BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company to Determine Violations of Public Utilities Code Section 451, General Order 112, and Other Applicable Standards, Law, Rules and Regulations in Connection with the San Bruno Explosion and Fire on September 9, 2010.	I.12-01-007 (Filed January 12, 2012)

OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES

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"Pay no attention to that man behind the curtain! The Great Oz has spoken!"

Oz speaking in "The Wizard of Oz," a 1939 American fantasy adventure film produced by Metro-Goldwyn-Mayer and based on the 1900 novel, The Wonderful Wizard of Oz, by L. Frank Baum.

[M]any of the organizational deficiencies were known to PG&E, as a result of previous pipeline accidents in San Francisco in 1981, and in Rancho Cordova, California, in 2008. 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.

National Transportation Safety Board, Pipeline Accident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, adopted August 30, 2011, Ex. CPSD-9, pp. 117-118 (*citations omitted*).

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

At 6:11 p.m. on September 9, 2010, a 30-inch diameter natural gas transmission pipeline, owned and operated by Pacific Gas and Electric Company (PG&E) ruptured in a residential neighborhood in San Bruno, California. Gas escaping from the rupture ignited, causing an intense fire which killed eight people, injured 58 others, destroyed 38 homes, and damaged another 70 homes.

The National Transportation Safety Board (NTSB), the Independent Review Panel (IRP), and the Commission's Consumer Protection and Safety Division (CPSD)[1] have all completed investigations into the causes of the incident. Each of these investigations has found PG&E responsible for the explosion on multiple levels. The gas pipeline was defective when PG&E installed it in 1956; it was so defective that it would have been obvious to anyone looking at the line that it did not meet safety standards in place at that time. As the NTSB Report unequivocally states: "The accident pipe segment did not meet any known pipeline specifications" and "[c]onstruction and quality control measures for the 1956 relocation project were inadequate in that they did not identify visible defects."[2]

The reports then describe PG&E's failures to maintain its gas system over time, its missed opportunities to correct those failures, and other systemic failures resulting from PG&E managements' culture of profits over safety.[3] The NTSB found that the San

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[1] The Consumer Protection and Safety Division was renamed the Safety and Enforcement Division (SED) effective January 1, 2012. However, for clarity and consistency, we refer to SED as CPSD throughout this pleading.

[2] Ex. CPSD-9, NTSB Report, p. 116. The Order Instituting Investigation (OII) issued in this proceeding summarizes the findings of the NTSB Report:

> The NTSB Report (issued on August 30, 2011) finds that the pipeline segment that ruptured was not properly manufactured or installed, safety standards were overlooked or ignored, PG&E's inspection and maintenance practices over time were deficient and ineffective, and that PG&E's response to the incident was excessively slow.

I.12-01-007, p. 2 *summarizing* Ex. CPSD-9, NTSB Report.

[3] The OII issued in this proceeding summarizes the conclusions of the CPSD San Bruno Report:

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Bruno explosion was an "organizational accident" that could have been prevented had PG&E operated its gas transmission system prudently.[4] In sum, the investigations reveal that PG&E's gas operations prior to the San Bruno were a mess at virtually every level, and that this has been going on for decades.

Notwithstanding the nearly endless parade of PG&E mismanagement that these investigations have revealed, PG&E argues that its only mistake was when it improperly installed Line 132 in 1956, and that the Commission and the parties simply want "someone to blame" when they suggest that other factors contributed to the San Bruno explosion. In his opening remarks, PG&E's attorney explains that, aside from the unsafe installation 1956, there is nothing "any operator would reasonably have done that would have prevented this tragedy":

> It is human nature when bad things happen to look for someone to blame. And make no mistake about it, that is what this proceeding is all about. While PG&E acknowledges that it is responsible for this terrible accident and its consequences, it does not agree that once that pipe was put in the ground in 1956 there was anything any operator would reasonably have done that would have prevented this tragedy. Nor does PG&E agree that any of the alleged safety violations contributed in any way.[5]

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> The CPSD Report being issued with this Order alleged that PG&E violated the California Public Utilities Code, various federal and state pipeline safety regulations, and accepted industry standards. CPSD's investigation alleges that the incident in San Bruno was caused by PG&E's failure to follow accepted industry practice when installing the section of pipe that failed, PG&E's failure to comply with federal pipeline integrity management requirements, PG&E's inadequate record keeping practices, deficiencies in PG&E's data collection and reporting system (known as Supervisory Control and Data Acquisition, or SCADA), inadequate procedures to handle emergencies and abnormal conditions, PG&E's deficient emergency response actions after the incident, and a systemic failure of PG&E's corporate culture that emphasized profits over safety.

I.12-01-007, p. 2 *summarizing* Ex. CPSD-1, CPSD San Bruno Report.

[4] Ex. CPSD-9, NTSB Report, pp. 117-118.

[5] 3 RT 49:24 – 50:7, Malkin/PG&E.

Stated plainly, PG&E argues that once a bad pipe is put in the ground, there is nothing an operator can "reasonably" do to discover and correct the mistake. If true, this claim has terrifying implications for our nation's gas transmission infrastructure and the people who live near it. But PG&E does not stop there.

PG&E's attorney concludes his opening remarks by admitting that the Administrative Law Judge (ALJ) may find that its past practices "fell short" but that "none of those shortcomings was responsible in any way for the San Bruno accident" because "PG&E's practices have been consistent with industry practices at the time."[6] Thus, PG&E admits it is responsible for the San Bruno explosion, but not really, because it was complying "with industry practices at the time."

Reading PG&E's testimony in this proceeding, one wonders why we are here at all. PG&E tells a good story about its integrity management program and the protocols that it follows.[7] As if this proceeding were a friendly parlor discussion, PG&E characterizes as "differing viewpoints of subject matter experts" those instances where PG&E and everyone else disagree (which they do on most material issues). But the real story, the story PG&E refuses to tell, is born out by the evidence gathered, and the various reports' conclusions about what really happened, and is happening, within PG&E.

In summary, the reports reveal that PG&E has had "safety culture" issues for decades, that San Bruno is not an isolated incident, and that PG&E has been on notice of its employees' troubling lack of compliance with standards for decades, but has failed to take a systematic approach to resolve those problems. PG&E responds to the reports' allegations by engaging in misdirection techniques a magician would admire.

For example, the reports found, among other things, that PG&E's recordkeeping procedures and its integrity management program were seriously deficient and contributed to the explosion. In response, PG&E attempts to make much of the fact that

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[6] 3 RT 52:3-20, Malkin/PG&E.

[7] Ex. PGE-1, PG&E Testimony, Chapters 4 and 5.

PHMSA[8] and CPSD audits of its integrity management program did not identify violations.[9] However, as PG&E well knows, those audits were facial reviews of PG&E's protocols.[10] Unfortunately, they did not look behind PG&E's representations to ensure PG&E was actually *doing* what it said. And now, as this investigation looks behind PG&E's representations, the evidence reveals that PG&E has been mismanaged for decades and that all of this mismanagement contributed to the San Bruno explosion. The evidence shows that San Bruno was an avoidable accident.

Possibly more troubling, throughout this case PG&E appears to have forgotten its overarching obligation to operate its system safely. PG&E's testimony reflects that PG&E is only concerned, even now, about nominal regulatory compliance. For example, PG&E defends its decision to assess the condition of Line 132 – and ultimately the majority of the pipelines in its system – using external corrosion direct assessment (ECDA) rather than in-line-inspection (ILI) because *the regulations allowed it*. PG&E does not ask whether ECDA was appropriate, and in fact, it was not, as its engineers knew. And PG&E does not disclose that it chose ECDA over ILI in many circumstances because it was substantially cheaper, even though it now admits an ILI assessment of line 132 would have shown its deadly defects.[11]

PG&E's commitment to nominal compliance over safety pervades PG&E's arguments in this case. And these arguments must be recognized for what they are – attempts to distract the Commission from the real issues.

"Pay no attention to that man behind the curtain! The Great Oz has spoken!"[12]

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[8] PHMSA stands for the federal Pipeline and Hazardous Materials Safety Administration.

[9] Ex. PGE-1, PG&E Testimony, pp. 4-11 to 4-12.

[10] 11 Jt. RT 1210:18-1211:4 ("Q: Do you know or are you aware that the audit that CPSD conducts of PG&E is primarily a records audit? A: Records in that they look at our procedures and sometimes they also look at the policy, and then they also look at some supporting records in evaluating a particular process. Yes, I'm aware of that. Q: Right. They look at paper. They don't go out into the field and dig up and examine pipelines; correct? A: Um, I – that is correct.")

[11] Ex. PGE-1, Testimony, pp. 4-35 to 4-36.

[12] Oz speaking in"*The Wizard of Oz,*" a 1939 American fantasy adventure film produced by Metro-

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It is critical that we look behind the curtain, and that we look behind what PG&E *says* it was doing to understand what PG&E was *actually* doing. How was PG&E *really* operating its system? Was PG&E management making choices to ensure the safety of PG&E's high pressure natural gas transmission system?

The answers to these questions are easy. The bald facts of the defective pipeline installation in 1956 should put the Commission on notice that even in the "good old days" of the 1950s when people might have put "quality first," PG&E was mismanaged. As the NTSB reports:

> [T]he rupture of Line 132 was caused by a fracture that originated in the partially welded longitudinal seam of one of six short pipe sections, which are known in the industry as "pups." *The fabrication of five of the pups in 1956 would not have met generally accepted industry quality control and welding standards then in effect, indicating that those standards were either overlooked or ignored.* The weld defect in the failed pup would have been visible when it was installed.[13]

The magnitude of the errors in the installation, and the fact that the defects could be seen with the naked eye demonstrates that *even in the 1950s* PG&E lacked basic functional quality assurance procedures for its major gas pipeline installations, and that it was not following industry standards of the time. Many workmen, supervisors, and inspectors would have participated in the installation.[14] Any one of them could see that the installation was not performed to any form of industry standard. If you were a workman or supervisor or inspector involved in the installation of those pups, what would you have done? The fact that there is *no record* of anyone reporting what happened on

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Goldwyn-Mayer and based on the 1900 novel, *The Wonderful Wizard of Oz,* by L. Frank Baum.

[13] Ex. 9, NTSB Report, p. x (*emphases added*).

[14] When asked who might have reviewed the records for the Line 132 installation, Ms. Keas answered: "I would say that I would expect that the person that installed the pipe, the inspector that inspected that section, the crew leader, the supervisor for that particular job, mappers, could have done an evaluation of the information that was used to populate the job file and then ultimately the GIS." 10 Jt. RT 1013:3-10, Keas/PG&E.

this installation speaks volumes about PG&E's standard practices at the time. Common sense dictates that it is unlikely that the poor quality installation of Line 132 was an anomaly. And there is no evidence that PG&E's installation or quality assurance practices changed over time, thus suggesting the very real and terrifying prospect that there are potentially many other San Bruno-like "time bombs" in PG&E's system.

PG&E's extensive remedial activities undertaken since the San Bruno explosion, in large part pursuant to recommendations of the NTSB and orders of the Commission, also belie PG&E's argument that it had been following industry standards since the 1956 installation. As described in Commission Decision (D.)12-12-030 (the Pipeline Safety Implementation Plan Decision), PG&E is now in the process of rebuilding its gas system records and database from the ground up, and testing and/or replacing pipelines where insufficient records exist to confirm that the pipe is safe. Such extensive work is necessary because very little in the existing system can be relied upon.

In sum, PG&E hopes to circumscribe this case so that it will only be penalized for its defective installation of Segment 180 in 1956, and to limit its exposure for the costs of the remedial work that it is now undertaking to ensure the safety of its high pressure gas pipeline system. It argues that its actions were consistent with standard utility practices at the time, and that the actions that followed the defective installation in 1956 have nothing to do with the San Bruno explosion. However, the evidence shows that PG&E's historic mismanagement, including its deficient integrity management program, and its culture of profits over safety, contributed to the San Bruno explosion.

In order to ensure that PG&E "gets the message" and truly embarks on the "safety journey" envisioned in D.12-12-030, this Commission must look behind PG&E's curtain of rhetoric and hold PG&E accountable for the full range of violations it has committed since 1956. Further, to the extent that PG&E is found to have committed errors and omissions in the installation, operation, or maintenance of its gas transmission system, PG&E shareholders, not ratepayers, should be responsible for that remedial work and refunds should be ordered, as contemplated in D.12-12-030, and as required by Public Utilities Code §§ 451 and 463. Finally, to ensure that all further gas transmission system work is performed consistent with current industry standards and this Commission's orders, rules, and regulations, the Commission should require an independent third party monitor to oversee all aspects of PG&E's work being performed in response to the San Bruno explosion, including, without limitation, work ordered in Decisions 11-06-017 and 12-12-030.

II. BACKGROUND (PROCEDURE/ FACTS)

III. LEGAL ISSUES OF GENERAL APPLICABILITY (TO THE SB OII)[15]

A. The Commission Is Responsible For Enforcing the Utilities' Obligation To Provide Safe Service As Required By Public Utilities Code § 451

The Commission is responsible for ensuring that all public utilities subject to its jurisdiction comply with all applicable laws:

> The commission shall see that the provisions of the Constitution and statutes of this State affecting public utilities … are enforced and obeyed, *and that violations thereof are promptly prosecuted and penalties due the State therefor recovered and collected,* and to this end it may sue in the name of the people of the State of California.[16]

Public utilities must comply with many legal requirements, but the obligation to operate their systems safely, as set forth in § 451, is the most fundamental legal requirement of all. As recognized in the Order Instituting Rulemaking (OII) opening this proceeding, § 451 requires utilities to operate safely, and if they violate that requirement they are subject to fines:

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[15] There are a number of legal issues of general applicability to this investigation. The vast majority of them will likely be briefed by the other parties to this proceeding. For efficiency, DRA focuses on those legal issues which may potentially be overlooked and are relevant to ratemaking issues implicated by this investigation. DRA does not intend this to be a comprehensive or exclusive list and may supplement this list in its later pleadings in this proceeding.

[16] California Public Utilities Code § 2101 (*emphases added*). Unless otherwise stated, all further section references are to the California Public Utilities Code.

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> Section 451, which has been in effect since 1909, requires all public utilities to provide and maintain "adequate, efficient, just, and reasonable" service and facilities as are necessary for the "safety, health, comfort, and convenience" of its customers and the public. A violation of the Public Utilities Code or a Commission decision or order is subject to fines of $500 to $20,000 for each violation, for each ongoing day, pursuant to Sections 2107 and 2108.[17]

As the OII explained, PG&E's electric and gas activities are potentially dangerous and the public, as well as PG&E employees, are entitled to expect PG&E to operate safely:

> Members of the public as well as PG&E employees are entitled to expect that PG&E will transport and distribute natural gas as safely as reasonably possible. Public Utilities Code Section 451 requires Commission-regulated utilities to operate safely.[18]

The language of § 451 is broad, but enforceable. The Commission has held, and Courts have confirmed, that a violation of § 451 is a separate offense for which a fine may be imposed, regardless of whether the conduct in question also violates a more specific regulatory requirement.[19]

B. The Commission Has Authority To Disallow Rate Increases Pursuant to Public Utilities Code §§ 451 and 463

Section 451 also has rate impacts on utility practices. Pursuant to § 451, all utility rates and charges must be just and reasonable:

> All charges demanded or received by any public utility … for any product or commodity furnished or to be furnished or any service rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity is unlawful.[20]

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[17] I.12-01-007, p. 7 (*footnotes omitted*). Effective January 1, 2012, the statutory maximum fine was increased to $50,000 for each offense.

