant the relief requested herein.

Respectfully submitted,

Michael E. Boyd

Michael E. Boyd, Individually and as President
CAlifornians for Renewable Energy, Inc. ("CARE")
5439 Soquel Drive, Soquel, CA 95073
Phone: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net

Robert M. Sarvey, Individually
501 W. Grantline Rd., Tracy, Ca. 95375
Phone: (209) 835-7162
E-mail: sarveybob@aol.com

Verification

I am an officer of the complaining corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except matters, which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on January 3, 2013 at Soquel, California

Michael E. Boyd

Michael E. Boyd – President, CARE
CAlifornians for Renewable Energy, Inc. (CARE)
5439 Soquel Dr.
Soquel, CA 95073-2659
Tel: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net

UNITED STATES OF AMERICA
BEFORETHE
FEDERALENERGYREGULATORYCOMMISSION

CAlifornians for Renewable Energy, Inc., (CARE); Michael E. Boyd; and Robert M. Sarvey Complainant, v. Pacific Gas and Electric Company, Respondents.	Docket No. EL

DECLARATION OF MICHAEL E. BOYD

1. My name is Michael E. Boyd

2. I live at 5439 Soquel Drive, Soquel California 95073.

3. I am a natural gas customer of Pacific Gas and Electric Company ["PG&E"] respondent herein.

4. I participated as a Party to the Decision 12-12-030 issued by CPUC on December 20, 2012 in the *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* under Rulemaking 11-02-019 (Filed February 24, 2011). (Exhibit 1.)

5. I prepared the February 7, 2011 e-mail to Congress member Speierregarding Rulemaking 11-02-019 (Exhibit 4.)

6. I prepared the above Complaint of CARE, Michael Boyd, and Bob Sarvey.

7. The statements in the foregoing document are true of my own knowledge, except matters, which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on January 3, 2013 at Soquel, California

Michael E. Boyd

Michael E. Boyd – President,
CAlifornians for Renewable Energy, Inc. (CARE)
5439 Soquel Dr.
Soquel, CA 95073-2659
Tel: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net

Cc.
CPUC Rulemaking 11-02-019 Service List

Martin Homec, martinhomec@gmail.com

Ross Reineke - US DOT
CATS Manager
PHMSA/ Western Region
E-mail: Ross.Reineke@dot.gov

Exhibit A

UNITED STATES OF AMERICA
BEFORETHE
FEDERALENERGYREGULATORYCOMMISSION

CAlifornians for Renewable Energy, Inc., (CARE); Michael E. Boyd; and Robert M. Sarvey Complainant, v. Pacific Gas and Electric Company, Respondents.	Docket No. EL

NOTICE OF SECTION 206 COMPLAINT

(January ___ 2013)

Take notice that on January ___ 2013, CAlifornians for Renewable Energy, Inc. (CARE) (Complainant) submitted a complaint against Pacific Gas and Electric Company ("PG&E") for its violation of the terms and conditions of their blanket certificate through a failure to meet requirements to maintain its natural gas transmission system [18 C.F.R. § 157.14(a)(9)(vi)] in the events that lead up to, including the events following the fire that proceeded the explosions that destroyed 35 homes and killed 8 individuals [including an alleged CPUC pipeline safety whistleblower]; and the subsequent response and cover up by the CPUC and NTSB following the San Bruno pipeline explosion. The explosions occurred on September 9, 2010, involving the rupture of Line 132, a 30-inch natural gas intrastate transmission line operated by the Pacific Gas and Electric Company and regulated by CPUC. The root cause of the fire and resulting explosions remains undetermined.

Copies of this filing were served upon Respondents and other interested parties.

Any person desiring to be heard or to protest this filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions or protests must be filed on or before _______________, 2013. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding.

Any person wishing to become a party must file a motion to intervene. Answers to the complaint shall also be due on or before ___________, 2013. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the web at http://www.ferc.gov using the "RIMS" link, select "Docket#" and follow the instructions (call 202-208-2222 for assistance). Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link.

Secretary

ALJ/MAB/avs/jt2 **Date of Issuance 12/28/2012**

Decision 12-12-030 December 20, 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, ALLOCATING RISK OF INEFFICIENT CONSTRUCTION MANAGEMENT TO SHAREHOLDERS, AND REQUIRING ONGOING IMPROVEMENT IN SAFETY ENGINEERING

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DECISION MANDATING PIPELINE SAFETY IMPLEMENTATION PLAN, DISALLOWING COSTS, 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

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

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

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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

Footnote continued on next page

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.

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

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necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

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 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:

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

> 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 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

4 Independent Review Panel Report at 65-66.

5 Independent Panel Report at 50, 73.

6 Id. at 54.

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.)
- 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.)

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[7] Id. at 64.

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

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.

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

[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).

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, 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

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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).

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 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]

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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.)

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

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 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:

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.

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[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

[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

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[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

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[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

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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

[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

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

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.
- 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 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

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

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 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

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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.

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 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

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

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 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.

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.

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

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 should be assigned to shareholders. TURN estimates that pressure testing approximately 90 miles of 1956 to 1961 pipeline accounts for $45 million of

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45 Hearing Exh. 31 at 75 - 77.

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

[46] PG&E Reply Brief at 8.

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-testing this pipeline in revenue requirement. PG&E argues that because it was not legally required to pressure test these pipeline segments previously, even

[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.

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 shareholders should be held to their obligation for re-testing costs, but not extended to replacement costs. Shareholders should not be excused from their

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

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.

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		
	DDRA	PPG&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

Footnote continued on next page

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	DRA[59]		PG&E[60]
	UC Davis Study	Pacific Northwest	

[59] Hearing Exh. 147 at 3 – 8.

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

(inches)		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]

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]

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61 DRA Opening Brief at 95.

62 Hearing Exh. 21 at 3-32.

63 Id. at 3-39.

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 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 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

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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.

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.

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

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, 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 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.

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[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."

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

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 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

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

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 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

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71 Hearing Exh. 2 at 4-25.

72 Hearing Exh. 2 at 4-7.

73 City of San Bruno Opening Brief at 5.

74 DRA Opening Brief at 124.

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 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.

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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.

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. 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]

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

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

[78] Hearing Exh. 21 at 3-47

[79] TURN Opening Brief at 126 – 127.

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 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

80 PG&E Reply Brief at 46.

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 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

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[81] TURN Reply Brief at 35.

[82] PG&E Reply Brief at 41.

[83] Id. at 42.

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 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 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.

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

[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.

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 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.

<u>Consumer Protection and Safety Division Oversight (CPSD)</u>

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

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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.)

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]

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

[89] Id. at 42.

[90] DRA Opening Brief at 43.

[91] TURN Opening Brief at 101.

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 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

92 TURN Opening Brief at 103.

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 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

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

[94] PG&E Reply Brief at 26.

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

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

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 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 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

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

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.

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

97 Id. at 8 – 9 (citations omitted).

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]

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

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98 49 CFR 192.619(c).

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.

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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.

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 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

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102 TURN Opening Brief at 69 – 74.

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 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

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

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.

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]

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[104] Hearing Exh. 147 at 16.

[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.

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 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

[109] Id.

[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%.

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 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

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112 PG&E Opening Brief at 82 - 83.

113 Id. at 84 - 85.

> 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 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

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114 D.11-06-017 at 22.

115 Id. at 28.

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.

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

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[116] TURN Opening Brief at 121.

[117] Hearing Exh. 2 at Chapter 10.

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.

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.

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

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.

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.

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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.

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 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.

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[121] NCIP Opening Brief at 34-35.

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.

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 December 20, 2012, at San Francisco, California

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

I reserve the right to file a concurrence.

/s/ TIMOTHY ALAN SIMON
Commissioner

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ATTACHMENT A

************ SERVICE LIST R1102019***********

Last Updated on 10-OCT-2012 by: JVG

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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.*

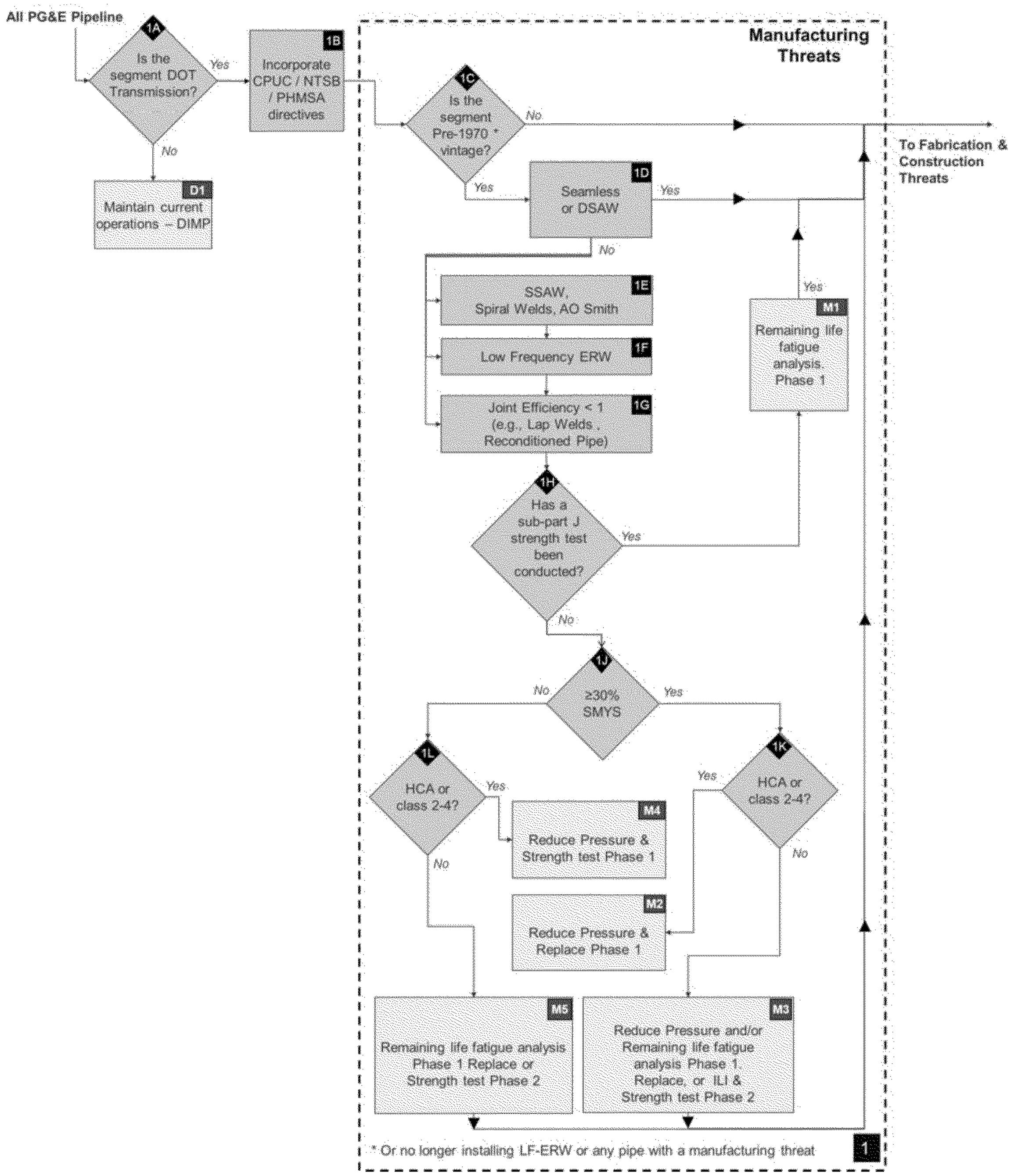
6.2.4.2	*Greater involvement by staff in industry groups such as the Gas Piping Technical Committee (GPTC) will better enable the CPUC staff to keep abreast pipeline integrity management advancements from a technical, process, and regulatory perspective. In addition, the CPUC can, through such forums, 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*

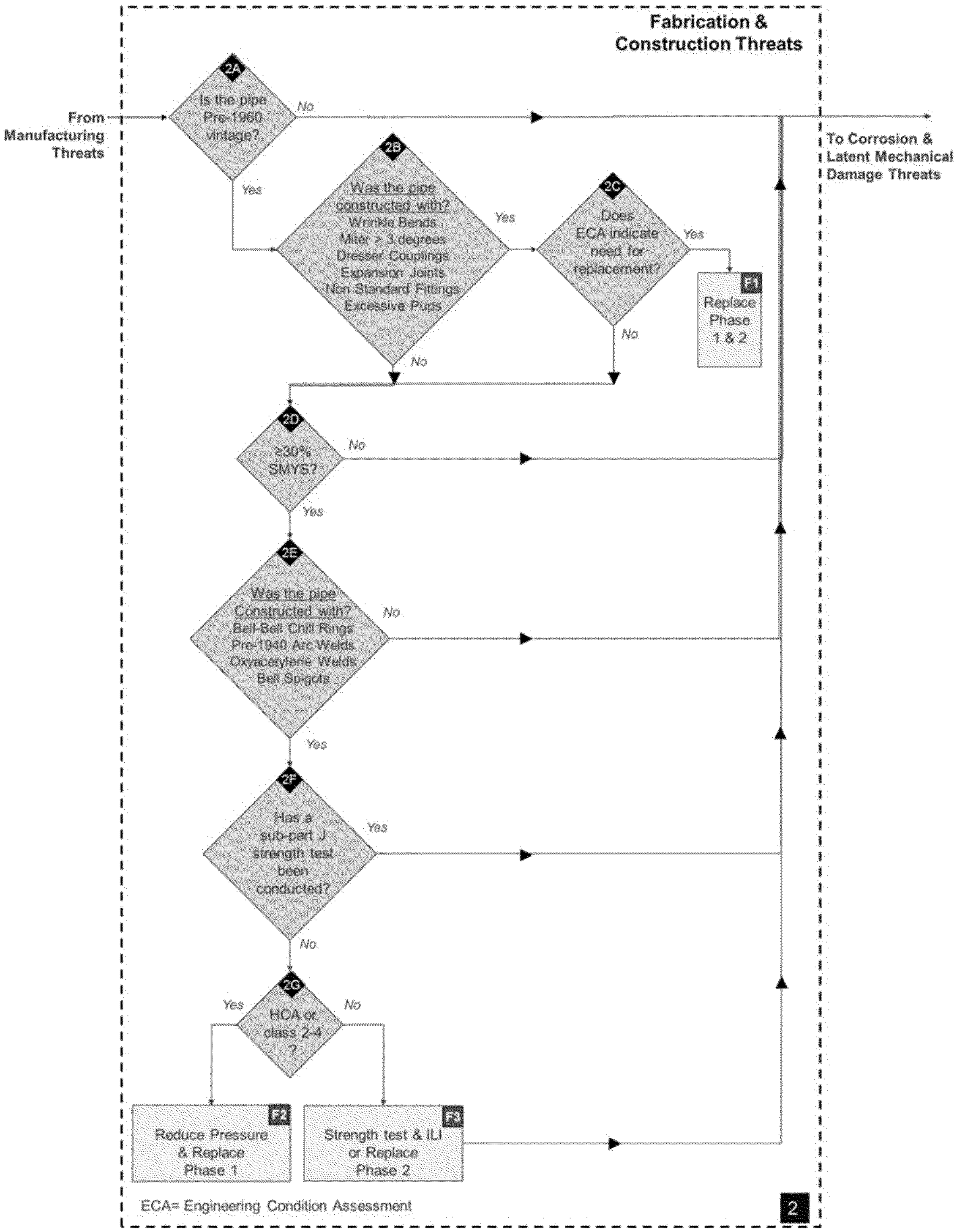
	interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so there is an enhanced understanding of the costs associated with pipeline safety.
6.8.3.2	*Consider, as appropriate, transferring the USRB gas safety staff to the OSFM, and with them the responsibility 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)

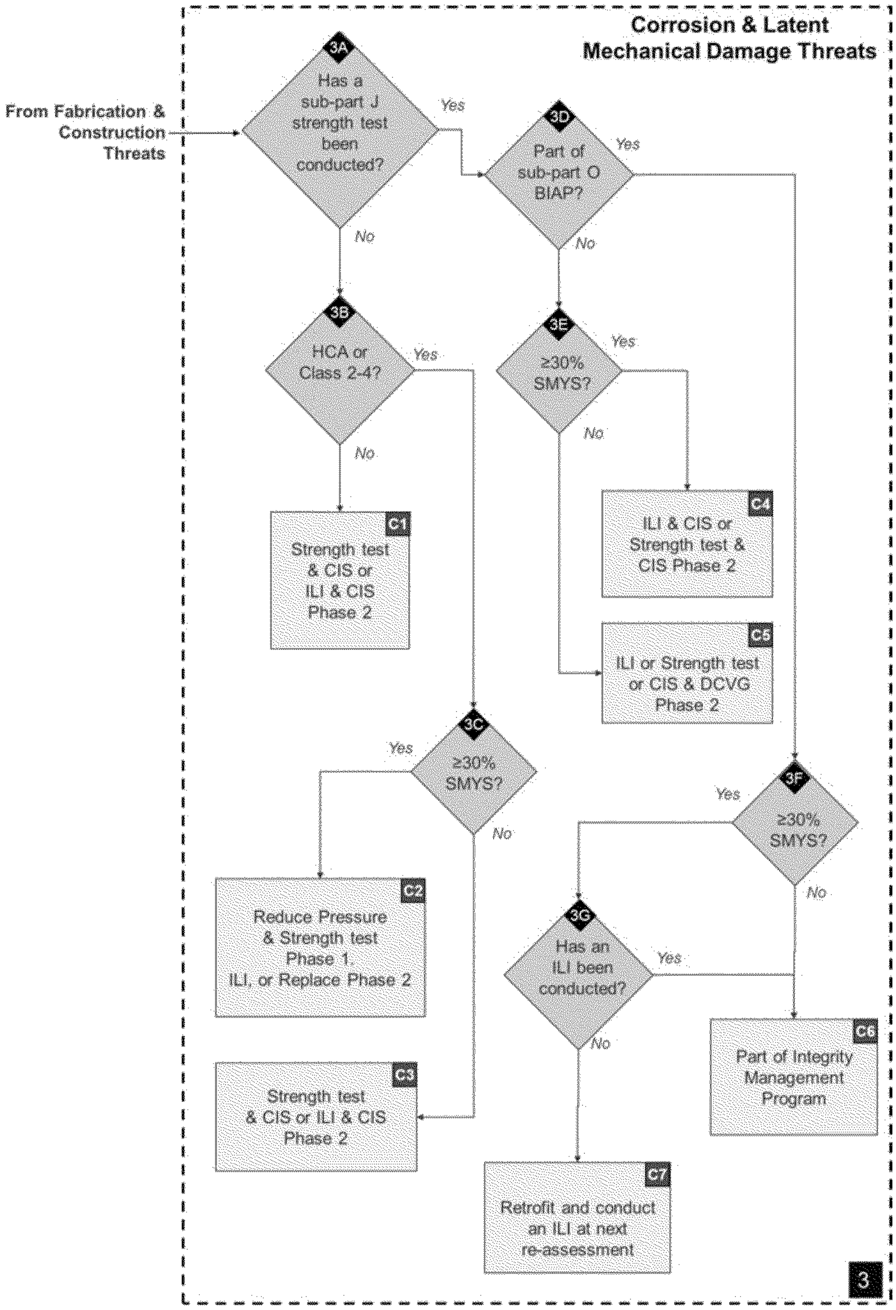
ATTACHMENT C
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
MANUFACTURING THREAT DECISION QUERY



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

Line No	Description	2011(a)	2012(b)	2013	2014	Total
	TABLE E-2 Program Expenses					
	PACIFIC GAS and ELECTRIC COMPANY					
	EXPENSES (w/escalation adjustment)					
	($ IN MILLIONS)					
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)

Decision D.12-12.030
Adopted December 20, 2012 R.11-02-019

Concurrence of Commissioner Timothy Alan Simon on Item 50 Decision D.12-12-030 Mandating Pipeline Safety, Disallowing Costs, and Requiring ON-Going Improvement in Safety Engineering

I support Decision D.12-12-030 that approves the Pipeline Safety Implementation Plan and other rules for Pacific Gas and Electric (PG&E) utility. As always, my prayers go to the families of San Bruno. This tragedy occurred during my term as a Commissioner and can never be erased from my memory. Visiting the San Bruno site shortly after the explosion is a vivid and ugly reminder that the cost of pipeline safety management is used and useful. It is a just and necessary part of gas delivery.

This Decision mandates a specific pipeline safety implementation plan for PG&E and evaluates PG&E's gas pipeline safety implementation proposal. The specific actions are necessary on a permanent safety mission that PG&&E, its officers, employees, shareholders, must adopt going forward. This Decision requires that PG&E will engage in: pressure testing of 783 miles, replacement of 186 miles, installation of 228 automated valves and upgrade of 199 miles of gas pipeline.

The Decision strikes the right cost balance between shareholders and ratepayers. In cost sharing PG&E's shareholders will bear the pressure testing costs when pressure test records are missing. Also PG&E's record management and computer database costs may not be recovered from ratepayers. Similarly, the Decision clarifies that PG&E's shareholders bear the risk of cost overruns. This is a forward looking Decision that focuses on PG&E's safety implementation plan for its natural gas pipeline transmission system. To the extent PG&E has failed to perform its due diligence, its shareholders will be responsible. To the extent PG&E is required to provide safety as a result of federal and state mandates, PG&E's ratepayers should bear such costs under the finding that PG&E has not previously recovered cost for such enhancements.

It is regrettable that the Decision did not include a true third party independent monitor as suggested by the City of San Bruno and City and County of San Francisco and the Division of Ratepayer Advocates. The Decision should have ordered PG&E to hire an Independent Monitor who would report to the Commission and the public regarding the status and quality of PG&E's work, in addition to the ongoing monitoring work done by the California Public Utilities Commission Division of Safety and Enforcement staff.

As chair of National Association of Regulatory Utility Commissioners, (NARUC) Gas Committee and a member of the National Pipeline Safety Taskforce, I believe this is a balanced Decision that will require PG&E to continue its work to becoming one of the nation's safe natural gas transmission system operators. I must point out that while this Decision strikes a balance, it is also hindered by the failure of this Commission and the parties to the Order Instituting Investigations (OII) (I.) 11-02-016, I.11-11-009, and I.12-01-007 to complete the sanctions of PG&E for the September 8, 2012 San Bruno explosion. As a result, penalties for PG&E permeating into PG&E's gas operations that should be limited to the OII.

While at this time my colleagues and I have no reasonable choice, it is imperative that this commission complete the OII *post- haste*. I speak with authority having gained as Assigned Commissioner a 5-0 vote on the $38 million fine I imposed against PG&E's inaction in a natural gas explosion that occurred on December 24, 2008, in Rancho Cordova, Calif., which resulted in one fatality, other injuries, and property damage (California Public Utilities Commission

Investigation, Docket No. I.10-11-013). This Decision also suffered unnecessary delays.

Accordingly, I concur with this Decision and urge PG&E to quickly implement its natural gas safety improvements as approved in this Decision.

Dated December 27, 2012, at San Francisco, California.

/s/ TIMOTHY ALAN SIMON

TIMOTHY ALAN SIMON
Commissioner

National Transportation Safety Board

Washington, D.C. 20594

Safety Recommendation

Date: SEP 26 2011

In reply refer to: P-11-8 through -20 and P-11-1 and P-11-2 (Reclassification)

The Honorable Cynthia L. Quarterman
Administrator
Pipeline and Hazardous Materials Safety Administration
Washington, DC 20590

On September 9, 2010, about 6:11 p.m. Pacific daylight time, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company (PG&E), ruptured in a residential area in San Bruno, California. The rupture occurred at mile point 39.28 of Line 132, at the intersection of Earl Avenue and Glenview Drive. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. PG&E estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.[1]

The NTSB determined that the probable cause of the accident was PG&E's (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section.

Contributing to the accident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects. Also

[1] For additional information, see *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010,* Pipeline Accident Report NTSB/PAR-11/01 (Washington, DC: National Transportation Safety Board, 2011), which is available on the National Transportation Safety Board (NTSB) website at <http://www.ntsb.gov/>.

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contributing to the accident was the CPUC's failure to detect the inadequacies of PG&E's pipeline integrity management program.

Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas.

Notifying Emergency Responders

The NTSB noted that PG&E did not notify emergency officials that the accident involved the rupture of one of PG&E's pipelines, even after they had deduced this to be the case. On June 8, 2011, the NTSB made the following recommendations to address these issues. Specifically, the NTSB recommended that the Pipeline and Hazardous Materials Safety Administration (PHMSA) do the following:

> Issue guidance to operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines regarding the importance of sharing system-specific information, including pipe diameter, operating pressure, product transported, and potential impact radius, about their pipeline systems with the emergency response agencies of the communities and jurisdictions in which those pipelines are located. (P-11-1)

> Issue guidance to operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines regarding the importance of control room operators immediately and directly notifying the 911 emergency call center(s) for the communities and jurisdictions in which those pipelines are located when a possible rupture of any pipeline is indicated. (P-11-2)

To PG&E, NTSB recommended the following:

> Require your control room operators to notify, immediately and directly, the 911 emergency call center(s) for the communities and jurisdictions in which your transmission and/or distribution pipelines are located, when a possible rupture of any pipeline is indicated. (P-11-3)

Because of emergency response awareness issues discovered in the Carmichael, Mississippi,[2] and San Bruno investigations, the NTSB is concerned that similar problems may exist with other pipeline operators and believes that the guidance recommended in Safety Recommendations P-11-1 and -2 should be codified as requirements. To address these concerns, the NTSB recommends that PHMSA require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to provide system-specific information about their pipeline systems to the emergency response agencies of the communities and jurisdictions in which those pipelines are located. This information should include pipe diameter, operating pressure, product transported, and potential impact radius. As a result of this new recommendation to PHMSA, Safety Recommendation P-11-1 is classified

[2] See *Rupture of Hazardous Liquid Pipeline With Release and Ignition of Propane, Carmichael, Mississippi, November 1, 2007*, Pipeline Accident Report NTSB/PAR-09/01 (Washington, DC: National Transportation Safety Board, 2009).

"Closed—Superseded." Further, the NTSB recommends that PHMSA require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to ensure that their control room operators immediately and directly notify the 911 emergency call center(s) for the communities and jurisdictions in which those pipelines are located when a possible rupture of any pipeline is indicated. As a result of this new recommendation to PHMSA, Safety Recommendation P-11-2 is classified "Closed—Superseded."

Line Break Recognition

Although supervisory control and data acquisition (SCADA) staff quickly realized that there had been a gas line break in San Bruno, they were slow to recognize the connection between the line break and the overpressure at the Milpitas Terminal, and some staff were initially unsure of whether the break was in a transmission or a distribution line.

In a postaccident interview, SCADA operator B[3] stated that within 7 minutes of the rupture, he knew there had been a break in Line 132, and that by 6:30 p.m., he knew it was within a 12-mile corridor in the vicinity of San Bruno. At 6:53 p.m., SCADA operator D indicated that he knew the break was in Line 132, telling the on-scene SCADA transmission and regulation supervisor, "Yeah, absolutely we believe it's a break on Line 132." However, at about that time, there was still confusion among other employees as indicated by comments made at 6:51 p.m. by SCADA operator C to a PG&E pipeline engineer, indicating that although the engineer said he thought there was a PG&E transmission line close to the area of the fire, SCADA operator C did not think the break was in a transmission line. At 6:55 p.m., in a telephone discussion between SCADA operator C and the on-scene PG&E gas maintenance and construction superintendent, both indicated that they believed a distribution line and not a transmission line had been breached.

SCADA staff also had difficulties determining the exact location of the rupture. At 6:49 p.m., the SCADA center[4] was still uncertain of the rupture point, as illustrated by the comment of the senior SCADA coordinator to a dispatch employee, "We are going to feed the line break at this pressure but I would take the pressure down if I knew more about what was feeding it... ."

The PG&E SCADA system lacked several tools that could have assisted the staff in recognizing and pinpointing the location of the rupture, such as real-time leak or line break detection models, and closely spaced flow and pressure transmitters. A real-time leak detection application is a computer-based model of the transmission system that runs simultaneously with SCADA and provides greater feedback to SCADA operators when a large scale leak, line break, or system anomaly is present. Such models use actual SCADA pressures and flows to calculate actual and expected hydraulic performance; when the values do not match, an alarm is generated.

[3] SCADA operators B, C, and D referenced in this letter were all working at the SCADA center in San Francisco. Operator D became the primary point of contact for workers at the Milpitas Terminal on the evening of the accident.

[4] In this letter, SCADA center refers to PG&E's gas control center.

Appropriate spacing of pressure transmitters at regular intervals[5] allows SCADA operators to quickly identify pressure decreases that point toward a leak or line break.