[18] I.12-01-007, p. 8.

[19] *Pacific Bell Wireless, LLC v. Public Utilities Commission,* 140 Cal. App. 4th 718, 741-742 (2006). The parties' recommendations for fines and other penalties are to be addressed in separate briefs. Accordingly, regarding fines, DRA limits its comments here to the point that the Commission may impose fines for violations of § 451.

[20] *See also* § 728 ("Whenever the commission, after a hearing, finds that the rates or classifications, demanded, observed, charged, or collected by any public utility for or in connection with any service,

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Section 463, when it is applicable, governs the Commission's ratemaking decisions as well. As a supplement to § 451, and consistent with the Commission's general ratemaking authority, § 463 requires the Commission to disallow direct and indirect expenses where they are related to the unreasonable errors or omissions of a utility and add more than $50 million to the cost of providing service:

> [T]he 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) ....

The Commission has relied upon § 463 and its general ratemaking authority on many occasions to disallow costs resulting from unreasonable utility errors and omissions, and should do so here.[21]

While ratemaking issues are not usually taken up in an OII, the Commission invited consideration of such issues here in D.12-12-030, the decision approving PG&E's post-San Bruno remediation plan and addressing the ratemaking treatment of the plan's costs.

In D.12-12-030 the Commission recognized that the evidence and findings in this proceeding could (and possibly should) impact the rate treatment of PG&E's remedial

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product, or commodity, or the rules, practices, or contracts affecting such rates or classifications are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force.").

[21] *See, e.g., Re Pacific Gas and Electric Company* (1998) 83 CPUC 2d 208 (D.98-11-067, affirming disallowance of $100 million from recoverable Diablo Canyon nuclear plant sunk costs, based on an admitted error by contractors during the plant's construction); *Re Southern California Edison Company* (1994) 53 CPUC 2d 452 (D.94-03-048, disallowing costs associated with an accident and explosion at a coal slurry generating plant that killed six utility employees); *Re Pacific Gas and Electric Company* (1985) 18 CPUC 2d 700 (D.85-08-102, disallowing costs based on managerial imprudence and inadequate attention during construction of Helms Pumped Storage Project); *Re Southern California Edison Company* (1985) 17 CPUC 2d 470 (D.85-03-087, disallowing repair costs associated with defective steam generator equipment at San Onofre Nuclear Generating Station Unit 1); *Re Southern California Edison Company* (1986) 22 CPUC 2d 124 (D. 86-10-069, disallowing $344.6 million in construction costs of SONGS units 2 and 3 as a result of imprudence and unreasonable delays in completion of the project).

pipeline safety plan, which was approved in that decision. The Decision expressly made the rate increases approved in that decision subject to refund based on "ratemaking adjustments … adopted in [the Commission's] investigations":

> 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.[22]

Ordering Paragraph 3 of D.12-12-030 reinforces this finding:

> All increases in revenue requirement authorized in Ordering Paragraph 2 [of this decision, D.12-12-030] are subject to refund pending further Commission decisions in Investigation (I.) 11-02-016, I.11-11-009, and I.12-01-007.[23]

Consequently, to the extent the parties to this proceeding have shown that PG&E has committed unreasonable errors or omissions that added more than $50 million to PG&E's costs, those costs, direct and indirect, should be disallowed. Given the provisions of D.12-12-030, the Commission should order those disallowances in this proceeding.

IV. OTHER ISSUES OF GENERAL APPLICABILITY (TO THE SB OII)

V. CPSD ALLEGATIONS

A. Construction of Segment 180

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[22] D.12-12-030, p. 4.

[23] D.12-12-030, p. 126, OP 3.

B. PG&E's Integrity Management Program

1. PG&E's Expert Testimony That Its Integrity Management Program Met Requirements Is Not Credible And Should Be Disregarded

a. Every Report On the San Bruno Explosion Concludes That PG&E's Integrity Management Program Was Deficient

i. NTSB Report

PG&E's integrity management program failures, and their pivotal role in the San Bruno explosion, were quickly evident to the NTSB. In the immediate aftermath of the explosion, PG&E told the NTSB it was a seamless pipe that had failed. PG&E based this statement on data from its electronic Geographic Information System (GIS), the primary source of information about the design and construction of its pipeline system. Of course, anyone viewing the remains of the pipe section lying on the ground in San Bruno could see that the pipe had split along a longitudinal seam, and thus could not have been seamless.

Within three months of the accident, in recognition of the dangers posed by PG&E's integrity management deficiencies, the NTSB issued an "urgent safety recommendation" that PG&E survey all of its gas transmission records to ensure that PG&E calculated maximum allowable operating pressure (MAOP) for a pipeline using only "traceable, verifiable, and complete" records.[24]

[24] On January 3, 2011, the NTSB issued multiple "Safety Recommendations" to PG&E, this Commission, and the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). As summarized in D.11-06-017 at 2, the Safety Recommendations included substantially the same descriptions of findings by NTSB as a result of the initial stages of its investigation of the San Bruno pipeline rupture and fire. The two Safety Recommendation letters (reflecting safety recommendations P-10-1 and P-10-2 through 4) are available at http://www.ntsb.gov/recsletters/DisplayLetters.aspx?FolderYR=2011

In the NTSB's later report regarding the causes of the San Bruno explosion, PG&E's integrity management failures played a significant role. The NTSB concluded that the explosion was caused by a gas pipe that was defective when PG&E installed it in 1956, and that the defect "would have been visible when it was installed."[25] The NTSB identified two probable causes for the accident. The first was PG&E's "inadequate quality assurance and quality control" which allowed installation of the defective line in 1956.[26] The second was PG&E's "inadequate pipeline integrity management program" – a records-based program – which "failed to detect and repair or remove the defective pipe section."[27]

The NTSB found that PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective because it relied on pipeline information that was inaccurate and incomplete, was missing mission critical information, and was not designed to consider the most relevant information – such as pipeline design, materials, and repair history – when determining how to prioritize repairs and replacements.[28] As a result, the NTSB concluded that PG&E's integrity management program "led to internal assessments .... that were superficial and resulted in no improvements."[29]

ii. IRP Report

The IRP Report found similar problems with PG&E's integrity management program. Based on discussions with PG&E staff, the Panel found that "experienced piping engineers were well aware" of the characteristics of the San Bruno segment, and that it was not a seamless pipe.[30] On this basis, the IRP Report concludes that "[t]here is

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[25] Ex. CPSD-9, NTSB Report, p. x.

[26] Ex. CPSD-9, NTSB Report, p. xii.

[27] Ex. CPSD-9, NTSB Report, p. xii.

[28] Ex. CPSD 9, NTSB Report, p. xi.

[29] Ex. CPSD 9, NTSB Report, p. xi.

[30] Ex. CPSD-10, IRP Report, p. 7.

a lack of coordination between field resources and engineering management regarding which data are to be collected and where and how records are to be preserved."[31] The IRP Report recognized the pipeline industry "challenges" to digitize and systematize pipeline data, but concluded: "[W]e find PG&E's efforts inchoate."[32] It further explained the impacts of PG&E's data management failures on its ability to use its integrity management program to identify threats and possible failures to its gas system:

> The lack of an overarching effort to centralize diffuse sources of data hinders the collection, quality assurance and analysis of data to characterize threats to pipelines as well as to assess the risk posed by the threats on the likelihood of a pipeline's failure and consequences.[33]

The IRP Report concludes that PG&E's integrity management program *"is not identifying all threats, as required by regulation; is not identifying the segments of highest risk and remediating significant anomalies; and hence is not taking programmatic actions to prevent or mitigate threats."*[34]

Significantly, the IRP Report notes that it supports PG&E's additional testing efforts post-San Bruno, but that even there it "has observed some troubling issues with the company's implementation of its threat identification methodology."[35] The Panel observes that even when PG&E identifies actual threats to its lines and assesses those individual threats, "the interaction or multiplicative effect of those threats appears not to be given adequate consideration."[36] The Panel notes that even if the faulty segment on Line 132 had eventually been properly identified in PG&E's records, "the risk ranking for that segment would not have changed because of the way [PG&E] ranks risks."[37]

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[31] Ex. CPSD-10, IRP Report, p. 7.

[32] Ex. CPSD-10, IRP Report, p. 8.

[33] Ex. CPSD-10, IRP Report, p. 8.

[34] Ex. CPSD-10, IRP Report, p. 8 (*emphases added*).

[35] Ex. CPSD-10, IRP Report, p. 8.

[36] Ex. CPSD-10, IRP Report, p. 8.

[37] Ex. CPSD-10, IRP Report, p. 8.

Thus for multiple reasons, including incomplete and inaccurate records, the IRP Report finds PG&E's integrity management system deficient and ineffective.

b. PG&E Missed Multiple Opportunities To Correct Its Records and Integrity Management Program

Well before the San Bruno explosion, PG&E was put on notice of its significant recordkeeping deficiencies, and their impacts on its integrity management risk assessments. In 1981, the NTSB investigated a gas pipeline leak in San Francisco where PG&E took 9 hours and 10 minutes to stop the flow of gas because it could not locate one emergency valve due to inaccurate records.[38]

In 1983, PG&E engaged Bechtel to design a gas pipeline replacement program. The results of that program provided the foundation for PG&E's current integrity management plan. Throughout the development of the program in the 1980s, Bechtel advised PG&E where data was missing or assumptions were made, and the risks that missing or inaccurate information posed. For example, a September 1986 Bechtel document explained the difficulties posed by missing records and the need to "research or excavate to find the required data and eliminate the uncertainty":

> The problem of missing records caused some difficulties during the data collection process. In these cases, a "blank" entry was made in the database, so the leak probability analysis would assume the worst case for that entry. …
>
> Uncertainty values are intended to serve as a warning, pointing out the necessity for further research on those pipeline segments whose high priority values may not be justified. Additional time and effort will be required to research or excavate to find the required data and eliminate the uncertainty.[39]

An earlier Bechtel report made almost identical observations, but also emphasized that the value of the risk assessment would be limited by "unknowns and highly suspect data variables":

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[38] Ex. CPSD-9, NTSB Report, p. 81.

[39] Ex. CPSD-164, Exhibit 120 to Deposition of C. Tateosian, Vol. III, p.14 (*emphases added*).

> *Clearly the result of any risk analysis is entirely dependent upon the quality of information accessed.* The presence of unknowns and highly suspect data variables combined with the lack of mathematical precision in the evaluation of risk parameters places limitations on the applicability of the risk values.[40]

While it appears that PG&E made "a last effort" at the end of 1984 to gather missing information,[41] it is also evident that these efforts were not productive, or Bechtel would not have included its admonition – quoted above – in its September 1986 report to PG&E. PG&E was thus on notice that the best way to obtain the missing information, absent existing records was to uncover pipes in the field. However, "uncovering of the pipe never took place, mainly because of cost considerations."[42]

In December 2008, a gas distribution line exploded in Rancho Cordova killing one person and injuring several others. The NTSB "Pipeline Accident Brief" concluded that the incident was the result of PG&E's "use of a section of unmarked and out-of-specification polyethylene [PE] pipe with inadequate wall thickness that allowed gas to leak from the mechanical coupling installed on September 21, 2006."[43] The NTSB also found: "Contributing to the accident was the 2-hour 47-minute delay in the arrival at the job site of a Pacific Gas and Electric Company crew that was properly trained and

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[40] *See, e.g.,* Preliminary Report by Bechtel Petroleum, Inc, performing Engineering Consulting Services for PG&E, on Pipeline Replacement Program Transmission Line Risk Analysis (dated January 1984), pp. 1 and 13-14 (*emphases added*). This Bechtel Report is available on the Commission's website at http:/www.cpuc.ca.gov/NR/rdonlyres/E75846A0-FAD1-4A0C-AACF-C176D9F8DD7B/0/TransmissionLineRiskAnalysis1984.pdf

[41] Ex. CPSD-164, Exhibit 118 to Deposition of C. Tateosian, Vol. III, p.3011A.5 ("In December 1984, PGandE also requested divisions to review the data base output and try to fill in the many openings where no information had been found by the Bechtel field engineers. This was a last effort to complete the data base without having to uncover the pipe in the field.").

[42] Ex. CPSD-164, Exhibit 118 to Deposition of C. Tateosian, Vol. III, p.3011A.3.

[43] D.11-11-001, p. 6, *quoting* the NTSB Pipeline Accident Brief attached to the CPSD Report at Appendix L.

equipped to identify and classify outdoor leaks and to begin response activities to ensure the safety of the residents and public."[44]

The NTSB Report on the San Bruno explosion observed that PG&E was put on notice of its recordkeeping deficiencies several times over many decades and that if PG&E had taken appropriate corrective actions, the San Bruno explosion "might have been prevented":

> [M]any of the organizational deficiencies were known to PG&E, as a result of previous pipeline accidents in San Francisco in 1981, and in Rancho Cordova, California, in 2008. 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.[45]

c. PG&E's Experts Argue That PG&E's Integrity Management Program Met Requirements, Even Though It Lacked Accurate Data

Notwithstanding the authoritative and consistent findings regarding the failures of PG&E's integrity management program *over many decades*, PG&E's experts argue that PG&E's integrity management program complied with requirements, that its data gathering and integration complied with requirements, and that *accurate data is not a requirement or a goal of the integrity management rules*. PG&E's experts are able to make these assertions because they – evidently – only speak to PG&E's *written policies and protocols*. They assiduously ignore the evidence suggesting that PG&E employees were not actually *complying* with these policies and protocols. In sum, PG&E's experts refuse to look behind the curtain.

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[44] Id., pp. 6-7.

[45] Ex. CPSD-9, NTSB Report, pp. 117-118 (*citations omitted*).

PG&E's expert on integrity management, Mr. Zurcher, has an impressive resume which describes, among other things, his close ties to the gas pipeline industry, and his pervasive involvement as an industry representative in the development of the integrity management rules and gas company programs to comply with those rules.[46] He claims to have reviewed the integrity management programs of companies representing 220,000 of the 300,000 miles of pipeline installed in the United States.[47] Therefore, PG&E's expert, and his numerous gas industry clients, have much to lose if PG&E is found to have violated those rules.

Mr. Zurcher's direct testimony, and his performance on cross examination, both demonstrate Mr. Zurcher's bias as a hired apologist for PG&E and all of his future industry clients. For $390 per hour,[48] Mr. Zurcher's testimony is limited almost entirely to materials provided to him by PG&E, and relies on virtually no observations of PG&E's actual practices.[49] In sum, he compares PG&E's written integrity management program protocols to the regulations, and concludes they comply.[50] His analysis and conclusions fail to incorporate any of his own prior knowledge of PG&E's practices, which he should be familiar with given his post-San Bruno audit of PG&E's integrity management program.[51] This experience is conveniently forgotten, if his cross examination responses can be believed. And he did not ask PG&E to confirm, with evidence, the accuracy of its assertions that are key to his compliance determinations.[52]

[46] *See, e.g.,* 7 Jt. RT 679: 14-28, Zurcher/PG&E.

[47] 8 Jt. RT 798:11-21, Zuercher/PG&E.

[48] 7 Jt. RT 651:10-14, Zurcher/PG&E.

[49] *See, e.g.,* Ex. PG&E-1, Testimony, pp. 5-3 to 5-4.

[50] *See, e.g.,* Ex. PG&E-1, Testimony, p. 5-6, lines14-17 ("In connection with this testimony, I have reviewed materials relating to PG&E's pipeline data records as maintained in its Geographic Information System (GIS). My understanding from the materials that I have reviewed is that ...."); and similar at p. 5-8, lines 16-18 and p. 5-13, lines 22-24, and p. 15, lines 11-15.

[51] 7 Jt. RT 695:20 – 705:27, and specifically 704:20 – 705:27 ("Q: And so before you said that you didn't review any of PG&E's TIMP as part of this audit, do you recall that? A: Yeah, and I am struggling. ..... Q: But you did review PG&E's Integrity Management Program as part of this audit? A: Yes.")

[52] 7 Jt. RT 674:8 – 675:5, Zurcher/PG&E.

On cross examination, ignoring the well-documented evidence that PG&E's integrity management records have significant errors and omissions,[53] and have for years, Mr. Zurcher answers questions based upon the *theoretical* integrity management program PG&E *might have had* if it had followed its written rules regarding recordkeeping and gas pipeline assessments. Mr. Zurcher assiduously steers clear of agreeing with the NTSB, the IRP and numerous other consultants that "accurate" records are needed to operate a functional integrity management program. When directly asked whether he agrees with the NTSB that the elements of an effective integrity management program include accurate, complete, and verifiable data, he unequivocally states: "I would disagree with that."[54] When asked whether he would agree that accurate data is essential for an integrity management program to reach reliable conclusions he states: "I would not necessarily agree with that."[55] When asked if records can be useful for determining the condition of a pipeline, he disagrees: "No, I don't think that's a true statement."[56] When asked the basis for his testimony that the "NTSB got it wrong" on these points he explains: "Well, NTSB is just like any other organization. … They are entitled to their opinion, but their opinion is not always right."[57] Failing to provide any specific examples of how the "NTSB got it wrong," or why he is right, Mr. Zurcher reluctantly admits that the NTSB had qualified experts working on the report: "I'm sure they were qualified, yes."[58]

Upon further examination, it becomes clear that while Mr. Zurcher opines that accurate data is not necessary to populate an integrity management program *at the*

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[53] Mr. Zurcher reviewed the report and testimony of Margaret Felts in developing his own testimony. Ex. PGE-1, Testimony, p. 5-3. As such, he would have been familiar not with Ms. Felts' criticisms and supporting evidence, but also with the Bechtel warnings regarding the quality of the data in the integrity management program.

[54] 7 Jt. RT 658:28 – 659:5, Zurcher/PG&E.

[55] 7 Jt. RT 658:28 – 659:9-10, Zurcher/PG&E. See also 7 Jt. RT 662:13-19.

[56] 8 Jt. RT 733:8-21, Zurcher/PG&E.

[57] 8 Jt. RT 795:19 – 796:10, Zurcher/PG&E.

beginning, he expects that the data will later be updated with information from pipeline assessments[59] or be otherwise corrected.[60] Mr. Zurcher emphasizes that a "prescriptive program" like PG&E's, which requires mandatory pipeline assessments under the regulations, would be lacking information and required the gathering of data.[61] He explains: "Sometimes we just entered data and left items blank with the full intention of coming back later on. But we designed those systems at that time in late '80s and early '90s and probably even into today *with the idea that we would go back and supplement it with data as it became available*."[62] Mr. Zurcher emphasized this point throughout his cross examination and at again the end:

> ... I know I have to say this all the time, but the *integrity management programs directed us to where we need to find additional data to make better decisions about pipeline safety going forward.* So it was always forward looking, *where do I need to go to get this additional data, what data do I want, and then how do I integrate that data back into my program to make decisions.*[63]

However, Mr. Zurcher refused to acknowledge that, in reality, PG&E's integrity management program did not meet any quality assurance standards at the outset and that PG&E took no meaningful actions to correct its errors and omissions over time. As described in Section V.B.1.b above, this problem, and the need to correct data errors going forward, was brought to PG&E's attention by Bechtel early in the life of its initial

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(continued from previous page)
[58] 8 Jt. RT 796:11-20, Zurcher/PG&E.

[59] 7 Jt. RT 659:19 – 660:1, Zurcher/PG&E ("But remember, also the assessment process provided the operator, once the assessment was performed, with a wealth of information that they were going out and seeking. For instance, if I decided to do a smart pig run, an ILI, I would come back with a lot of information.").

[60] 7 Jt. RT 663:8-17, Zurcher/PG&E ("Again, as we would find errors in the data, those would get corrected.").

[61] 7 Jt. RT 660:7-13, Zurcher/PG&E ("[T]he operator had to recognize lacking information, I want a prescriptive program and I need to go gather that data.").

[62] 7 Jt. RT 663:1-7, Zurcher/PG&E (emphases added). *See also* 8 Jt. RT 814:9-23 ("And the integrity assessment, to a large degree, is for the purposes of finding information that you didn't have before.").

[63] 8 Jt. RT 870:2-11, Zurcher/PG&E (emphases added). *See also* the four footnotes immediately above.

integrity management program. Thus, PG&E *knew* that its database errors and omissions posed significant problems to the validity of its integrity management program, yet did nothing to address that problem. Had PG&E attempted to systematically populate its database with complete and accurate information starting in the 1980s when it hired Bechtel to develop its integrity management program, or if it had taken action at any time after that to do so, even with information learned over the years – as Mr. Zurcher explains is part of the integrity management process – PG&E might have developed an effective integrity management program and we would not be here today. Instead, it is evident that PG&E's database has historically contained, and continues to contain, so much missing and/or inaccurate data that the integrity management system itself poses a safety threat.[64]

d. Mr. Zurcher's Testimony Is Not Credible and Should Be Disregarded

Mr. Zurcher testifies to PG&E's compliance with integrity management regulations and industry standards without ever confirming for himself that PG&E actually complies with those regulations and standards. His disingenuous attempts to apply only a facial analysis should be rejected. Mr. Zurcher's credibility is questionable, and his testimony should be disregarded on this basis.

Mr. Zurcher's claims that PG&E's integrity management program is compliant with regulations and industry standards is intentionally provided in a vacuum where PG&E's *actual* practices and the *observed outcomes of those practices* are deemed irrelevant.[65] When asked whether he requested documentation from PG&E demonstrating that PG&E had complied with its own quality control requirements for entering data into the GIS system, he admitted that he did not. He simply took PG&E's

[64] Ex. CPSD-9, NTSB Report, p. xi (PG&E's integrity management program "led to internal assessments …. that were superficial and resulted in no improvements"); Ex. CPSD-10, IRP Report, p. 8 ("The lack of an overarching effort to centralize diffuse sources of data hinders the collection, quality assurance and analysis of data to characterize threats to pipelines as well as to assess the risk posed by the threats on the likelihood of a pipeline's failure and consequences.")

[65] As demonstrated during cross examination, Mr. Zurcher should be extremely knowledgeable about PG&E's practices given his numerous audits of its various systems. See e.g., 8 Jt. RT 726:7-19.

word that it had complied.[66] In fact, all evidence regarding PG&E's *actual* data collection and integration efforts is contrary to Mr. Zurcher's assertions that PG&E met "requirements." As the IRP Report recognized, PG&E did not even take the obvious step of having an experienced pipeline engineer review its data for accuracy.[67] If it had, PG&E would have known that Line 132 was not a seamless pipe.

Mr. Zurcher baldly asserts that PG&E's data gathering and integration "practices" complied with integrity management requirements, but fails to provide any evidence in support. When asked whether he actually *observed* whether PG&E was following its standards, Mr. Zurcher admitted that his observations were limited to "certain people" over "a few days":

> Q: And when you – you mentioned in response to a question from Ms. Strottman that you looked for PG&E's standards and for – and they were consistent with the industry, *did you actually observe whether or not PG&E employees were following the standards?*
>
> A: I would not say that I looked at the following of the process to the detail that I looked at the actual documents and the records of the documents. We did observe certain people performing certain tasks. Of all the tasks that I saw performed, they were in compliance with their procedures. But it was not a – it wasn't a several month effort. It was a few days.[68]

Mr. Zurcher ignores the Overland Audit findings that PG&E had recordkeeping problems as recently as 2007 in several of its gas divisions, as discussed in Section V.F.3.b below.

Mr. Zurcher also testifies that PG&E's use of ECDA for Line 132 was appropriate. He overlooks the fact that PG&E's integrity management program data was deficient and that ECDA, as compared to ILI, significantly limited the quality and quantity of new information to provide missing data points or correct inaccuracies. He also ignores evidence presented in the Overland Audit that PG&E engineers characterized ECDA as "a much less thorough evaluation of the pipeline via statistical

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[66] 7 Jt. RT 674:8 – 675:5, Zurcher/PG&E.

[67] Ex. CPSD-10, IRP Report, p. 7.

[68] 8 Jt. RT 829:1-16, Zurcher/PG&E (*emphases added*).

methods rather than by direct inspection" and conclude that "Gas Engineering would strongly prefer to smart pig PG&E's higher stress pipelines to obtain a much better initial evaluation of the line…"[69]

Ultimately, even Mr. Zurcher admits that "I think you want [data used in the integrity management program] as accurate as possible…"[70] And: "Again, where you were missing data, you could make conservative assumptions. And the whole process was *also where you were missing data, you would perform the integrity assessment and gather that data*."[71]

By applying only a facial analysis, Mr. Zurcher's review of PG&E's integrity management program falls prey to the same mistakes made by the CPSD and PHMA audits that PG&E relies upon to support its assertions of compliance.[72] Mr. Zurcher's testimony misses the point that while PG&E's integrity management program may be *written* in a manner that complies with regulations (although everyone except PG&E and Mr. Zurcher questions even this), the point is that PG&E's *implementation* of that program was not compliant, and Mr. Zurcher fails to address these concerns. Specifically, while even Mr. Zurcher insists that an integrity management program's data base must be constantly and iteratively updated, he refuses to confirm whether PG&E, in fact, engaged in this iterative process, thus undermining the entire foundation of his testimony.

Mr. Zurcher's testimony lacks credibility for the additional reason that he repeatedly contradicted himself on cross examination. For example, at one point Mr. Zurcher stated emphatically that gas pipeline operators routinely operate above maximum allowable operating pressure (MAOP) and that this is not prohibited by regulations: "…

[69] Ex. CPSD-168, Overland Audit, p. 7-8 *quoting* OC-68 (CPSD-186), Attachment 3, p. 1 (*no emphasis in original*). This issue is addressed in detail in Sections V.F.2.c.i and ii below.

[70] 7 Jt. RT 668:11 – 669:24, Zurcher/PG&E (but he qualifies: "but I don't think that there was ever an expectation that you have the most accurate data.").

[71] 7 Jt. RT 669:25 – 670:1, Zurcher/PG&E (*emphases added*).

[72] Ex. PGE-1, PG&E Testimony pp. 4-11 to 4-12.

there is no regulation that says I cannot exceed my MAOP. …. I know MAOP is exceeded by every operator every day. There is not a rule that says you can't do it."[73]

However, when presented with his own testimony to the contrary on behalf of El Paso Gas in another case, he had no response. There, he emphatically testified the opposite, that regulations require "operators to operate pipeline facilities in a manner so that they will not exceed Maximum Allowable Operating Pressure (MAOP)" and that the regulatory definition of MAOP provides that "'may not exceed' means may never exceed.'"[74] Mr. Zurcher's El Paso testimony concludes: "Therefore prudent pipeline operators manage system pressures to never exceed MAOP, which often means that a safety margin below MAOP is necessary … When considering deliverability, maximizing pressure as close to MAOP is desirable; however, it must be done to ensure that MAOP is not exceeded."[75]

At still another point in cross examination, Mr. Zurcher, after significant prompting and presentation of written documentation, admitted that he had performed an audit for PG&E after the San Bruno explosion. But he claimed to have forgotten virtually everything about the audit and what he did for the audit, including the fact that he was responsible for auditing employee practices regarding PG&E's integrity management program – an issue his testimony here assiduously avoids.[76] Incredibly, he stated: "I don't believe any of [the audit] was relevant to the report or the testimony that I prepared."[77]

Finally, after repeatedly testifying that PG&E's integrity management program was compliant with regulations,[78] Mr. Zurcher stated that only a court could answer

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[73] 7 Jt. RT 713:14-27, Zurcher/PG&E.

[74] 8 Jt. RT 789:20-790:12, Zurcher/PG&E (*emphases in original).*

[75] 8 Jt. RT 790:19-791:7, Zurcher/PG&E.

[76] 7 Jt. RT 695-705, Zurcher/PG&E; see specifically 704:20-705:18.

[77] 7 Jt. RT 706:3-5, Zurcher/PG&E

[78] Ex. PGE-1, Testimony, pp. 5-6 and 5-13 to 5-14.

whether PG&E complied with the regulations.[79] Certainly, this is a strange position for a self-acclaimed regulatory compliance expert to take. And if this is the case, shouldn't his earlier testimony to the contrary be disregarded?

e. Ms. Keas' Testimony Is Hearsay, Is Not Credible, And Should Be Disregarded

PG&E offers the testimony of its recently hired employee, Ms. Keas, to further support Mr. Zurcher's conclusions that PG&E's integrity management program met requirements. Here, PG&E has the opportunity to correct the deficiencies of Mr. Zurcher's testimony, and to show that its program *as applied* was compliant – yet it fails to do so.

Ms. Keas joined the company post-San Bruno and cannot testify as an eye witness to PG&E's actual data collection and integration practices before San Bruno. Nor can she testify regarding the actual functionality of PG&E's integrity management program at that time. But this does not stop her from trying. While she admits that she has no "personal knowledge of what was done prior to San Bruno" she elaborates on what she did to understand PG&E's practices before San Bruno,[80] and she testifies to those practices, as they were explained to her.[81] Among other things, Ms. Keas testified regarding how PG&E integrated its integrity management data from various sources using GIS before San Bruno.[82] This is classic hearsay testimony – "evidence not proceeding from the personal knowledge of the witness, but from the mere repetition of what she has heard others say"[83] – and it is being offered for the truth of the matter asserted. As such, it should be disregarded.