The NTSB concludes that PG&E's SCADA system limitations contributed to the delay in recognizing that there had been a transmission line break and quickly pinpointing its location. Therefore, the NTSB recommends that PHMSA require that all operators of natural gas transmission and distribution pipelines equip their SCADA systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.

Rapid Shutdown, Automatic Shutoff Valves, and Remote Control Valves

Two mechanics had self-reported to the Colma yard at 6:35 p.m., and they decided to depart the yard at 7:06 p.m. to shut off the valves. Because gas was being supplied to the break from both the north and the south, shutdown and isolation of the rupture required closure of manual shutoff valves closest to the break, which were located about 1.5 miles apart, on either end of the break. The mechanics identified and manually closed those valves at 7:30 p.m. (south valve) and 7:46 p.m. (north valve). Also, about 7:29 p.m., the SCADA center remotely closed valves at the Martin Station in response to a request from a SCADA transmission and regulation supervisor who had joined the mechanics.

The NTSB is concerned that the mechanics were unnecessarily held at the Colma yard and that the response could have been delayed even longer if the two mechanics had waited for official orders from PG&E. Further, the SCADA center staff could have reduced the flow sooner by shutting the remote valves at the Martin Station sooner, but they did not. These delays needlessly prolonged the release of gas and prevented emergency responders from accessing the area.

The total heat and radiant energy released by the burning gas was directly proportional to the time gas flowed freely from the ruptured pipeline. Therefore, as vegetation and homes ignited, the fire would have spread and led to a significant increase in property damage. The pressurized flow from the south resulted in an intense flame front similar to a blowtorch, and emergency responders were unable to gain access to the area. If the gas had been shut off earlier, removing fuel flow, the fire would likely have been smaller and resulted in less damage. Also, buildings that would have provided protection to residents in a shorter duration fire were compromised because of the elevated heat. In addition to exposing residents and their property to increased risk, the prolonged fire also negatively affected emergency responders, who were put at increased risk by having to be in close proximity to fire for a longer time and were not available to respond to other potential emergencies while they were waiting for the fire to subside.

[5] SCADA data on Line 132 are currently received from only a few transmitters at randomly spaced intervals.

The NTSB concludes that the 95 minutes that PG&E took to stop the flow of gas by isolating the rupture site was excessive. This delay, which contributed to the severity and extent of property damage and increased risk to the residents and emergency responders, in combination with the failure of the SCADA center to expedite shutdown of the remote valves at the Martin Station, contributed to the severity of the accident.

The NTSB has long been concerned about the lack of standards for rapid shutdown and the lack of requirements for automatic shutoff valves (ASV) or remote control valves (RCV) in high consequence areas (HCA). As far back as 1971, the NTSB recommended, in Safety Recommendation P-71-1, the development of standards for rapid shutdown of failed natural gas pipelines. In 1995, the NTSB recommended, in Safety Recommendation P-95-1, that the Research and Special Programs Administration (RSPA), the predecessor agency of PHMSA, expedite requirements for installing automatic- or remote-operated mainline valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments. The NTSB classified Safety Recommendation P-95-1 "Closed—Acceptable Action," believing that the RSPA 2004 integrity management rulemaking (requiring that each gas transmission operator determine whether installing ASVs or RCVs would be an efficient means of adding protection to an HCA) would lead to a more widespread use of ASVs and RCVs. However, it did not.

Federal regulations prescribe, at Title 49 *Code of Federal Regulations* (CFR) 192.179, the spacing of valves on a transmission line based on class location. However, other than for pipelines with alternative maximum allowable operating pressures (MAOP),[6] the regulations do not require a response time to isolate a ruptured gas line, nor do they explicitly require the use of ASVs or RCVs. The regulations give the pipeline operator discretion to decide whether ASVs or RCVs are needed in HCAs as long as they consider the factors listed under 49 CFR 192.935(c).[7] Therefore, there is little incentive for an operator to perform an objective risk analysis, as illustrated by PG&E's June 14, 2006, memorandum—which was issued after the CPUC 2005 audit identified PG&E's failure to consider the issue and does not directly discuss any of the factors listed in section 192.935(c). Rather, it cites industry references to support the conclusion that most of the damage from a pipeline rupture occurs within the first 30 seconds, and that the duration of the resulting fire "has (little or) nothing to do with human safety and property damage." The memorandum concludes that the use of an ASV or an RCV as a prevention and mitigation measure in an HCA would have "little or no effect on increasing human safety or protecting properties."

In the case of the San Bruno transmission line break, nearby RCVs could have significantly reduced the amount of time the fire burned, and thus the severity of the accident. Had the two isolation valves, located 1.5 miles apart, been outfitted with remote closure

[6] Under 49 CFR 192.620, "Alternative Maximum Allowable Operating Pressure for Certain Steel Pipelines," issued in 2008, an operator is allowed to operate a pipeline at up to 80 percent specified minimum yield strength (SMYS) in class 2 locations as long as it meets a very specific and stringent set of criteria. Section 192.620(c)(3) states that an RCV or ASV is required for such pipelines if the response time to mainline valves exceeds 1 hour under normal driving conditions and speed limits.

[7] Those factors are (1) the swiftness of leak detection and pipe shutdown capabilities; (2) the type of gas being transported; (3) the operating pressure; (4) the rate of potential release; (5) the pipeline profile; (6) the potential for ignition; and (7) the location of nearest response personnel.

capability, prompt closure of those valves would have reduced the amount of fuel burned by the fire and allowed firefighters to enter the affected area sooner. The PG&E manager of gas system operations acknowledged at the NTSB's investigative hearing held on March 1–3, 2011, that the use of RCVs could have reduced the time it took to isolate the rupture by about 1 hour.

Damage from the pipeline rupture could have been reduced significantly if the valves on either end of the rupture point had been equipped with ASVs. Analysis of pressure differentials indicated that the San Bruno rupture would have resulted in the closure of an ASV at the downstream location[8] and would likely also have resulted in the closure of an ASV at the upstream location.[9] Even the closing of a downstream ASV alone would have been beneficial in that it would have immediately alerted SCADA to a more precise location of the break.

Concerns about ASVs have focused on the cost of installation and their susceptibility to inadvertently trip based on pressure transients in the system. However, vendors have developed newer models that address these shortcomings by combining the features of traditional ASVs with RCVs. These "smart" valves include sensors that can trend the pressure transients on a line to identify what constitutes normal operation, thereby lessening the chances of an inappropriate shutdown. Also, the newer models can alert a SCADA center when the valve hits a trip point, allowing SCADA operators the option of overriding the valve closure and precluding an undesired shutdown.

The NTSB concludes that the use of ASVs or RCVs along the entire length of Line 132 would have significantly reduced the amount of time taken to stop the flow of gas and to isolate the rupture. The NTSB is aware that PG&E is in the process of expanding its use of ASVs and RCVs and has added this capability to some valve locations since the accident. Still, the NTSB recommends that PHMSA amend 49 CFR 192.935(c) to directly require that ASVs or RCVs in HCAs and in class 3 and 4 locations be installed and spaced at intervals that consider the factors listed in that regulation.

Deficiencies in Postaccident Drug and Alcohol Testing

After the accident, PG&E identified four employees at the Milpitas Terminal for postaccident toxicological testing pursuant to 49 CFR 199.105 and 49 CFR 199.225. Test results were negative for the presence of specified drugs. Testing for drugs was accomplished successfully within the time constraints defined in 49 CFR 199.105; that is, within 32 hours of the accident. However, alcohol testing was not conducted properly in accordance with 49 CFR 199.225, which requires that testing be administered within 8 hours of an accident, and,

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[8] The pressure decay at the Martin Station showed a decrease from 386 to 200 pounds per square inch, gauge (psig) in the course of 3 minutes (62 psig per minute), beginning at 6:11 p.m. This drop would have been more than sufficient to trip an ASV located at the downstream valve near the rupture point.

[9] The pressure decay in Line 132 was not captured because the transmitter at that location was not installed directly on the main line but on a smaller transmission line (at Half Moon Bay) that branched off from Lines 132 and 109. Although the Half Moon Bay pressure readings cannot be used past 6:11 p.m. to approximate the Line 132 pressures upstream of the rupture, because the differential pressure was great enough to trip an ASV on the smaller line branching off Line 132 at Half Moon Bay, an ASV located on Line 132 likely would have tripped as well. (The smaller line crossed the San Andreas fault and, therefore, was equipped with an ASV to address seismic risk.)

if it is not, the operator shall cease attempts to do so. Results for the alcohol tests were invalid and therefore, the use of alcohol cannot be excluded.

Alcohol testing of the four Milpitas Terminal employees commenced at 3:10 a.m. and concluded at 5:02 a.m. on September 10, 2010. The accident occurred at about 6:11 p.m. on the previous evening. Therefore, alcohol testing should have been completed by 2:11 a.m. on September 10, at the latest. PG&E officials explained that toxicological testing was delayed because the decision to perform testing was not made until approximately midnight and that the request for testing was made at 12:30 a.m.

The NTSB is concerned by PG&E's delay in contacting the toxicological testing contractor until 12:30 a.m., more than 6 hours after the rupture. Further, upon arrival at the Milpitas Terminal about 2:00 a.m., the contractor should have determined the time of the rupture and attempted to expedite alcohol testing, given that only minutes remained before the regulations prohibited testing.

The NTSB is concerned that the alcohol testing was conducted after the prescribed 8 hours following an accident. Further, the NTSB is concerned that PG&E did not perform any drug or alcohol testing of its SCADA staff. The regulations in 49 CFR 199.105 and 49 CFR 199.225 require testing of any employee whose performance cannot be discounted completely as a contributing factor to the accident and that a decision not to administer a test must be based on a determination that the employee's performance "could not have contributed to the accident." The SCADA personnel were directly involved in monitoring and controlling the events that unfolded during the accident scenario. Therefore, the SCADA personnel should have been tested.

The NTSB concludes that the 6-hour delay before ordering drug and alcohol testing, the commencement of alcohol testing at the Milpitas Terminal 1 hour after it was no longer permitted, the failure to properly record an explanation for the delay, and the failure to conduct drug or alcohol testing on the SCADA center staff all demonstrate that the PG&E postaccident toxicological program was ineffective.

The NTSB is concerned that the regulations requiring operators to conduct postaccident drug and alcohol testing give operators too much discretion in deciding which employees to test, because it states that the decision not to administer a drug test "...must be based on the best information available immediately after the accident that the employee's performance could not have contributed to the accident...", and the decision not to administer an alcohol test "...shall be based on the operator's determination, using the best available information at the time of the determination, that the covered employee's performance could not have contributed to the accident." Therefore, the NTSB recommends that PHMSA amend 49 CFR 199.105 and 49 CFR 199.225 to eliminate operator discretion with regard to testing of covered employees. The revised language should require drug and alcohol testing of each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The NTSB also recommends that PHMSA issue immediate guidance clarifying the need to conduct postaccident drug and alcohol testing of all potentially involved personnel despite uncertainty about the circumstances of the accident.

Grandfathering of Pre-1970 Pipelines

Of broader concern is the exemption of pre-1970 pipelines nationwide from the requirement for a postconstruction hydrostatic pressure test. This exemption was added at the final stage of rulemaking, not having been subject to public comment as part of the original notice of proposed rulemaking (NPRM). It was based on an assertion from the Federal Power Commission that, "there are thousands of miles of jurisdictional interstate pipelines installed prior to 1952 [when the voluntary industry pressure test standards incorporated in section 192.619 were established], in compliance with the then existing codes, which could not continue to operate at their present pressure levels and be in compliance with" the proposed standard in the NPRM calling for the MAOP to be limited to a percentage of the pressure to which it was tested after construction. It is not clear from the preamble to the final rule what rationale, if any, the Federal Power Commission or the U.S. Department of Transportation (DOT) pipeline staff relied on to justify exempting pipelines such as Line 132, which were constructed without complying with the voluntary hydrostatic pressure testing standards of then-existing codes.

Grandfathering of Line 132 by the CPUC in 1961 and then by RSPA in 1970 resulted in missed opportunities to detect the defective pipe. In 1961, the CPUC began requiring a postconstruction hydrostatic test to 1.5 times MAOP for newly constructed pipelines in class 3 areas. In 1970, RSPA began requiring a postconstruction hydrostatic test to 1.5 times MAOP in class 3 locations. For a MAOP of 400 psig, this corresponds to a hydrostatic test pressure of 600 psig. However, pursuant to the 1970 grandfather clause, Line 132 and other existing gas transmission pipelines with no prior hydrostatic test were permitted to use as their MAOP the highest operating pressure recorded during the previous 5 years (that is, between 1965–1970) and allowed to continue operating with no further testing. Thus, the NTSB concludes that if the grandfathering of older pipelines had not been permitted since 1961 by the CPUC and since 1970 by the DOT, Line 132 would have undergone a hydrostatic pressure test that would likely have exposed the defective pipe that led to this accident.

Other examples of how the grandfather clause results in reduced safety margins include the following:

- Title 49 CFR 192.195, "Protection Against Accidental Overpressuring," which requires that pressure relieving or limiting devices ensure that pipeline pressure (for pipelines operated at 60 psig or higher) does not exceed MAOP plus 10 percent or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower. However, for a pipeline whose MAOP was established in accordance with the grandfather clause, this pressure (MAOP plus 10 percent) may be greater than any pressure it was subjected to in its lifetime.
- Title 49 CFR 192.933(d)(1), "Immediate Repair Conditions," which allows operators to continue operating a gas pipeline with a known defect unless "a calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure." Again, this pressure (1.1 times the MAOP) may be greater than any pressure a grandfathered pipeline was subjected to in its lifetime.

More than half of the nation's onshore gas transmission pipelines (about 180,000 miles) were installed prior to the effective date of the 1970 requirement for hydrostatic pressure testing. PHMSA does not keep track of how many of these pipelines have had their MAOP established under the grandfather clause. The state of California has already taken action to address grandfathering for pipelines within its jurisdiction. In its June 9, 2011, order requiring PG&E and other gas transmission operators regulated by the CPUC to either hydrostatically pressure test or replace certain transmission pipelines with grandfathered MAOPs, the CPUC stated that natural gas transmission pipelines "must be brought into compliance with modern standards for safety" and "historic exemptions must come to an end." The NTSB agrees and concludes that there is no safety justification for the grandfather clause exempting pre-1970 pipelines from the requirement for postconstruction hydrostatic pressure testing.

Studies have shown that hydrostatic pressure testing is most effective when it incorporates a spike test in which the pipeline is initially pressurized to a higher level for a short time. Accordingly, the NTSB recommends that PHMSA amend 49 CFR 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.

Regulatory Assumption of Stable Manufacturing- and Construction-Related Defects

In accordance with 49 CFR 192.917 (e)(3), an operator may consider manufacturing- and construction-related defects to be stable defects not requiring assessment so long as operating pressure has not increased over the maximum operating pressure (MOP) experienced during the preceding 5 years. When a pipeline with a manufacturing- or construction-related defect is operated above the highest pressure recorded in the preceding 5 years, it must be prioritized as a high risk segment for assessment. According to section 6.3.2 of the integrity management supplement American Society of Mechanical Engineers (ASME)-sponsored code B31.8S,[10] 2004 edition, in that case, "pressure testing must be performed to address the seam issue."

PG&E raised the pressure at the Milpitas Terminal to 400 psig in 2003 and 2008 to set a 5-year MOP for Line 132. The PG&E director of integrity management and technical support acknowledged at the NTSB investigative hearing that this practice allowed PG&E to regard manufacturing threats as stable, thereby continuing to use only external corrosion direct assessment as the assessment method. Thus, this practice allowed PG&E to avoid seam integrity inspections it might otherwise have been required to conduct. However, the PHMSA deputy associate administrator for field operations testified at the investigative hearing that it was not the intent for this rule to be used to avoid an assessment. (PG&E has discontinued this practice since the accident.)

[10] ASME-sponsored code B31.8S, 2004 edition, *Managing System Integrity of Gas Pipelines: ASME Code for Pressure Piping, B31 Supplement to ASME B31.8.*

Furthermore, studies have discredited the assumption that manufacturing- and construction-related defects are stable in pipelines that have not been hydrostatically pressure tested to an appropriate level. According to a Gas Research Institute (GRI)[11] report dated September 17, 2004—

> the risk of pressure-cycle-induced fatigue can be dismissed if and only if the pipeline has been subjected to a reasonably high-pressure hydrostatic test. Therefore, ... eliminating the risk of failure from pressure-cycle-induced fatigue crack growth of defects that can survive an initial hydrostatic test of a pipeline requires that the test pressure level must be at least 1.25 times the [MAOP].[12]

Similarly, a 2007 PHMSA report concluded—

> experience and scientific analysis indicates that manufacturing defects in gas pipelines that have been subjected to a hydrostatic test to 1.25 times MAOP should be considered stable. No integrity assessment is necessary to address that particular threat in such pipelines. The principal challenge for deciding whether or not to consider manufacturing defects to be stable is associated with those gas pipelines that have never been subjected to a hydrostatic test to a minimum of 1.25 times MAOP.[13]

In summary, under 49 CFR 192.917(e)(3), operators are entitled to consider known manufacturing- and construction-related defects to be stable, even if a line has not been pressure tested to at least 1.25 times its MAOP. However, such defects may not, in actuality, be stable. The NTSB concludes that the premise in 49 CFR Part 192 of the Federal pipeline safety regulations that manufacturing- and construction-related defects can be considered stable even when a gas pipeline has not been subjected to a pressure test of at least 1.25 times the MAOP is not supported by scientific studies. Therefore, the NTSB recommends that PHMSA amend 49 CFR Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a postconstruction hydrostatic pressure test of at least 1.25 times the MAOP.

Summary of PG&E Practices

The NTSB accident investigation revealed multiple deficiencies with PG&E's practices. To summarize, PG&E's practices were revealed to be inadequate because—

- The accident pipe segment did not meet any known pipeline specifications.
- Construction and quality control measures for the 1956 relocation project were inadequate in that they did not identify visible defects.

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[11] In 2000, the GRI combined with the Institute of Gas Technology to form the Gas Technology Institute (GTI), a nonprofit research and development organization that develops, demonstrates, and licenses new energy technologies for private and public clients, with a particular focus on the natural gas industry. PG&E is a member of the GTI.

[12] *Effects of Pressure Cycles on Gas Pipelines*, report GRI-04/0178 (Des Plaines, Illinois: Gas Research Institute, 2004).

[13] *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, No. 05-12R (Washington, DC: Pipeline and Hazardous Materials Safety Administration, 2007).

- The integrity management program, including self-assessment of that program, was ineffective.
- Emergency response to the pipeline rupture was slow, and isolation and shutdown of gas flow were unacceptably delayed.
- The postaccident drug and alcohol testing program had multiple deficiencies.
- SCADA staff roles and duties were poorly defined.
- SCADA work clearance procedures were inadequate.
- Critical components at the Milpitas Terminal were susceptible to single-point failures.
- The public awareness program, including self-assessment, was deficient and ineffective.

Although PG&E has taken some corrective actions since the accident, many of these deficiencies should have been recognized and corrected before the accident.

Further, the NTSB notes that several of the deficiencies revealed by this investigation, such as poor quality control during pipeline installation and inadequate emergency response, were also factors in the 2008 explosion of a PG&E gas distribution line in Rancho Cordova, California.[14] That accident involved the inappropriate installation of a pipe piece that was not intended for operational use and did not meet applicable pipe specifications. The response to that event was inadequate in that an unqualified person was initially dispatched to respond to the emergency, and there was an unnecessary delay in dispatching a properly trained and equipped technician. Some of these deficiencies were also factors in the 1981 PG&E gas pipeline leak in San Francisco,[15] which involved inaccurate record-keeping, the dispatch of first responders who were not trained or equipped to close valves, and unacceptable delays in shutting down the pipeline.

Accident investigations often uncover a broad range of causal relationships or deficiencies that extend beyond the immediacy of components damaged or broken in a system failure. As indicated by the list above, a multitude of deficient operational procedures and management controls led to hazardous circumstances persisting and growing over time until the pipeline rupture occurred. These higher-order or organizational accident factors must be addressed to improve PG&E's safety management practices.

Organizational accidents have multiple contributing causes, involve people at numerous levels within a company, and are characterized by a pervasive lack of proactive measures to ensure adoption and compliance with a safety culture. Moreover, organizational accidents are catastrophic events with substantial loss of life, property, and environment; they also require complex organizational changes in order to avoid them in the future. In its report on the

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[14] *Explosion, Release, and Ignition of Natural Gas, Rancho Cordova, California, December 24, 2008*, Pipeline Accident Brief NTSB/PAB-10/01 (Washington, DC: National Transportation Safety Board, 2010).

[15] *Pacific Gas & Electric Company Natural Gas Pipeline Puncture, San Francisco, California, August 25, 1981*, Pipeline Accident Report NTSB/PAR-82/01 (Washington, DC: National Transportation Safety Board, 1982).

2009 collision of two Washington Metropolitan Area Transit Authority trains near Fort Totten Station in Washington, DC,[16] the NTSB stated that "the accident did not result from the actions of an individual but from the 'accumulation of latent conditions within the maintenance, managerial and organizational spheres' making it an example of a 'quintessential organizational accident.'"[17] The Chicago Transit Authority train derailment in 2006,[18] which caused injuries to 152 people and over $1 million in damages, is another case study in organizational accidents. Similarly, the BP Texas City Refinery organizational accident in 2005[19] killed 15 people, injured 180 others, and caused financial losses exceeding $1.5 billion.

The character and quality of PG&E's operation, as revealed by this investigation, indicate that the San Bruno pipeline rupture was an organizational accident. PG&E did not effectively utilize its resources to define, implement, train, and test proactive management controls to ensure the operational and sustainable safety of its pipelines. Moreover, many of the organizational deficiencies were known to PG&E, as a result of the previous pipeline accidents in San Francisco in 1981,[20] and in Rancho Cordova, California, in 2008.[21] As a lesson from those accidents, PG&E should have critically examined all components of its pipeline installation to identify and manage the hazardous risks, as well as to prepare its emergency response procedures. If this recommended approach had been applied within the PG&E organization after the San Francisco and Rancho Cordova accidents, the San Bruno accident might have been prevented. Therefore, based on the circumstances of this accident, the NTSB concludes that the deficiencies identified during this investigation are indicative of an organizational accident.

The NTSB also concludes that the multiple and recurring deficiencies in PG&E operational practices indicate a systemic problem. Therefore, NTSB recommends that PHMSA assist the CPUC in conducting the comprehensive audit recommended in Safety Recommendation P-11-22. The NTSB urges the CPUC and PHMSA to complete this comprehensive audit and require PG&E to take corrective actions as soon as possible, to reap the maximum safety benefit. The NTSB believes that 6 months would be a reasonable time frame for conducting the audit and that an additional 6 months after the completion of the audit would be a reasonable deadline for PG&E to take action in response to audit findings.

[16] *Collision of Two Washington Metropolitan Area Transit Authority Metrorail Trains Near Fort Totten Station, Washington D.C., June 22, 2009,* Railroad Accident Report NTSB/RAR-10/02 (Washington, DC: National Transportation Safety Board, 2010).

[17] (a) J. Reason, *Managing the Risks of Organizational Accidents* (Burlington, Vermont: Ashgate Publishing Company, 1997). (b) J. Reason, "Achieving a Safe Culture: Theory and Practice," *Work and Stress*, vol. 12 (1998), p. 227.

[18] *Derailment of Chicago Transit Authority Train Number 220 Between Clark/Lake and Grand Milwaukee Stations, Chicago, Illinois, July 11, 2006,* Railroad Accident Report NTSB/RAR-07/02 (Washington, DC: National Transportation Safety Board, 2007).

[19] *Refinery Explosion and Fire,* Investigation Report, report No. 205-04-1-TX (Washington, DC: U.S. Chemical Safety and Hazard Investigation Board, 2007).

[20] NTSB/PAR-82/01.

[21] NTSB/PAB-10/01.

Inspection Technology

The detection, identification, and elimination of pipeline defects before they result in catastrophic failures is critical to a successful integrity management program for gas transmission pipelines. In the NTSB's judgment, the use of specialized in-line inspection tools that identify and evaluate damage caused by corrosion, dents, gouges, and circumferential and longitudinal cracks is a uniquely promising option for identifying defects. Unlike other assessment techniques, in-line inspection is continuous throughout the entire pipeline segment and, when performed periodically, can provide useful information about defect growth. Although in-line inspection technology has detection limitations (generally at best a 90 percent probability that a certain type of known defect will be detected, although the probability of detecting a crack can be improved with multiple runs), it is nonetheless the most effective method for detecting internal pipeline defects.

At the time Line 132 was constructed, in-line inspection tools had not been developed. Due to construction limitations such as sharp bends and the presence of plug valves, many older natural gas transmission pipelines, like Line 132, cannot accommodate modern in-line inspection tools without modifications. According to testimony provided during the NTSB investigative hearing, the technical challenges of conducting in-line inspections of older gas transmission pipelines relate not to the sensors, but to the platforms (the tool or pig) that need to move through the pipeline. Gas transmission pipeline operators have also asserted that, because of differences in the flow regimes between natural gas (a compressible fluid) and hazardous liquids (an incompressible fluid), the use of in-line inspection tools in gas transmission pipelines presents additional technical challenges, especially when the operating pressure many not be sufficiently high to push the tool through the pipeline.

According to testimony from the NTSB investigative hearing, current in-line inspection technology is advanced enough to have detected the defect that caused the rupture of Line 132, but it could not be used without significant modifications to the pipeline. The NTSB concludes that because in-line inspection technology is not available for use in all currently operating gas transmission pipeline systems, operators do not have the benefit of a uniquely effective assessment tool to identify and assess the threat from critical defects in their pipelines. Only in-line inspection can provide visualization of the internal pipe structure. The geometry of Segment 180,[22] like many older pipelines, would not accommodate in-line inspection tools. The NTSB is concerned that in-line inspection is not possible in many of the nation's pipelines, which—because of the date of their installation—have been subjected to less scrutiny than more recently installed lines. Therefore, the NTSB recommends that PHMSA require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines.

[22] In 1956, PG&E relocated 1,851 feet of Line 132 that had originally been installed in 1948. This relocation included the installation of the pipe at the accident location. In 1961, PG&E completed a second relocation project on a portion of Line 132 immediately to the south of the 1956 relocation. As a result, 1,742 feet of the original 1,851 feet of pipe from the 1956 relocation project, including the rupture location, remained in operation. In PG&E's records, this segment is known as Segment 180.

Performance-Based Safety Programs

Over the past few years, PHMSA, with the support and assistance of the pipeline industry, has added to its prescriptive regulatory scheme a performance-based regulatory scheme with broad performance goals as the basis for its pipeline safety program, most notably with respect to integrity management programs, and to a lesser extent, to public awareness programs. This new regulatory scheme applies to gas transmission and distribution systems and to hazardous liquid pipeline systems. Under performance-based regulations, the fundamental premise is that an individual pipeline operator knows its system best, and thereby is best able to develop, implement, execute, evaluate, and adjust its integrity management programs to ensure the safe maintenance and operation of its pipelines.

Performance-based management systems include activities to ensure that goals are consistently being met in an effective and efficient manner. Performance management can focus on an organization, a department, an employee, or even the processes to build a product or service, among many other areas. Performance measurement involves determining what to measure, identifying data collection methods, and collecting the data. Evaluation involves assessing progress toward the performance goals, usually to explain the causal relationships between program activities and outcomes. Performance measurement and evaluation are components of performance-based management, the systematic application of information generated by performance plans, measurement, and evaluation to strategic planning and budget formulation.

The PG&E integrity management plan was audited by the CPUC in 2005, with PHMSA's assistance, and again by the CPUC in 2010 using PHMSA's inspection protocol. Almost none of the issues identified in this investigation were identified in either of these audits despite the fact that many of them should have been easy to detect.

The deficiencies in the PG&E geographic information system (GIS) data should have been readily apparent to CPUC and PHMSA inspectors during integrity management audits. However, the PHMSA integrity management audit protocol does not formally call for a check of the completeness and accuracy of information contained in the operator's pipeline attribute database. The PHMSA inspection protocol includes only one inspection item (C.02.d), related to the completeness and accuracy of information used in developing integrity management programs. That item requires inspectors to verify that the operator has checked the data for accuracy, and if the operator lacks sufficient data or the data quality is suspect, instructs the inspector to verify that the operator has followed ASME B31.8S. At the NTSB investigative hearing, a CPUC supervisory engineer testified that CPUC auditors did not examine GIS data in detail; however, they did randomly spot check GIS data and verified that when data were unknown, PG&E was using appropriately conservative values.

Furthermore, PHMSA regulations do not require an operator to supply missing data or assumed values within any time frame. This allows incomplete or erroneous information to continue in an operator's records indefinitely, as was the case with the PG&E GIS, which continued to show Segment 180 as seamless X42 pipe until the time of the accident. PHMSA should require operators to correct data deficiencies within a specific time frame.

Another deficiency not identified during the audits was the mismatch between PG&E's threat weighting and its actual leak, failure, and incident experience. The PHMSA integrity management inspection protocol includes inspection item C.03.c for inspectors to verify that the operator uses a feedback mechanism to ensure that its risk model is subject to continuous validation and improvement. However, the PHMSA inspection protocol placed insufficient emphasis on continuous validation and improvement of risk models.

Another concern is the fact that the CPUC did not follow up on its 2005 audit finding that PG&E lacked a process to evaluate the use of ASVs and RCVs, as required by 49 CFR 192.935(c). Although PG&E prepared a memorandum, dated June 14, 2006, addressing this issue, the CPUC apparently did not evaluate the adequacy of this response. If it did, it failed to identify the flawed analysis that concluded the use of ASVs would have little effect on increasing safety or protecting property.

CPUC and PHMSA officials acknowledged at the NTSB investigative hearing that it is difficult to oversee performance-based regulations, such as the integrity management rules, because there is no "one-size-fits-all" standard against which to measure performance. Overseeing an operator's compliance with the integrity management rules is very different from overseeing compliance with more clear-cut prescriptive regulations because integrity management requires the auditor to evaluate the adequacy of an operator's technical justification rather than its compliance with a hard and fast standard.

The effectiveness of performance-based pipeline safety programs is dependent on the diligence and accountability of both the operator and the regulator—the operator for development and execution of its plan, and the regulator for oversight of the operators. However, as evident in this investigation, the PG&E integrity management and public awareness programs failed to achieve their stated goals because performance measures were neither well defined nor evaluated with respect to meeting performance goals. By overlooking the existence of, and the risk from, manufacturing and fabrication defects under its integrity management program, PG&E took no actions to assess risk and ultimately was unaware of the internal defects that caused the rupture of Line 132.

Similarly, the CPUC and PHMSA continue to conduct audits that focus on verification of paper records and plans rather than on gathering information on how performance-based safety systems are implemented, executed, and evaluated, and whether problem areas are being detected and corrected.

Critical to this process, for operator and regulator, is the selection of metrics that quantify results against a specified value to provide a rate of occurrence for either a desired or undesired outcome. For example, useful metrics might include the number of incidents from internal defects per mile of operating pipeline or the number of incidents in a specific location per total incidents on a specific pipeline. Such metrics can provide a basis for comparison of the frequency of various types of defects and identify specific problem locations on pipelines. Similar assessments of operator performance can be used by regulators to exercise more effective oversight by focusing on those operators with problems, and to identify the causes of critical safety problems.

In summary, PHMSA should develop an oversight model that allows auditors to more accurately measure the success of a performance-based pipeline integrity management program. Specifically, PG&E should develop, and auditors should review, data that provide some quantification of performance improvements or deterioration, such as the number of incidents per pipeline mile or per 1,000 customers; the number of missing, incomplete, or erroneous data fields corrected in an operator's database; the response time in minutes for leaks, ruptures, or other incidents; and the number of public responses received per thousands of postcards/surveys mailed. Such metrics would allow a comparison of current performance against previous performance.

The NTSB concludes that the PHMSA integrity management inspection protocols are inadequate. Therefore, the NTSB recommends that PHMSA revise its integrity management inspection protocol to (1) incorporate a review of meaningful metrics; (2) require auditors to verify that the operator has a procedure in place for ensuring the completeness and accuracy of underlying information; (3) require auditors to review all integrity management performance measures reported to PHMSA and compare the leak, failure, and incident measures to the operator's risk model; and (4) require setting performance goals for pipeline operators at each audit and follow up on those goals at subsequent audits.

The NTSB also concludes that because PG&E, as the operator of its pipeline system, and the CPUC, as the pipeline safety regulator within the state of California, have not incorporated the use of effective and meaningful metrics as part of their performance-based pipeline safety management programs, neither PG&E nor the CPUC is able to effectively evaluate or assess the integrity of PG&E's pipeline system. The NTSB also concludes that, because PHMSA has not incorporated the use of effective and meaningful metrics as part of its guidance for effective performance-based pipeline safety management programs, its oversight of state public utility commissions regulating gas transmission and hazardous liquid pipelines needs improvement.

Therefore, the NTSB recommends that PHMSA (1) develop and implement standards for integrity management and other performance-based safety programs that require operators of all types of pipeline systems to regularly assess the effectiveness of their programs using clear and meaningful metrics, and to identify and then correct deficiencies; and (2) make those metrics available in a centralized database. The NTSB also recommends that PHMSA work with state public utility commissions to (1) implement oversight programs that employ meaningful metrics to assess the effectiveness of their oversight programs and make those metrics available in a centralized database, and (2) identify and then correct deficiencies in those programs.

Therefore, the National Transportation Safety Board makes the following safety recommendations to the Pipeline and Hazardous Materials Safety Administration:

Require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to provide system-specific information about their pipeline systems to the emergency response agencies of the communities and jurisdictions in which those pipelines are located. This information should include pipe diameter, operating pressure, product transported, and potential impact radius. (P-11-8) *This recommendation supersedes Safety Recommendation P-11-1.*

Require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to ensure that their control room operators immediately and directly notify the 911 emergency call center(s) for the communities and jurisdictions in which those pipelines are located when a possible rupture of any pipeline is indicated. (P-11-9) *This recommendation supersedes Safety Recommendation P-11-2.*

Require that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines. (P-11-10)

Amend Title 49 *Code of Federal Regulations* 192.935(c) to directly require that automatic shutoff valves or remote control valves in high consequence areas and in class 3 and 4 locations be installed and spaced at intervals that consider the factors listed in that regulation. (P-11-11)

Amend Title 49 *Code of Federal Regulations* 199.105 and 49 *Code of Federal Regulations* 199.225 to eliminate operator discretion with regard to testing of covered employees. The revised language should require drug and alcohol testing of each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. (P-11-12)

Issue immediate guidance clarifying the need to conduct postaccident drug and alcohol testing of all potentially involved personnel despite uncertainty about the circumstances of the accident. (P-11-13)

Amend Title 49 *Code of Federal Regulations* 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. (P-11-14)

Amend Title 49 *Code of Federal Regulations* Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a postconstruction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure. (P-11-15)

Assist the California Public Utilities Commission in conducting the comprehensive audit recommended in Safety Recommendation P-11-22. (P-11-16)

Require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines. (P-11-17)

Revise your integrity management inspection protocol to (1) incorporate a review of meaningful metrics; (2) require auditors to verify that the operator has a procedure in place for ensuring the completeness and accuracy of underlying information; (3) require auditors to review all integrity management performance measures reported to the Pipeline and Hazardous Materials Safety Administration and compare the leak, failure, and incident measures to the operator's risk model; and (4) require setting performance goals for pipeline operators at each audit and follow up on those goals at subsequent audits. (P-11-18)

(1) Develop and implement standards for integrity management and other performance-based safety programs that require operators of all types of pipeline systems to regularly assess the effectiveness of their programs using clear and meaningful metrics, and to identify and then correct deficiencies; and (2) make those metrics available in a centralized database. (P-11-19)

Work with state public utility commissions to (1) implement oversight programs that employ meaningful metrics to assess the effectiveness of their oversight programs and make those metrics available in a centralized database, and (2) identify and then correct deficiencies in those programs. (P-11-20)

In addition, Safety Recommendations P-11-1 and -2 to PHMSA are classified "Closed—Superseded" in section 2.4.2, "Notifying Emergency Responders," of the accident report.

The NTSB also issued safety recommendations to the U.S. Secretary of Transportation, the governor of the state of California, the California Public Utilities Commission, the Pacific Gas and Electric Company, the American Gas Association, and the Interstate Natural Gas Association of America.

In response to the recommendations in this letter, please refer to Safety Recommendations P-11-8 through -20. If you would like to submit your response electronically rather than in hard copy, you may send it to the following e-mail address: correspondence@ntsb.gov. If your response includes attachments that exceed 5 megabytes, please e-mail us asking for instructions on how to use our secure mailbox. To avoid confusion, please use only one method of submission (that is, do not submit both an electronic copy and a hard copy of the same response letter).

Chairman HERSMAN, Vice Chairman HART, and Members SUMWALT, ROSEKIND, and WEENER concurred in these recommendations and the reclassification of Safety Recommendations P-11-1 and -2. Chairman HERSMAN filed a concurring statement and Vice Chairman HART filed a concurring and dissenting statement, both of which are attached to the pipeline accident report for this accident.

By: Deborah A.P. Hersman
Chairman

From: Michael Boyd (michaelboyd@sbcglobal.net)
To: rstates@mail.com;
Date: Mon, January 31, 2011 11:26:54 AM
Cc: curry@ucsc.edu; svolker@volkerlaw.com;
Subject: Re: WELLINGTON WHISTLE BLOWER

Rob,

You miss-understand my filing stating I identify root cause of "the San Bruno ignition source as RF transmission to a near by antenna receiver with a spark gap". The FCC regulation says that both intentional and unintentional radiators can not cause harmful interference.

My hypothesis is that the San Bruno Smart Meters all functioned as intended but that since the nearby homes in San Bruno where not properly grounded the breaker switches in the homes flipped sending a power surge to the gas main. The grounding wasn't proper because the power to the gas main went down in Milpitas a few hours before the explosion occurred. There are two possible scenarios I see for producing the arc flash spark, one is a power surge from Milpitas, and the other is a power surge from nearby homes when the Smart Meters there tried to take a reading and flipped the breakers in the nearby homes.

The recent NTSB report and my analysis of the data only reinforces my theory (see attached) since clearly there was a fire below the pipe before the explosions began to occur. My conclusion this suggests an arc flash event must have started the fire.

PS I am copying this e-mail to my attorney Mr. Volker and Dr. Curry who is a pipeline safety expert. They might want to speak to you about this matter.

Respectfully,

Michael E. Boyd President
CAlifornians for Renewable Energy, Inc.
(CARE)
5439 Soquel Drive
Soquel, CA 95073
Phone: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net

--- On **Mon, 1/31/11, rstates@mail.com** ***<rstates@mail.com>*** wrote:

> From: rstates@mail.com <rstates@mail.com>
> Subject: WELLINGTON WHISTLE BLOWER
> To: michaelboyd@sbcglobal.net
> Date: Monday, January 31, 2011, 10:52 AM
>
> Your CPUC filing lists the San Bruno ignition source as RF transmission to a near by antenna receiver with a spark gap. This is difficult to demonstrate, and an engineering simulation is likely to be unconvincing because the flammability limits to trigger the fire would be narrow.
>
> However, a mis-installed meter has a rampant ignition source, is easy to demonstrate, will ignite anything near by (read wide flammability), and is spectacular to simulate. This also brings into the legal picture the lack of California certified electricians on Wellington's staff (there has been one registered supervisor since '09).
>
> Since I am a registered Mechanical Engineering PE in California, I could possibly document facts as part of a modification to your existing filing.
>
> Below is an email I sent to our legal team (all anonymous).

Sincerely,

Rob States, M.S., P.E.
Chief Engineer, Wave Dry, LLC.
415-927-2739 Office
415-596-2718 Cell
5 Mohawk Avenue, Corte Madera, CA 94925

-----Original Message-----
From: rstates@mail.com
To: rstates@mail.com
Sent: Mon, Jan 31, 2011 10:40 am
Subject: Fwd: WELLINGTON WHISTLE BLOWER

I am assessing the legal import of the whistle blower interview below. The legal action I am currently pursuing is with the Marin County Grand Jury, and we have an expert attorney advising us. However, the revelations in the whistle blower's comments below add new wrinkles to the legal picture.

None of the Wellington installers are operating with valid California electrician's licenses, and the first three years of installations, there was no Wellington employee, NONE, that had a valid California electrician's license (one got registered in '09). If we look, we can locate mis-installed meters, and document it with a scrupulous chain of custody.

However, given the contorted CPUC / PG&E legal jurisdiction, it is not clear if there is a clean Cause of Action and a reasonable court to file in.

Thanks in advance for any comments, all held in confidence.

Rob
====================================

Subject: WELLINGTON WHISTLE BLOWER

This explains the fires that have been reported, and some of the power line noise I have measured.

I will get this to CARE, who has a much wimpier claim for the San Bruno ignition source. This is far more important - because PG&E cannot show proper training of any of the meter installers, and mis-installation is rampant in the system.

I have measured DIRECTLY the spin PG&E claims - 45 seconds of transmission per day - which is extremely false. They always put a modifier in every sentence containing this statistic so they are not actionable - the PG&E attorneys are on the job to make sure there is no deliberately false statement of fact. I will be datalogging some of this so we have DIRECT FIELD MEASUREMENT that PG&E's stated duty cycle is false.

Rob

General Community: Stop Smart Meters! Exclusive: Interview with the Wellington Energy Whistleblower
From: mweaver Supporting Member
Posted: January 28, 2011, 5:04 pm

Wellington Energy is the company that is installing PG&E's new wireless 'smart' meters in California. A former Wellington Energy employee sent us an e-mail late last year offering to speak with us about his experience installing smart meters in the San Francisco Bay Area. He has requested anonymity. Here is the Stop Smart Meters! interview with the 'Wellington Whistleblower' in full:

SSM: Thank you for getting in touch with us. What made you want to come forward?

WW: I'm disgusted by what I've seen. PG&E and Wellington need to make the public aware that there are risks with these things. They need to come clean about the emissions of harmful radio waves, potential arcing etc. No one is taking the steps necessary to protect the public. People need to be aware the risks that are being taken with their homes and with their lives.

SSM: How long did you work for Wellington and where were you based?

WW: I worked at the Capitola yard from June until the beginning of September 2010, when they abandoned the yard following community protests. After that, I worked out of the San Jose yard until the end of September when I was laid off. I primarily installed in the Santa Cruz Mountains.

SSM: What is your opinion of PG&E and Wellington Energy?

WW: The only thing they are concerned with is money. Safety was an afterthought.

SSM: What was your experience with the public? Are people happy to have these devices installed on their homes?

WW: Most people who had looked into the issue on their own did not want the meters installed. We were dealing with an increasingly resistant public. Forcing these meters on people makes the job really difficult and stressful. A few of my colleagues reported that the police were called on them multiple times.

SSM: The FCC requires that these devices be installed by trained professional electricians. [1] What kind of training did you receive prior to working as a 'smart' meter installer?

WW: We received only two weeks of training before they sent us out to do the installations. Though the procedure is relatively simple, if you get it wrong this can lead to arcing, shorts- even house fires. The blades on the back of the meter have to be aligned properly with the jaws on the socket the meter gets placed in. I kept hearing one of the managers say, "you guys weren't trained properly."

SSM: What did he mean?

WW: Many of the installers would come back to the yard and report that they had come across meters that were hanging by an electrical wire, or other clearly unsafe conditions. There was a lot of pressure on workers to install as many meters as possible in a day in order to earn bonuses. One employee went out into the Santa Cruz Mountains and I think he is still out there somewhere he got so disoriented. Needless to say, improper training, and being under incredible pressure, there HAS TO be error, especially with new people working in new territory. I overheard numerous times while at work, "you could have burned that goddamned house down."

SSM: Did you personally come across safety hazards? What happened when you tried to report them?

WW: The more you called Wellington, the worse it looked on your record- because you're wasting time. I saw sparks coming from one of the meters on a home. I reported it but am not sure what- if anything- was done.

SSM: Based on your observations while working for Wellington, what are your fears about the risks they are taking with the public's safety?

WW: First off I can only speak about what I personally observed. I believe- based on what I observed- that there is a chance that due to inadequate training some meters were not installed properly. I do feel that Scotts Valley, Boulder Creek, Ben Lomond, Corralitos, to name a few should be informed enough to prepare for what could realistically turn into another San Bruno. (emphasis added)

SSM: Of course at the time of the explosion San Bruno was 100% installed with smart meters. Are you aware that PG&E and the CPUC have not yet responded to questions about what safety precautions they took while installing smart meters adjacent to gas lines? Seems like a fairly reasonable question given that the technology can generate sparks.

WW: It really doesn't surprise me that they haven't answered questions regarding the smart meters and San Bruno. When I asked one of my managers who was in charge of training "is it possible in your opinion that a fire could start from an arc from a meter located above a gas meter" (which always has some blow off gas emitting from it) he would not give me a direct answer! He avoided the question like the plague, quoting some plumber he knew and on and on, avoiding an answer. Could the San Bruno fire have been started by an arc from a meter? I'll let you decide. The definition of an electrical arc is: "a sustained luminous discharge of electricity across a gap in a circuit". The definition of ignition: the process or means (as an electric spark) of igniting a fuel mixture. Gas is a fuel. I'll leave it at that. It doesn't take a rocket scientist to put it all together.

SSM: Why did you stop working for Wellington?

WW: I was let go because I took too much time with each resident. When you are dealing with people's lives, I don't feel that it is proper to hang the door hanger, do your installs, and get out of there. With the reception of these meters I felt people at least needed to be talked to and listened to beforehand. This of course resulted in my dismissal. I talked too much and too long with the customers. As a Wellington employee you must log in to your handheld computer every 15 minutes or it creates a 'red zone' in your day's activities. This is likely to be addressed to you on the phone by your boss the next day as you are trying to get your numbers up that day. A reduction in work force was eventually used as an excuse for my dismissal. Meanwhile a training class for the same position was going on at the same time!

SSM: What do you think is really behind PG&E's 'smart' meter program?

WW: The smart meter has a hell of a lot of potential that they're not talking about. PG&E claims they're not going to use that potential, but who can believe them? Believe me they have plans for these things. They could use it for cell phone reception, broadband, tv services etc.

SSM: As you know, people are desperate. They're suffering headaches, nausea, etc. This has driven some people out of their homes. They're now calling them 'smart meter refugees.' Meanwhile PG&E and the CPUC refuse to remove them even in cases where doctors confirm that health is being jeopardized. Based on your knowledge, can a resident remove the meters themselves? How risky is this?

WW: First of all, about health issues. I was never really concerned about this, because I believed what I was told from Wellington, that the meters only emitted radio waves to send usage to a transponder close by so it could relay it to PG&E...on a short time basis, rarely more than once a month except in the start up, and then not a lot. My manager reiterated that as well, during one of our conversations.

I was surprised to hear that the meters send signals- what- 15 per minute? We all were told they only transmit a few times a month if that, just enough to send the total usage from that account.

As far as a DIY de-installation, I don't advise anyone who hasn't been trained as an electrician to try and remove the meter themselves. However, if you can find a professional electrician to help you, it's not really that big a deal. There is an aluminum ring that holds the meter in place. The ring comes off easy with a pair of wire cutters. Like a watchband or a locking suitcase- you push it in and it pops off easily. You can pull the ring off and then the meter comes right off. There are 4 pins on the back of the meter, and if you have access to an old analog meter, you could just pop it right on. Of course the pins are now essentially live wires so these would be very dangerous to touch.

SSM: The information that I have seen indicates that the new meters can actually be transmitting constantly [2], so it sounds like your managers were not being straight with you. What about the smart meter attachment on the gas meter? How would one go about removing that?

WW: You can remove a smartmeter from a gas meter by removing the screws that attach the module (meter) it to the gas meter itself. It won't interrupt the gas service at all. All the module does is track usage, the index (dial apparatus) has a key on the back which slips onto a key in the meter which has a diaphragm regulating gas pressure and turning the gas index key.

SSM: You were working at the Capitola yard in late August 2010 when the protests were going on. What was the response from PG&E?

WW: PG&E sent a senior security executive out to handle the situation. The protests were effective at informing the public about the risks of smart meters- something PG&E desperately wanted to avoid. They didn't want the situation to escalate so they withdrew from that site, and moved us all to San Jose.

SSM: Thanks for taking the time and being brave enough to speak out. Any last thoughts?

WW: I was never out to hurt people- this was just a job for me. I really feel these days that big brother- in the form of the government and corporations working together- is screwing us big time. I hope we can get regulators to pay attention on this as I believe there is a real chance of more people getting hurt if nothing is done.

Editor's note: There have been a number of documented cases of 'smart' meters starting house fires, interfering with AFCI's and GFCI's [3] (devices intended to prevent electrical shocks), and other potentially dangerous interference. It is not outside the realm of possibility that a smart meter played a role in the San Bruno disaster. At the very least, this possibility needs to be investigated and questions answered. And we find it distinctly odd that this has not happened.

Also, it is important to note that Wellington installers are temporary workers, not professionals. They are not required to have prior experience or electrical education. Installers have only brief training and are paid according to the volume of meters they install. Therefore, it is typical not to report electrical irregularities because this might slow them down. In addition, non-professionals may not recognize irregularities as well as professionals and they may be gone to another place and job before the electrical emergency occurs. This lack of training has raised concerns in other states including Maine [4]. In addition, there are documented cases of gas smart meters being installed without adequate safety certification. [5]

How many homes and neighbourhoods have to burn down before regulators get serious and halt further installations? How many people have to suffer sudden health deterioration before we admit there is a problem? How many suffering people does it take to halt a $2.2 billion project? More than a few apparently.

If you work for PG&E or Wellington Energy and you have inside information you'd like to share with the public, please contact us at info[at]stopsmartmeters[dot]org We will absolutely respect your anonymity.

[1] https://sites.google.com/site/nocelltowerinourneighborhood/home/wireless-smart-meter-concerns/emf-safety-network-finds-smart-meter-fcc-compliance-violations-dec-14-2010

[2] EPRI, 2010. A Perspective on Radio-Frequency Exposure Associated With Residential Automatic Meter Reading Technology, Electric Power Research Institute, Palo Alto, CA.

[3] Advanced Metering Infrastructure; January 2010 Semi-Annual Assessment Report and SmartMeterTProgram Quarterly Report (Updated), Pacific Gas and Electric Company.

[4] http://www.theforecaster.net/content/s-scarsmartmeterforum2-121710

[5] http://www.smartmeters.com/the-news/1472-silver-springs-smart-meter-recall-halted.html

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General Community: Assessment of Radiofrequency Microwave Radiation Emissions from Smart Meters

From: Sabrina

Posted: January 4, 2011, 11:04 am

Finally, Sage Associates Environmental Consultants, have completed a report on the environmental impact of Radiation Emissions from Smart Meters. It has just been made available as of 1/1/2011. This does not make up for what the CPUC or FCC should have been studying all along, but it's something, and still must be pressured to do. Here's the forwarded message from EMF Safety Network, along with the down-loadable report.

Notice of Availability

Sage Associates has published an on-line report titled Assessment of Radiofrequency Microwave Radiation

Emissions from Smart Meters, dated January 1, 2011.

Contact: info@sagereports.com

The Report is available for download at:
http://sagereports.com/smart-meter-rf/

About the Report (from the website)

This Report is prepared in support of open discussion on radiofrequency microwave radiation levels (RF radiation levels) that are produced by wireless electric meters (i.e., smart meters) in California. There has been virtually no information made available to the public, nor to decision-makers on RF radiation levels. Significant unanswered questions still exist about what levels of radio-frequency microwave radiation will be produced by these meters.

This question has very important consequences for public health and welfare, because the public may be subjected to exposures at levels that either violate federal safety limits, or face chronic exposure levels that have already been associated with adverse health impacts, or both.

This Report uses computer modeling to predict power density levels that may be present where smart meters are in operation. The methodology used in this assessment is consistent with FCC OET 65 equations for prediction of RF power density levels. Many scenarios are modeled, to bracket the range of reasonably predictable RF exposures in typical living conditions. Many variables must be considered (installation very close to occupied space, how many meters are installed on a single wall, how frequently they will transmit an RF pulse, how powerful the RF radiation pulses will be, how far inside a home they will penetrate and at what intensities, how much 'piggybacking' of RF signals will occur from neighboring wireless meters, reflections that may increase RF levels, and what amount of RF wireless exposure may already be present beforehand, etc.)

To date, California's electric utilities have told the California Public Utilities Commission only that they will comply with applicable federal safety limits. However, there are substantial discrepancies in what the FCC compliance testing says is needed for wireless meters to comply with their safety limits, and the manner in which many meters are being installed and are operating.

People may use this assessment to further their knowledge about wireless meters, using the tables that predict RF radiation levels, the tables that highlight potential violations of safety limits, and the health study-related tables showing RF radiation levels reported to pose health impacts. Although the authors expect there will be differences of opinion about the content of this report, we believe it will provide a basis for more educated decision-making and full disclosure of impacts.

The Report is not intended to be a substitute for disclosure of RF radiation levels by the CPUC and the electric utilities it regulates. They are responsible to the public to provide reliable and comprehensive information on impacts from wireless meters.

General Community: Re: SMART METER ALERT! Stop installation in Sonoma County!
From: spam1   Posted: January 2, 2011, 11:02 pm

Sasu wrote:

...

Smart Meters are costing us money, our privacy, our health and safety. Some people's bills have doubled, tripled and more. Smart Meters have exploded, burned out appliances and are making some people very sick, insomnia, split second head aches and high pitched ringing in the ears, nausea, etc. This is RF pollution, just like cell towers, only right on our homes!

There's been no environmental safety study. Smart Meters transmit pulsed microwave radiation (RF) constantly, throughout the day and night.

Sandi Maurer

www.emfsafetynetwork.org

Maybe money (although more expensive electricity would reduce usage, thereby reducing green house gasses, but that is beside the point). Most likely, the cost will be found in the future if they enforce time-of-use pricing to all: but this doesn't relate to smart meters, just to time-of-use meters (of which smart meters are one example).

If the old meters were not reliable, and reporting less usage than they should have, we should applaud the improvement to make people pay for the resources that they use. The State of California is undertaking a study of smart meter accuracy. If they are determined to be on-the-average over reporting usage, then it is a simple matter for the state to dictate that the smart meter reading be "prorated" for the average error to ensure there is no net increase in the rate of overcharging. By the way, from my understanding of regular meters, the failure mechanism is to record lower usage than actual due to friction and loss in the "wheel" that measures the electric use; so it is reasonable to expect a majority of people might see an increase as they are finally paying for their actual usage.

Doubtful privacy: Is having a person walk up to your house more or less private than a meter reporting your usage? Tracking usage vs time could tell someone when you were home (unless your heater and air-conditioner are on a timer and thus go on-and-off at normal intervals) but the difficulty of hacking into the system is undoubtedly much more difficult than just buying an Infra Red (IR) camera and pointing it at the house. This is how "grow" houses are often found, and it is easy to see people walking around inside.

Health: well here is just where the science and math just don't bear you out. The fields are so small and so infrequent, compared to the ubiquitous fields that they simply cannot have much effect. There is RF in the form of AM and FM stations, Cell towers, and neighbors WiFi that are several orders of magnitude larger. It makes no sense at all to argue this; even if you say it is cumulative (and there is absolutely no evidence, mechanism or hint that low lever signals can accumulate with even the perceived possibilities of high level signals causing some dna damage), the accumulation is so many orders of magnitude below the existing levels and for so short of time that it cannot possibly be considered significant. So to argue it affects your health just makes you look silly and uninformed w.r.t. to even extreme "precautionary" principles.

My son commented to me "are you arguing with those smart meter guys again; it's like arguing with the homeless at a bus stop; they're mostly irrational and is just a waste of your time". I don't suppose there is any possibility that any science or study could convince you, but I don't intend to let you make these completely false posting without at least presenting the logical extension of even your "facts"; which is...the effects you claim, beyond any reasonable doubt, cannot be caused by RF of smart meters. And did you know that the old meters relied on EM fields to turn the little wheel (eddy currents) which can only occur in the presence of radiating RF fields: thus, perhaps the new meters radiate less RF than the old meters.

Safety: I have never heard an example of a smart meter exploding or damaging anything. I can't see how they possibly can since there are a nearly passive monitor. If you did have a smart appliance, then maybe it could have an effect if it "pulled-the-plug" at the wrong instance in the operating cycle, but to my knowledge no smart appliances have been made available. Further, I would like to know if any regular meters have exploded? I would guess so too. A reasonable scenario for an explosion would be an installation where the meter is poorly connected in-line, causing a heat build up at the contacts: but that would be the same whether it is a Smart Meter or a regular meter being installed. However, if one could say "1 in 1000" meter installations results in a bad installation that can cause problems" then I would consider that a valid justification for asking whether it is wise to replace all meters. If it's 1 in 30 million, then I would guess the benefits outweigh the risks.

General Community: Re: SMART METER ALERT! Stop installation in Sonoma County!