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[79] 7 Jt. RT 686:3-10 ("But it's always been my opinion and my understanding that it's only the courts who get to decide what compliance is") and 687:13-17 ("Again, only the court in my mind can actually determine what the regulations require, so I can't really answer that.")

[80] 11 Jt. RT 1155:3 – 1156:11, Keas/PG&E.

[81] *See, e.g.,* 11 Jt. RT 1152:13 – 1155:8, Keas/PG&E.

[82] 11 Jt. RT 1152:13 – 1155:8, Keas/PG&E.

[83] Black's Law Dictionary, Abridged 6th Edition, 1991.

The NTSB Report concludes that, contrary to fundamental integrity management principles, PG&E was *not* updating its GIS with ECDA information.[84] The NTSB Report explains that "many of the pipe segments for which records had missing, assumed, or erroneous data *had previously been exposed* in connection with ECDA excavations as part of the integrity management program."[85] This is evidence PG&E was not updating the data. The NTSB also observed that though PG&E officials at its investigative hearing claimed that PG&E required data to be updated when field staff noticed discrepancies, this was not happening:

> At the NTSB investigative hearing, PG&E officials testified that if discrepancies between GIS data and actual conditions are discovered by field personnel, field engineers are required to report them to the mapping department, which validates the information. However, the documents provided to the NTSB indicate that PG&E does not use the ECDA process for validating assumed values, determining unknown values, or correcting erroneous values.[86]

If PG&E wanted to rebut this NTSB finding in this proceeding, it should have put on a witness with *personal knowledge* of PG&E's pre-San Bruno data integration practices. PG&E's failure to produce such a witness speaks volumes about the validity of its position. Quite simply, the conclusions of the NTSB and IRP Reports that PG&E did not properly populate or maintain its integrity management data base trump Ms. Keas' hearsay testimony regarding historic events that she did not witness. All of the evidence, aside from Ms. Keas' hearsay testimony regarding PG&E's practices pre-San Bruno, demonstrates that PG&E was not engaging in the "iterative" process of database correction that effective integrity management requires.

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[84] Ex. CPSD-9, NTSB Report, p. 108.

[85] Ex. CPSD-9, NTSB Report, p. 108 (*emphases added*).

[86] Ex. CPSD-9, NTSB Report, p. 109, *see also id,* p. 110 ("As stated earlier in this section, in many cases, accurate information could have easily been obtained during ECDA digs, but the information was either not obtained or not entered. The lack of complete and accurate pipeline information in the GIS prevented PG&E's integrity management program from being effective.").

C. Recordkeeping Violations

D. PG&E's SCADA System and the Milpitas Terminal

E. PG&E's Emergency Response

F. PG&E's Safety Culture and Financial Priorities

1. PG&E Fostered a Culture of Profits Over Safety

Every investigation of the San Bruno explosion concludes that PG&E's lack of a safety culture contributed to the explosion.

The NTSB left no doubt that PG&E was a dysfunctional organization at many levels, that it lacked a safety culture, and that both of these factors contributed to the San Bruno explosion. It concluded that "the deficiencies identified during this investigation are indicative of an organizational accident" and that "the multiple and recurring deficiencies in PG&E operational practices indicate a systemic problem."[87] The NTSB explained: "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*."[88] On this basis, NTSB recommended that the Commission "with assistance from PHMSA, conduct a comprehensive audit of all aspects of PG&E operations, including control room operations, emergency planning, record-keeping, performance-based risk and integrity management programs, and public awareness programs."[89]

Thus, while PG&E may characterize this proceeding as a witch hunt, with the Commission simply looking for "someone to blame," the fact is that the NTSB, after looking at the evidence, found that PG&E lacked a safety culture and urged the Commission to proactively audit a *wide range* of *specified* PG&E operations that were factors contributing to the San Bruno explosion.

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[87] Ex. CPSD-9, NTSB Report, p. 118.

[88] Ex. CPSD-9, NTSB Report, p. 117 (*emphases added*).

[89] Ex. CPSD-9, NTSB Report, p. 118.

The IRP Report examined PG&E's company culture and found it lacking.[90] It connected PG&E's lack of a safety culture to its focus on profits. The IRP Report provides examples of PG&E management's lack of attention to safety in favor of financial performance. It explains that in an interview with a top PG&E executive, the question was asked as to what factor would most positively affect safety in the future. "The response given was *the provision for the recovery of costs for safety improvements would be the most important factor*."[91] It also observed that in the high level corporate goals material presented to the Panel "*the company did not include any goals for safety as part of its long-term aspirations.* It did include an aspiration for financial performance, however."[92]

The IRP Report also noted that PG&E's "top utility management" did not address public safety when asked to describe PG&E's safety program. Instead, they focused on cost savings resulting from employee safety programs:

> [Top utility management] described how a program of personal safety improves productivity and saves money. Despite the opportunity to talk to the Panel about how the San Bruno situation related to or influenced its system safety program, the leaders did not address potential risks to the public or what the company was doing to make public safety central to the organization.[93]

From this response, the IRP Report surmises that "Management has embraced an occupational safety culture because it's smart business, but seemed generally unaware of the quality of its pipeline integrity efforts."[94]

In conclusion, the IRP Report presciently observed that "top management appears to be focused on financial performance" and "when top management focuses on financial performance and does not appear to be engaged in operational safety and performance, it

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[90] Ex. CPSD-10, IRP Report, pp. 48-54.

[91] Ex. CPSD-10, IRP Report, p. 50 (*emphases added*).

[92] Ex. CPSD-10, IRP Report, p. 50 (*emphases added*).

[93] Ex. CPSD-10, IRP Report, p. 53 (*citations omitted; emphases added*).

[94] Ex. CPSD-10, IRP Report, p. 53.

affects the willingness of the organization to challenge the priorities or resources put in place by upper management."[95] This observation was born out in PG&E's budget setting processes which gutted PG&E's integrity management program between 2008 and 2010. As in Section V.F.3 below, the Overland Audit shows how PG&E top management was focused only on saving money, thus minimizing concerns regarding reliability and safety expressed by the lower-level staff.

The CPSD San Bruno Report dedicates a chapter to PG&E's "Safety Culture"[96] which reiterates many of the points made by the IRP Report and questions PG&E's ability to meet its obligation to provide safe and reliable gas service given its corporate culture.[97] The CPSD Report opines that while a focus on financial performance is "understandable", safety must come first:

> It is understandable that PG&E Corporation has a goal in growing its financial performance. It is also understandable that PG&E Company focuses on being financially healthy; however, its primary and overarching focus should be on the safe and reliable operation of the electric and natural gas pipeline facilities.[98]

In another attempt to shift responsibility to the Commission and DRA, PG&E argues that its cost requests for safety improvements were challenged or denied.[99]

PG&E's attempts to deflect responsibility for its lack of a safety culture, or failure to invest in safety, are misguided. First, PG&E is required to operate its system in a safe manner at all times (§ 451) and PG&E's rates have been set for decades at a level adequate to maintain safe operations. In fact, a PG&E executive expressly acknowledged in the related rulemaking proceeding, R.11-02-019, that over the last 30 years the

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[95] Ex. CPSD-10, IRP Report, p. 52.

[96] Ex. CPSD-1, CPSD San Bruno Report, pp. 126-161.

[97] Ex. CPSD-1, CPSD San Bruno Report, p. 126.

[98] Ex. CPSD-1, CPSD San Bruno Report, p. 130 (*emphases added*).

[99] *See e.g.*, 3 RT 130:6-12 and 131:5-13. In some instances, PG&E refers to ORA or "Office of Ratepayer Advocates," the predecessor to DRA.

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Commission has generally authorized cost recovery and full capital return for PG&E.[100] Second, as PG&E knows, its rates are calculated based upon an identified revenue requirement. Itemized cost-recovery requests used in general rate cases (whether adjudicated or settled) have no bearing on how PG&E spends the money it collects; how PG&E spends its money is up to PG&E. Third, as discussed in Section V.F.2 below, everyone agrees that PG&E's gas transmission and storage operations have been extremely profitable for more than a decade – producing far above PG&E's authorized return on equity – yet the evidence shows that PG&E's top management repeatedly cut the integrity management budget against staff recommendations, funding only minimal regulatory compliance, rather than promoting gas safety excellence. Thus, try as it might, PG&E cannot lay the blame of its profits over safety philosophy on anyone but itself. Further, a company that truly accepts responsibility does not try to blame others for its failures.

2. PG&E Has Been a Very Profitable Business For Many Years

The Overland Audit commissioned by CPSD explains that PG&E's gas transmission and storage operations have been "highly profitable" between 1999 and 2010, but that PG&E failed to utilize its surplus revenues to "improve gas safety." The report states:

> PG&E's GT&S revenues were $430 million higher than the amounts needed to earn the authorized return during the twelve-year study period. The surplus revenues averaged $36 million a year. PG&E could have used the surplus revenues, at least in part, to improve gas safety. Instead, PG&E chose to use the surplus revenues for general corporate purposes.[101]

PG&E does not disagree with the findings regarding its high profits in the Overland Report. In fact, PG&E's expert finds that the Overland Audit *understates* its

[100] R.11-02-019, 9 RT 959-960, Bottorff/PG&E.

[101] Ex. CPSD-168, Overland Audit, p. 1-3.

earnings, and that PG&E actually earned $479.5 million over its "actual revenue requirement" and $515.5 million over its imputed adopted revenue requirements.[102] PG&E's expert finds that PG&E's authorized return averaged 11.2% during the audit period, and he estimates that PG&E's *actual* return on equity averaged 14.6% during that period.[103]

3. PG&E's Systematic Underfunding Of Gas Transmission Maintenance and Integrity Management Demonstrates Its Disregard For The Safety Of Its Gas Transmission System In Favor of Least-Cost Regulatory Compliance

The Overland Audit examines PG&E's Gas Transmission and Storage (GT&S) expenditures for the period 1996 to 2010 and compiles multiple examples demonstrating PG&E's culture of profits over safety. Specifically, Overland demonstrates that PG&E systematically sought to reduce costs with no concern for safety by reducing, eliminating, or deferring pipeline monitoring, maintenance, and replacement activities during the audit period, including:

- Transitioning from a Gas Pipeline Replacement Program (GPRP) which mandated the replacement of 15 miles per year to a Risk Management Program (RMP) which resulted in less than 25 miles of pipeline replacement between 2000 and 2010;
- Systematic and unjustified budget cuts to both the Maintenance and Integrity Management budgets within GT&S.
- Moving from the preferred in-line-inspection (ILI) method for assessing the condition of gas pipelines to the less informative, but significantly cheaper, external corrosion direct assessment (ECDA) methodology.
- Undertaking all of these unnecessary cost-cutting measures knowing that fundamental safety aspects of its GT&S operations were being compromised.

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[102] Ex. PGE-10, O'Loughlin MPO-1, pp. 6-7.

[103] Ex. PGE-10, O'Loughlin MPO-1, p. 7.

While PG&E expended significant effort in this proceeding rebutting the Overland Audit's imputation analysis and findings in Chapters 2 through 5,[104] PG&E has not challenged the Overland Audit findings summarized above and discussed in detail below.[105]

a. PG&E's Cost-Saving Move From A Gas Pipeline Replacement Program of 15 Miles Per Year To A Risk Management Program Resulted In 25 Miles Of Replacement Over 11 Years

The Overland Audit finds that in 2000 PG&E moved from a Gas Pipeline Replacement Program or "GPRP" which committed PG&E to replacing 15 miles of pipeline each year, to a replacement program driven by a records-based "Risk Management Program" or "RMP."[106] Under the RMP, pipeline replacements dropped significantly, such that PG&E replaced only 25 miles of pipeline under the RMP between 2000 and 2010. Had the Gas Pipeline Replacement Program remained in place, PG&E would have been required to replace 165 miles of pipeline during that period[107] – a difference of more than 500%. More troubling is the fact that while risk played a role in determining replacements under the RMP, it appears PG&E did not apply a consistent risk strategy to ensure that the most risky lines were replaced first.[108] On this basis, the Overland Audit concludes there are no risk metrics in PG&E's RMP:

[104] See Exs. PG&E-10 and PG&E 11, O'Loughlin.

[105] 8 RT 539:13-22 and 617:3-618:14, O'Loughlin/PG&E; see 8 RT 618:8-14 (" Q: Can you respond to any of the points that [Harpster] makes in Chapter 6, 7, 8 or 9? A: No. My testimony report does not address Chapters 6 through 9. I did not respond to those in any way and I did not analyze these issues in any way.").

[106] Ex. CPSD-168, Overland Audit, p. 6-13 and 7-1.

[107] Ex. CPSD-168, Overland Audit, p. 6-13 and 7-1. Note the Errata to the Overland Audit on page 6-13 reflects that PG&E does not actually know whether pipelines were replaced, or installed new, only that a pipeline was installed. Thus, the number of replacement miles under the integrity management program may be overstated.

[108] *See list of factors considered by Overland at* Ex. CPSD-168, Overland Audit, p. 6-15.

> PG&E no longer prepares metrics, goals or annual reports for its risk management program. PG&E does not prepare separate risk management plans or track risk management projects. Risk continues to be a factor in prioritizing projects. However, the evidence suggests risk management continued to be a separate program in name only at some point after 2004.[109]

Thus, PG&E cannot argue that its significant reduction in gas pipeline replacements under the RMP was due to a reasoned evaluation of pipeline risk which resulted in only necessary pipelines being replaced. Further, the scope of testing and replacement in PG&E's remedial safety plan approved in D.12-12-030 would belie such an assertion. More relevant, it is evident from PG&E's own documents that PG&E's move from the Gas Pipeline Replacement Program to the RMP was a "cost reduction initiative."[110] PG&E's internal budget documents provided to Overland emphasize the cost saving rationale for the move: "Avoided $6 million in capital GPRP in 1999 (over previous years spending), sustainable in future years. Over the life of originally planned GPRP program (to 2009), will yield a total of $60 million dollars in savings."[111] Thus, it is clear that PG&E moved from a plan which required 15 miles of pipeline replacement each year, to one that resulted in 25 miles of replacement over 11 years, *to save money*. And the plan did not replace pipelines in a manner that meaningfully considered risk. Had PG&E left the GPRP in place and complied with its replacement plan, it is possible that Line 132 would have been replaced before the explosion.[112] PG&E's actions here reflect a culture of profits over safety.

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[109] Ex. CPSD-168, Overland Audit, p. 6-16 (emphases in original).

[110] Ex. CPSD-168, Overland Audit, p. 7-12.

[111] Ex. CPSD-168, Overland Audit, p. 7-1.