From: Sabrina

Posted: January 2, 2011, 12:11 am

If you don't understand the potential erosion of personal land and health rights as posed by the smart meter grid, you can find PLENTY of well documented info on these two sites: http://emfsafetynetwork.org/ , here: http://stopsmartmeters.wordpress.com/, and more on health risks here: http://www.radiationresearch.org/, and here: http://wiredchild.org/, and those are just a few that can be found. The fact that we are not given a "choice" in the matter of installing a smart meter is an invasion of personal property freedom of choice rights. While it's true we are bombarded with electromagnetic fields these days, most all of the technology are choices we can make, such as Wi fi or cell phones, and other wireless media. According to PG & E, I believe a privately held stock company, we do not have a choice in the matter of having a smart meter installed; they say they are mandated by the state.

" ....In California alone, 23 Cities (including Morro Bay) and three counties have formally opposed the wireless PG&E smart meters...." and "....Prudent avoidance of electromagnetic radiation has been adopted in Australia, Sweden and several U.S. states including California, Colorado, Hawaii, New York, Ohio, Texas and Wisconsin...." says Judy Vick in a recent Cal Coast News Article. See: http://calcoastnews.com/2010/12/lega...-smart-meters/. While some folks may not be sensitive to the electromagnetic fields and feel that this should not be such a big deal, think of those who are sensitive and actually do develop illness's from it. They should have a choice in the matter and not have it forced on them. After all there has been NO study done by the PG&E, the CPUC or the FCC on the health risks of these meters. Any statement that they are "safe" is false, because the study has not been done to determine that.

[To see the original message and previous replies click on the website/reply button below]

a.. The following member has expressed gratitude to Sabrina for this post:

Barry

General Community: Re: SMART METER ALERT! Stop installation in Sonoma County!
From: Sasu Posted: January 2, 2011, 8:30 am

Thanks to Barry and Sabrina for posting the concerns with Smart Meters: here's more info:

Smart Meters are costing us money, our privacy, our health and safety. Some people's bills have doubled, tripled and more. Smart Meters have exploded, burned out appliances and are making some people very sick, insomnia, split second head aches and high pitched ringing in the ears, nausea, etc. This is RF pollution, just like cell towers, only right on our homes! While some people have gotten meters removed, others are stuck fighting PG&E.

PG&E cannot be trusted to provide substantiated or believable information to consumers about Smart Meters. There's been no environmental safety study. Smart Meters transmit pulsed microwave radiation (RF) constantly, throughout the day and night.

Here's some science simplified: http://emfsafetynetwork.org/?p=609
Also: http://emfsafetynetwork.org/wp-conte...09/10/sage.pdf

People are getting sick from Smart meters http://emfsafetynetwork.org/?page_id=2292

Read these shocking comments : burnt out appliances, serious over billing, interference http://www.ucan.org/forum/forums/ene...illing dispute
http://emfsafetynetwork.org/?page_id=1223

And Smart Meter fires and explosion http://emfsafetynetwork.org/?page_id=1280

People can reduce their EMF exposure- something the State of California advises people to do! Here's some suggestions on how to do it: http://emfsafetynetwork.org/?page%20id=327

Read more about why we and many cities and several counties oppose them here: http://emfsafetynetwork.org/?page_id=872

The fact is, a microwave, a cell phone, wi-fi are a choice, and you can purchase or not. You can also turn these devices on or off at your convenience. A Smart Meter is part of a microwave radio system that the utility is forcing on our homes and they and they are using our property for their use without compensation- this violates California law!

PGE will be able to turn off your power remotely, or turn down your heat, or AC or water heater when they need to. Plus they will be able to track your personal activities, and do you want to trust your privacy to PGE?

All new Appliances will be sold with RF chips so our homes will be further polluted with wireless, where there's evidence of harm, scientific and anecdotal!

Need more? See this: http://www.waccobb.net/forums/showth...956#post126956
and
http://emfsafetynetwork.org/?page_id=1546

Sandi Maurer
www.emfsafetynetwork.org

[To see the original message and previous replies click on the website/reply button below]

a.. The following member has expressed gratitude to Sasu for this post:

Barry

General Community: Re: SMART METER ALERT! Stop installation in Sonoma County!
From: Sasu   Posted: January 2, 2011, 3:06 pm

PS... and here's what you can do about it!
Refuse Smart Meters! Post signs on utility meters or demand removal and complain (in CA send this: http://emfsafetynetwork.org/?p=1588) to your public utilities commission!

Take Action! http://emfsafetynetwork.org/?page_id=649

From: Michael Boyd (michaelboyd@sbcglobal.net)
To: brian.perkins@mail.house.gov; kelsey.kerr@mail.house.gov; richard.steffen@mail.house.gov;
Date: Mon, February 7, 2011 12:25:46 PM
Cc: troy.phillips@mail.house.gov; Michael_Weiss@boxer.senate.gov; matthew_nelson@feinstein.senate.gov; senator@boxer.senate.gov;
Subject: San Bruno Explosion San Bruno Blast Investigator Has PG&E History NTSB investigator and state utility commission attorney spent years at utility

Dear Representative Jackie Speier,

I contacted the NTSB to discuss making a presentation before the NTSB at their so-called March 1st through 3rd **Public Hearing**: Natural Gas Pipeline Explosion and Fire, San Bruno, CA, September 9,

Unfortunately when I asked for an opportunity Ms. Ward of the NTSB Staff told me it wasn't really a public hearing where the public could give input, but a Hearing where pre-selected "experts" would make presentations and the "Parties" and Commissioners could then cross examine the witnesses.

I explained that I had a Application 10-09-012 pending before the CPUC regarding PG&E's SmartMeters in the San Bruno neighbor where the pipeline exploded being the root cause of the fire and explosions there and therefore wanted to know how to become a Party? Ms. Ward indicted also that the Parties had been pre-selected and there was no opportunity for CARE to be a Party to the investigation.

I then asked how I could provide my information on the PG&E SmartMeters in the San Bruno neighbor where the pipeline exploded being the root cause of the fire and explosions and I was directed to mail my information to the Chief NTSB Investigator Mr. Ravi Chhatra.

My research reveals that Mr. Ravi Chhatra the "federal investigator leading the National Transportation Safety Board's inquiry into the deadly gas pipeline explosion in San Bruno worked for Pacific Gas & Electric for 20 years." [See article below.] It also reveals that the Frank Lindh the "general counsel for the CPUC... came to the agency from PG&E where he had worked for a decade as an attorney" and that he is the father of the "the so-called "American Taliban".

This left me scratching my head asking myself why such individuals who clearly have a professional if not financial conflict of interest in PG&E why they would have any role what ever in the NTSB investigation of the San Bruno pipeline fire and explosion? For the life of me I can't understand how the Dad of the American Taliban could have any role and this doesn't create a risk to national security as well???

Come on you politicians you are putting your political futures in the trash by putting these guys in charge. The public deserves better than this and you know it.

We want a real investigation by real independent experts not ex-PG&E employees and we want a real public hearing where the public has an opportunity to shine a little more sun shine on PG&E and the root cause of the San Bruno pipeline explosion.

Respectfully,

Michael E. Boyd President
CAlifornians for Renewable Energy, Inc.
(CARE)
5439 Soquel Drive
Soquel, CA 95073
Phone: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net

https://www.ntsb.gov/Pressrel/2010/100910.html

NTSB Advisory
National Transportation Safety Board
Washington, DC 20594
September 10, 2010

NTSB LAUNCHES TEAM TO INVESTIGATE APPARENT GAS PIPELINE EXPLOSION IN CALIFORNIA

The National Transportation Safety Board has launched a Go Team to investigate last night's explosion and fire in a California neighborhood that appears to be related to a natural gas pipeline.

Local authorities in San Bruno, California, report that dozens of homes were destroyed in the accident. The extent of injuries and possible fatalities is still being assessed.

Ravi Chhatre will serve as Investigator-in-Charge for the 4-member team from the NTSB. The Board's Vice Chairman, Christopher Hart, is accompanying the team and will serve as principal spokesman for the on-scene investigation.

Peter Knudson is the public affairs officer accompanying the team. Once the team arrives in California, Mr. Knudson may be reached on his cell phone at 202-557-1350.

\- 30 -

NTSB Press Contact: Peter Knudson (California)
202-557-1350

NTSB Public Affairs Office (Washington)
202-314-6100

San Bruno Explosion San Bruno Blast Investigator Has PG&E History NTSB investigator and state utility commission attorney spent years at utility

By Katharine Mieszkowski on *September 15, 2010*

http://www.baycitizen.org/san-bruno-explosion/story/san-bruno-blast-investigator/

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National Transportation Safety Board

The federal investigator leading the National Transportation Safety Board's inquiry into the deadly gas pipeline explosion in San Bruno worked for Pacific Gas & Electric for 20 years.

Ravi Chhatre is the investigator-in-charge for the four-member team from the NTSB.

Chhatre, who has been with the board for almost 13 years, previously worked at PG&E as a material scientist in its research department. He was employed there from 1978 to 1998.

"Mr. Chhatre divested himself of all PG&E stock before becoming employed by the NTSB in 1998," Peter Knudson, a spokesman for the agency wrote in an e-mail. The agency prohibits investigators from having any stock in a company subject to its investigation, Knudson wrote, adding that neither Chhatre's spouse nor his adult children own PG&E stock, either.

Yet, Chhatre will still receive a retirement benefit from PG&E in the form of a defined pension payment, but it is not tied to the profitability of PG&E, according to the spokesman.

The fact that Chhatre left PG&E more than a decade ago reassures some observers that he will not suffer from divided loyalties as he conducts the investigation.

“I doubt that someone that left in 1998 would feel much of a sense of identity with the company today,” said John Geesman, who served on the California Energy Commission from 2002 to 2008. “Given the way PG&E is as a culture, someone who was around way back when might actually be tougher on them, given the widespread feeling that they don’t perform as well now as they did in the good old days.”

An official at the California Public Utilities Commission, which regulates PG&E, is a more recent recruit from the utility.

Frank Rich Lindh has been the general counsel for the CPUC since June of 2008. He came to the agency from PG&E where he had worked for a decade as an attorney. Andrew Kotch, an information officer for the CPUC, said that Lindh has “no financial interests in PG&E.”

“When you are hired at the PUC you have to divest of any stocks that you may have with a company that we regulate,” said Kotch.

Lindh is best-known as the father of John Walker Lindh, the so-called "American Taliban," who is now serving a 20-year term in federal prison for fighting as a soldier with the Taliban in Afghanistan.

SAN FRANCISCO, CALIFORNIA, APRIL 11, 2011

10:00 A.M.

* * * * *

ADMINISTRATIVE LAW JUDGE BUSHEY: The Commission will come to order.

This is the time and place set for Oral Argument and report by Pacific Gas and Electric Company in Rulemaking 11-02-019.

Good morning. Our first matter this morning is oral argument. I have five presenters beginning with Pacific Gas and Electric Company and then four parties following with ten minutes each. PG&E will have 15 minutes.

Do any of the Commissioners wish to make opening statements?

COMMISSIONER FLORIO: Yes. Thank you.

I am the assigned Commissioner in this matter, and I think it's important to put what we are doing here today in context.

This is closing argument on the Order to Show Cause that the Commission issued at its last meeting. This is not about the cause of the San Bruno explosion or whether PG&E has any degree of fault for that accident.

This is also not addressing the Investigation that we have launched into

PG&E's recordkeeping practices.

The Order to Show Cause is a narrow matter regarding the filing that PG&E made on March 15th which the Commission perceived as inadequate given our prior directives. PG&E then on March 21st made an additional filing which prompted our staff to negotiate a stipulation that is before you today.

This is not the only enforcement proceeding involving San Bruno. For example, the so-called recordkeeping OII is still ongoing. This has nothing to do with that proceeding. And there may be other enforcement proceedings launched as the NTSB investigation goes forward.

Now, PG&E filed a motion for clarification of the ruling that called for this hearing today. And I did not issue a written ruling because I think there are a couple of points that I need to make clear. The focus today is on the stipulation and whether the Commission should approve the stipulation. But as assigned Commissioner, I cannot dictate, nor would I wish to, to my colleagues about what questions they may wish to ask.

There is obviously a great deal of interest in this matter. And we did have an evidentiary hearing previously, but because of notice requirements only two Commissioners at a time were able to attend that. So I did request that the parties make their witnesses available if other Commissioners have questions of those witnesses in addition to any questions they may have for counsel making arguments. And I appreciate that the parties have made those folks available.

PG&E also asked essentially what happens if the stipulation is rejected. And in my view, at least, if that were to be the will of the Commission, we would go back to a full hearing on the original Order to Show Cause. Again, I'm just one voice on that, but I believe that will be the appropriate way to proceed.

Finally, there's been some confusion about where we go from here on this matter. Because this is an adjudicatory proceeding, ALJ Bushey will prepare a Presiding Officer's Decision. Typically, a Presiding Officer's Decision goes out for review, and if no one requests a decision by the full Commission, that becomes the order of the Commission after 30 days. Then again, because of the great public interest in this matter, we will treat it more like a normal Proposed Decision in a ratemaking or Rulemaking proceeding and we will have comments on the Presiding Officer's Decision and then place it on the next Commission agenda for a full Commission vote and essentially skip that step of seeing if anybody wants the full Commission to vote on it, because I think the full Commission does want to vote on it.

And with that, other Commissioners with opening comments?

President Peevey.

COMMISSIONER PEEVEY: Thank you, Commissioner Florio.

I just wanted to seek, commenting on something that Commissioner Florio has said, I want to seek a little further clarification.

I have been very concerned about the way that the media has described the stipulation, again today singling out our executive director Brad [sic] Clanon. And I want to give a little context of this by pointing out something that each Commissioner received at the end of last week. And this is from our General Counsel. I am going to read it.

It is important to

recognize that this Order

to Show Cause and proposed Stipulation do not even begin to address whether PG&E should be found to be at fault for poor recordkeeping, or more importantly, for any irresponsible or negligent or other actions that may have contributed to the September 9th explosion in San Bruno. The allegations about PG&E's poor recordkeeping are the subject of a pending Order Instituting Investigation.

Which Commissioner Florio just referenced.

Meanwhile, any allegations about fault on PG&E's part of the San Bruno explosion itself will occur, if at all, in the future only after the NTSB completes its roots cause investigation. It is unfortunate that news media incorrectly characterized the proposed Stipulation,

and in particular the $3
million fine, as somehow
freeing PG&E from any
further Commission
sanctions for the explosion
in San Bruno. This is
entirely inaccurate and
should not influence the
Commissioners as they
evaluate the specific
question of whether to
approve the instant
stipulation; that is, the
Compliance Plan and the
proposed civil penalty.

End of quote.

I hope that puts some of this in some context. I can't control the irresponsibility of some in the political world or media in refusing to characterize properly what the Stipulation sets forth, but I do think that the words of our General Counsel are wise as we go forward in this matter this morning.

Thank you, Commissioner Florio.

ALJ BUSHEY: Commissioner Simon.

COMMISSIONER SIMON: Yes. Thank you, Commissioner Florio. And I also want to thank you for agreeing to conduct this en banc hearing in response to a memorandum that I sent to you and my fellow Commissioners expressing my concerns regarding the process used to arrive at the stipulated resolution and how that resolution was brought before the Commission's adoption.

Resolution 11-02-019 and Resolution L-410 directed PG&E to provide the Commission with the records by March 15th, 2011, relating to the maximum operating pressure for certain high risk gas transmission pipelines.

When the item was introduced at the March 24th business meeting, the Commission, or at least I should say my office, was not presented with an Order to Show Cause for consideration but instead a stipulated agreement reached between the CPUC staff and the PG&E.

I was led to believe by the March 16th letter by Executive Director Paul Clanon and related press release that we would be considering an Order to Show Cause at the March 24th business meeting. At no time prior to the meeting was I briefed or informed of any settlement discussion or possible outcomes of a settlement.

While there is a need for confidentiality in settlement discussions, I am deeply concerned that my office was not at least notified of the fact that settlement discussions were in fact in place and that a settlement had been adopted.

Ultimately, the intent of the Commission's proceedings is to ensure that the September 9th, 2010, San Bruno explosion does not again occur in this state, but at this time I have reservations about whether the proposed penalty and Compliance Plan contemplated by the stipulated agreement fully effectuates this intent.

Some question whether a penalty of 6 million, 3 million of which is paid after the stipulation is approved and 3 million of which will be suspended and may never be paid, is sufficient to serve the purpose of the punishment and deterrent.]

I particularly point this out when this week the press covered a severance package of a PG&E executive that I believe is $2.3 million.

I also have concerns about --

COMMISSIONER PEEVEY: 3.2.

COMMISSIONER SIMON: Oh, excuse me. $3.2 million. Thank you for that correction, President Peevey.

I also have concerns about the Compliance Plan, in particular the timeline for determining maximum pipeline pressure, the need for strict Commission oversight of PG&E's compliance actions, and the importance of public transparency. Bottom line, why will it take nearly a year after the San Bruno explosion for PG&E to demonstrate to the Commission and the public that it is not putting neighborhoods at risk of explosions.

Separately, it seems more reasonable to me that any plan approved by the Commission should be clear, and the Commission, not PG&E, I repeat, the Commission, not PG&E, will decide when assumptions rather than documents can serve as an appropriate basis for establishing maximum pressure, and the Commission will have a final say on whether the assumptions are valid.

I just want to say in closing that I do look forward to PG&E's testimony. I do -- I will maintain an open mind regarding this transaction or occurrence, but I still have concerns as to why we're not hearing oral arguments on an Order to Show Cause. That was the original purpose of this process, and

I am looking forward at some point, Commissioner Florio, to hearing why PG&E should not be sanctioned for the failure to comply with the order issued by this Commission.

Thank you.

COMMISSIONER FLORIO: Commissioner Sandoval.

COMMISSIONER SANDOVAL: Thank you very much. Thank you so much for the opportunity to have this hearing. I think this is a very important opportunity.

I, like Commissioner Simon, was very surprised to hear on the dais about the proposed settlement. I too have been -- have received the documentation regarding the Order to Show Cause and was not informed of the fact of a proposed settlement and any negotiations and was in no way a party to the settlement, which is also important to underscore that this proposed Stipulation is merely that, a proposal by PG&E and certain members of the CPUC staff and not by any means a fait accompli.

In the oral arguments today there are a few questions which I would like the parties to answer and any witnesses to address your testimony to. One would be to examine what should be the appropriate unit used to calculate a fine. Should fines be calculated per pipeline segment, per document which is missing for a pipeline segment? What is the appropriate unit? And therefore, is the calculation of this, of any proposed fine appropriate given the qualitative character of any fine and also any violations and also the extent of violations?

The California Public Utility Code also requires that we take into account the utility's actions to prevent a violation, the utility's actions to detect a violation, and the utility's actions to disclose and rectify a violation. Therefore, we also need to look at whether or not the proposed work plan and the proposed Stipulation would help to rectify those violations, particularly when it proposes to substitute assumptions for actual documents that were required by either CPUC rules or by the Code of Federal Register in the Transportation Code.

Second, I would like the witnesses to address the adequacy and fit of the work plan to protect public safety and the public interest. That is, I think, the -- the other thing that is absolutely critical here is, apart from fines, does this proposed work plan actually increase public safety, and particularly since the proposed work plan proposes to substitute assumptions for actual documentation, is this well calculated to protect the public safety both in the short term and in the long term?

Number three, the NTSB reiterated in its March 29th, 2001 letter, which was submitted after PG&E's March 25th and March 21st submissions, that if the documents and records that were requested regarding pipeline segments, which were supposed to be complete, verifiable, and traceable, could not be satisfactorily produced, then PG&E was to provide and oversee spike and hydrostatic testing.

So why isn't this directive included in the work plan? It was also included in the NTSB's January 3rd letter, and I also note that PG&E has already committed in its March 21st letter to this Commission and also in a separate proceeding involving L-411, which provides the opportunity for 100 percent depreciation on certain operating capital deployed by the end of 2011 and 50 percent depreciation for operating capital deployed by the end of 2012. In their proposals regarding L-411 PG&E identified as an area of priority pipeline replacement.

So particularly in light of PG&E's commitments, why aren't these commitments to test or replace, which would also be consistent with the NTSB's requirements, incorporated into the work plan? And is their absence indicia that this plan is or is not well calculated to protect public safety and the public interest?

Thank you very much for the opportunity to have this hearing.

COMMISSIONER FLORIO: Commissioner Ferron.

COMMISSIONER FERRON: Thank you very much. I guess this is the cost of being last in the line. I'll try to be incremental here.

Firstly, I just want to say that I'm very, very concerned that we make immediate progress on addressing the safety shortcomings of the pipeline system in California. So to me that, making steady and quick progress on ensuring that is the number one priority for me.

I guess, as described earlier, to me this session is about trying to understand two elements. One would be to determine the appropriateness of the size of the fine that's being imposed on PG&E, and secondly, to examine the appropriateness of the Compliance Plan itself.

I know there's been a lot of attention in the press on the former. To me, I understand, as President Peevey mentioned, this is not the only such proceeding against PG&E. To me the issue is, really surrounds, in terms of the size of the fine, as Commissioner Sandoval pointed out, the code is clear that fines, the size of the fine should be determined by a number of factors including the conduct of the utility, as she mentioned, the utility's action to prevent a violation and the utility's action to detect a violation.

To me the question I have, and I'd like to try to have that addressed here, is to understand the decisionmaking process that took place within PG&E surrounding appropriation of the March 15th submission. I'd like to understand what that process was, who the author was, who did the review and so forth.

Again, thank you very much, Commissioner Florio, for leading this proceeding.

ALJ BUSHEY: Thank you, Commissioners.

Is there anything else before we begin with oral argument?

(No response)

ALJ BUSHEY: Hearing none then, Mr. Malkin.

ARGUMENT OF MR. MALKIN

MR. MALKIN: Thank you, ALJ Bushey, Commissioners, and thank you, Commissioner Florio.

Thank you, Commissioner Florio, for your clarification this morning. We appreciate that the focus of this proceeding is going to be on the Stipulation and are prepared both through oral argument and with witnesses if you wish to address that Stipulation.

Even before the Commission voted out the Order to Show Cause, PG&E and the Commission's enforcement staff, CPSD, realized that working together to enfor -- to enhance the safety of PG&E's natural gas transmission system is more important than arguing about what happened in the past.

The very day the Order to Show Cause was issued, as several of you Commissioners have noted this morning, CPSD and PG&E signed and filed a Stipulation resolving the Order to Show Cause and agreeing on a Compliance

Plan that will lead to an engineering validation of the MAOPs, the Maximum Operating --

COMMISSIONER SIMON: Excuse me, Mr. Malkin. Was this a resolving of the compliance or the failure to comply or a proposal to resolve?

MR. MALKIN: This is a very good question, Commissioner Simon. It is a stipulation and agreement between the enforcement staff and PG&E that is expressly subject to the approval of the five Commissioners. So it is our agreement that this is an appropriate resolution, but it is your decision whether or not it is.

COMMISSIONER SIMON: Thank you. I appreciate that clarification.

MR. MALKIN: You're welcome.

So our agreement, PG&E's and the enforcement staff's, includes a plan that will lead to an engineering validation of the MAOPs on all of PG&E's HCA, High Consequence Area pipelines that do not have pressure tests by August 31st of this year. It is this Stipulation, as you've said, that is before you today.

The January 3rd NTSB safety recommendations leading to the MAOP validation work were unprecedented in their scope. They went far beyond existing requirements calling for PG&E in effect to abandon the grandfathering allowed by the federal regulations and instead to engage in a massive search, collection, organization effort for documents relating to 1805 miles of pipe followed by a forensic engineering evaluation and analysis of every pipe segment, every valve, every bend, every fitting, and every other component, literally a foot-by-foot review of every one of these pipelines without pressure test records.

To put that recommendation in context, there was recently proposed an amendment to the Senate Pipeline Safety Bill that would add a similar requirement for all pipeline operators to conduct an MAOP validation. It gives the operators 18 months to perform that work.

Knowing that what was asked of it was a daunting task, PG&E nevertheless embraced the challenge. In fact, as we have said in several filings and orally to the Commission, PG&E decided on its own to go beyond what the NTSB recommendation was, to go beyond what this Commission asked it to do and to do field verifications to verify that the information it was deriving from these sometimes ancient documents was accurate, to fill in gaps in documents, to answer questions.

Secondly, we're going beyond the recommendations in that we are extending this review to the pipe in HCAs that already have pressure test records. And then finally, when PG&E is done with that, we're going to take it another step further and we're going to apply the same methodology, the same MAOP validation to the rest of PG&E's gas transmission system.

So on January 5th, two days after getting the Executive Director's letter asking it to undertake the NTSB recommendations by February 1st, PG&E personnel met with the Commission staff, shared with them the draft MAOP Validation Report that PG&E had already prepared documenting its work on Line 101, and told the staff that this was the type of analysis that it planned to do and that it would take a long time.

On January 7th PG&E wrote back to the Executive Director saying it would comply with the directives and advising that it would take until March 15th to complete the first step, the record collection and verification of which pipe segments had already been pressure tested. That was the first requirement, because the MAOP validation applies to those pipes that have not been pressure tested.

Now, I may be dating myself with this reference, but what followed was, in the words of the movie Cool Hand Luke, a failure to communicate. Where PG&E thought it was being clear as to what it could physically accomplish by March 15th, record collection and verification of those pipe segments that had been pressure tested, the Commission obviously thought otherwise.

Despite what you may read about PG&E in the newspapers, it was literally stunned when it received the Executive Director's March 16th letter accusing it of willfully disobeying this Commission's order. The company immediately set about preparing and filing a supplemental report both acknowledging its failure to communicate clearly and emphasizing its commitment to fulfill the Commission's directives and to enhance the safety of its natural gas pipeline system.

Now, you have before you the

Stipulation and a Compliance Plan agreed upon by your enforcement staff and PG&E. This Stipulation and Compliance Plan in our view puts the most important priority first, safety. It includes what PG&E views as a substantial penalty, and I'll comment more about that in a moment, but more importantly, the Stipulation includes a concrete Compliance Plan with definitive milestones and enforceable along the way. It provides for regular reporting to the Commission to ensure transparency and regular consultation with the enforcement staff.

To those, including some of you on the dais, who think the Compliance Plan may provide too much discretion to PG&E, the Compliance Plan really says otherwise. It requires PG&E to report and consult with the enforcement staff on a regular basis. Now, it does not literally provide that PG&E will not use any assumption with which the CPSD disagrees. But do you really think at this point in time PG&E wants to be in a position to stand before you trying to justify an assumption that is contrary to what CPSD or its retained experts said it should use and not only have to justify that but risk the Commission agreeing with CPSD and its expert and saying that it was inappropriate and thus having to start the MAOP validation all over again? That's simply not going to happen.

The filed comments on the Stipulation generally ask the Commission to order more, although in most cases without being terribly specific about what that more is. Now, TURN and CCSF both take positions that the agreed upon penalty is too low, and this is one of the specific questions that was raised from the dais this morning, the appropriateness of the size of the penalty.

As the Commissioners have already noted, this is a penalty for a specific issue, whether or not PG&E adequately complied with a specific directive to collect records. It's not broader than that.

Now, in CCSF's case they assert the penalty is just generally too low. TURN agrees that the $3 million penalty for past conduct is adequate but says there should be a bigger future penalty hanging over PG&E's head.

The touchstone of looking at any penalty ought to be the code, and several of you Commissioners have referred to the code this morning. But before those factors come into play in determining how the Commission exercises its discretion, it's the discretion to fix a penalty between the $500 per violation and the $20,000 per violation that the code permits. So the touchstone is, what is a violation? And the code does provide that a continuing violation every day can be considered a separate violation.

In this case, Commissioner Sandoval, you've asked specifically the question, what is a violation here? In our view, and there is, I believe, good case law to support this position, the issue that has been raised, the allegation that is made is that PG&E committed an act of contempt by not complying with this Commission's directives on March 15th, or that it failed to comply with that order on March 15th.

In either event, it is a singular wrong that is alleged. It is a failure to comply or a willful disregard of a Commission order. And while you could look at it in terms of if you violated the order on March 15th, when did you stop violating the order and say every day is a singular vio -- a singular violation that can be cumulated, there simply is not in our view a way derived from any normal principle of American jurisprudence where you could say every document that was not produced on March 15th is a separate violation, every segment of pipe for which all of the documents were not collected on March 15th is a separate violation. The violation is in not completing the work if that's the violation that you want to look at.

So we think the appropriate penalty is, as CPSD said, six days worth of penalty. They pegged it at a million dollars a day. We agreed to pay 3 million with another potential 3 million if we miss on an unexcused basis any of the milestones we've agreed to in the Compliance Plan. Our own view, as we said in our motion, is it should have been $20,000 a day for six days, $120,000, if any penalty at all is warranted. But having said that, that really diverts us from what is the important point to us and what ought to be everyone's top priority in thinking about this Stipulation and the Compliance Plan, safety, and that's what I want to get back to.