[112] *See, e.g.,* Ex. CPSD-167, Exhibit 178 to Deposition of C. Tateosian, Vol. IV, which is a 1978 draft memorandum proposing a long term pipeline replacement program. Mr. Tateosian's testimony submitted as Ex. CPSD-162 through CPSD-167 discusses PG&E's need for such a pipeline replacement program and its intent to pursue such a program to replace older, potentially defective, pipelines.

b. PG&E Had Knowledge Of Serious Safety-Related Deficiencies In GT&S Operations, Yet Continued To Pursue Staffing Reductions and Other Cost Saving Measures

The Overland Audit shows that GT&S staffing from PG&E's gas distribution divisions was reduced by approximately 30% between 1996 and 2010, and that this staffing decrease had safety impacts on PG&E's GT&S operations,[113] as evidenced by various safety-related deficiencies PG&E discovered between 2007 and 2009, including: (1) Significant operational and recordkeeping problems, including incomplete or inaccurate maintenance records, inadequate inspections, unauthorized work methods, employees doing work they were not qualified to perform, and unjustified levels of overtime;[114] and(2) serious systemic deficiencies in PG&E's leak survey program.[115]

The first set of operational and recordkeeping problems came to light from two internal audits performed in 2007 in response to allegations made by employees of improper practices in one of PG&E's gas divisions. In addition to the general findings described above, specific findings included: one employee falsified completion records for work that was not performed and supervisors pre-signed approvals on blank maintenance forms before work was done.[116] In response, a system-wide regulator station audit was initiated in May 2008, with a report issued in May 2009.[117] That audit revealed that the problems identified in the two previous audits were not limited to one PG&E division.[118] "The audit identified three divisions where, in the past, required

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[113] Ex. CPSD-168, Overland Audit, p. 6-6.

[114] Ex. CPSD-168, Overland Audit, p. 7-4.

[115] Ex. CPSD-168, Overland Audit, p. 6-16 to 6-19.

[116] Ex. CPSD-168, Overland Audit, p. 7-4.

[117] Ex. CPSD-168, Overland Audit, pp. 7-4 to 7-5.

[118] Ex. CPSD-168, Overland Audit, p. 7-5.

regulator/and or valve maintenance was omitted."[119] Among other things, the auditors concluded that field staff did not understand PG&E's work procedures and so it was unlikely the standards were being followed as written; supervisors were too busy to manage field staff; and records were not adequately completed to ensure equipment was being maintained.[120] Significantly, this evidence of PG&E's actual practices corroborates the findings of the NTSB and the IRP that led them to conclude that PG&E's integrity management program was dysfunctional. To the extent that PG&E employees' failure to comply with written standards was the result of understaffing, this reflects PG&E management's choice to pursue profits over safety.

PG&E shortly learned that its safety deficiencies extended to its leak survey operations where, among other things, they discovered employee failures to follow processes. In October 2008, PG&E initiated a system-wide leak resurvey project to address "systemic system-wide deficiencies in leak survey, leak grading process, standards, controls, training and operator qualification."[121]

As a result of these findings, which reflect, among other things, serious employee omissions and lack of management oversight, the Overland Audit reasonably concludes that PG&E appeared to be suffering from safety-related resource constraints.[122]

Notwithstanding the fact that PG&E's high level management should have been well aware of these safety-related deficiencies starting in 2007, PG&E then embarked on a series of budget cuts for the GT&S division that only worsened an already bad situation.

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[119] Ex. CPSD-168, Overland Audit, p. 7-5.

[120] Ex. CPSD-168, Overland Audit, p. 7-5.

[121] Ex. CPSD-168, Overland Audit, p. 7-5 (*quoting from a PG&E Executive Status Report*).

[122] Ex. CPSD-168, Overland Audit, p. 7-5

c. Contrived Budget Constraints Between 2008 and 2010 Compromised Gas Transmission Safety

The Overland Audit documents in vivid detail the budget constraints imposed on PG&E's GT&S operations between 2008 and 2010, and their implications for the safety of PG&E's gas system.[123] In sum, the Overland Audit explains that from 2008 to 2010 PG&E top management repeatedly and inexplicably reduced the GT&S budget. Facing these deep cuts, GT&S reduced expenses in two primary ways – both of which reduced the safety and effectiveness of PG&E's integrity management program:

1. GT&S changed the assessment method for many gas transmission lines from in-line-inspection (ILI) or "pigging" to a less effective and less costly method of assessing the condition of a gas pipeline, external corrosion direct assessment (ECDA); and
2. GT&S deferred certain pipeline assessments to future years.

As the PG&E documents produced in the Overland Audit reveal, there is no logical explanation for the repeated and deep cuts to the GT&S budget – with most of the cuts in Maintenance and Integrity Management – other than the fact that PG&E top management wanted to cut costs, and did not value the safety of the system. ***PG&E's own internal documents demonstrate that PG&E management cared only for least-cost compliance with integrity management regulations and expressed no concern for the actual safety of PG&E's gas transmission system.***

The tables below, which were created from information gleaned from Chapters 7, 8 and 9 of the Overland Audit, provide an overview of the budget impacts on Integrity Management and Maintenance between 2008 and 2010. In sum, and as described in more detail below, PG&E repeatedly and inexplicably cut the requested budgets for gas transmission Maintenance and Integrity Management, providing these groups insufficient monies to perform their core responsibilities in a safe manner – despite an adequate level of funding provided by Commission-authorized rates. The Maintenance and Integrity

[123] Ex. CPSD-168, Overland Audit, Chapters 7, 8, and 9.

Management groups were repeatedly directed to reduce their initial budget requests, and then those requests were cut further by management, sometimes several times over the year, with no appreciation for the work that needed to be performed. Actual expenses varied minimally over the three year period reviewed, and when emergency maintenance was required, it was funded through the existing budgets, with other work cancelled or deferred to meet projections. The budget process that unfolds through a review of the Overland Audit reveals a singular concern to meet nominal regulatory requirements in the least costly manner possible, regardless of the impact on system safety.

Overview of GT&S Integrity Management Budgets 2008-2010 (In $ Millions)

Budget Year	Prior Year's Actual Expense	Budget Request	Approved Budget	Difference between Request & Approved Budget	Actual Expense	Difference Between Approved Budget and Prior Year's Actual Expense
2008	$11.8	$23.4	$16.4 – reduced in November 2008 to $15.4	($7.0)	$15.2	$4.6 nominally but actually $.08[124]
2009	$15.2	Reduced from $25.6 to $18.0	$17.4 - reduced mid-year to $15.6 to fund unplanned repairs	($8.2)	$15.5	$2.3
2010	$15.5	$19.7	$17.6	($2.1)	$16.9	($.700)

[124] The $4.6 million includes $3.8 million in smart pig costs that were previously allocated as capital expenditures. Ex. CPSD-168, Overland Audit, p. 7-6.

Overview of GT&S Maintenance Budgets 2008-2010 (In $ Millions)

Budget Year	Prior Year's Actual Expense	Budget Request	Approved Budget	Difference b/t Original Request & Approved Budget	Actual Expense	Difference Between Approved Budget and Prior Year's Actual Expense
2008	$54.0	$67.679	$51.4	($16.2)	$53.5	($2.6)
2009	$53.5	Reduced from $61.1 to $55.4	$54.0	($7.1)	$56.1	$0.5
2010	$56.1	$62.1	$47.2	($14.9)	$71.6[125]	($6.3)

i. Budget Year 2008 - The Move From ILI to ECDA

In 2008, PG&E management cut the requested GT&S budget of $115.6 million by 20%, down to $92.3 million.[126] The primary cuts were to Maintenance and Integrity Management, which were reduced a total of $23.2 million below their initial budget requests.[127] The total 2008 GT&S budget reflected a small increase of $5.6 million over the actual expenditures in 2007. However, the bulk of this increase – $3.8 million – was due to an accounting change which recharacterized ILI from a capital cost to an expense.[128] Thus, the actual differential between the 2007 and 2008 GT&S budgets was only $1.8 million. Further, GT&S made a commitment in November 2008 to reduce its expenses by an additional $1 million, requiring the deferral of expenses from 2008 to 2009, and reductions in integrity management costs.[129]

[125] The significant increase in 2010 actual expenses is attributable to $24 million in costs associated with the San Bruno explosion. See Ex. CPSD-168, Overland Audit, p. 9-3.

[126] Ex. CPSD-168, Overland Audit, p. 7-6.

[127] Ex. CPSD-168, Overland Audit, p. 7-6.

[128] Ex. CPSD-168, Overland Audit, p. 7-6 to 7-7.

[129] Ex. CPSD-168, Overland Audit, p. 7-7.

For 2008, Integrity Management had originally requested $23.4 million, but received a budget of $16.4 million – a reduction of 23%. Previously, when the budget was expected to be as low as $13.4 million, internal PG&E documents from 2007 opined that the low 2008 budget, combined with expected flat funding in 2009 and 2010 would "drive the [integrity management] program to non-compliance in 2012"[130] and that $22 million was needed to meet existing 2008 mileage targets:

> Recommended minimum funding level to achieve 2012 compliance is $18 million. $22 million will keep program on existing mileage targets for 2008.[131]

Thus, PG&E's 2008 funding of its Integrity Management program was $1.6 million below the "minimum funding level" required to achieve 2012 compliance and $5.6 million below that necessary to keep the program "on existing mileage targets for 2008."

PG&E documents reflect that the Integrity Management budget cuts resulted in "many pigging projects" being changed to ECDA to reduce costs. In those documents, PG&E unequivocally characterizes ECDA as "*a much less thorough* evaluation of the pipeline via statistical methods rather than by direct inspection" and concludes that "*Gas Engineering would strongly prefer to smart pig PG&E's higher stress pipelines to obtain a much better initial evaluation of the line*, but that is not financially viable at current funding rates."[132]

Thus, beginning in 2008, based solely on a desire to save money, and against the recommendation of its gas engineering staff, PG&E began the move from in-line-inspection (ILI or "pigging"), a reliable method for assessing the condition of a gas

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[130] Ex. CPSD-168, Overland Audit, p. 7-7 *quoting* OC-68 (CPSD-186), Attachment 4, p. 18.

[131] Ex. CPSD-168, Overland Audit, p. 7-8 *quoting* OC-68 (CPSD-186), Attachment 4, p. 18.

[132] Ex. CPSD-168, Overland Audit, p. 7-8 *quoting* OC-68 (CPSD-186), Attachment 3, p. 1 (*no emphasis in original*).

transmission pipeline, to ECDA, "a much less thorough evaluation of the pipeline via statistical methods rather than by direct inspection."[133]

ii. ECDA Is Not The Industry Standard, Nor PG&E Engineers' Preferred Method, For Assessing Pipelines

Pursuant to federal regulations, PG&E was obligated to assess all of the HCA lines in its 2004 Baseline Assessment Plan (BAP) – 975 miles – by December 17, 2012.[134] Regarding pipeline assessments, PG&E's RMP-06[135] section 5.4 states that "it is the company's desire to inspect pipelines utilizing in-line inspection whenever it is physically and economically feasible."[136] However, PG&E documents reflect that PG&E initially planned to ILI only 328 miles of those lines,[137] leaving approximately 2/3 of its system to be assessed using ECDA. Presumably, PG&E did not believe it was "economically feasible" to assess additional HCA lines using ILI, regardless of its earnings well above its authorized rate of return. At the same time, PG&E documents reflect that PG&E *knew* that Sempra (Southern California Gas Company) intended to "pig approximately six times the covered mileage under the Pipeline Safety Rule than PG&E."[138] Internal PG&E notes reflect this understanding:

> [Southern California Gas] has...made a business decision to primarily utilize ILI as their integrity assessment method. Hence, it is proposing to pig approximately six times the covered mileage under the Pipeline Safety Rule than PG&E. PG&E is primarily utilizing ECDA as the integrity assessment method.[139]

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133 Ex. CPSD-168, Overland Audit, p. 7-8 quoting OC-68 (CPSD-186), Attachment 3, p. 2.

134 Ex. CPSD-168, Overland Audit, pp. 6-11 and 9-11.

135 "RMP" stands for "Risk Management Procedure."

136 Ex. CPSD-9, NTSB Report, p. 63, *quoting from* PG&E RMP-06, which is provided in Ex. PGE-6.

137 Ex. CPSD-168, Overland Audit, pp. 6-11 to 6-12 quoting OC-85 (Ex. CPSD-192), Attachment 1, Job Estimate dated February 1, 2004, p. 4.

138 Ex. CPSD-168, Overland Audit, p. 6-12 quoting OC-268 (Ex. CPSD-232), Attachment 5, p. 2.

139 Ex. CPSD-168, Overland Audit, p. 6-12 quoting OC-268 (Ex. CPSD-232), Attachment 5, p. 2.

Notwithstanding PG&E's original minimal commitment to ILI 328 miles to meet BAP compliance, and its knowledge that Sempra was planning to ILI most of its system, the Overland Audit shows that PG&E progressively moved many of its pipelines scheduled for ILI to ECDA starting in 2008 in order to save money. By 2009, the shift from ILI to ECDA had significant impacts. Overland explains: "During 2005 to 2008, ILI accounted for 54 percent of the total miles assessed. In 2009 and 2010, ILI only accounted for 13 percent of the total miles."[140]

The IRP Report identified PG&E's failure to redesign its system to accommodate ILI as a shortcoming in its Integrity Management Program. Among other things, it found that ILI was the best method to detect many of the threats identified by PG&E and that other companies had already begun the work to modernize their systems to accommodate ILI. The Panel criticized PG&E for its failure to take advantage of the "the best available technology" given that it has substantial pipeline mileage in HCAs. It surmises: "*If in-line inspection is the best method to detect the threat – which is clearly the case for many of the threats PG&E identified,* then it is prudent to develop a plan to use the appropriate methods.":

> PG&E has no overall strategy to improve how it assesses the integrity of its system. It has done little to redesign its system to facilitate in-line inspection through the use of in-line inspection (ILI) tools. Only 21% of PG&E's system is able to utilize in-line inspection. Yet, *PG&E has substantial pipeline mileage in HCAs, which makes the significance of being able to inspect its system with the best available technology particularly important.*
>
> The Panel learned there have been many technical advances in in-line inspection equipment over the last decade, but PG&E has not developed concrete plans to take advantage of these changes in technology. As we understand the federal pipeline integrity

[140] Ex. CPSD-168, Overland Audit, p. 6-8. Considering only HCA segments (because ILI usually includes non-HCA segments while EDCA is limited to HCA), ILI accounted for 20% of HCA assessments between 2005 and 2008 and 7.5% of the HCA miles assessed in 2009 and 2010. Compare Table 6-8 and Table 6-9, Ex. CPSD-168, Overland Audit, p. 6-9.