In this regard, I note that some of the comments including some from the Commissioners this morning asked about the hydro testing and replacement that PG&E has said it plans to do this year and raise the question, why isn't that part of the Compliance Plan?]

First, it doesn't have anything to

do with the NTSB's recommendations, although, as Commissioner Sandoval noted, the NTSB made three safety recommendations, the third one of which was if you don't have records -- and in our view that is a recognition of the fact that for old pipelines no one is expected to have all the records -- the NTSB said in its third recommendation if you do not have complete, verifiable, traceable records, then you should do a hydro test preceded by a spike test.

When Executive Director Clanon directed PG&E to comply with the NTSB recommendations, he specifically excluded that recommendation saying that's the recommendation, we don't want you to do anything about that, we want to think about what is the right thing to do if you cannot validate the MAOP through an engineering analysis.

And in fact, we are currently in dialogue with the Safety Branch of the Commission about that planned hydro testing. And before that plan is going to go forward, we are looking for some broad concurrence from the CPSD, from retained experts.

The CPSD, for example, wants us to look at alternate technologies, not simply do hydro testing in all of those places we had planned to do it. Local communities have to be considered as well. Some of those are indicating they, too, prefer that PG&E use alternate technologies and not hydro test pipes that are in their communities.

There is a lot of complexity around that hydro testing and pipe replacement. And it doesn't serve the principle of safety or the Commission well to try to legislate, in effect, what that should be.

The appropriate way to deal with it, we believe, and I think we have the concurrence of the safety staff because they agreed that it should not be part of the stipulation, is to let us continue to work with your staff, with their experts, with local communities, with other experts and devise a plan that is best suited to meet the objective that we all share, enhancing the safety of the natural gas transmission system.

There is important work to be done, work to enhance the safety of PG&E's natural gas transmission system, work that will provide added assurance to the public, to this Commission, and to PG&E itself that PG&E's gas transmission lines are operating at safe MAOPs.

The stipulation allows PG&E and your enforcement staff to focus on that important work and not to devote their resources, time and energy to an enforcement proceeding in which the staff has the burden of proving beyond a reasonable doubt whether or not PG&E committed a willful violation of the Commission's directives, a proceeding focused on who said what in the past rather than on who is doing what in the future to enhance the safety of the pipeline.

We urge you to approve the stipulation as submitted by PG&E and your staff.

ALJ BUSHEY: Thank you, Mr. Malkin.

Questions for Mr. Malkin, or should we move on to the next oral presenter?

(No response)

ALJ BUSHEY: Okay. Mr. Heiden.

ARGUMENT OF MR. HEIDEN

MR. HEIDEN: Good morning, Commissioners and Judge Bushey. My name is Greg Heiden. I am representing the Consumer Protection and Safety Division in this stipulation of the Order to Show Cause.

Julie Halligan, the Deputy Director of CPSD, is available today to answer any questions.

You heard from PG&E about what the stipulation accomplishes. In recommending that you adopt the stipulation, I would first like to talk about what the stipulation does not do. Then I will talk about why the stipulation is in the public interest and why it should be adopted by the Commission.

First, what the stipulation does not do, my comments are going to reflect what you heard already this morning from President Peevey and from Commissioner Florio, the stipulation only purports to resolve the narrow issues set in the Order to Show Cause.

The stipulation expressly provides in Paragraph 3(C) the penalty specified above does not limit the Commission's authority to impose additional penalties for any violation of law or regulation with regard to the Commission's Investigation into the San Bruno pipeline rupture not related to the completion of the Compliance Plan.

So the stipulation really only covers the narrow issue of PG&E's response to the Commission's Resolution L-410 and not other issues associated with the San Bruno explosion.

The following current and possible future proceedings concerning the San Bruno explosion are not affected by the stipulation.

First, the ongoing National Transportation Safety Board and CPSD root cause San Bruno investigation: Our staff and NTSB staff continue to investigate the cause of the San Bruno explosion. We expect the NTSB to issue findings on that investigation in August of this year.

Our staff will also be releasing a report on that accident which could form the basis of a future Commission Order Instituting Investigation into the San Bruno explosion.

The stipulation does not impact this potential OII.

Second, the stipulation does not impact the current Commission Order Instituting Investigation into PG&E's recordkeeping, which is docket number I 11-02-016. That Investigation, and not this Order to Show Cause proceeding, is the venue to investigate PG&E's recordkeeping.

That order states at page 1, I will

read from it:

By this order the Commission institutes a formal Investigation to determine whether PG&E violated any provision or provisions of the California Public Utilities Code, Commission General Orders or Decisions or other applicable rules or requirements pertaining to safety recordkeeping for gas services and facilities. This proceeding will pertain to PG&E's safety recordkeeping for the San Bruno, California gas transmission pipeline that ruptured on September 9th, 2010, killing eight persons. This Investigation will also review and determine whether PG&E's recordkeeping practices for its entire gas transmission system have been unsafe and in violation of the law.

So any concern that this stipulation represents any judgment of PG&E's

recordkeeping practices is misguided.

The OII 11-02-016 will judge PG&E's recordkeeping practices and determine what, if any, penalty is appropriate. The stipulation does not impact the Commission's ability to judge PG&E's recordkeeping in any way.

Third, this stipulation does not affect any forward-looking rules on recordkeeping that might be adopted in this Rulemaking, docket R 11-02-019.

The Order to Show Cause states:

Other issues related to this Rulemaking are specifically excluded from the scope of the Order to Show Cause.

Parties to the Rulemaking will have the opportunity to submit comments on issues identified in the Rulemaking. In fact, opening comments that we will be making are due this week on April 13th.

The stipulation does not impact any forward-looking rules established in the Rulemaking.

Fourth, the stipulation does not affect potential litigation related to the San Bruno explosion by private parties for damages or other remedies, nor does it impact any other prosecution by the Attorney General, District Attorney or other law enforcement.

Next, I would like to talk about what the stipulation accomplishes and why it is in the public interest, which is what Deputy Director Julie Halligan testified about on March 28th.

As PG&E has testified today, the stipulation requires PG&E to comply with urgent safety recommendations issued by the National Transportation Safety Board by August 31st of this year. This means that PG&E will have completed two important steps in improving pipeline records, which we believe will help make PG&E's pipeline safer and restore confidence in pipeline integrity.

One, PG&E will have completed its records search for pipelines in specified high consequence areas, or HCAs, that do not have a maximum allowable operating pressure or MAOP established through hydrostatic testing.

Second, PG&E will have calculated a

valid MAOP based on the weakest segment of the pipeline.

The Compliance Plan divides up the records search and MAOP process into four priorities.

The first priority is to search for records and validate the MAOP of 152 miles of pipeline that is most similar to the pipeline involved in the San Bruno explosion.

The additional three priorities are shown in Attachment A, the MAOP prioritization and work plan, and also detailed in PG&E's March 25th filing.

All four priorities will be completed in five months.

The Compliance Plan requires PG&E to submit monthly progress reports and have meetings to review these reports with the CPUC staff and provides for PG&E to reimburse the Commission for any fees, expenses or costs for consultants retained by the Commission for implementing, monitoring or enforcing the Compliance Plan.

Finally, the stipulation provides for a fine, $3 million now and a potential fine of another $3 million. We think this fine is a serious and appropriate remedy for the allegations raised in the Order to Show

Cause.

We believe it sends the right message that complying with NTSB safety recommendations is very important to improving PG&E's pipeline safety.

The purpose of the fine is compliance. We want to get PG&E to comply with these recommendations.

In conclusion, staff recommends you adopt the stipulation. The stipulation, to borrow from Commissioner Florio's language from the March 28th hearing, helps us to get to a place where PG&E itself and this Commission and the broader public can be assured that PG&E's gas system is safe.

I want to respond to a few of the questions that were raised today, specifically by Commissioner Sandoval, first, having to do with the fine, what units should be used to calculate a fine, should it be per segment or per document. That's a good question.

Public Utilities Code 2107 and 2108 provide for a $20,000 fine for violating a Commission order. 2108 provides each fine is a separate offense.

So the question is how do you calculate that fine and what exactly counts as an offense.

You heard PG&E's interpretation that they think this potentially would be one offense which would be a $20,000 per day fine. If this case were litigated, CPSD would probably take a different position.

I don't have a calculation for you today, Commissioner, but one interpretation would be each segment of pipeline is an offense. There's other variations, but I don't have a calculation for you today. I think it is something that would be litigated.

Another issue you raise is the adequacy of the work plan to protect public safety, the concern about assumptions. Staff shares your concern. We saw the assumptions in both the March 15th and March 21st filing. We think that is addressed in the Compliance Plan.

If you look at page 2, third paragraph, the last few lines, I am looking at the Compliance Plan, it is says if the determination is based on assumptions, each must be identified. This is very important to staff. If PG&E is going to use assumptions rather than actual documents, we want there to be a record of it so it is very clear to anyone auditing or as part of the process to know exactly what are your assumptions and which are your documents. I think that is consistent with what the NTSB wanted.

The PFL will also identify all source documents for the data in the PFL including, but not limited to, as-built drawings. All such documents will be available in our electronic data bases. We will provide the CPUC staff with access to these documents.

Then looking at the next paragraph, any MAOP calculation based on assumptions will be identified as such, along with all assumptions. In no case will an MAOP increase as a result of this calculation.

So I don't think this is a situation where PG&E is going to be making assumptions in the field with no record of it, no way to verify it, no way to audit it. I think this is going to be a collaborative process, and they are certainly -- we don't expect them to be making secret calculations.

The other thing to keep in mind, your Honor, is it may not be possible to do an MAOP validation. It just might not be possible. They may have to do some assumptions -- they have to use some actual source documents, but if they don't have enough they just can't do it, in which case they would probably have to excavate or maybe remove the pipe. I am not an engineer, but that is my understanding.

The third issue you raised is NTSB recommendation number three which asks PG&E to spike test or hydrostatic test where they can't do the MAOP. That is not contained in the Commission order, that third recommendation. That was in the NTSB order but not in the Commission order.

PUC has not ordered this. My understanding is it is controversial and some of this hydrostatic testing might not be practical and might be dangerous, might not be the best way to prove pipeline safety.

In some instances they will need to replace pipelines or there may be other alternatives available. I am sure there are engineers here today that can talk about that in more detail.

Thank you. And I am available for questions.

ALJ BUSHEY: Thank you, Mr. Heiden.

Next, Mr. Hawiger.

ARGUMENT OF MR. HAWIGER

MR. HAWIGER: Thank you very much, Judge Bushey and the Honorable Commissioners. I am Marcel Hawiger, staff attorney with The Utility Reform Network.

TURN recommends that the Commission adopt the stipulation but if, and only if, PG&E and CPSD agree to two modifications: First, in the scope of work, to add a deadline, whether December 31st, 2011, or some other date negotiated, for doing the testing or replacement of the 152 miles of pipeline identified by PG&E; second, the penalty in the future, as Mr. Malkin mentioned, hanging over PG&E's head if they fail to meet the deadlines in the Compliance Plan should be increased more in the range of $30 million, not just another $3 million.

We believe that those two modifications will advance the goal, as Commissioner Sandoval mentioned, of promoting public safety and make the stipulation a stronger document.

If the stipulation is not modified, regretfully, I must recommend that you reject the stipulation and continue with the Investigation into PG&E's violation of the Commission order.

Now, in evaluating the stipulation,

there is a certain dilemma here. How can we evaluate the reasonableness of a stipulation filed on the very same day as the Order to Show Cause was filed without having some sense of the merits of the allegations in the Order to Show Cause, especially where here PG&E itself claims that the $6 million penalty is reasonable because it would be the maximum amount even if PG&E was found to be in contempt of the Commission order. And PG&E bases this claim on the rather extreme notion that they were in compliance with Commission orders by March 21st.

Now, PG&E encourages you to move forward without litigating the Order to Show Cause, and I am extremely sympathetic to that suggestion. TURN would also prefer that PG&E focus on finding its records, validating the MAOP and ensuring the safety of its pipelines. TURN would rather expend our resources on the other matters raised in this Rulemaking to improve pipeline inspections and management going forward.

But as I reviewed the various documents in responding to the motion, I was struck by the fact that on the prima facie basis it is clear that PG&E violated the directives of Resolution L-410.

Now, PG&E mentioned that there were subsequent letters and communications with the Commission, and we go into some detail in our response that I don't want to repeat, but essentially, especially when I looked at the letter PG&E wrote, there was no indication that PG&E was not going to be able to do, provide the documents and the MAOP validation by March 15th.

In its first letter of January 7th, PG&E promises that, quote, we will deliver the results of our pressure testing verification work to you on March 15, 2011.

In its letter of February 1st, PG&E stated that, quote, it is aggressively and diligently working to meet the expectations of the Commission to perform our records review and verification work by March 15, 2011.

Now PG&E already asked for an extension. It could have asked for another extension. And perhaps then we wouldn't be sitting here today. But PG&E failed to do so. And I think the Order to Show Cause and the letter from Executive Director Clanon very well explained the problem with PG&E's -- we are back to where we started, PG&E seems to say that having the records of the highest pressure kind of somehow takes place of pressure testing.

But I suggest that on the prima facie basis PG&E is still in violation of the Commission order.

And with this background in mind, I ask you to weigh the reasonableness of the stipulation.

Now, in terms of the Compliance Plan, the schedule, this is basically the schedule by which PG&E will now comply with the Commission directive to produce records and verify the MAOPs. And essentially I cannot second guess the timeline, and I realize this is a large undertaking, and so we do not object to providing PG&E up until August 31st to do the validation. But PG&E had already prior to the stipulation in its own filing committed to doing the testing and repair of the 152 miles of pipeline most similar to the San Bruno pipeline. So I was actually very surprised not to see that in this stipulation.

And I would suggest that to promote safety we should go ahead, PG&E should include that commitment in the stipulation subject to the same penalty provisions as are the other deadlines.

Now, whether it has to be December 31, 2011, or whether PG&E and CPSD can negotiate another deadline if PG&E feels that's not totally realistic, we take no position on that. And we really want PG&E to do what's right in the timeline they need, but they need to have something hanging over their heads to make sure they do this work.

And that leads me to my second modification, and that is that the $3 million penalty for future compliance is just not enough. PG&E has agreed to pay $3 million for its failure to meet the March 15th deadline. I see no reason why having another deadline six months out should only be subject to the same additional 3 million penalty.

The Commission has identified various factors that it uses to weigh an appropriate penalty. And that is contained in our response and I think in the response of the City and County of San Francisco. I will not go into those in detail. But let me just mention two things. One, this is certainly an issue of very serious public safety. And so in terms of the physical health and safety, we are dealing with one of the most critical areas, ensuring that the proper testing, validation of the pressures in the pipelines.

And in terms of the harm to the regulatory process, PG&E by my account had a direct order from the Commission, had asked for an extension, twice in written letters stated -- promised to deliver those validations by March 15th and then completely turned around in its March 15th filing and said we are going to do this by the end of 2011. On its face it just appears preposterous.

But I don't want to quibble about how much we are going to fine them for the past violation, but at a minimum going forward the Commission needs to indicate that this is a very serious matter that will be subject to much stiffer penalties.

I fully agree that, as Commissioner Florio stated, this is just a first step. Evaluating and fixing the pipeline system must be done expeditiously but also in a systematic and thoughtful manner. This document search and validation is really just the first step in this process. But how the Commission responds and shows its resolve in deciding on this first step and PG&E's recalcitrance in this first step will help us navigate this serious work ahead of us.

So I fully urge you to request that the parties change the stipulation in two relatively -- they are not minor -- but they are in ways that do not add new commitments but that will really ensure that PG&E does the right thing.

Thank you very much.

ALJ BUSHEY: Thank you, Mr. Hawiger.

Our next speaker the Ms. Mueller.

ARGUMENT OF MS. MUELLER

MS. MUELLER: Thank you, your Honor.

Good morning, Commissioners. I am Theresa Mueller from the San Francisco City Attorney's Office. Thank you for the opportunity to present comments to you.

The City submitted comments on Friday, and I won't repeat all of those in detail, although I know that they do address a lot of the issues that you have mentioned here.

One of the things that we learned at the March 28th hearing on this issue was that no actual safety improvements in the pipeline system have been made since the San Bruno explosion. And PG&E talked about its plan to do the hydro testing and replacement program and also identified the potential disagreement with that proposal that the Commission staff, possibly PHMSA or other entities may have.

The City's concern about that is whatever the appropriate next step is, whether it is hydro testing, some other testing, pipeline replacement, that's for the Commission and PG&E to figure out, but it's got to be the highest priority, to move forward with actually making safety improvements.

So whether you include it in this stipulation or in a separate order, we would urge you to turn to that issue immediately.

Everyone acknowledges that it is important to have records, but having records is not a replacement for actually doing things.

And I think both PG&E and the staff witnesses acknowledge that we shouldn't be waiting to do actual improvements until we have all the records and particularly when it is going to take a very long time to get the records together.

I would like to address another issue, which is the penalty analysis. You heard a little bit about that from other parties. And several Commissioners asked questions about that.

The Commission has a great deal of discretion about how to set penalties. And as you have already heard, there are a lot of ways to compute those units. You can add them up however you want. And part of how you decide to do that is through the qualitative analysis of what you think happened. This is particularly what Commissioner Sandoval mentioned.

In this case we believe you have to think about the allegations that the staff made, the allegations in your OSC, in the Executive Director's letter, which are very serious. And for those of us who have been following the MAOP issue and the NTSB order, to see what PG&E filed on the 15th, it doesn't seem to leave a lot of doubt that that filing was not in compliance and on a pretty important issue. So we would urge you to think about that.

I think this is a very important issue to the public, and they're watching what the Commission does.

Related to that is the scope of the stipulation. There's been a lot of talk about that this morning. And the City agrees completely that the scope of this stipulation is very narrow. I think what we wrote on Friday is almost identical to what the General Counsel sent to you as read by President Peevey. But just because this issue is narrow does not mean it's not important. What the Commission does here is very important. In the context of the San Bruno explosion and its consequences, PG&E compliance with every Commission order is related to public safety and it should be treated like that.

Both PG&E and CPSD indicated in the hearing that they don't assume the pipeline system is unsafe. And we all hope that that's correct, but the Commission cannot go forward assuming that the system is safe. Operating a gas pipeline system is inherently risky. It requires the highest degree of care, and that extends to recordkeeping, operations, maintenance, testing and compliance with Commission orders.

And although nothing has been finally adjudicated, there is a great deal of public information that raises at least serious questions about how PG&E has carried out some of those duties.

And as a legal matter, the old

doctrine of res ipsa loquitur suggests that if a pipeline explodes, something is wrong; they just don't do that on their own.

And I think certainly the public feels that way. Something is wrong here for this to have happened.

So both for safety and for public confidence the Commission needs to be very aggressive in monitoring PG&E's practice and ensuring its compliance with Commission orders.

This is a new Commission in part. It has three new members appointed by a new Governor. And I think that even for those of you who are veteran Commissioners, there is a renewed emphasis on safety and monitoring and enforcement. And that's appropriate given the situation you're in now.

A resolution of the OSC is one of the first public steps that you are going to take in that process, and it requires a full investigation of what happened.

The Commission doesn't have to choose here between fully investigating the OSC and moving forward with compliance. PG&E already stated at the hearing that they were moving ahead, they were implementing their Compliance Plan and getting their records and getting ready to make improvements.]

So the Commission does not have to risk getting caught up in a battle about, you know, who said what or who did what at the expense of public safety and accurate records. PG&E is already doing the records search.

And not that any one, including the City, would look forward to such a proceeding. I would hope not to participate in one myself, but the Commission can require a stipulation that appropriately enforces your orders and your authority.

Thank you.

ALJ BUSHEY: Thank you, Ms. Mueller.

On to speaker, Ms. Chen.

ARGUMENT OF MS. CHEN

MS. CHEN: Thank you. Good morning, your Honor, President Peevey, Commissioners, and thank you for your time this morning.

My name is Stephanie Chen, and I'm Senior Legal Counsel for the Greenlining Institute. And my remarks here this morning will be brief because there's simply not that much left to say.

The one remaining question, at least for the time being right now, is whether or not to approve the Stipulation and Compliance

Plan offered by PG&E and CPSD staff. This question comes down, as many parties have mentioned, to safety and compliance, and nothing is more important than that.

So while we're going to find ourselves here talking about whether this was produced by this date and whether that was equivalent to this, what we're really talking about is whether or not we're all on the same page when it comes to safety and compliance.

Now, as Mr. Malkin noted, this shouldn't be about what happened in the past, and that's true. It shouldn't. What it should be about is what all of this means, what everything that has happened thus far means for the future. And I would urge you when you're considering this question to consider the actions that have been taken and not the words that have been spoken.

Simply put, the order was to produce certain traceable, verifiable records by March 15th along with calculations based on those records that would accurately demonstrate Maximum Allowable Operating Pressure. It was actually supposed to be produced by February 1st, but PG&E requested an extension because the scope of this project proved to be so immense.

As the City and County of San Francisco pointed out in its written comments, when PG&E realized, as it must have, prior to March 15th that it would be unable to comply by that due date, rather than request another extension or even explain at that point where it was in the process and why it wouldn't be able to meet deadline, PG&E instead filed a noncompliant report that relied heavily on historical MAOP.

Now, at the time of that filing, Mr. Clanon, and that would be Paul and not Brad, noted that this data was an insufficient substitute for sound calculations based on verified records.

Next, PG&E, no doubt aware that this Commission was prepared to heavily sanction it for failure to comply, filed a supplement to its report on March 21st, which still didn't bring it into compliance. The supplement describes PG&E's search and how it plans to go ahead with validating MAOPs, but this still is not the documentation and calculation that was required by Resolution L-411.

Next, on March 24th PG&E introduced the Stipulation which is at the heart of today's hearing. This Stipulation still doesn't bring PG&E into compliance with Resolution L-410 or with the NTSB's urgent safety recommendations. It relies extensively on certain assumptions that PG&E would be allowed to make without any oversight of any kind about what components it has in the ground and what kind of pressure these components can safely handle.

Now, PG&E says, we wouldn't make any inappropriate assumptions, and CPSD says they won't make any inappropriate assumptions. But Commissioners, would you rather believe these words that are spoken here today, or would you rather see them on paper?

It's worth remembering that these recommendations came up in the first place because PG&E was mistaken about the components of the San Bruno pipeline and what kind of pressure they could handle.

This isn't simply a question of whether or not PG&E has turned in its homework on time. PG&E has been asked to demonstrate, according to sound engineering practices, the safety of its gas transmission system. This is something it should be able to do on demand. Safety demands that these records in question be at the ready and that they be accurate and complete. But instead of producing these records, PG&E is asking for more time, the better portion of a year, to do the job incompletely.

Commissioners, this series of actions does not inspire customer confidence in a company that is engaged in an inherently dangerous business. As seriously as PG&E is approaching this problem, and no one here, I think, mistakes the massive nature of this undertaking, the facts demonstrate that minimum expectations are being missed, not just form PG&E's customers, but even the expectations that have been clearly set forth by this Commission.

The question is, what is the appropriate course of action for this Commission to take to properly motivate PG&E to meet these minimum expectations? What can we reasonably expect a $3 million fine or even a $6 million fine to accomplish? Will it inspire confidence among PG&E's customers that this Commission is seeking the culture change that was stated by Mr. Clanon? Will the nearly year-long search from the time of this incident to the time of the completion date listed in the Compliance Plan inspire the kind of confidence and promote the kind of cultural change that I think everyone in this room is looking for?

Greenlining urges PG&E, for the sake of its customers as well as for the company, to focus on finding solutions rather than miring itself in another public battle. PG&E's hints that it might engage in a protracted legal battle over this issue are counterproductive to what we are all trying to accomplish. Following through on these hints risks losing what little patience the general public has left in PG&E's leadership. There would be nothing to gain by PG&E or its customers if the company chose that path.

I will close by saying this. Commissioners, California depends on you. PG&E's customers depend on you. Even before all these investigations are complete, plenty of troubling information has already surfaced about the nature of PG&E's pipelines, recordkeeping, and management practices.

Even at this early stage in the game, it's clear that it's time for a culture change. Mr. Clanon himself recommended this need. This Commission is in the position to spur that change, and indeed it must.

Greenlining urges that this portion of the proceeding remain open, and that means rejecting the Stipulation at hand, until we can implement a solution that will include appropriate monetary penalties and a truly aggressive and complete Compliance Plan that will create the kind of culture change we all need to see.

Thank you for your time.

ALJ BUSHEY: Thank you, Ms. Chen.

Questions from the Commissioners?

Commissioner Sandoval.

COMMISSIONER SANDOVAL: Go ahead.

COMMISSIONER SIMON: Is there another party?

ALJ BUSHEY: Oh, Mr. Boyd, you weren't here when we signed up. Okay.

ARGUMENT OF MR. BOYD

MR. BOYD: I guess I'm the newest party, so, new to the party.

My name is Mike Boyd, and I'm the President of Californians for Renewable Energy, Inc., CARE. And I was at your meeting last week and spoke to you, and I have some follow-up information to provide you.

First, on the Stipulation. CARE believes that a stipulation is unlawful, and here's why. First, in order for you to enter into an agreement for compliance you have to have either evidence of compliance or a schedule of compliance. By a schedule of compliance I mean an approved schedule of compliance. You approve the schedule, not CPSD, to my knowledge. So without either, I don't see how you're in a legal position to approve the stipulated agreement because PG&E certainly hasn't provided you that and nor has CPSD.

So without that, I don't see how you can do it. And as I said before at the meeting last week, you're not my only relief. I can go to the FERC, and the FERC does have a million dollar a day fine. And I believe this is a federal compliance issue as well as a state compliance issue. And therefore, I would ask that you support what CARE is saying and go for the federal standard, a million dollars a day, until they establish compliance through evidence or a schedule that you've approved for compliance. Okay.

Because we believe Pacific Gas and Electric Company, PG&E, cannot or will not produce the required records to complete the validation of pipeline Maximum Allowable Operating Pressures as well as to complete the pipeline testing and repairs promised by PG&E, Californians for Renewable Energy and

CARE hereby submits two Google Earth pictures of the site of the San Bruno natural gas pipeline explosion that killed eight of PG&E's natural gas service customers to define the exclusion zone necessary to, quote, "avoid potential high risk for fatalities in future pipeline explosions."

The line pictured in yellow measures a distance of approximately 600 feet. I provided a picture from October 1st, 2009, for the fire to show you the homes that were present there. The next figure shows you after the fire, two days after the fire, that there were some homes there that were destroyed 600 feet from the fire, from the explosion source. And if you look to the south on the road in the picture, you'll see the section of pipeline that exploded is still present there on the 11th sitting there.

Without these necessary records to determine safe operating pressures for PG&E's continued operations of natural gas pipelines in its service territory, the Commission is not in a position to say that any of those pipelines PG&E is operating are safe to the general public and PG&E's customers. But PG&E is not alone in its liability because the local government, the city or county issued building permits for all the homes that burned in San Bruno, likely after the pipeline was built. Where were our elected local leaders then?

I have attached a copy of Robert Sarvey's rebuttal testimony, Exhibit 405, on hazardous materials before the California Energy Commission on the Mariposa Natural Gas Turbine Project in CEC Docket 09-AFC-03 on two other high risk natural gas pipelines at PG&E where Mr. Sarvey states:

> The combination of these two projects and their impact [to degrade] -- to the degraded PG&E Line 002 are not addressed or analyzed in staff's testimony. A significant increase in natural gas volume will occur because of the addition of the MEP and the conversion of the Tracy Peaker Project to combined cycle. Pipeline pressure fluctuation from the cycling of these projects will cause

additional stress to Line 002. Given the significant risk of a natural gas line failure as evinced by the recent San Bruno Tragedy, this impact needs to be addressed. We certainly cannot rely on PG&E's incomplete and inaccurate records and inadequate safety practices.

Mr. Sarvey has provided on page 5 of his testimony a picture of a temporary fence PG&E erected at the site of a proposed sports park in Tracy where apparently PG&E allowed heavy equipment to operate unattended as an offer of proof to PG&E's safety practices or lack thereof.

Therefore, first we need to know what is the safe zone where residential dwellings, parks and recreation facilities and businesses can be built? The City and County then must change its general plans and zoning designations to exclude any development where there is a high risk pipeline where high risk may be based on the lack of recordkeeping by PG&E. PG&E must buy out all those affected landowners along the exclusion zone along the line under eminent domain exercised by authorization of this Commission, if necessary, at fair market value.