> management regulations, operators are to identify their threats and then select the inspection assessment methods which can detect where the threat(s) is present. Operators must implement the appropriate assessment methods, or else they face the prospect of not accurately characterizing their pipeline facilities. *If in-line inspection is the best method to detect the threat – which is clearly the case for many of the threats PG&E identified,* then it is prudent to develop a plan to use the appropriate methods. Other companies we interviewed have already begun the work to modernize their systems to enable in-line inspection and/or have begun focused pipeline replacement efforts where the in-line inspection technology could not be readily used.[141]

The IRP Report also found that PG&E was "significantly behind" the rest of the gas industry in implementing ILI to facilitate its Integrity Management Program. While 17% of PG&E's overall pipeline transmission system could accommodate ILI, the Panel found this was "dramatically less than the 60% in-line inspection average for cross-country natural gas transmission and 40% average for utilities with transmission and distribution facilities." The Panel recognized the irony of these statistics when compared to PG&E's corporate vision to be "the leading utility in the United States."[142]

The IRP Report concludes that part of the reason for PG&E's Integrity Management Program failures is PG&E management's focus on profits instead of "operational safety and performance," notwithstanding its stated goals emphasizing utility excellence:

> …[W]hile the company has multiple stated goals*, top management appears to be focused on financial performance.* Certainly our utilities must be financially healthy to fulfill their respective missions, but *when top management focuses on financial performance and does not appear to be engaged in operational safety and performance, it affects the willingness of the organization to challenge the priorities or resources put in place by upper management.*[143]

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[141] Ex. CPSD-10, IRP Report, p. 12 (*emphases added; footnotes omitted*).

[142] Ex. CPSD-10, IRP Report, p. 51 (*footnote omitted*).

[143] Ex. CPSD-10, IRP Report, p. 52.

The CPSD San Bruno Report adopted all of the IRP Report findings on these issues and confirmed that Southern California Gas Company had implemented its business plan to ILI the majority of its system. It found that 80% of Southern California Gas Company's HCA transmission pipeline has been inspected using ILI tools.[144] It noted that PG&E's 2009 Investor Conference presentation included a slide on "Expenditures" showing decreasing investment in gas transmission infrastructure.[145] The CPSD San Bruno Report reiterates the findings of the IRP Report that PG&E's investment in the gas transmission pipeline system has been minimal, and there are no plans to modernize the system. Instead, it finds that PG&E's focus was to provide the minimal funding necessary to ensure compliance with the proscriptive aspects of the Integrity Management rules.[146] As further elaborated below, the Overland Audit bears out these conclusions that PG&E management was only interested in nominal compliance with regulations.

iii. The Move To ECDA Was Based On Cost And Engineering Concerns Were Ignored

There is no question that PG&E made the move from ILI to ECDA to save money. A 2007 email from PG&E's Supervising Engineer for Gas System Integrity proposes to move a line ILI to ECDA to save over $2.5 million. He explains that under RMP-06, PG&E preferred to inspect pipelines using ILI whenever "physically and economically feasible."[147] With regard to the line in question, he explains that "[t]he physical barriers are few. The ILI team has notified us that few physical modifications to the line are required, and there are no operational reasons why the line cannot be pigged. There are

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[144] Ex. CPSD-1, CPSD San Bruno Report, p. 134.

[145] Ex. CPSD-1, CPSD San Bruno Report, p. 135.

[146] Ex. CPSD-1, CPSD San Bruno Report, p. 135.

[147] Ex. CPSD-168, Overland Audit, p. 7-9 *quoting* OC-264 (Ex. CPSD-230), Supplemental Attachment 5, p.1.

economic barriers though."[148] PG&E's Supervising Engineer goes on to explain that the total costs for pigging the line would be over $3 million, while the total cost for ECDA is expected to be $360,000, and he recommends a switch from ILI to ECDA on this basis. Thus, in 2009, the line was assessed using the less informative ECDA, rather than pigging.[149]

A 2008 email from PG&E's Gas Transmission Expense Manager confirms PG&E's desire to use "the less costly ECDA method." The email recognizes that regardless of the "strongly preferred ILI method," "the ECDA [process] will meet the code requirement for inspection,"[150] thus revealing PG&E's commitment to do the minimum required for regulatory compliance at the lowest cost, rather than perform more costly work that would provide more relevant information about safety threats and ensure a safer system:

> … I have heard [the Director of Integrity Management] say in past meetings that the ECDA process *will meet the code requirement for inspection and while it is not our strongly preferred ILI method for some of the pipes we will assess*, it is certainly adequate and *given cost constraints* we should use the less costly ECDA method.[151]

In sum, the Overland Audit concludes, among other things, that "[a]ctual 2008 integrity management spending was 35% below the initial request and 16% below the 'minimum funding level to achieve 2012 compliance.'"[152] It is evident that a significant portion of these cost savings came from the move from ILI to ECDA.

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[148] Ex. CPSD-168, Overland Audit, p. 7-9 *quoting* OC-264 (Ex. CPSD-230), Supplemental Attachment 5, p.1.

[149] Ex. CPSD-168, Overland Audit, p. 7-9 *citing* OC-264 (Ex. CPSD-230), Supplemental Attachment 5.

[150] Ex. CPSD-168, Overland Audit, p. 7-9 *quoting* OC-264 (Ex. CPSD-230), Attachment 4. The original has a typographical error which was corrected in the Overland Audit and herein. The original stated that "the ECDA progress will meet the code requirement" rather than "process will meet the code requirement."

[151] Ex. CPSD-168, Overland Audit, pp. 7-9 to 7-10 *quoting* OC-264 (Ex. CPSD-230), Attachment 4 (*emphases not in original*).

[152] Ex. CPSD-168, Overland Audit, p. 7-12.

iv. PG&E Documents Explain That 2008 Maintenance Budget Cuts Jeopardized Reliable Operations and Safety

PG&E management budgeted $13.4 million for GT&S maintenance projects in 2008, only 53% of the $25.2 million that was requested.[153] PG&E documents comment on the safety issues raised by the 2008 budget constraints, as well as long term system impacts in the event of "flat funding into 2009 and 2010" concluding that "[f]or the Gas Transmission business as a whole, long-term reliable operations is jeopardized at the current level of funding":

> Challenges: MWC BX [Major Work Category Transmission Maintenance] projects were funded to $11.3 million instead of the requested $25.2 million. *Funding at this level will not fund many high priority projects including critical compressor repair and overhaul projects, an OSHA compliance employee safety program and, numerous pipeline repair and corrective maintenance projects recommended for completion in 2008.*
>
> Risks: For MWC BX, *not doing high priority projects will likely lead to poor pipeline and storage reliability* and thereby puts PG&E at risk of customer complaints, regulatory response leading to investigations and potential fines. *In some cases, not completing projects may lead to employee and public safety issues* (such as mechanical failure of compressors or pipeline failure from existing landslides). …
>
> and
>
> *With flat funding into 2009 and 2010, system reliability may be adversely impacted and the backlog of corrective maintenance will grow.* A priority will be to manage reliability risk with constrained expense funding [and] identifying ways to improve maintenance productivity.
>
> *For the Gas Transmission business as a whole, long-term reliable operations is jeopardized at the current level of funding.*[154]

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[153] Ex. CPSD-168, Overland Audit, p. 7-10.

[154] Ex. CPSD-168, Overland Audit, pp. 7-10 to 7-11 *quoting* OC-68 (Ex. CPSD-186), Attachment 4, p. 18 (*emphases added*).

Other PG&E documents also left no question regarding the likely impacts of the budget cuts, including "more frequent breakdowns," with special vulnerability for the "Line 300 system" due to "high flow rates and resulting high duty cycles with up to fifty year old assets."[155] This PG&E document concludes that deferring maintenance over a multiple year period, such as 2008 to 2010, would make the situation worse:

> While[the] effects of deferred maintenance can immediately impact operations and reliability, effects are most impactive when maintenance is deferred over a multiple year period as will likely be the case in 2008 to 2010.[156]

Notwithstanding these warnings, GT&S saw more of the same in 2009.

v. Budget Year 2009 – More Of The Same

As PG&E's internal documents from 2007 and 2008 anticipated, funding for Maintenance and Integrity Management did not improve in 2009. PG&E management continued to underfund these programs, further jeopardizing the reliability and safety of the system, notwithstanding the warnings from their staff.

The Overland Audit shows that while PG&E documents from spring 2008 anticipated a budget request of $25.6 million for Integrity Management, GT&S later reduced its request to $18 million, and even then, it was only given $17.4 million. And then that budget was reduced later in 2009 to offset unanticipated maintenance costs.[157] A September 2008 email from the GT&S Expense Program Manager reflects his intent to reduce the original budget request of $25.6 million to $16 million, a cut of over 37%:

> For the 2009 Integrity Management program, our IM program management group has requested 22+ million and I am limiting their budget allocation to $16 million at this point.[158]

[155] Ex. CPSD-168, Overland Audit, p. 7-11 *quoting* OC-68 (Ex. CPSD-186), Attachment 3, p. 2.

[156] Ex. CPSD-168, Overland Audit, p. 7-11 *quoting* OC-68 (Ex. CPSD-186), Attachment 3, p. 2.

[157] Ex. CPSD-168, Overland Audit, pp. 8-1 to 8-2, *citing* OC-66 (Ex. CPSD-184), Attachment 23, 2009 GSM&TS Expense Order Budget – Draft 1, as of May 27, 2008. Regarding reductions later in the year, see Overland Audit, p. 8-3 and note 11; see also the discussion below.

[158] Ex. CPSD-168, Overland Audit, p. 8-2, *citing* OC-262 (Ex. CPSD-229), Attachment 3.

As follow up to achieving this $16 million budget proposed by the GT&S Expense Program Manager, an October 2008 email from the same manager entitled "2009 IM forecasts – further reductions necessary" tells the recipients that the 2009 Integrity Management budget would be similar to the 2008 budget (which had been $16.4 million). The email entreats the recipients to search for ways to further reduce their requested budget, and it proposes consideration of project deferrals notwithstanding the regulatory requirement to assess all BAP pipelines by the end of 2012:

> As expected we got saddled with a very low 2009 budget. What was unexpected was how low it was; basically equivalent to 2008. Below [is a list of] the IM projects planned for 2009. I am meeting with [the Vice President, Gas Transmission & Distribution] to discuss what can be reduced to make ends meet. *I realize you have already significantly scrubbed this list, but I must ask again if there are any reductions that can be made while maintaining compliance.* Maintaining compliance needs to be broadened to now include deferring some projects a year or more while still maintaining feasibility to meet the goals in December 2012. That is, if we can fall behind the 2012 pace a little and still retain feasibility to catch up, I ask you to consider that option when looking for reductions.[159]

Once again, PG&E reduced the requested funding by changing some proposed pipeline assessments from ILI to ECDA. PG&E documents are clear that this was a cost-cutting measure:

> ...for the Integrity Management Program, the program has altered inspection methods to significantly reduce costs from $23 million to $17 million in 2009.[160]

Another PG&E document confirms that Integrity Management has "changed program inspection methods to reduce spend."[161]

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159 Ex. CPSD-168, Overland Audit, p. 8-2 to 8-3, *citing* OC-262 (Ex. CPSD-229), Attachment 5.

160 Ex. CPSD-168, Overland Audit, p. 8-3, *quoting* OC-68 (Ex. CPSD-186), Attachment 2, p. 28.

161 Ex. CPSD-168, Overland Audit, p. 8-3, *quoting* OC-68 (Ex. CPSD-186), Attachment 2, p. 14.

The Integrity Management budget of $17.4 million was then reduced by another $1.8 million in May 2009 to help fund unplanned maintenance work.[162] The unplanned costs included $1.7 million for the Line 187 dig-in repair, $1.5 million for pipeline failure repairs, and $0.6 million for compressor overhauls and repairs.[163] The $1.8 million contribution from Integrity Management was achieved by moving more pipeline segments from ILI to ECDA, and deferring other projects.[164]

To make matters worse, in August 2009, PG&E's Senior Vice President, Financial Services asked GT&S to identify expense reductions equal to 5% of the remaining 2009 budget.[165] GT&S submitted three potential reductions to meet the goal, including deferring an ILI project. GT&S identified the compliance risks of such an ILI deferral in light of PG&E's obligation to assess all BAP lines by the end of 2012:

> Deferral would result in significant risk of being in non-compliance with the DOT pipeline inspection requirements and would increase the expense requirements in 2010 to achieve the required compliance by 2012. GT&D has already deferred $1.8 million of work into 2010 from 2009, which is believed to be the maximum amount feasible to avoid significant compliance risk.[166]

We do not know whether the proposed ILI deferral was implemented.[167]

The 2009 Maintenance request of $61.1 million was revised to $55.4 million and the approved budget was $54 million – 88% of the originally planned request. PG&E's Gas Transmission Engineering Director communicated the dire state of the budget and its impact on both Maintenance and Integrity Management, including a decision not to ILI Line 300A (the over 50 year old line reference above) "if ECDA is an option":

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162 Ex. CPSD-168, Overland Audit, pp. 8-3 to 8-4.

163 Ex. CPSD-168, Overland Audit, p. 8-3, note 11.

164 Ex. CPSD-168, Overland Audit, pp. 8-4 to 8-5.

165 Ex. CPSD-168, Overland Audit, p. 8-5.

166 Ex. CPSD-168, Overland Audit, p. 8-5 *quoting* OC-257 (Ex. CPSD-224), Attachment 5a. The quotation from the Overland Audit had a typographical error which has been corrected to quote the original here.

167 Ex. CPSD-168, Overland Audit, p. 8-5.

> Suffice it to say, the project expense budget cuts are very deep, we're not able to fund all Priority 1 work [work required by code, standard or law] at this time.
>
> As much as I would like to support your recommendation to ILI L-300A North of Hollister, I'm not sure it's the highest priority work within GT if ECDA is an option. The [pipeline] integrity team should further reduce MWC II 2009 expense costs. *Everyone is being asked to make significant cuts to address the 2009 expense budget.*[168]

Similar to 2008, to make ends meet, Maintenance deferred projects, including $4.3 million of Priority 1 work – work required by code, standard, or law – and $2.1 million of Priority 2 work, which is work classified as non-deferrable for safety or reliability reasons or economically attractive.[169] PG&E documents identified the risks of not doing this work, including reliability impacts and reduced efficiency.[170]

Like Integrity Management, Maintenance was expected to cut its 2009 budget in May 2009 to help cover the $6.9 million in unplanned maintenance. Maintenance identified $1.8 million in cuts, including deferring certain compressor overhauls and training for station operators and transmission coordinators.

Relying on PG&E planning documents, the Overland Audit explains the critical role of training at PG&E, and the safety consequences of deferring that training:

> The station operator training was for operators at PG&E's gas storage facilities. According to PG&E's planning documents *deferring that training "may lead to operator errors and safety and reliability may be compromised." Similarly, not training transmission coordinators "will result in less efficient operations [and] operator errors which can impact system reliability and safety."*[171]

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[168] Ex. CPSD-168, Overland Audit, p. 8-6 *quoting* OC-264 (Ex. CPSD-230), Attachment 9 (*emphases added*).

[169] Ex. CPSD-168, Overland Audit, p. 8-7.

[170] Ex. CPSD-168, Overland Audit, p. 8-7 *citing* OC-68 (Ex. CPSD-186), Attachment 2, p. 18.

[171] Ex. CPSD-168, Overland Audit, p. 8-8 *quoting* OC-264 (Ex. CPSD-230), Attachment 9 (*emphases added*).

According to the Overland Audit, "PG&E also deferred gas system control room training and clearance operations training for field organizations. Prior to the deferral, MWC CM, System Operations, included $75,000 for that training."[172]

These cuts were made notwithstanding the fact that PG&E management was on notice of significant employee-related safety deficiencies between 2007 and 2009, as described in Section V.F.3.b above – many of which are logically attributed to a lack of training.

In November 2009, Maintenance, like the rest of GT&S, was asked by PG&E's Senior Vice President, Financial Services to further reduce its remaining budget by 5%.[173] GT&S submitted two proposals impacting Maintenance. GT&S described the "adverse impact on reliability and code compliance" that one of the proposals would have:

> *Reduction would result in further erosion of gas transmission reliability and....being in non-compliance with code.* Revenue loss would likely be much greater and most certainly would exceed any expense reduction benefit. Reduction would also require a substantial reduction in FTEs, which would create *significant adverse impact on reliability and code compliance in 2010.*[174]

Again, we do not know if the reductions were implemented. However, the Overland Audit finds that on October 15, 2009, PG&E suspended corrosion maintenance work for the remainder of the year to free up crews to repair the large number of leaks discovered in the 2009 leak resurveys.[175] Thus, as a result of PG&E management's self-imposed budget crisis, the cycle of robbing Peter to pay Paul continued.

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[172] Ex. CPSD-168, Overland Audit, p. 8-8.

[173] Ex. CPSD-168, Overland Audit, p. 8-8 *citing* OC-257 (Ex. CPSD-224), Attachment 5.

[174] Ex. CPSD-168, Overland Audit, pp. 8-8 to 8-9 *quoting* OC-257 (Ex. CPSD-224), Attachment 5a (*emphases added*).

[175] Ex. CPSD-168, Overland Audit, p. 8-9.

vi. Budget Year 2010 – More Of The Same, And Then It All Falls Apart

In 2010 PG&E management appears to have taken a slightly different approach to setting budgets. Instead of allowing groups to submit a proposed budget, and then unilaterally mandating reductions, PG&E management set a "target" budget for GT&S of $94.9 million, the same as the 2009 budget, and stated that "[a]ll increments over 100 percent of your program's target must be critical items that need to be completed in 2010."[176] Each expense was required to be prioritized as "Mandatory" or Priority 1 or 2. Priority 1 included projects where "[s]tated organizational benefits and operational targets are *critically dependent* upon the execution" of the project.[177] Priority 2 included projects where "stated organizational benefits and operational targets would be moderately impacted without the execution" of the project.[178]

In response to this mandate, GT&S requested $111.2 million,[179] $16.3 million over the "not to exceed" target. The GT&S requested budget included $90.2 million in "Mandatory" expenses, $17.7 million in Priority 1 expenses, and $3.3 million in Priority 2 expenses.[180] The GT&S budget was set at $89.8 million, which was $6.7 million *less* than the 2009 *actual expenses,* $21.3 million *less* than the GT&S requested budget, and $18 million *less* than what GT&S identified as "critical" by categorizing the expenses as either "Mandatory" or "Priority 1."[181]

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[176] Ex. CPSD-168, Overland Audit, p. 9-1 *quoting* OC-264 (Ex. CPSD-230), Supplemental Attachment 3a, p. 1. See also p. 9-3 which states that the target budget was $94.6 million and was set equal to the 2009 budget. However, this appears to be a typographical error because the 2009 budget was $94.9. See, e.g., p. 8-2.

[177] Ex. CPSD-168, Overland Audit, p. 9-2 *quoting* OC-264 (Ex. CPSD-230), Supplemental Attachment 3b (*emphases added*).

[178] Ex. CPSD-168, Overland Audit, p. 9-2 *quoting* OC-264 (Ex. CPSD-230), Supplemental Attachment 3b.

[179] Ex. CPSD-168, Overland Audit, p. 9-1. Note that while one table on page 9-1 shows the budget request as $111.1 million, another shows it as $111.194 million. Appropriate rounding reflects that the requested budge was $111.2 million.

[180] Ex. CPSD-168, Overland Audit, p. 9-1.

[181] Ex. CPSD-168, Overland Audit, pp. 9-1 to 9-2.

Ultimately, actual total expenses in 2010 were $22.8 million above budget because of $24 million spent to address the San Bruno explosion.[182]

Similar to 2008 and 2009, GT&S expected to address its budget constraints by deferring work to later years.[183] GT&S held brainstorming sessions and sought cost reduction options from its various organizations in order to meet the $89.8 million budget it was ultimately given.[184] Integrity Management made a number of cut cutting proposals, including moving more lines schedule for ILI to EDCA, and redefining PG&E's definition of transmission so that certain lines would not be subject to the integrity management regulations and therefore not required to be assessed by the end of 2012.[185] However, even this proposal acknowledged the preference for ILI as "most suitable" despite the fact that it covers many non-HCA miles: "Pigging (ILI) method must run many miles to assess HCA pipeline, *but may be most suitable for pipeline being inspected.*"[186]

Integrity Management pursued two cost-cutting initiatives to meet its 2010 budget, mindful of the need to perform significant work to meet end of 2012 compliance requirements. Those initiatives – the "Assessment Change Initiative" and the "TIMP Rescheduling Initiative" – were marketed internally as proposals that would generate savings in later years. A PG&E document explained the key challenges and risks of the "TIMP Rescheduling Initiative," which deferred work to later years. In sum, it recognized the risk of meeting 2012 compliance obligations if any further projects were deferred, and the possible higher costs of performing assessments in 2011 and 2012 because of competition for vendors: "If we 'starve' our 2010 schedule any further, we run

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[182] Ex. CPSD-168, Overland Audit, p. 9-3.

[183] See, e.g., Ex. CPSD-168, Overland Audit, p. 9-4 and Table 9-6.

[184] Ex. CPSD-168, Overland Audit, pp. 9-5 to 9-8.

[185] Ex. CPSD-168, Overland Audit, pp. 9-9 and 9-12. The pipeline redefinition initiative was not pursued. *Id.*, p. 9-12.

[186] Ex. CPSD-168, Overland Audit, p. 9-9 *quoting* OC-264 (Ex. CPSD-230), Supplemental Attachment 6, p. 9 (*emphases added*).

the risk of contractor unavailability to meet our aggressive needs in the future."[187] To respond to this scheduling challenge, PG&E documents reflect that the deferrals were "made feasible by the change in assessment methods" from ILI to ECDA under the Assessment Change Initiative.[188] Thus, the two initiatives went hand in hand, with the deferral and change to ECDA producing savings in future years. A November 2009 email from the Gas transmission Expense Program Manager explained the relationship between the two initiatives as a "win/win. We get to shift $ out of 2010 [that was earmarked for ILI], and the expenditures increase [in] 2011 and 2012 dollars due to the shift *is mostly offset by the savings from changing inspection methods*."[189]

vii. PG&E's Planned Redefinition of Transmission Pipeline Led to Delays in 2010

Despite the deferral of 19 miles to 2011 and prior shifts from ILI to ECDA (requiring assessment of fewer miles not in an HCA), PG&E's Integrity Management program still did not meet its primary goal for 2010 to assess 215 miles of HCA pipeline. PG&E only assessed 191.5 miles of HCA pipeline, 23.5 miles below its target.[190]

Internal PG&E documents produced in response to the Overland Audit reflect that PG&E had reduced the Integrity Management budget and the pace of pipeline assessments in 2010 based on the assumption that *PG&E planned to re-define its definition of transmission pipeline*, and thus would ultimately be required to assess fewer miles by the end of 2012.[191] Overland finds "[t]he reduced pace put PG&E behind

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[187] Ex. CPSD-168, Overland Audit, pp. 9-11 to 9-12, *quoting* OC-259 (Ex. CPSD-226), Attachment 4, p. 9, but citation missing from Overland Audit.

[188] CPSD-168, Overland Audit, p. 9-12 *quoting* PG&E from OC-260 (Ex. CPSD-227), Attachment 8.

[189] Ex. CPSD-168, Overland Audit, p. 9-13 *quoting* PG&E from OC-264 (Ex. CPSD-230), Supplemental Attachment 2 (*emphases added; typographical errors in the Overland Audit quote are corrected here*).

[190] Ex. CPSD-168, Overland Audit, p. 9-15 *citing* OC-46 (Ex. CPSD-179), Attachment 16, pp. 11.

[191] Ex. CPSD-168, Overland Audit, p. 9-15 *citing* OC-46 (Ex. CPSD-179), Attachment 16, p. 11 and 17.

schedule for achieving the 215 mile goal."[192] A December 2010 PG&E document explains:

> The effort to redefine PG&E's interpretation of what is a transmission line has been placed on hold and there is not time in the year to assess the additional 25 miles of pipe that would be necessary to meet the target of 215.

A PG&E data response reflects that the decision not to change the definition of transmission pipe occurred "at midyear."[193] PG&E declined to provide internal documents describing how and why it planned to realign its definition of transmission pipeline on the basis that "PG&E ultimately did not change its definition."[194] It is possible the decision not to change the definition of transmission pipe occurred as the result of the San Bruno explosion and PG&E's recognition that its "gaming" of such an important regulatory definition would not be viewed favorably.

viii. Budget Year 2010 – Maintenance Is Cut, Continuing PG&E Management's "Run to Failure" Policy

In 2010, GT&S Maintenance projected savings to meet its budget through "labor productivity" related to the local transmission leak survey work, "performing less preventative maintenance/overhauls" on gas compressors, and reducing pipeline project work. All of these budget cuts were predicted by PG&E staff to have sub-optimal impacts, reflecting the third year in a row in which PG&E management pushed its teams to reduce costs by compromising preventive maintenance and thus reliability and safety.

With regard to the leak survey work, PG&E documents reflect that the "leak survey is poorly managed at present. Unsure whether there is adequate supervision and

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[192] Ex. CPSD-168, Overland Audit, p. 9-15.

[193] Ex. CPSD-168, Overland Audit, p. 9-15 *citing* OC-254 (CPSD-194).

[194] The Overland Audit explains: "Overland asked PG&E to explain how and why it realigned its definition of transmission pipe and to provide the internal documents that discuss the interpretation. PG&E did not provide any information in response to that request because 'PG&E ultimately did not change its definition.'" Ex. CPSD-168, Overland Audit, p. 9-15, note 42 *citing* OC-254 (CPSD-194).

attention to task to improve."[195] PG&E documents identify the following challenges/risks associated with the reductions in gas compressor maintenance, including more unplanned emergency work, equipment failures, and express recognition of PG&E's "run to failure" approach:

- .... Will likely result in additional emergency unforeseen work as equipment fails...
- …Unplanned equipment failures will increase (***run to failure***), repair costs may increase vs. scheduling work at lowest impact times & costs.[196]

The same PG&E document reflects the following challenges and risks posed by the reductions in gas pipeline maintenance, including reliability issues and "public and CPUC concern over conditions of facilities":

- …Deferral of work may increase cost of mitigation in the future, may result in pipeline failure (small risk since atmospheric corrosion and reliability issues in advance stages are not deferred). May create public and CPUC concern over conditions of facilities...[197]

Other PG&E documents acknowledge that the "Reduce Project Work" Initiative described above created "a moderate risk of driving unplanned corrective maintenance" and that "funding for emergent projects is very limited."[198]

A January 2010 email from the Gas Transmission Expense Program Manager transmitted the approved budget to the GT&S managers and directors. The email paints a dire picture of the budget shortages. It explains that certain "high priority" items were not in the budget and that there would be no further funding unless a project was "necessary to return a critical asset to service." To the extent such work was necessary, offsets would be expected from the existing program:

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[195] Ex. CPSD-168, Overland Audit, p. 9-16 *citing* OC-259 (CPSD-226), Attachment 4, p. 15 (*emphases in Overland Audit, but not in original*).

[196] Ex. CPSD-168, Overland Audit, p. 9-16 *citing* OC-259 (CPSD-226), Attachment 4, p. 20 (*emphases added*).

[197] Ex. CPSD-168, Overland Audit, p. 9-17 *citing* OC-259 (CPSD-226), Attachment 4, p. 21.

> Not-in-budget items - Includes high priority not funded items per discussion with Gas Engineering leadership. There may be some Gas Operations projects to add to this list. We'll keep this list current during the year, but I have little hope of funding these unless they are mandatory or necessary to return a critical asset to service. In addition, I will ask for offsets from the respective program when a new project must be funded.
>
> In summary, the 2009 YE spend for Maintenance Projects was $19.8 million and the 2010 budget is $13.1 million, including emergency/unforeseen [sic] contingency. Of that $13.1 million, $10.6 million is committed per the attached list. Every effort must be made to reduce spend on all funded projects. This is the only program in GT Expense with contingency and all other budgets have been reduced. It is very unlikely that additional funding will be available due to underruns elsewhere.[199]

ix. CPUC Audit of Integrity Management Program

In May 2010, CPSD conducted an audit of PG&E's Integrity Management Program. PG&E's Integrity Management team scrambled for the six months prior to the audit, devoting about 2/3 of their time to audit preparation.[200] Based on this extensive audit preparation, the Overland Audit surmises that Integrity Management resources were constrained and that there was a significant backlog of work, possibly because of understaffing:

> The amount of effort required to prepare for the audit is an indication that integrity management had a very large backlog of incomplete work. That, in turn, implies staffing shortages in the Integrity Management organization.

The Overland Audit confirms in detail the high level findings of the Commission Audit. In a letter dated October 21, 2010, the Commission highlighted two areas of

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(continued from previous page)
198 Ex. CPSD-168, Overland Audit, p. 9-17 *quoting* OC-68 (CPSD-186), Attachment 2, pp. 4-5.

199 Ex. CPSD-168, Overland Audit, p. 9-17 *quoting* OC-261 (CPSD-228), Attachment 1.

200 Ex. CPSD-168, Overland Audit, p. 9-14 *citing* OC-92 (CPSD-194), Attachment 4.

particular concern. The first concern, relevant to the changes from ILI to ECDA and the deferrals to later years, was that PG&E was "diluting the requirements" of the Integrity Management Program through its exception process and that PG&E appeared to be "allocating insufficient resources to carry out and complete assessments in a timely manner."[201] The letter specifically noted that several pipeline assessments had been delayed, and in some cases changed to ECDA.[202] The second concern, reflecting Overland's finding that PG&E was resource constrained, was that PG&E needed to analyze, review, and formulate appropriate actions or responses to internal audits in a more timely manner. The Commission Audit observed that it took PG&E two years to formulate a response to an internal audit conducted in December 2007. PG&E agreed that it needed improvement with regard to both sets of concerns.[203]

x. Conclusions for 2010 and Beyond

The Overland Audit concludes that "GT&S was under significant pressure to reduce expenses for a third straight year in 2010. The 2010 budget was set $6.7 million below the already constrained 2009 actual expense level."[204] It notes that PG&E's 2011 GT&S rate case forecast reflected significant increases in Integrity Management and Maintenance expenses for 2011 to "catch up for deferred maintenance."[205] However, since PG&E's GT&S was more than adequately funded from prior rate cases to perform work between 2008 and 2010,[206] there is no indication that PG&E would have changed its practices if it had received more funding in 2011. In fact, all the evidence is to the contrary. Because of the San Bruno explosion, we will never know.