In absence of knowing the root cause of the failure that caused PG&E's pipeline to explode, the Commission has no choice but to exclude future development and remove existing developments from the safety exclusion zone. Otherwise, the question will not be if this will ever happen again, but when is the next pipeline explosion going to occur?

Thank you.

ALJ BUSHEY: Thank you, Mr. Boyd.

Other parties that wish to present oral argument?

(No response)

ALJ BUSHEY: If not, we'll begin the questions from the Commissioners.

Commissioner Florio.

COMMISSIONER FLORIO: I was able to ask my questions at the earlier hearing. So I would defer to my colleagues at this point.

ALJ BUSHEY: Thank you.

Any Commissioner with questions? Commissioner Simon.

COMMISSIONER SIMON: Thank you, ALJ

Bushey.

First, Mr. Heiden, as CPSD is aware, there is a PG&E Gas Accord, that's A.09-09-013, that also involves safety issues. Separate from the rulemaking in the OII, is the Gas Accord part of the -- or is it cross-referenced or recognized in your Stipulation?

MR. HEIDEN: Not that I'm aware of, Commissioner.

COMMISSIONER SIMON: Do you feel it would be appropriate to do so?

MR. HEIDEN: I really don't know anything about the Accord. Sorry. But I can respond in writing.

COMMISSIONER SIMON: Okay. Thank you. I have another question for you. Regarding the order of the Commission and specifically the letter of Mr. Clanon, the Stipulation seems to at least mitigate the effect of that.

Did you -- does CPSD consider that order to be frivolous?

MR. HEIDEN: Are you referring to -- which letter of Paul Clanon?

COMMISSIONER SIMON: The Resolution L-410, the order for PG&E to produce records by, which was originally February 2nd, as

Commissioner Sandoval stated, and then March 15th.

Was that a frivolous order on the part of the Commission? Because it appears that, you know, we were operating under that order, and now I'm hearing all the reasons why we should not go forward under that order. So is CPSD -- how do you assess that order since you're coming with a recommendation for now a stipulation from that order?

MR. HEIDEN: Well, it's a serious order, and we think a stipulation accomplishes the order. It just sets out a timeline with specific goals and benchmarks, and it clearly does extend the date to the end of August.

COMMISSIONER SIMON: Now, Mr. Malkin stated that there had been regular meetings with enforcement staff. Did those meetings occur after the Clanon letter and prior to the date of submission?

MR. HEIDEN: Yes.

COMMISSIONER SIMON: So during this time was CPSD --

MR. HEIDEN: Excuse me. Sorry. I want to make sure I answer your question correctly. You mean the meetings were after the Commission order?

COMMISSIONER SIMON: Correct.

MR. HEIDEN: After his letter?

COMMISSIONER SIMON: Excuse me. After his letter.

MR. HEIDEN: The?

COMMISSIONER SIMON: The letter requesting the MAOP documents be submitted by the specified date, which was February 2nd and then moved to March 15th. During that period of time was CPSD meeting with PG&E?

MR. HEIDEN: Yes.

COMMISSIONER SIMON: Was enforcement staff meeting with PG&E?

MR. HEIDEN: Yes.

COMMISSIONER SIMON: Was CPSD staff aware of the fact that PG&E could not comply with that order during this period?

MR. HEIDEN: I wasn't at those meetings. So I can't speak for CPSD. But my understanding is that they were not aware.

COMMISSIONER SIMON: So they were not aware of the fact that PG&E could not meet the order until the March 15th submission by PG&E?

MR. HEIDEN: That's my understanding, Commissioner.

COMMISSIONER SIMON: And does CPSD view

the March 15th submission as being in compliance with the order?

MR. HEIDEN: No.

COMMISSIONER SIMON: Do you know what CPSD or enforcement staffers were involved in these weekly meetings with PG&E during this period?

MR. HEIDEN: Prior to March 15th?

COMMISSIONER SIMON: Prior to March 15th.

MR. HEIDEN: No, I do not.

COMMISSIONER SIMON: Because I'm puzzled to how PG&E cannot be in compliance while in dialogue with CPSD and we're not aware of the fact that they're not in compliance until the March 15th deadline and then we have a stipulation from CPSD. It just -- the lines seem very blurred here, and I'm just trying to understand the chronol -- the timetable, okay, the chronology on what has in fact transpired.

And I say this because, as you know, under current Bagley-Keene interpretations we as commissioners are very limited in the dialog that we can have on open dockets of this nature. So I'm just simply trying to understand how for all this time that PG&E clearly could not comply that there was not a notification by CPSD that they could not comply.

MR. HEIDEN: I understand, Commissioner. If this helps, I think following the March 15th filing the Commission issued or drafted an Order to Show Cause. There was a draft Order to Show Cause on the web site. There was also a letter from Paul Clanon to PG&E saying, you're not in compliance with our order. I'm going to recommend or staff recommends -- may recommend an Order to Show Cause. PG&E, according to their March 21st filing, I believe, acknowledged that they saw the draft order on our web site and they got the letter from Mr. Clanon and they understood that staff didn't think they were in compliance and that the Commission was prepared to vote on this issue.

I think PG&E at that point, and I think you'd have to ask PG&E for some clarification, I think at that point staff and PG&E engaged in negotiations to try to get us on the same page.

So I think it was basically them understanding the seriousness following their March 15th submission, which was not what staff expected, if that's what you're asking.

It was not what staff expected.

COMMISSIONER SIMON: So Mr. Malkin, in these weekly meetings that occurred, was there any dialogue with staff that would notify staff that we're frankly not in a position to meet the March 15th deadline, or had PG&E operated on this failure to communicate presumption or basis?

MR. MALKIN: Commissioner Simon, in our view there were repeated communications with the CPSD that were clear that what PG&E could physically accomplish by March 15th and what it was working to accomplish by March 15th was the record collection and an analysis to determine which of the 1805 miles of HCA pipeline that are subject to the order had previous pressure tests. That would be the first step in the analysis.

The next step after that was done would be to look more closely at the miles of pipe for which there were not pressure test records to do the MAOP validation on those miles of pipe. And that was described in our March 15th report and described in meetings to the staff as Phase 1, collecting the records and doing the determination of the pressure tests, and Phase 2, the longer term more complicated MAOP validation.

COMMISSIONER SIMON: So in your March 15th response the methodology that you adopted, this Phase 1, Phase 2, was a result

of dialogue with CPSD through these weekly meetings?

MR. MALKIN: First of all, let me say, the meetings were not weekly. They were I would say frequent but not weekly.

COMMISSIONER SIMON: Okay. Frequent or periodic.

MR. MALKIN: And yes, what is in the report in our view is completely consistent with both what we told the Commission in our letters that we would accomplish by March 15th and what in terms of the phasing of Phase 1 and Phase 2 was made even more explicit in discussions with the staff.

COMMISSIONER SIMON: Thank you.

ALJ BUSHEY: Commissioner Sandoval. I'm sorry. Commissioner Peevey.

COMMISSIONER PEEVEY: Mr. Hawiger, I want to ask you a question. I appreciate your comments. As I understand it, you support the stipulation with two provisos or changes to it, and I want to ask you about the second one.

You suggested that you don't have a quarrel with the $3 million but you do think -- the original 3 -- but you think that the second 3 should be boosted to 30. Did I understand you right?

MR. HAWIGER: Yes, President Peevey. That's correct.

COMMISSIONER PEEVEY: Is that because 30 is not chump change?

MR. HAWIGER: You have it exactly right.

COMMISSIONER PEEVEY: Can you work out a scale? And what has become chump change?

(Laughter)

MR. HAWIGER: You know, there's several --

COMMISSIONER PEEVEY: We need a little levity, but this is a very serious matter here.

MR. HAWIGER: Certainly. Look, 3 mil -- PG&E's average profits are about 1.1 billion a year and have been increasing steadily from '06 through 2010. We have a chart in our comments.

COMMISSIONER PEEVEY: I saw that.

MR. HAWIGER: 3 million is .3 percent. And as you -- as I think Commissioner Simon indicated, it's less than one severance package that was recently adopted. You know, it's a judgment call certainly. I think 11 million represents 1 percent of net profits. So that starts, I think, to get to a figure that is slightly meaningful.

COMMISSIONER PEEVEY: Beyond chump change?

MR. HAWIGER: Yes. Beyond chump change.

COMMISSIONER PEEVEY: I mean it's a term that your organization has used.

MR. HAWIGER: Absolutely. It was not my quote, but it's I think appropriate.

COMMISSIONER PEEVEY: I assume you stand by it. I stand by everything Simon said.

(Laughter)

MR. HAWIGER: Absolutely, absolutely.

At the rate of a million dollars a day by August 31st you get 250 million.

COMMISSIONER PEEVEY: Thank you very much. But I do think that you made a positive contribution to this. Thanks.

ALJ BUSHEY: Commissioner Sandoval.

COMMISSIONER SANDOVAL: Thank you very much.

I have a couple of technical questions. I see that Mr. Johnson is in the room. So some of these technical matters, I know Mr. Malkin is extremely knowledgeable, but a couple of them are engineering related. So it might be appropriate to ask Mr. Johnson to come forward.

I know as a lawyer I studied these things but would never hold myself out as an engineering expert.

Thank you very much.

KIRK JOHNSON

resumed the stand and testified further as follows:

EXAMINATION

BY COMMISSIONER SANDOVAL:

Q So my first question, and this gets in part to the issue of how do we define the appropriate unit for calculating a violation or a penalty but also to get a sense of the scope of potential safety concerns here. So I think this is appropriate for Mr. Johnson.

How many pipeline segments are in a mile?

A A pipeline segment is not defined as a length. A pipeline segment is any time the pipeline characteristics change, it becomes a new segment. So a segment could be a foot long, a segment could be five miles long. But if the diameter were to change, the wall thickness were to change, the class location of the pipeline were to change, that becomes a different segment for purposes of integrity management. And that's the term we've used throughout the discussions we've had with folks.

Q Okay. So that explains in part what the NTSB found was at the section of -- let's call it the section of pipeline that was the subject of the explosion in San Bruno was in part composed of four different segments of pipe, which they said also had different longitudinal welds.

So you're saying that that's not unexpected, that sometimes within, you know, I'm calling it a segment that blew, but that that, it turns out, was actually composed of four smaller segments; is that correct?

A Well, I think we're using different terms here. When I spoke of segments, I was talking about the engineering definition as used in the integrity management program to define what a segment of pipe is. And we talk in terms of integrity management for each segment.

I think what you're referencing is that one, a joint, one section of pipe that was made up of the segment that failed in San Bruno, that segment was about 1800 feet long, if I recall correctly, one 30-foot section of that was made up of what we oftentimes refer to as joiners, which are small sections of pipe that are manufactured that way.

And so what the NTSB was referencing in their metallurgy report was the different aspects of each joiner or each piece of -- small piece of pipe in that overall segment of the pipe, or a stick of pipe as we oftentimes refer to it.

Q So is there any way then to calculate how many segments one would likely find in a mile without having the documentation that tells you that?

A Well, for integrity management for areas that are defined as High Consequence Areas and for that matter for PG&E anyway, every time a piece of pipe changes or something in the system changes its characteristic, it becomes a new segment. So we can calculate or calculate how many segments are in our system with some clarity. And again, that changes on a daily, daily basis. As we make changes to our system, of course the segments change.

Q And I believe there was a previous PG&E submission where PG&E stated that in the 152 miles of high consequence pipeline that there were 699 segments. Do you recall that?

A I do recall that there was some notification of how many segments we're referring to. I don't have --

My counselor is showing me the document. So 699 pipeline segments as of the date of that writing.

Q Great. Engineering knowledge, by the way, is always helpful.

Okay. So for the 152 miles of identified -- so these are the 152 miles that are identified in what I would call Category 1 of your proposed work plan where it talks about the 152 miles that are targeted for document completion by June 10th.]

That has 699 segments; is that correct?

A That is correct. The document we are talking about, Attachment A of the Compliance Plan, talks about 152 miles, and 152 miles would calculate out to 699 pipeline segments at the time of that writing.

COMMISSIONER SANDOVAL: Q Thank you.

Then my next question -- so I am going to refer to these for the sake of convenience as the June 10th section, I will call it Category 1, the July 10th target I will refer to as Category 2, the August 10th target I will refer to as Category 3, and then I am going to ask you about some additional categories that were listed in your March 21st letter from PG&E. So we have got our nomenclature clear.

So with regard to Categories 1 and 2, Category 1 refers to 152 miles of DSAW pipe, 24 to 36-inch outside diameter and installed prior to 1962.

Can you please tell us nonengineers what is DSAW.

A That is a type of welded pipe known as double submerged arc welded pipe. When a pipeline is manufactured, it is manufactured generally speaking out of plate, plate steel. That plate steel is rolled together to create a pipeline segment. And then it is welded at the seam. And the seam -- a pipe segment usually runs about 30-plus feet long. That 30-foot long seam is known has a longitudinal seam, oftentimes referred to as the long seam. And DSAW, or double submerged arc weld, is one technique to weld that long seam.

Q For the pipeline segment that exploded at San Bruno, did NTSB find that it was in fact double submerged arc welded?

A I don't believe that the NTSB has specifically stated what type of weld they have seen at this point in time. They have only stated that a missing inside weld existed on one of those small segments of the joint.

Q If there were -- let me just back up. A double submerged arc weld would indicate in nontechnical terms it was welded both from the top and from the inside, correct?

A Correct. The technique for double submerged is it is welded from the top or from one point and then the other point. So in this particular case the top first and then the inside. It can also be done the inside and then the top by other manufacturers. And the other term that is oftentimes used is single submerged arc weld which would indicate one weld, period.

Q So the NTSB indicated that at least a portion of the pipeline which exploded appeared to be single submerged arc welded and not double submerged arc welded; is that your understanding of their findings today?

A My understanding of their findings today is that the pipeline, the small piece of pipe that ruptured on the longitudinal seam, was missing its inside weld.

Q Which would indicate it's not

double submerged arc welded?

A It might indicate it was double submerged arc welded but it wasn't manufactured correctly. The inside weld didn't happen properly.

Q So it could be double submerged arc welded but welded improperly, or single submerged arc welded?

A That was also not welded properly, that's correct.

Q So then Category 1 also proposes to identify documents for seamless pipe greater than 24 inches outside diameter and installed prior to 1974.

In what year was seamless pipe available for gas pipelines?

A I would have to go back to the records of vintage pipe and determine exactly when it was available.

For gas transmission pipelines there are smaller techniques such as 8-inch still available, but for larger pipelines we would have to go back into the records and determine exactly when it was manufactured in either the U.S. or in other countries.

Q My understanding is that seamless pipe of 24 inches diameter and greater was not available before 1962. Is that your understanding as well?

A I don't know if that is correct or not.

When we say not available, I am not sure if we are talking about manufactured in the U.S. or manufactured somewhere else.

But again, we would have to go back to the records of what is known as vintage pipe for the industry and verify that.

Q Is that something that you could find out? Because I have done some research and found that in the industry it is known that before 1962 that basically seamless pipe was not available, which would indicate that you would never have seamless pipe before 1962. Is that something that you could verify what is the status of that?

A Certainly we will look at what we have available and respond back.

Q Thank you. That would be very helpful.

So with regard to Category No. 2, the document whose completion is scheduled for July 20th, that is 295 miles of ERW pipe, so let's start with that first. Can you tell us what is ERW?

A ERW is also a type of welding on the longitudinal seam, electric resistance weld it is oftentimes referred to. It also goes by other nomenclature from back in its day.

Q An article in the San Francisco Chronicle this weekend discussed these ERW welds and said that these ERW welds had been tied to at least 100 failures nationwide.

Are ERW welds seen as more or less reliable than double arc welds?

A I think from an industry point of view and as referenced on our Attachment A, we talk about those welds having a joint efficiency of less than one. And in general a joint efficiency means that the weld is not as strong as the pipe itself. It is welded together. So there is, if you will, a safety factor put into the calculation of the pressure that the pipeline can operate under.

Q So those, then, that would fall within Category No. 1 should have a joint efficiency of greater than one, is that what I'm understanding from your testimony?

A A DSAW weld under the code and under PG&E's guidelines has a coefficient of one. I am not aware of any welds that could have a coefficient greater than one.

Q Okay. And having a coefficient of one indicates what?

A It indicates that the weld would be, for all practical purposes, it indicates the weld would be as strong as the pipe itself.

Q Okay. So the weld is as strong --

A -- as the pipe material itself.

Q So then everything which falls in Category No. 2 has a joint efficiency of less than one which would indicate it would be less strong, the weld may be less strong than the pipe; is that correct?

A I want to clarify that. It is how PG&E has chosen to design its coefficient, the joint coefficiency of less than one. The code itself, Part 192 and GO 112 (E), allows certain categories of weld to have a joint efficiency of one. PG&E discounts the ones that we are stating here that you have stated as Priority 2. So it is PG&E's desire to add additional safety factors in place.

Q Okay. Then SSAW would be the single submerged arc welded; is that correct?

A That's correct.

Q And that would be -- with the SSAW, are they welded from the top, or from inside? Is that always consistent?

A Without saying how things were done back in the '30s, '40s and '50s, I believe most of them were welded from the outside.

Q From the outside. All right.

And so that is one of the questions, was the pipe that exploded at San Bruno in fact single submerged arc welded, or was it double submerged arc welded but improperly done, so it wasn't welded on both sides?

A In terms of San Bruno, what we have put forth to the NTSB and the NTSB has shared in public documents is that we believe that pipeline was purchased from Consolidated Western. Consolidated Western manufactured double submerged arc weld at the time we purchased it. That pipe was purchased between roughly, I believe it was, 1946, '47, up to about 1956. And certainly that was the process that Consolidated Western was using for 30-inch pipeline at that time. So what we believe, it is double submerged arc welded pipe.

Q So can you tell us what is the next category, flash and lap welded, what are those?

A Those are just different types of welding techniques used over the years for different types of pipes.

As pipelines were manufactured

through the years, whether it be the '30s, '40s, '50s or '60s, different welding techniques were used and these are just different welding techniques available and still in service.

Q And ERW, as you stated, are flash and lap welded, they are all according to your calculations welds that produced joint efficiencies of less than one; is that correct?

A We assume a joint efficiency of less than one for those types of welds, that's correct.

Q Do you have the documents that are necessary to determine which pipes fit into which categories?

It seems that as you read Category No. 1 and Category No. 2, you would have to have some documents either to classify which belong into which categories.

A Correct. I think for purposes of this document, we used our GIS database, our summary database, to articulate how many segments and how many miles we believe we have in our system.

Q And this may be a question for Mr. Malkin.

Do you believe that you have the

proper documentation to at least determine which pipelines belong into which categories?

A We are certainly verifying that as part of the process. As we do the MAOP validation and the pipeline features list, we will verify if indeed we see something on our documents that don't match what we previously had in our summary sheet, which is what we have talked about last time in our GIS database, we will be looking at that source document, those as-builts and seeing if they match. And that is part of the MAOP validation process.

Q It seems you would need information about welds to even determine which category the pipes fit into?

A Correct. And as I stated, we used GIS as a summary level to identify how many miles of pipe we believe we have in each category.

Q So this is really a question about priority. As a nonengineer, it strikes me that Category 2 is in many ways a category that poses a greater potential concern about safety than Category 1 because Category 2, as you said, includes those with the joint efficiency of less than one. So why is Category 1 with the DSAW pipe which is likely to have the joint efficiency of one prioritized as being completed first over Category 2?

A Well, I think in terms of what is in priority one, as you have listed it, that is the pipe that has similar characteristics of San Bruno, and we want to make sure that we don't have and we want to make sure we do everything possible to ensure that that situation doesn't exist anywhere else in the system. So we are prioritizing that as the first pipe that we would like to go after and ensure that what happened in San Bruno never happens again.

In terms of comparing the two, they are somewhat equivalent, I guess. In terms of priority two as you have listed it, that pipe that is ERW, that pipe already has an additional safety factor put in place because of that type of weld. So it's already going to operate at a lower pressure than it might have if it was a DSAW pipe.

So the pipeline pressure is already operating below that. And in fact PG&E goes above the code on these pipeline joints. So whereas the code might say, for example, single submerged arc weld is a joint efficiency of 1.0, we already discount it to a .8 discount and have the pressure operating in accordance. So we don't believe there's any additional risk there associated with the weld pipe.

Q So the next question, so for the next category, Category No. 3, so that really identifies two different types of pipe. So it says in what is listed as number three, priority focus, 206 miles, all remaining 619C documented pipe and pipe installed prior to 7/1/1970 with records still under review. What is 619C documented pipe?

A 619C references the Part 192 code, 49 CFR, Part 192. That document is also referred to oftentimes as a grandfather clause. That is a section that was put into the code, as I understand it. Obviously, the code didn't exist, the federal code didn't exist prior to the middle of 1970. And it was an acknowledgment that records for purposes of calculation didn't exist for many of these pipes prior to the code, that records weren't necessarily required in some areas as part of a code, and therefore those records wouldn't exist. And therefore to establish a safe operating pressure, that pressure was deemed to be whatever the highest pressure had been the previous five years prior to the code, so back to 1965, irregardless of what records you might have or irregardless of what the yield strength might be. So that pipeline might be operating a yield strength of 21, 22 percent, very, very low. That pipeline was still locked into the highest pressure you had seen the previous five years.

Q And then the category you identify as number four, 52 miles, all pipe installed after 7/1/1970, with records still under review. So can you inform us, please, about what does the transportation code require for the maintenance of pipeline records for pipes installed after 7/1/1970?

A I don't have the code in front of me. I think there's numerous references to the code after the federal code was put into place. But I don't have that code right in front of me.

MR. MALKIN: If I may add, Commissioner Sandoval, as part of the records OII, we were asked and agreed to provide by next Monday, April 18th, a report, if you will, summarizing the history of the regulations both on the state and federal level that will be covering that subject.

COMMISSIONER SANDOVAL: Q Okay. So it

would be useful to have your understanding of what does the code require with regards to records retention and production for the post July, 1970 pipes. And also when you say these records are still under review, is still under review in compliance with the Code of Federal Register requirements?

A I think the concept of under review references back to earlier documents, where we have strength test pressure reports for those pipelines, but we are still trying to match that strength test pressure report to the exact footage of the pipeline.

I think it is important to remember that even in 1970 we didn't have computers, we didn't have GPS, we didn't have documents across the board that would indicate exactly what segment of pipe was where. And so you need to go back through and match those records now up with the new NTSB recommendations and the Commission order. You need to literally match those up with foot by foot of pipe.

So we are still reviewing some of our strength test pressure reports to do that physical match.

Q All right. Then if we refer to PG&E's March 21st filing, on page 17, PG&E

submitted a table discussing priorities for MAOP validation work. So Categories 1 through 4 appear to be captured in what I would call Categories 1 through 3 in the proposed stipulation. Is that correct?

A Well, we are looking at page 17 of the --

Q -- March 21st --

A I'm sorry. I didn't follow your entire question. But we listed there seven priorities as we called them at that time.

Q Right. So it appears that what is listed on page 17, priority one through four, appeared to correlate with what I would call Categories 1 through 3 in the proposed stipulation? Is that your understanding?

A Yes. As you laid it out, priority three was what was due on August 31st, and that's priority three and four laid out per this table, per the table on page 17, that's correct.

Q All right. So my question on page 17 goes to Category No. 5. It is 83 miles of pipe, all remaining pipe with partial test records and pressure test records from the 1968 CPUC filing.

So let's start with the latter. Can you tell us a little bit more about the

1968 CPUC filing and what types of test records we could expect from that?

A We will have to pull that out of the document. I don't recall exactly what the '68 filing was.

Q If you could provide us some information on that, that would be very helpful.

A Okay.

Q And then you are saying the first category there is partial pressure test records. What does partial mean in this context, to have a partial pressure test record?

A It can mean -- what it probably means is that the job that it worked on doesn't match exactly the footage of pipe we see on our strength test pressure report. So again we have to go back and do all the matching and ensure that we have covered foot by foot of that pipeline.

So it has a record of strength test pressure report. We just haven't been able to match it up foot by foot per the job estimate.

Q All right. And then with regard to what is listed here on the March 21st letter as priority number six, it says pipe with verified pressure test documentation for the STPR footage test does not equate to the pipeline HCA footage. What is STPR?

A Strength test pressure report.

Q And how important is it that this strength test pressure report footage does not equate -- does not equal the pipeline HCA footage? What does that indicate to you?

A It indicates that potentially when the strength test pressure report was done, whether it be in the 1970s or 1980s, their ability to delineate feet aren't as accurate as it is today. So whereas we have GIS and GPS and all these sort of things that help us understand exactly what's in each location, we now need to go back and try to verify that with the strength test pressure report that may say something to the effect that from 2nd Street to 3rd Street, and those streets may no longer exist. It is just a matter of matching everything up and making sure it matches up and we have got strength test pressure reports for every foot of those pipes and identify those that don't have strength test pressure reports.

Q I am trying to understand how important is it that there is this mismatch with regard to measurement?

A Well, I think it is important to note that after 1970 after the federal code went into place, that strength test pressure report, strength testing was completed on that pipeline. So in terms of how important it is, it is something we need to do as part of our MAOP validation activity. We want to make sure we have covered every foot of that pipe in its entirety, but it is not something that at this point in time we are concerned with. We believe that pipe is strength tested, and now we are just going back through the excruciating effort to do the forensics 30, 40 years back to determine that every foot matches up as it stands today.

Q So why isn't priority number five from the March 21st filing included in the work plan that is proposed in response to the Order to Show Cause?

A I think the intent of the Compliance Plan was to identify and focus on those locations where strength test pressure reports weren't required necessarily and for which we don't have records of the strength test pressure report. So we are really trying to get to, for all practical purposes, the pre-1970 or potentially pre-1961 pipelines. And that is how we prioritized it, laid out.

Q But you are making a distinction between no pressure test records versus partial pressure test records. And this indicates that there are at least 83 miles with only partial pressure test records. And the question is what is missing in the partial could be crucial.

A We need to understand what is missing, if anything is missing. We just haven't gone through all the forensics to be able to match it up.

It is a very, very time consuming process to try to match up every foot of pipeline that was constructed as early as 1930s with documentation that back then was a tape measure and some estimates going back to today's world that we are used to where we can get foot by foot of what we're doing.

So it is just an extraordinary effort to try to match everything up. That is what we have been focused on since the day we received the order, and we continue to work on that effort.

Q So I would like to suggest that this is a question that should be reviewed, whether priority number five should be included in the work plan or priority number six you seem to indicate that because there is pressure test documentation but the numbers don't match up, that's why it is not in the work plan; is that correct?

A Well, I think what you see in front of you is a Compliance Plan that I signed that says this is what we believe we want to focus on and is consistent with what was in the order that the CPUC issued to us.

And this is the agreement we have right now with at least four priorities will be worked first.

Having said that, we have already stated that we will be doing all 1805 miles of pipe, MAOP calculations for that and pipeline features list for that activity, and in addition we will be going forth and completing that for all our gas transmission system. So it is really a matter of prioritizing the work, working through it and trying to get it done as soon as we practically can with the accuracy that we absolutely need for this type of work.

Q And thus the issue of the schedule becomes important?

A The issue of schedule is it needs to be done and it needs to be done accurately. And as we said earlier, this is a very, very aggressive schedule.

And the other thing I think that is important to note and it's been brought up several times is we put forth in early January what we thought a MAOP validation study looked like. What we are trying to do here in many cases is meet a definition or a statement by the NTSB and order by the CPUC that isn't well defined. What does it mean to be complete, et cetera, for a 1970s pipe where records never did exist for that pipeline, what do you do?

And so we have done that for Line 101. We shared that in early January with the Commission staff. We shared it again as one of our recent filings of what we believe is appropriate.

We had already started this work prior to the NTSB ruling anyway. And we just want to make clear we understand the scope of this work so we can understand exactly what we are trying to accomplish before we agree to deadlines and dates.

Q All right. So moving onto a different question, this may bring up a mix of engineering and legal questions, so whichever of you is appropriate to answer this.

In the proposed work plan in Footnote 2, it defines "complete," when you refer to each of these steps start with "complete these tasks."

So, first of all is complete the search for records. And there's a Footnote 2 which says for search and collection, complete signifies that the vast majority of records have been collected.

How do you define the vast majority of records? And is that a qualitative assessment, or a quantitative assessment?

A What we have previously said is we believe we have collected 70 to 80 percent of the records necessary. As you do with forensics, you may find additional records that are needed. And in fact you oftentimes find records that have nothing to do with gas transmission lines that you must also pull in order to do what we have defined as an MAOP validation activity.

So we have pulled the records on the gas transmission system as defined. There may be records you have to pull from the distribution system also to do an MAOP validation as we have defined it.

Q I am still trying to understand, because this proposes to define "complete" as production of the vast majority of records. So are you asserting that you have -- by collecting 70 to 80 percent of the records that you have already produced complete records?

A What we are trying to say is until you absolutely finish your MAOP validation study you can't say you have completed all your records. You must continuously search for those records.

We have pulled all the job files we are aware of that we might need, but again, oftentimes you have to go into other documents unrelated to gas transmission to see if other available information exists that can help you verify what's in the ground.

COMMISSIONER SANDOVAL: So it seems, ALJ Bushey, that there's a question of what does "complete" mean and especially with this vast majority of records, is this a qualitative distinction, is this a quantitative distinction, particularly if what is missing is records relative to welds.

So I would suggest that that would be an area that needs clarification.

Also, I note that footnote number two is only listed for what I call

Category 1, the category for completion date is June 10th.

Mr. Malkin, did you intend that definition of "complete" to apply to all three of these categories, or only to the June 10th category?

MR. MALKIN: The intention, Commissioner Sandoval, is that the two footnotes, 2 and 3, apply to all of the uses of the word "complete" in the context of those specific activities.

COMMISSIONER SANDOVAL: That is a helpful clarification.

Q So therefore, this definition of "complete," as well as Footnote 3, would apply throughout this work plan. So we will get to the rest of that.

So then with regard to footnote number three, it says once you gather the documents you are supposed to calculate the MAOP based on the documents, then number three says completion of a MAOP validation assumes limited field work. If more field work is needed PG&E may ask the executive director to use his authority to approve a modification of the schedule.

So, Mr. Johnson, what does limited field work mean?

A We defined limited field work from our MAOP validation study that we previously filed on Line 101 where we did, I believe it was, six digs were required on that pipeline, subject to check, for over 30 miles of pipe. So we are talking about having to do one dig roughly every four or five miles in order to do the field verification.

As I mentioned earlier, we had shared the MAOP validation efforts with the staff, both in January and again recently. And the issue is if certain other expectations are needed and additional field work is needed, do the verification to a different standard or different expectation, those field digs can take an extraordinary amount of time depending on location, whether they are in freeways or streets, and that would certainly have a potential impact on the timing of this work.

Q And what are the standards that determine when field work is needed?

A We laid out in our MAOP validation study of when we believe a dig would be necessary. Most of the digs on Line 101, and that is the one we have completed so far, were to verify and validate the seam type on a piece of pipe. But they can be used for other activities, too, such as having to do a tensile strength test or yield strength test on a piece of pipe, a nondestructive test, or potentially to dig up an elbow to look for particular information on it.

So it depends on what you can find in your records. It obviously probably depends on the generation which the pipe was built and how many of these we will have to do.

We did Line 101. That is the one pipeline that has been completed. I believe we had 6 digs in over 30 miles. And that is the basis by which we have going forward.

If those assumptions are wrong or if staff comes back and says we want you to do X, Y, Z as opposed to what you put forth, then obviously there would be a change in the scope of the work.

COMMISSIONER SANDOVAL: And this question would go I think either to PG&E or to Mr. Heiden from CPSD.

PG&E referred to the MAOP validation study. Is reference to that incorporated in this work plan as governing the standard for when field work is triggered?

MR. MALKIN: The MAOP validation study for Line 101 is specifically referenced on page 2 of the Compliance Plan, the third paragraph from the bottom, which identifies that the staff is reviewing it. And we were expecting to be advised within ten days if the staff believed we should make any changes in the approach to the MAOP validation. We haven't gotten that feedback yet. We are still looking for it.

As I said in my opening remarks, while we think this is an appropriate approach, we are not going to march down a path of doing an MAOP validation for 1800 miles of pipe at the end of which your staff says to you what they did was all wrong.

So we are very much looking for their input. We have started the work, as we said, following the same procedure. So we urge them to give us input as quickly as possible. But we take very seriously their suggestions, both because of the quality of the staff that you have and also because we know how important their guidance is to you as Commissioners.

COMMISSIONER SANDOVAL: Having a standard for when field work is triggered and what field work is appropriate would be very helpful because I don't feel it is well articulated in the proposed stipulation.]

My next set of questions, and this I think may go to -- I'm not trying to make you a witness, ALJ Bushey, but it says that PG&E may ask the Executive Director to use his delegated authority to approve a modification of the schedule.

Since this particular proceeding will result in a Presiding Officer's Decision, would it be more appropriate to have what I understand is called a mod POD, a Modified Presiding Officer's Decision, rather than delegated authority to determine whether or not extensions are merited?

ALJ BUSHEY: Well, a Presiding Officer's Decision becomes a decision of the Commission, and then that would trigger the Commission's Rules of Practice and Procedure which allow for the Executive Director to grant extensions of time to comply with a Commission decision.

A mod POD is a Modified Presiding Officer's Decision, and it's really an internal review document. It's not something that becomes -- that necessarily would become final. I think what you're thinking of is something more like a modified Commission decision, perhaps a petition to modify the decision. That would require the full process, which can take several months to complete, as opposed to an Executive Director letter which can be issued in minutes if we write fast enough.

COMMISSIONER SANDOVAL: Okay. That's very helpful, especially for a new member of the Commission such as myself.

So, but my other question would be, what would be -- this might go to CPSD, what would be the standard for approving the modification of the schedule? This doesn't list any standard for approving modification.

MR. HEIDEN: I think PG&E would have to show good cause for a modification. I think it would have to show good cause, and I think we discussed that at the hearing last week at the evidentiary hearing. That's CPSD's position.

COMMISSIONER SANDOVAL: And under this proposal, if the schedule is modified, is it CPSD's understanding that that would pull the deadline for the payment of the second penalty if the August 31st deadline is not met?

So for example, if it were determined that an extension until let's say September 15th was appropriate and August 31 is past, would the second payment still be due, or would that be pulled so that it would not be due unless the documents are not produced or the MAOP is not calculated within the time of the modification?

MR. HEIDEN: It's our position that if it's an excused delay, then the penalty would be excused also. It would be pushed back.

COMMISSIONER SANDOVAL: So isn't there a difference between an excused delay and a modification of the schedule? Is a modification of the schedule automatically an excused delay?

MR. HEIDEN: I was referring to a modification of the schedule.

COMMISSIONER SANDOVAL: So thus, I think it becomes even more critical to have standards articulated for when a modification of the schedule is appropriate and also what types of modification are we talking about, 30 days, 60 days, 90 days, six months. So that would be extremely helpful.

Q All right. So then the proposed Stipulation admits on page 2 that PG&E doesn't believe it will find complete verifiable and traceable records of each component and instead proposes to use assumptions including assumptions about fittings and elbows based on material specifications to help determine pipeline characteristics.

So this -- I understand, Mr. Johnson, you've been the one supervising the document production. So this material specifications would rely on procurement records in part; is that correct?

A Well, in terms of fittings where records were never kept on specific components and now we've been asked to do that for each individual component under the NTSB order or recommendation and the CPUC order, since those documents never in many cases even existed, what we are proposing and what we recommended in our MAOP validation study is, for example, elbows, where you may have purchased, let's say, 30 elbows for a job or PG&E may have purchased 30 elbows, under a specification where we have documented what that elbow is supposed to be, that that documentation exists for that elbow, but we cannot necessarily trace every purchase order for every piece of equipment for an individual elbow from back in, say, the '70s or '60s. It just never existed. We didn't purchase material that way.

Q And you testified in the previous

hearing that information about elbows and fittings is not necessarily going to give you information about welds; is that correct?

A Well, the information about the elbows and fittings will give you information about the strength and capabilities of those elbows and fittings themselves, of those components.

Q But not about pipeline welds?

A The pipeline segments, you have to look at the pipeline. For elbows you have to look at elbows. For valves you have to look at the valves.

Q Right. So elbows give you information about elbows?

A Correct.

Q Fittings give you information about fittings. But elbows and fittings don't tell you anything about what I'm calling pipeline segments and welds; is that correct?

A In general, they're not going to tell you anything about the pipeline itself. That's correct.

Q But my question is also trying to get at what types of documents you have or you believe you would have to have. So you're saying that you're going to look at basically procurement records to try to find information about what I understand is called appurtenances such as fittings and elbows; is that correct?

A Well, we said material specifications. Those aren't necessarily purchase documents. Those are engineering documents that state what should be -- what that elbow should be made up of, how it's designed, what the criteria is for that particular case.

Q So I'm trying to make a distinction between, as you said, purchase orders, which might be procurement records, versus the engineering specification documents.

Does PG&E retain those engineering specification documents from the 1950s?

A In some cases those engineering specification documents are still available, and we have found some of them. That's correct.

Q And where PG&E does not have those in your possession, in its possession, what is the plan for getting those specifications?

A Well, we'll either continue to look for those specifications. If we can't find any other mechanism to verify what's in the ground, ultimately you have to dig it up and do some sort of testing on it.

COMMISSIONER SANDOVAL: All right. So then the next question, and so this, I think, is appropriate for CPSD as well as a comment perhaps for ALJ Bushey.

So the work plan states that PG&E proposes to work with staff to discuss assumptions. So which staff is this? Is this CPSD? It just says Commission staff.

MR. HEIDEN: Yes. CPSD and any consultants that CPSD retains. This is extensive work, and we expect to have consultants working with our internal staff.

COMMISSIONER SANDOVAL: So, and again, as a relatively new member of the Commission, a procedural question which perhaps ALJ Bushey can assist me with.

So since CPSD is a party to this proceeding, is this appropriate for one party to be consulting with another party about compliance with the plan and assumptions used in the plan? You know, I've been concerned about just the entire way that this came about that CPSD became a party, which has various ramifications including ramifications for consultation with a full Commission and even ramifications for consultation with the Administrative Law Judge.

ALJ BUSHEY: Well, the Commission's ex

parte rules do not apply to party-to-party communication. So it's just communication with decisionmakers. So to the extent that

CPSD staff is acting as a member of the proceeding, they can communicate with the parties. It's when they try to communicate with the decisionmakers that the ex parte rules are implicated. So there's often collaboration and communication between parties that don't include decisionmakers at the Commission.

COMMISSIONER SANDOVAL: So then under this proposed plan, the discussion of assumptions with CPSD's staff, it would be party to party, but if such a stipulation were approved, would the ex parte rules remain in effect such that CPSD staff that were at least involved as a party could not therefore brief Commissioners on the assumptions?

ALJ BUSHEY: Depending on the staff, if they were acting as advocacy staff or advisory staff. So that would be the problem about bringing any type of information back to the Commission.

It seems to me that many of your questions surround the indefiniteness of the agreement and the likelihood that the parties would need to add greater detail to the agreement on sort of an as they're proceeding through this.

COMMISSIONER SANDOVAL: Well, on a going-forward basis, and also, as you identified, I think that there has been a problem with drawing that line between what is advocacy staff versus, what was the other word you used?

ALJ BUSHEY: Advisory.

COMMISSIONER SANDOVAL: Advisory staff. So I mean this entire status is new to me. Having worked for the Federal Communications Commission for six years, no division would ever become a party in this type of fashion. So having clearly delineated lines to ensure that advocacy doesn't overtake advice I think would be critical going forward.

MR. HEIDEN: Your Honor, can I comment on that briefly?

COMMISSIONER SANDOVAL: Please.

MR. HEIDEN: CPSD is not -- was not a party to the rulemaking, was not planning on submitting comments in the rulemaking. CPSD's role in the rulemaking was to advise the Administrative Law Judge and the Commissioners.

CPSD is a party to this limited

enforcement action because we're the party at the Commission that enforces the Commission's orders. It's not CPSD's anticipation that they are suddenly going to become a party to the rulemaking. CPSD staff wants to be advisory. It's appropriate that they're advisory. And obviously, safeguards would be put into place so you don't have the same people advising as advocating. It's not anything that CPSD would ever allow to happen.

COMMISSIONER SANDOVAL: And having clarity about the advisory role with regard to if there were any proposed stipulation would be I think extremely important to delineate that line going forward.

So my next question is that in the proposed Stipulation PG&E says that it will consider any recommendations made by CPUC staff. It does not bind itself to actually adopt recommendations made by the staff.

Could either CPSD or PG&E please speak to why it says that you will -- that PG&E will consider staff recommendations as opposed to binding itself to staff recommendations?

MR. MALKIN: I'm happy to address that, Commissioner Sandoval. As I mentioned in my opening remarks, the Compliance Plan does not say in so many words, we will do what CPSD says. And it's written the way it is because what is contemplated is a collaborative process. But as I said, realistically, PG&E is either going to convince the CPSD and its consultants, which we're paying for, that the proposed course is a sensible one, or as a practical matter we will have to change course.

We cannot put ourselves in the position and you wouldn't want us to be in the position either of coming at the end of this process with some kind of adversary proceeding in which we're trying to prove to you what we did that was better than what your advisory and compliance staff had been recommending.

So the language is not prescriptive in part because we didn't want the power to go to anybody's head, but it's going to be a process that requires consensus building because we have the mutual objective of doing this in a way that provides added assurance about the safety of PG&E's pipeline system. So for us to do it in a way that CPSD says doesn't accomplish that goal, per se doesn't accomplish that goal.

COMMISSIONER SANDOVAL: And I'd like to hear from CPSD about that. PG&E commits that it will consider your recommendations but doesn't commit itself to adopting staff recommendations.

MR. HEIDEN: I think that's what the Stipulation provides for.

COMMISSIONER SANDOVAL: That's what the words say, right.

MR. HEIDEN: Certainly if staff saw PG&E doing something that we thought was unsafe, there's many things staff could do. We could bring a proceeding. We could write a letter. I mean what staff normally does when they do inspections, the same type of thing. Staff is not going to allow them to just do something that is unsafe. I think it will be a collaborative process.

COMMISSIONER SANDOVAL: So again, ALJ Bushey, this is another area where I believe that we need more standards for when recommendations would be adopted because it seems rather open ended. And I want to thank everybody for indulging me in my questions. I assure you I am on my last three questions, last page.

Q So do PG&E -- so you're proposing that where you do not have complete, verifiable and traceable records that you will use assumptions as discussed in this proposal.

What do you propose to do with these assumptions? For example, will you populate the GIS database with assumptions? You also mention a Pipeline Features List.

I'm just trying to get to what will these assumptions -- what is the end result that the assumptions will produce and how will it be reflected in databases?

A Well, in the terms of the databases as it stands even today, if you have an assumption in there, you highlight that assumption so all parties know when they look at the database it's an assumption. And in fact, that's very clear in the GIS database of what's assumed and what's a known value. Again, the assumption level that you have to go to depends, but as we talked about, there are no records for certain pieces of pipe, and so you must assume something in terms of what was put in the ground.

It will be the same, as we envision it right now, it will be the same in the new GIS system or the updated GIS system, and also in the Pipeline Features List would identify that along with a listing of where that information comes from. So, and again, in the MAOP validation study we try to be very clear on how that process would work, and that's the process we want feedback on as we are going down this path right now. And to change it after 15 days or 20 days or in this case months of work will potentially have a dramatic impact on our ability to get the work done.

Q And does the identification of assumptions clearly identify what is missing? Right? Again, in my nonengineer mind, I imagine something that says we assumed X. So for example, we assume double arc welded or double submerged arc welded pipe. Does it indicate what is missing, e.g., no records of welds available?

A Well, it indicates it's an assumption. To say it's missing is probably not quite correct in that it probably never existed. I mean we are using terms today like double submerged arc weld that weren't even used when it was originally started. It had its own terminology. Things have changed over time. What it will indicate is that that document is an assumption, and we will have a link to what document we're utilizing for purposes of that work.

So for example, PG&E is going to use its material specifications, and we are going to assume that the fittings we purchased are under those material specifications. That's what we ordered. That's what we got. That's what we installed. You won't have a document that says, for this elbow it was purchased on, you know, June 3rd of 1956 on this day and installed in this location because that's certainly not how equipment was purchased.

So we will have assumptions and we will have links to those assumptions. If there's an assumption involved, it will be highlighted in the database.

Q Okay. You know, again looking forward to, looking to the future, identifying not just what the assumptions are but also what there is not can be very helpful. You know, looking to the future, I mean part of what we're dealing with is the problem of interpreting records or nonrecords that are 50 or 60 years old.

I remember when I took a computer class once I got a B because I didn't put comments in my code. And they said you need comments because years later somebody will come back and look at this APL document and try to figure it out. So that certainly would have happened in the year 2000. So clearly identifying not just what the assumptions are, but therefore being clear about what is missing would be helpful.

So just on this subset of questions. So how will these assumptions then affect the Pipeline 2020 Report, which I understand is due in May? Can you tell us something about that Pipeline 2020 Report?

A I assume you're referring to as our -- like the filing we'll be making in May? I don't know. I mean obviously as we go through and find out, if we find specific issues on our pipeline, if they're safety related, we'll deal with them immediately. If there's something we're learning about our pipeline that's new, we will share that. We will be implementing that in our proposal for Pipeline 2020.

Pipeline 2020 is more of a methodology of what we propose to do for each section of our pipeline going forward. So if characteristics of a piece of pipe change either because we find new information or if in fact because it gets changed in the next coming months because something else happens, that will just work right into the proposal.

It's a decisionmaking process or a decision tree to Pipeline 2020. It will just feed into that.

Q And last set of questions. Particularly for pipelines where assumptions are made or there are incomplete records, what action will that trigger with regard to pipeline testing or pipeline replacement, and does this document include those standards for the actions triggered?

What I'm trying to understand is, is this current work plan designed to suggest that populating a database with assumptions is sufficient to meet the NTSB recommendations and does CPUC request, or where you have assumptions, is that a complete data, will that actually target testing and replacement action and what are the standards for such a trigger?

A Well, if I understood your question correctly, our intent is to obviously collect all the data that we can to do the MAOP validation study, and we will state assumptions in there, and there will be assumptions in there. And in fact, the standard that was put forth by NTSB is a standard that pipeline operators that are building today probably cannot beat, quite frankly. So it will change the standards most likely going forward.

But I mean after we've done the MAOP Validation Study, and as we mentioned, there may be pipelines where this just isn't possible. There aren't enough records to do a valid MAOP Validation Study in terms of the way it's laid out. We will then sit down with the Commission, and either part of our Pipeline 2020 or some other proceeding or some other discussion and determine what we should do next steps. Do you lower the pressure of the pipeline? Do you run a pig through the pipeline? Do you hydro test the pipeline? Are there other technologies you want to use? Just what do you do in those circumstances? And you have to look at each one of them individually.

COMMISSIONER SANDOVAL: And very last question for CPSD. This work plan is silent on at what point is testing or replacement appropriate. I'm concerned here about the lack of standards or a trigger to determine when there are not complete, verifiable and traceable records and instead assumptions are used, what are the standards for determining when testing or replacement is appropriate given that our highest goal and duty is the protection of public safety and the public interest?

MR. HEIDEN: Right. And certainly in some instances I think PG&E and staff would agree that pipeline is going to need to be replaced if they don't have the records. The question is, what are the standards for doing that? I don't know what they are. I think that's an engineering question. I also think it depends on a lot of factors, but I can't answer it today or give you objective criteria on when they should replace or when they should not.

COMMISSIONER SANDOVAL: So, and I would submit to ALJ Bushey this is another example of a very open-ended standard that also doesn't incorporate NTSB's Step 3 or even a consideration of what testing is appropriate as perhaps a complement or a substitute in certain circumstances for hydro testing.

And again, I find this particularly curious in light of PG&E's commitment in the March 21st letter and also statement in a separate filing related to Resolution L-411 that one of its priorities is to engage in gas pipeline replacement in order to take advantage of certain provisions of the tax code which allow a hundred percent depreciation this year and 50 percent depreciation next year. I just find the absence of this trigger to be not only curious but inconsistent with the NTSB recommendations.

So thank you all very much for indulging my questions. This has been extremely helpful follow-up to our last meeting.

ALJ BUSHEY: Commissioner Ferron, before we move on to you, I just want to confirm with Mr. Johnson that at our hearing last week we placed you under oath, and that oath continues to apply.

Is there any of your testimony that you would like to change in light of that reminder?

THE WITNESS: No, I don't believe so.

ALJ BUSHEY: Thank you.

Commissioner Ferron.

COMMISSIONER FERRON: Thank you very much. And I'd like to thank Commissioner Sandoval for thorough questioning on the issue of compliance with the work plan. So I won't cover that area.

But what I would like to do is go back to the question of the scale of the fine, which I guess we now have a range of between 6 million and 153 million.

I guess the question is, as I read the code here, it says, the purpose of a fine is to go beyond restitution to the victim and to effectively deter further violations by the perpetrator or others.

So what I'd like to understand here is what the process was internally within PG&E surrounding the submission on the 15th of March. I see here that the document is signed by you, Mr. Malkin and by Mr. -- where are their names now -- Pendleton and Garber. And I presume that they're from the Law Department. I presume that the work was not entirely theirs.

So what I'd like to understand, as you said earlier, what we've had here is a failure to communicate. So I'd like to understand from our end with whom within PG&E we are communicating, and specifically within the hierarchy of the organization where was the document commented on and who ultimately approved the March 15th document?

MR. MALKIN: The March 15th report, like the March 21st supplement, received a relatively broad review by senior management of the company both in the specific business lines and more generally.

In terms of the circulation, I can tell you the circulation included the President of the company as well as the Senior Vice Presidents.

COMMISSIONER FERRON: So that would include the President, the COO, the SVP for Engineering. Did it include the Chairman as well?

MR. MALKIN: No, it did not.

COMMISSIONER FERRON: Would not have included the Chairman. Okay.

All right. Thank you. No more questions.

ALJ BUSHEY: Further questions?

COMMISSIONER SIMON: I did have one more. If you have closing.

COMMISSIONER FLORIO: No. Go ahead.

EXAMINATION

BY COMMISSIONER SIMON:

Q I did have a question, thank you, regarding pipelines segments that have been placed since 1970.

Mr. Johnson, based on some of your responses to Commissioner Sandoval's questioning, I'm getting the sense that we have documents missing for pipelines post-1970 as well or yet to be found documents for post-1970 pipelines?

A Pipelines post-1970 after the federal program was put into place had specific requirements for certain pipelines

to be hydro tested or pressure tested is the appropriate term. And we have not yet found every one of those documents to our understanding, to my understanding.

Q So we don't know if there was or was not hydro testing performed since 1970 on these pipes because of the lack of documentation?

A Well, I think we believe certainly that we've met the code criteria. That code had been in place for -- you know, we knew it was coming. So we believed we would meet that standard. We just haven't been able to find the documents yet or match them correctly to each piece of pipe.

Q Do you have any idea of what percentage of that pipeline is in HCAs or High Consequence Areas?

A I would have to actually look at the numbers specifically to know what was an HCA.

Q And in terms of the pre-1970 or grandfathered, do we know the percentage of pipe placed prior to 1970 that's in High Consequence Areas which is either by way of grandfathering or by way of record mismanagement or whatever term would be utilized that we know what percentage of that

pipe is unavailable from a recordkeeping standpoint?

A Well, I think what we filed, and Joe, you've got it in front of you there. It's Class 3 and Class 4 plus High Consequence Areas in Class 1 and 2. It is listed on page -- page 13 of the March 15th document in terms of what records we have for each vintage of pipe before 1961 and other dates specific to the codes.

COMMISSIONER SIMON: Mr. Malkin, you speak of a cooperative or collaborative effort. Would an Order to Show Cause on the originally proposed sanctions irrespective of what those calculations are, would that in any way inhibit or deter PG&E from going forward on a cooperative or collaborative basis with CPSD?

MR. MALKIN: Absolutely not, Commissioner Simon. What it would do and one of the things that we are seeking not to have to do by virtue of the Stipulation is it wouldn't keep us from cooperating. It wouldn't keep us from collaborating. It wouldn't keep us from going forward with the

Compliance Plan and doing the safety work. What it would do is it would distract some number of people who are important to doing that safety work who would have to split their time to litigation functions. It would do that on our side, and it would do that on CPSD's side.]

And that is why we both felt that since we are going to work together collaboratively, we are both going to focus on the safety work, that we should, if we could, and we did, try to reach a resolution of the backward-looking piece so that the people involved in that safety work didn't have to split their time thinking about the litigation part.

COMMISSIONER SIMON: So if the stipulation was rejected and the Commission opted to go with the Resolution originally presented for the Order to Show Cause, it would be PG&E's intent to protest and litigate that resolution?

MR. MALKIN: Commissioner Simon, if the hypothetical is the stipulation is rejected, we are still doing the safety work and what's on the table is allegations that the company was in contempt for having willfully disregarded the Commission's order or otherwise having violated it, at that point there really are only two paths. We tried the one path which is to resolve it amicably through an agreement with the enforcement staff, which is the way typically resolutions of enforcement proceedings come before the Commission is through an agreement of the Respondent, in this case PG&E, and the enforcement staff. So that path -- the hypothetical was that path is gone. That leaves us -- I guess you could say we have another path, we could just plead guilty. I don't think that one has ever crossed our mind particularly.

So that leaves us with the other path, which is to put the enforcement staff to its proof to put on our defense and then leave it in the first instance to a Presiding Officer's decision and then ultimately potentially to the Commission to decide.

All of that, that whole process I just described and everything that is involved in it from putting on the witnesses to writing briefs to arguments to the ALJ expending her time writing a decision, to you considering it again, those are all the reasons why we and CPSD got together right after we got the letter from Executive

Director Clanon and began discussions that led ultimately to the conclusion that the best course was to resolve that and focus on --

COMMISSIONER SIMON: Do you know the date on or about the time when this collaborative stipulation process began? Because that's where I am getting somewhat confused based on when we -- I apologize to my fellow Commissioners and Administrative Law Judge for being somewhat redundant here, but again, this is where I think the confusion lies for many of us in reference to when prior to March 15th did this stipulation preparation process begin?

MR. MALKIN: It didn't begin prior to March 15th. What the sequence is, we filed the report on March 16th. We got the Executive Director's letter that expressed displeasure with our filing on March 16th. We went ahead and filed our supplemental report on March 21st. And it was really between March 21st when we filed that supplement, so I guess it would have been starting the 22nd, and the 24th that the discussions began and came to fruition on the 24th. It was literally, we had the conceptual agreement at the time of your meeting. We did not have the actual documentation done until I think around 3 or 4 in the afternoon.

COMMISSIONER SIMON: Because as I recall, it was not prepared at our meeting. We were told something would be issued that afternoon, the afternoon of the meeting itself.

MR. MALKIN: That's right. We had gotten to a point where we had conceptual agreement, and I think both we and CPSD had the confidence we would be able to memorialize it in a mutually acceptable document. So that is when it was mentioned at the Commission meeting.

We continued to work on the documentation and got it done by, I want to say, 3 or 4 in the afternoon.

COMMISSIONER SIMON: Okay. Then lastly, you had mentioned the number of digs, the amount of experts and others. Are you seeking recovery on this investigative cost?

MR. MALKIN: If you are referring to the costs that we have agreed to pay for CPSD's consultants, the answer is no. We had said clearly that we are not going to seek to recover those costs.

COMMISSIONER SIMON: Thank you.

No more questions.

ALJ BUSHEY: Further questions of the Commissioners?

COMMISSIONER FLORIO: No. I'm thinking we probably need a lunch break before we go to the second half of this, which is the report.

ALJ BUSHEY: Why don't we go off the record.

(Off the record)

ALJ BUSHEY: Back on the record.

While we were off the record we rearranged the room to move on to our second topic for today, and that is the report from Pacific Gas and Electric Company.

Are there any statements from the Commissioners before we begin the report?

(No response)

ALJ BUSHEY: Hearing none, Mr. Johnson, would you like to begin.

THE WITNESS: Thank you.

Good afternoon. This report is at the request of the Commission to give a quick update on what's happened since September 9th. So please if you have questions as we go through it, I will be happy to answer. But in the interest of time and everyone's calendar I will move pretty quickly, if that's okay.

So the first slide is just an overview of PG&E's gas transmission system as we define it. We have 6750 miles of gas transmission pipeline. For purposes of the Gas Accord, regulatory requirements and a lot of our discussions, we talk in terms of gas transmission as everything over 60 pounds or 60 psig.

From a federal government point of view or from the Department of Transportation definition, which is any pipeline operating at 20 percent or greater of SMYS, specified minimum yield strength, we have 5,700 miles of pipeline. So there is a difference there, and that explains why sometimes you hear different mileage depending on who you are talking to or what you are specifically talking about.

All our discussion earlier this morning, that 1805 miles, that Class 3, Class 4 and high consequence area, Class 1 and 2, is a subset of that 5,700 miles of pipeline.

Also, we have 42,000 miles of distribution line, and we serve 4.4 million customers.

In terms of activity since September 9th, I am going to go through a little bit of detail in each of one of these, but we have pressure reductions, leak surveys. We have provided maps to our first responders. That was an item that we were requested to talk about. We have done some integrity management work, a lot of field work and field validation work.

We will talk about the MAOP validation study we started on Line 101 very shortly after the incident, talk a little bit more about proposed field work, planned field work, our remedial actions that we might be looking to in the future and our new mitigation programs or Pipeline 2020 going forward.

So immediately the evening of the rupture we reduced pressure by 10 percent on the three pipelines in the San Francisco Bay area. We then shortly reduced it down by 20 percent in terms of reducing the pressure on those pipelines and everything in the San Francisco Peninsula.

We subsequently reduced the pressure in two East Bay pipelines that had similar characteristics of San Bruno by 20 percent of its MAOP. And we have also reduced pressure on five pipelines that have exceeded their MAOP by 110 percent or more.

All this information has been shared with the Commission since September 9th in different filings. But that is a quick summary of our pressure reductions that we have taken so far.

We also conducted a leak survey of the gas transmission system. The leak survey for the San Francisco Peninsula was a traditional ground survey that was started the next morning after the event. That was September 10th. That was conducted over approximately ten-plus days for every section we could get to.

We then subsequently branched out and chose to do a leak survey on our entire gas transmission system. That's all 6750 miles of pipe as we define it.

We started with the helicopter aerial survey using LIDAR technology, a new technology that allows us to do a leak survey very, very rapidly but is not, quote, an authorized tool, but we wanted to understand how well it worked and how far it had come in the previous many years of using LIDAR.

So we started with that and followed up on the entire transmission system with a ground survey. That is either an individual walking specifically over the pipeline with a specific piece of equipment, or in areas where it is not safe to walk, we connected to a vehicle and traveled that pipeline at a

specific speed trying to find any leaks in our gas transmission system.

COMMISSIONER SANDOVAL: Is it appropriate to ask questions?

I have a question. There seems to have been conflicting testimony about whether or not there were actually reports of smelling gas before the San Bruno explosion. So let me ask that. Do you know if PG&E actually received reports of smelling gas before the San Bruno explosion? And what I mean by before, within the weeks or months immediately preceding the explosion.

THE WITNESS: My recollection, and I know we put this in writing to the Commission, we can get it back to you, we went through our records for months prior to the San Bruno explosion and found no indications of leaks in that particular area or no indications of people smelling gas in that particular area. But we can follow up and get that information to you.

COMMISSIONER SANDOVAL: Yeah. It would be helpful, because even at the public hearing that we had last week some of the witnesses who lived in the San Bruno area indicated that they smelled gas and that they had reported it. So this seems to be an issue of some dispute. So it would be very helpful to understand that.

THE WITNESS: Okay. And we have shared that at the public hearings we have had. Each and every time we asked if anybody did actually smell it in the San Bruno area, because that is the folks who come to these town halls, if you will, in San Bruno, to please come forward. Nobody has come forward. We met with the city on this issue many times. My recollection is we had no calls in that area for smelling gas many months prior to that event.

But we will verify that, and I know we have given a written report on that many months ago. I just can't remember exact wording of it.

COMMISSIONER SANDOVAL: If you were to get a call of smelling gas, is this a technique that you would use, this laser methane detection followed by a ground survey to determine whether or not there was actually gas that was coming out of the pipeline?

THE WITNESS: If we were to get a call

for smelling gas, we will send an individual out there who will then look at the situation himself and they would do ultimately a ground survey.

What is beneficial for a helicopter in this particular case, LIDAR survey, is you can do 6750 miles of pipe over very rough terrain very, very quickly. It is not what you would ultimately use as your tool, but we wanted to do it very, very quickly and then follow up with a ground survey which took about three and a half months, as I recall, to get done with that many qualified surveyors. We had over 125 qualified surveyors doing it.

But we would send a qualified surveyor out there if it was a pipeline.

If it is a home we have gas service reps go to the home and make repairs accordingly.

If it is on a pipeline area we will send somebody out there and actually ground survey it, look for that leak and take appropriate action.

COMMISSIONER SANDOVAL: So how broad was your aerial survey for your many miles of pipe?

THE WITNESS: The aerial survey, the

helicopter survey, sits at about 500 feet high and was ranging anywhere from 200 to 300 feet outside the corridor of the pipeline to down as low, as narrow as 20 feet. And it is a LIDAR methane detection system. So it picked up a lot of activity that had really nothing though do with pipelines.

COMMISSIONER SANDOVAL: How many miles were surveyed using this method?

THE WITNESS: Everything except for the San Francisco Peninsula was utilized. So it would be approximately 6,500 plus miles of pipe were surveyed using the helicopter, and then we followed up with a ground survey accordingly.

COMMISSIONER SANDOVAL: You said everything except for the San Francisco Peninsula?

THE WITNESS: The San Francisco Peninsula we started with a ground survey the next day, and the helicopters weren't in place for several weeks afterwards. Bringing them into the state, getting them qualified, certified to do the work took a couple of weeks. We were already done with the San Bruno area and all of the San Francisco Peninsula well before those helicopters showed up.

COMMISSIONER SANDOVAL: Thank you.

THE WITNESS: We also did an integrity review of the San Bruno area shortly thereafter that incorporated Lines 101, 109 and Line 132. That is primarily a look at the coating of the pipeline itself to see if there is any corrosion activity in the area. It also gives any indication if there is anything happening in the area that is unique in terms of cathodic protection. This was just one more tool we had available to us to again check the integrity of the pipeline in and around the San Bruno area immediately after the San Bruno rupture.

And again, we found no integrity issues that required any immediate action based on that integrity review.

We also started very shortly after the San Bruno incident what I referred to earlier as the MAOP validation activity on Line 101. So we did conduct as part of that, we had about 27 people working that six to seven days a week up to about 14, 16 hours a day.

We ultimately had to do six digs to do verification. Most of those digs were associated with verifying the type of seam on a weld -- on a pipe. Excuse me.

We wanted to make sure that what we saw in our records really reflected what was in the ground. So we did those digs there.

We were able and did confirm what we call A.O. Smith pipe. And this again is an MAOP validation study that we shared with everybody. But we were able to validate that the A.O. Smith pipe, which was of question that had come up during conversations, was certainly within code and the information we have on it is accurate.

And again, no long seam, longitudinal seam or long seam concerns were identified as any part of those digs.

We also had done some field work around Line 132 and line 109. Those are the other pipelines in the San Francisco Peninsula.

As I mentioned last time when we started our MAOP validation work, we started with the concept we were going to do one pipeline at the time starting with San Francisco. That's obviously changed. But we had gone down the road obviously of starting all the pipelines in the San Francisco Peninsula. We did 13 digs total. All those were nondestructive.

We also ran an internal camera

through some of the segments of Line 132 of similar pipe as that that ruptured in San Bruno, again looking for the missing inside weld.

There was one 10-inch section that looked different than the rest. In other words, the weld cap, if you will, was missing on the inside of the pipe. A weld cap is the little bump when you weld, it goes a little bit higher than the pipe itself. A ten-foot foot section was removed and sent to the NTSB for their investigation. We haven't heard anything at this point in time. Frankly, don't expect to. But they will do a final report and some testing on that piece of pipe.

Also on Line 300A and Line 300B we had an overpressurization event on that pipeline, and to ensure its integrity and to follow through with our MAOP validation activity that we're also doing on those sections of pipe, we completed 19 excavations. Most of those, as you can see, eleven were on 300A system. That was the first pipeline built. 300B system had 8. We did direct examination on those also, both X-rays, nondestructive testing, looking at elbows, trying to find additional information on that pipeline segment. And again, they confirmed the integrity of the pipeline. And of course that information will be feeding ultimately into the MAOP validation activity around those two segments of pipe also.

COMMISSIONER FERRON: Excuse me.

What was the third-party action you referred to?

THE WITNESS: The third-party action on the Line 300A and B, we have turned it over to -- we have turned over some of that information to Kiefer and Associates and asked them to validate that what we see is what they see and are there any other recommendations that organization may have.

Is that what you are referring to? Oh, I'm sorry. The caused by third-party actions. That's our interconnecting point with Transwestern Pipeline. It was their equipment that had trouble and overpressurized on the pipeline.

In terms of planned field actions, we have talked about this at length, so I will go through it quickly.

We talked about priorities and what we are doing. We have 152 miles of pipe that look a lot like San Bruno that we are looking for, continuing to look for pressure test records for. We have proposed hydro testing, and we will have a discussion with the staff on exactly how that will look sometime this week. And we have also got 435 miles of pipe. Again, we are going to go through this whole process of what will we do with that pipeline and what activity should take place in terms of do you reduce the pressure or replace the pipe, do you pig it or hydro test, et cetera. And those have all been talked about at great lengths this morning.

In terms of the actions that we are looking to take place going forward on the pipeline system itself and the types of things we think we should look at and we will have conversations with staff and others on, first you can use smart pigs that can look at the longitudinal seam properly. And we are continuing to look at what techniques and technology are available because it gets better each week, each month. So there may be some things we see coming forth that will be helpful to us.

The advanced camera inspection is just that, putting a high resolution camera inside the pipe and actually looking at the weld itself.

I think what is important to

remember is on San Bruno that pipeline segment that ruptured was, we believe it to be missing its inside weld. So you may not need a full blown smart pig or some other technique to look at that. It is visually evident that it is missing.

So a camera may serve the purpose of verifying that the inside weld actually exists.

Hydrostatic testing is an option --

COMMISSIONER SIMON: Excuse me.

Does the camera process comply with NTSB inspection guidelines?

THE WITNESS: The NTSB doesn't itself have any inspection guidelines. All the guidelines are under obviously the federal code or the state code.

COMMISSIONER SIMON: PHMSA.

THE WITNESS: The PHMSA guidelines for integrity management purposes only authorize smart pigging, direct assessment, which is what was done on Line 132, and pressure testing.

COMMISSIONER SIMON: So where does this high resolution camera come in in those three?

THE WITNESS: The high resolution camera is just one more tool we have available to us that we can send into the pipeline to actually look for something very specific like an inside weld.

COMMISSIONER SIMON: But this tool is not captured by the Code of Federal Regulations or any state or federal safety practice?

THE WITNESS: If it is high consequence area, which is a majority of what we are talking about, but we are going to do our entire pipeline system ultimately, if it is high consequence area, you use integrity management. Those three tools that I mentioned earlier are the only approved tools. But this is just one more tool we can utilize to check for integrity.

So, for example, if we have a segment of pipe that looks similar to San Bruno, 30-inch, built in or around 1950, '56, Consolidated Western pipe potentially, if we are doing a hydro test we may choose to put the camera in their first, verify we don't see any missing seams, then do the hydro test, and you kind of hit both activities.

If it is not high consequence area and we still want to check it, the code at this time doesn't require anything, we still might like to get a camera in there. It is just one more tool available to us.

Again, we are looking at new technologies and working with many vendors on

new types of cameras, new pigs that might be able to capture exactly what we are looking for.

You had specifically asked last week to talk about vehicular protection, I think it was, or vehicular crossings. I know that was referenced in our public hearing the other day.

In terms of PG&E's pipeline system, and actually this is covered in the code along with the standards that PG&E has, but we use what I believe is usually used in this concern is cased piping where a pipeline is inserted into another pipe so the pipe, the outer pipe, protects it, if you will, in theory from movement.

That is used a lot of times around perpendicular crossings or crossings under freeways, under railroads, railroad tracks, and in some other certain circumstances. There's code requirements for that as covered both in Part 192, covered in GO 112 (E). And it is covered under PG&E's standards of when these tools are utilized.

There are also other opportunities

to use. Instead of using casing over a pipeline, which casings have their own issues to be dealt with, there are also things in the code that allow for thicker walled pipe. There's other safety factors built in for crossings.

You can also utilize additional cover which reduces the amount of pressure that a pipe would see from heavy, heavy traffic, if indeed, and you could also use concrete caps or other activities to dissipate the load over the pipeline.]

It is covered in the code, but the reference that was brought up at the particular public hearing is this pipeline was in a roadway and therefore had issues. We don't see any circumstances where we understand it being in a roadway as a problem. It had the proper amount of depth, and there are pipelines built into roadways and in franchise areas throughout the service territory. But we do have a standard, and the code does cover vehicular crossings of pipelines.

EXAMINATION

BY COMMISSIONER SANDOVAL:

Q I have a question.

A Sure.

Q So were any of these or other what I'm going to call additional measures utilized for the segment of the San Bruno pipe that exploded to account for the fact that it was under a roadway?

A When the pipe is built, they look at a roadway being there. A roadway is obviously known. And so really what you're looking for in general is is there going to be anything unique to that pipeline other than the amount of cover it has. The deeper you put a pipeline, the more insulated it is from road activity, if you will. So as long as it's the proper depth, there really isn't any issues with roadways being put over pipelines. And in fact, roadways over pipelines are very, very common.

The issue that we usually look at in terms of vehicular crossings where you're actually going under very heavy travel like in a freeway or a railroad track, that's when you have to look at very, very specific items to mitigate that activity. But there was nothing necessary for Line 132 in San Bruno or any pipelines over and above what we would normally do.

Q Okay. So none of these additional steps or standards was used --

A No.

Q -- for that particular segment; is that correct?

A Well, in 1956 there was no federal code. So there wouldn't have been these obvious standards in place, but these standards only point to crossing over a roadway. So that's when you're actually going perpendicular or underneath a freeway, which happens occasionally in the PG&E system. It doesn't -- it doesn't cover a pipeline that's in a street. Pipelines in a street is a very common activity, and that activity is taken into account when the pipeline is built. And usually it's just the amount of cover over and above the roadway that you're looking for.

Q It would be helpful to understand how PG&E took into account the fact that it was under a roadway. So for example, if you're saying, the fact that it was under a roadway led us to bury it to X many feet. So I'm asking a factual question which you don't have to answer now, but it would be very helpful to understand what factors were taken into account.

A Well, we'll look in to see if the forensics engineering can solve that. That can mean our pipeline was built in 1956. So I'm not sure that information is available. But somebody will take a look at it.

And then in terms of the new programs, we talked about this. This is our Pipeline 2020 Program. In the interest of time I'll go through it very, very quickly because we covered a lot of it this morning. We will have a proposal to modernize the critical infrastructure. That's all of our pipeline infrastructure. Again, it will be a decision matrix, if you will, or decisionmaking tree that says, if a pipeline is under these circumstances, this is what we should do. And we'll be looking for obviously input from many parties including the Commission.

We will be and we agree to start the installation of automatic and remote control valves. Remote control valves are the majority of what those valves will be in High Consequence Areas. And we're also going to be talking about the use of automatic valves in areas that cross over an earthquake fault. So not necessarily near an earthquake fault. Being near an earthquake fault doesn't necessary bother the pipeline, but crossing an earthquake fault, if it can't be engineered out, if you can't use heavier walled pipe or specifically designed trenches, then it may be appropriate to use an automatic valve in those locations. And that will be part of the testimony also.

And we are looking for the next generation of technologies. We have put in $10 million into that. And again, this is not just making pigs smarter but the next generation of technologies to do nondestructive testing for our pipelines so we can look at integrity going forward and see if other industries have activities that might benefit us such as nuclear.

And then we've talked to others about our industry leading best practices, looking what other industries are doing, other countries are doing in terms of their best practices around pipeline infrastructure and utilizing those.

And then earlier I mentioned our public safety partnerships. We have shared drawings with folks. I think it's pretty common knowledge that after 9/11 we quit sharing gas transmission information. Prior to that we handed it out pretty regularly and, you know, with the fire chiefs. After it was listed as critical infrastructure, we quit sharing that information. We have gone back to at least first responders should have that information. We share that with them. We're also working on a couple of pilots to give it to them electronically so that they may be able to match it up with their system and potentially be able to use it for dispatch purposes. So we've got several of those pilots going on with cities and counties in PG&E's service territory.

And I think with that that probably covers the highlights of the presentation. If there's any questions, but I know we're short on time. So I don't want to go through a lot of details.

Q I have another question on this plan. So you mentioned earthquake safety. So trying to put 2 and 2 together with what's happening in the Japan. Japan has invested in a earthquake alert system which did allow time for things like all the high speed trains to be slowed, and that is being cited as a reason why no high speed trains derailed.

You know, with an earthquake alert system, and I understand that there are huge financial implications for that, it might be possible to do things like if you knew a massive earthquake was coming on the San Andreas Fault if you had a gas pipeline in that area particularly with remote shut-off valves to make a decision about whether or not that particular gas should be shut off.

So have you considered or would you consider the whole issue of, as part of the earthquake issues looking at any possible alert systems and how that might interact with remote shut-off triggers to try to ensure -- I understand that for the San Francisco earthquake in 1906 that gas pipeline explosions were part of the cause of the fires then. But just want to make sure that we're thinking broadly about putting all the factors together.

A Well, I can't speak, and I'm probably not the expert witness on predicting earthquakes. That's not something up my skill set. I would say that in general the gas transmission system is designed for the earthquakes we expect to see. Certainly in the San Francisco Bay Area there are many earthquake faults, both the Hayward Fault, San Andreas Fault and many others throughout the San Francisco Bay Area. We look at those. Pipelines generally speaking, steel pipelines of today's technology withstand earthquakes relatively well. There are some techniques we obviously want to continue to look at.

And for those, as I mentioned earlier, if we have to cross a fault, which is really the issue for -- there are really two issues in terms of earthquakes for PG&E that we concern ourself with at great length after reviewing Loma Prieta and the many earthquakes we've had in California.

One is if you cross an earthquake -- if you cross a fault line, that fault line is going to move, that clearly puts the pipeline in a difficult or a stressful situation. And the second one is, is everything bolted down properly, particularly above-ground piping and all the infrastructure that supports it. Well, the bolting down is relatively straightforward, and that's been completed. After Loma Prieta we bolted all our stuff down.

In terms of crossings, we're constantly looking at new technologies. There's new codes and standards constantly coming out for pipelines around crossings. You can design very heavy walled pipe that might withstand it, withstand that activity.

You can design special trenches that allow the earth to move but the pipe not to have to move. So V trenches filled with sand, if you will, that will just move around the pipeline. And if your engineering tells you that won't work for the magnitude you think you potentially have, that's when we'll look at these automatic valves.

But in terms of tying in automatic valves, automatic valves will sense it and shut it off. In terms of using remote control valves, I think as a pipeline operator I would tell you I want to make sure that that prediction system is very, very good because if I'm shutting off gas to 800,000 customers in San Francisco Bay Area on a feel that I might have an earthquake, those individuals would be out of gas for a very, very long time going forward. But it is -- earthquake preparedness in California certainly is a very big issue for us.

EXAMINATION

BY COMMISSIONER FLORIO:

Q One of your earlier slides you mentioned, I think it was in the initial post-San Bruno inspection that you found something like ten class leaks, and I think it was Class 1, but I wasn't sure. Yeah, 20 Grade 1 leaks. Is Grade 1 the lowest or the highest?

A Grade 1 is the highest. That is oftentimes referred to as a potentially hazardous or a hazardous leak. And there's a lot of criteria that goes along with grading, and I won't try to memorize and share it all with you, but in general terms that's a leak that has the potential to cause a problem. And so PG&E's response is immediate. We stand by until the leak is resolved. And that means that there were 20 Grade 1's found. A crew -- a standby person stays there. We send a crew out. We locate it. We repair it, fix it, and move on. And that was over the 67 -- you know, over the 5700 plus miles of DOT defined gas transmission pipeline.

Q And, you know, we seem to be driven a lot by the news media on these issues. Line 109, also on the Peninsula, was the subject of an article yesterday which I understand you haven't had much time to even read potentially, but, you know, you've done the Line 101 validation, obviously doing a lot with Line 132. What can you tell us today about Line 109?

A Well, and just so I can be very clear there. The validation we did on Line

101 was the high pressure section of Line 101 that operates at 400 MAOP. The section of line -- Line 101, Line 132, and Line 109 all feed San Francisco proper, and all of them have a regulator station prior to or just on the border of San Mateo County and San Francisco County that regulate the pressure down to approximate 150 pounds. So that's a much lower pressure system in terms of what I think is being referenced in San Francisco, if you will.

Line 101 is complete, as I mentioned. We, you know, we were able to verify a lot of information, but all of our digs on Line 101 verified that the seam type we thought we had is what we had. We haven't completed all of the digs on Line 132 or Line 109, but there hasn't been anything found that is of I would call it a significant surprise or anything that indicates that we have any issues with code compliance or are operating a pipeline outside of its class location at this point in time.

And I will read that article, I believe it was from The Chronicle, when I return to my office today.

ALJ BUSHEY: Questions, Commissioners?

(No response)

EXAMINATION

BY ALJ BUSHEY:

Q I have just two quick questions for you.

From your presentation, I'm concluding that you have not found any other defective welds similar to the one in Line 132; is that correct?

A That's correct. In terms of what we've done since September 9th and all the data we've found, we have not found the similar circumstances of what happened, which is a missing inside weld in Line 132. That's correct.

Q Do you have a tentative conclusion that the missing weld in Line 132 is simply a singular anomaly?

A Well, in ter -- we haven't found anything that indicates to us we have anything similar elsewhere in our system, but we'll continue to look for that, and that's part of the MAOP validation activity. But again, we've completed, you know, roughly 35 miles of Line 101. We've done some camera work on Line 132. We've done a lot of work on Line 109.

If you added all that up, you probably would come to the conclusion it's about a hundred miles of pipe plus or minus a little bit. You know, we have a lot of pipeline still to look at. But at this point in time we don't have any reason to believe we have that situation anywhere else, but we're certainly going to look and make sure we don't have it anywhere else.

Q Thank you.

One last question now looking forward. I noticed in all of your presentation you referenced several times that you're going to be conferring with our staff. Do you have any specific plans to bring any applications or specific proposals to the Commission?

A Well, in terms of hydro testing, I believe we're scheduled -- we were talking about our schedule and our proposal of hydro testing 152 miles this week. The MAOP validation study is in their hands, and we're looking for proposals there. And then the Commission staff will have seen all the proposal we're making forth as part of Pipeline 2020 prior to any filings.

Q I was distinguishing between the Commission staff and the Commission itself, like was a formal proposal that would possibly go to hearing and result in the

Commission decision as opposed to your collaborative, your ongoing collaborative efforts with our staff?

A   Well, if I understood your question correctly, I know we're going to have a formal filing for Pipeline 2020, including the remote control valves and the pipeline modernization activity will be filed mid-May.

Q   Mid-May. So that's the next time you -- or the first you time anticipate bringing something formally before the Commission for official Commission action?

A   You want to answer that?

MR. MALKIN: Let me add to the response. We will also be filing comments in two days on the rulemaking proposals in this proceeding, and those are certainly for formal Commission action. We have -- there is pending an application, I'm not sure it was an application, I think it was an advice letter filing requesting the establishment of a memorandum account. There's a draft resolution on that that is in front of the Commission as well as the record OII, and there are probably a number of proceedings that I'm forgetting.

ALJ BUSHEY: Thank you.

Final questions for?

COMMISSIONER SIMON: I just have one. Going back to this failure to communicate reference, and I don't want to use a term that animal rights activists would not like, but it has something to do with a horse. Are you saying that PG&E failed to communicate or there was a failure of communication between PG&E and CPSD or the wider Commission staff?

MR. MALKIN: I'm saying that there was a failure of communication among PG&E, the staff, and the Commission itself.

COMMISSIONER SIMON: And the staff has, to the best of your knowledge, admitted to that failure of communication? I know this would probably have been better asked of Mr. Heiden but --

MR. MALKIN: Yeah. The reason I'm pausing is I mean I think they would certainly agree that there was a failure of communication. I think they would say the failure was PG&E's. So I don't -- didn't want to misrepresent the staff's position in that regard. But I don't think that, at least from my conversations, I don't think there is a disagreement about the basic proposition that there was a failure of communication.

COMMISSIONER SIMON: Mr. Heiden, is

that a accurate assessment from your -- I imagine Mr. Heiden is still under oath, correct?

ALJ BUSHEY: He's counsel.

COMMISSIONER SIMON: Oh, he's counsel. So he's not under oath.

(Laughter)

COMMISSIONER SIMON: It gets a little confusing from this angle I should say.

Is that a fair depiction, that it was failure of communication between staff and PG&E in reference to the documents, the information that was required under the order issued by this Commission and the letter by, sent by Executive Director Paul Clanon? Is that where the failure is?

MR. HEIDEN: It's not staff's position that we failed to communicate. It's not staff's position that the Commission failed to communicate. That's not our position.

COMMISSIONER SIMON: So if you have a comment on this notion of failure to communicate, am I saying it properly, Mr. Malkin, that it's a failure to communicate versus failure to comply? Are you saying it wasn't a failure to comply but a failure to communicate?

MR. MALKIN: Well, I would say,

Commissioner Simon, from our vantage point, we believed, and I put it in the past tense because obviously Mr. Clanon's March 16th letter and the Order to Show Cause has to make us think the communication wasn't as clear as we believed at the time. We believed that our January 7th and February 1st letters were clear as were the other communications that we had with the Commission staff that what we were physically able to do by March 15th was to collect documents sufficient to allow us to determine, of the 1805 miles subject to the directives, which of them had pressure test records. And from that we would proceed to a second step or second phase which would not be completed anywhere near March 15th of looking more closely at the miles of pipe for which we didn't have the pressure test records and performing the engineering analysis to do the MAOP validation. That was what we believed.

As you can see from Mr. Clanon's letter and the fact that the enforcement staff brought this draft OSC to the Commission, while they may concur that there was a failure of communication, they think that we did not communicate that, that we understood and that the expectation on their part was that we would complete the MAOP validation by March 15th.

As I said, we have a very different view in terms of both written communications and the oral communications that we thought it was clearly understood certainly by all of the staff people we were meeting with what we were going to be able to physically do and what we would physically do later.

COMMISSIONER SIMON: So the phase, the phase process or concept was in collaboration with CPSD staff, this two-prong document submission -- document submission and testing process?

MR. MALKIN: I want to be precise because I don't --

COMMISSIONER SIMON: I want you to also.

MR. MALKIN: Yeah. What I would say is we clearly described to CPSD that the way we were approaching this huge, huge task which was in phases, and we described that. Phase 1 was going to be collecting the basic records, determining where we could verify pressure tests, and that Phase 2 was going to be then to analyze more closely the miles of pipe for which we didn't have the pressure test records.

The reason I hesitate to use the word "collaborative" is because we described that process. The staff asked us questions about what was going to be included in each. They asked us how long we thought Phase 2 would take to complete. And they didn't say, yes, we think you should do it in two phases; nor did they ever say, you realize if you do it that way, come March 15th you're out of compliance.

We -- there was never that communication, and that was the basis on which we believed that the expectations on the Commission's side were the same as what we thought we had communicated and that we would be doing this in two phases and in fact meeting the Commission's expectations in what we filed on March 15th.

COMMISSIONER SIMON: And Mr. Heiden, that's an accurate assessment on your part?

MR. HEIDEN: Well, I personally was not at meetings with PG&E that he's describing.

COMMISSIONER SIMON: Okay. So here we go again. Who was at the meeting? I'm sorry that I was not at the prior hearing, but who at CPSD? Was it Julie Halligan who participated in these meetings?

MR. HEIDEN: Probably. I don't know right now.

COMMISSIONER SIMON: Mr. Clark, can you verify who was in attendance at the meetings? And again I apologize for the delays here. This to me at least in my assessment is germane to the process.

MR. CLARK: Commissioner Simon, there were more than one meeting, and there were more than one person at these meetings. I was at some of these meetings. Julie Halligan was at some of the meetings. Staff were on the phone in the room. Paul Clanon was at many of these meetings also as I recall.

COMMISSIONER SIMON: And during these meetings there was a reasonable belief that there would be a two-phase submission as opposed to the complete submission on March 15th?

MR. CLARK: There was a belief that PG&E was going to undertake to identify all aspects of their -- all segments of their system which had been hydro tested, that they were then going to conduct a diligent and thorough search for the records which reflected hydro testing or lack of hydro testing on the rest of their system and that they were going to bring those documents to us on March 15th, that the completion of the MAOP validation study, the entire crunching of the numbers, analysis over all the underlying documents and that sort of thing was going to take longer.

COMMISSIONER SIMON: And August was the projected timeline?

MR. CLARK: I don't recall specifically what the timeline was.

COMMISSIONER SIMON: Okay. Thank you. I appreciate that. And Commissioners, I thank you as well.

ALJ BUSHEY: Final questions?

(No response)

ALJ BUSHEY: Hearing none then, this oral argument and report are concluded and the Commission is adjourned.

(Whereupon, at the hour of 1:32 p.m., this oral argument was concluded.)

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Document Content(s)