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[201] Ex. CPSD-9, NTSB Report, p. 68 *quoting* the CPUC Audit Letter dated October 21, 2010.

[202] Ex. CPSD-9, NTSB Report, p. 68 *relying upon* the CPUC Audit Letter dated October 21, 2010.

[203] Ex. CPSD-9, NTSB Report, p. 68.

[204] Ex. CPSD-168, Overland Audit, p. 9-19.

[205] Ex. CPSD-168, Overland Audit, p. 9-19.

[206] PG&E's gas transmission and storage operations have been very profitable since the Gas Accord Structure was implemented in March 1998. During that time, those *revenues exceeded* the amount needed to earn the *authorized rate-of-return by $430 million.* Ex. CPSD-168, Overland Audit, p. 1-1.

However, the evidence is clear that PG&E engaged in a pattern and practice of systematically underfunding its gas Maintenance and Integrity Management programs in the years preceding the San Bruno explosion. The evidence further shows that inadequate inspection methods were used and that maintenance, repairs, and replacements were deferred to save money. The many documented "errors and omissions" finally caught up with PG&E. The Commission should hold the company accountable for the costs of getting PG&E's gas pipeline system into acceptable condition.

4. PG&E's Ratepayers Paid For Maintenance and Operation of a Safe Gas Transmission System for Decades, But PG&E Pocketed The Money Rather Than Invest In Safety

There is no question that all of PG&E's integrity management work – over nearly three decades – has been funded by ratepayers through rates.[207] As described above in Section V.F.2, all the experts, including PG&E's, agree that PG&E's GT&S operations have been extremely profitable for over a decade. Everyone agrees that PG&E made substantial profits *over and above* its authorized rate of return. And PG&E admits it received enough money in rates to fund the maintenance and operation of a safe gas transmission system.[208] In short: Ratepayers paid rates more than sufficient for the maintenance and operation of a safe gas transmission system.

However, as we saw in Section V.F.3 above, the Overland Audit explains how PG&E systematically underfunded GT&S integrity management and maintenance operations for the years 2008 through 2010. PG&E engaged in a "run to failure" strategy whereby it deferred needed maintenance projects and changed the assessment method for several pipelines from ILI to the less informative ECDA approach – all to increase its

[207] *See, e.g.,* Decision 11-04-031, Appendix A, Gas Accord V Settlement Agreement, Section 7.3, p. 8.

[208] R.11-02-019, 9 RT 959-960, Bottorff/PG&E.

profits even further beyond its already generous authorized rate of return, which averaged 11.2% between 1996 and 2010.[209]

Given PG&E"s excessive profits over the period of the Overland Audit, there is no reason to believe that Overland's example regarding GT&S operations between 2008 and 2010 was unique. The IRP Report supplements the Overland Audit findings with additional examples of PG&E management's commitment to profits over safety. Thus, it is evident that while the example of GT&S underfunding between 2008 and 2010 might be extreme, it was not an isolated incident; rather, it represents the culmination of PG&E management's long standing policy to squeeze every nickel it could from PG&E gas operations and maintenance, regardless of the long term "run to failure" impacts. And PG&E has offered no evidence to the contrary.

5. Certain Findings Are Necessary To Ensure That Ratepayers Do Not Pay For PG&E's Remedial Work To Ensure The Safety Of Its Gas Transmission System

As described in Section III.B above, § 463 requires the Commission to disallow direct and indirect expenses related to the unreasonable errors or omissions of a utility costing more than $50 million:

> [T]he 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) ….

In Decision 12-12-030 the Commission recognized that findings could be made in this proceeding that would impact the rate treatment of PG&E's remedial pipeline safety plan approved in that decision. The Decision expressly provided for refunds based on "ratemaking adjustments … adopted in [the Commission's] investigations."[210]:

[209] Ex. PGE-10, O'Loughlin MPO-1, p. 7. Mr. O'Loughlin estimates that PG&E's actual ROE averaged 14.6% between 1999 to 2010. Put in text?

[210] D.12-12-030, pp. 4 and 126, OP 3.

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In this proceeding, we have established, and PG&E agrees, that PG&E has earned profits well in excess of its authorized rate of return for over a decade. We have also established, and PG&E agrees, that PG&E ratepayers paid for PG&E to operate and maintain a safe system. We have also established, and PG&E has not contested, that PG&E underfunded its GT&S operations for many years, while it earned profits above its authorized rate of return from those operations. We have also established, and PG&E has not contested, that PG&E accrued savings by deferring GT&S maintenance projects and by performing ECDA rather than the more expensive ILI to assess the condition of its gas transmission pipelines. It is uncontested that PG&E ratepayers paid for the less effective ECDA reviews of PG&E's pipelines, and PG&E ratepayers paid sufficient rates to fund both ILI reviews and appropriate maintenance for PG&E's gas transmission system. We have also established that PG&E's recordkeeping was a mess, that PG&E knew it was a mess, that PG&E did nothing to address this mess, and that PG&E's poor recordkeeping practices undermined the risk assessment value of its integrity management program. PG&E's arguments to the contrary, including hearsay evidence, are not compelling; its experts' testimony should be disregarded or, at a minimum, accorded little weight.

PG&E's decisions to engage in a "run to failure" strategy, including a deficient recordkeeping system, deferred maintenance, and less effective ECDA reviews of its gas transmission pipeline system, allowed the system to degrade and placed the public at risk. Those practices constitute inexcusable errors and omissions within the meaning of § 463. Consequently, § 463 requires that the company, not its ratepayers, be held responsible for the direct and indirect costs resulting from those errors and omissions. The company must bear the cost of bringing PG&E's gas transmission pipeline system up to an acceptable level of safety and reliability, because it has had an ongoing responsibility to operate the system safely and to maintain it properly it all along. Thus, the company must be held responsible for the billions of dollars in costs to test and/or replace pipelines.[211] The law does not permit shifting these costs to ratepayers.

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[211] D.12-12-030 estimates that the first phase of PG&E's plan, which will be implemented through 2014,
(continued on next page)

Appendix A, attached hereto, contains proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs necessary to implement this recommendation.

6. Given PG&E's Historic Inattention To Safety, An Independent Monitor Is Needed

a. PG&E's Inattention To Safety Is Pervasive And Goes Back Over 50 Years

While the focus of the various reports on the San Bruno explosion has been on PG&E's safety culture over the last 10 years or so, the reports identify several contributing factors to the San Bruno explosion, which, when viewed holistically, demonstrate that PG&E's inattention to safety is pervasive and goes back over 50 years.

The NTSB concluded that the explosion was caused by a gas pipe that was defective when PG&E installed it in 1956, and that the defect "would have been visible when it was installed."[212] The NTSB identified two probable causes for the accident. The first was PG&E's "inadequate quality assurance and quality control" which allowed installation of the defective line in 1956.[213] The second was PG&E's "inadequate pipeline integrity management program" – a records-based program – which "failed to detect and repair or remove the defective pipe section" in later years.[214] As discussed in Section V.B.1.b above, a form of PG&E's integrity management program has been in place for nearly 30 years. The evidence shows that PG&E's integrity management program lacked reliable data from the beginning, and that PG&E was on notice that it needed to systematically update the data as information became available, but that it did not. The NTSB also recognized that PG&E was on notice for many years, as a result of

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will cost $1.2 billion. D.12-12-030, p. E3, Table E-4. PG&E has estimated that Phase 2 (which could be submitted in its rate case application to be filed in 2014) will cost between $6.8 billion and $9 billion. R.11-02-019, Ex. 149, DRA Testimony, Chap. 9, p. 2 and note 5.

[212] Ex. CPSD-9, NTSB Report, p. x.

[213] Ex. CPSD-9, NTSB Report, p. xii.

[214] Ex. CPSD-9, NTSB Report, p. xii.

other gas system incidents, that its records were inaccurate and that quality assurance was a problem.[215]

Similar to the NTSB, CPSD found that the San Bruno explosion was caused by "PG&E's failure to follow accepted industry practice when constructing the section of pipe that failed, PG&E's failure to comply with integrity management requirements, [and] PG&E's inadequate recordkeeping practices…"[216]

The IRP Report concluded that "the explosion of the pipeline at San Bruno was a consequence of multiple weaknesses in PG&E's management and oversight of the safety of its gas transmission system."[217] Many of those weaknesses related to PG&E's inaccurate records and a lack of quality assurance. Specifically, the IRP Report identified the following deficiencies:

- A lack of coordination between field staff and engineering management regarding which data are collected and where and how records are preserved – resulting in the discovery that "experienced piping engineers were well aware the San Bruno segment was double-submerged arc welded (DSAW), rather than seamless;"[218]

- Integrity management program failures to adequately identify pipeline threats because of inaccurate data, inappropriate risk ranking methodology, a failure to have knowledgeable engineers reviewing the data for errors, and the disconnect between integrity management and field operations;[219] and

- A lack of a strong quality assurance program,[220] the same observation made by the NTSB regarding PG&E's activities in 1956.

[215] Ex. CPSD-9, NTSB Report, pp. 117-118

[216] Ex. CPSD-1, CPSD San Bruno Report, p. 1.

[217] Ex. CPSD-10, IRP Report, p. 5.

[218] Ex. CPSD-10, IRP Report, p. 7.

[219] Ex. CPSD-10, IRP Report, pp. 8-9.

Thus, it is clear that PG&E's mismanagement did not start with the energy crisis in 2000, or some other recent event outside its control. PG&E had quality assurance problems when it installed Line 132 in 1956. It had quality assurance problems when it began development of its Gas Pipeline Replacement Program with Bechtel in the early 1980s, and it has had quality assurance problems in the last decade related to its gas leak surveys and regulator stations. Internal audits in 2007 found than an employee had falsified completion records for work that was not performed and that supervisors pre-signed approvals on blank maintenance forms before work was done. And later audits found that these types of problems were not unique, and that similar problems existed with regard to PG&E's leak survey program.

Problems similar to those identified in the San Bruno explosion occurred in the 2008 gas distribution explosion in Rancho Cordova that killed one person and injured several others. There, the NTSB "Pipeline Accident Brief" concluded that the incident was the result of PG&E's "use of a section of unmarked and out-of-specification polyethylene [PE] pipe with inadequate wall thickness that allowed gas to leak from the mechanical coupling installed on September 21, 2006."[221] The NTSB also found that PG&E's poor emergency response contributed to the accident.[222]

The practices documented in these various audits and reports are the same kinds of practices that would have permitted Line 132 to be installed with no record of the 6 pups in the 1950s, and the same types of practices that would have permitted the GPRP data base to be developed with multiple errors, omissions, and inappropriate assumptions in the 1980s, and never corrected in later years.

All of this leads to the common sense conclusion that PG&E has never had a gas safety culture, or systematic and effective quality assurance or risk assessment

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(continued from previous page)
[220] Ex. CPSD-10, IRP Report, pp. 10-12.

[221] D.11-11-001, p. 6, quoting from the NTSB Pipeline Accident Brief attached to the CPSD Report at Appendix L.

[222] Id., pp. 6-7.

mechanisms in place to ensure the safe operation of a high pressure gas transmission pipeline system. In light of this history, it is unrealistic to expect PG&E to change its culture and develop these programs successfully overnight because of a partial change in management. The Commission, with the help of independent third parties, must adopt a qualitatively different type of oversight of PG&E at every level. And it must maintain this stepped-up oversight until PG&E has demonstrated that it can operate its gas transmission system safely.

b. An Independent Third Party Monitor Is Appropriate Here

Given PG&E's decades of gas system mismanagement, including failure to implement systematic quality assurance practices, there is a need for ongoing "hands on" oversight of PG&E's work testing and replacing its gas transmission system, and updating its records with accurate information. And the Commission cannot provide this oversight itself in a vacuum.

The IRP Report identified the Commission's failure to oversee PG&E's gas operations effectively and opined that the Commission as well as PG&E "must confront and change elements of their respective cultures to assure the citizens of California that public safety is the foremost priority."[223] The NTSB report found that the Commission's "failure to detect the inadequacies of PG&E's pipeline integrity management program" contributed to the San Bruno Explosion.[224]

To restore public confidence in the Commission's ability to supervise PG&E, and to provide the expertise necessary to ensure that PG&E's work is implemented in a timely and competent manner, the Commission should establish an oversight process that employs independent monitors to actively monitor PG&E's remedial work and who report publicly on their findings until the Commission has found that PG&E has fully

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[223] IRP Report at 8 and 18-22.

[224] NTSB Report at xii.

complied with its orders regarding testing, replacement, and database upgrades relative to its gas transmission system.

Independent third party monitors are routinely used on large scale public works projects, including the recent retrofits to the Golden Gate Bridge and the current construction of a new Bay Bridge. There, independent monitors are on site, inspecting all aspects of the work being performed on a daily basis as an additional check to ensure the public is getting what it is paying for.

Similarly, it is not uncommon for independent monitors to be employed in response to destructive oil and gas pipeline incidents, including the 2006 British Petroleum oil spills in Alaska[225] and the 1999 rupture of a Shell and Olympic Oil Company pipeline.[226] An independent monitor with expertise in risk assessment, pipeline integrity management, and data management systems was employed to review the implementation of remedial plans agreed to by El Paso Natural Gas Company as part of a 2007 Consent Decree resolving an action brought by the federal government against the company after a pipeline explosion that killed twelve people.[227]

To establish an independent monitor process, the decision in this matter should direct the parties to meet and confer and, if possible, file joint comments proposing an independent monitor process acceptable to the majority of them. At a minimum, the decision should require the parties' joint proposal to include these elements:

- A hiring process for the independent monitors that ensures their independence, to the extent practicable;
- PG&E will hire and pay for the independent monitors;
- The independent monitors will conduct and present all analyses and recommendations independently of any

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[225] See pp. 30-31 of British Petroleum's consent decree with the U.S. Environmental Protection Agency at http://www.epa.gov/compliance/resources/decrees/civil/cwa/bpnorthslope-cd.pdf.

[226] See http://www.epa.gov/compliance/resources/cases/civil/cwa/olympicshell.html.

[227] Consent Decree in US v El Paso Natural Gas Co. (Dist. Ct. New Mexico) at 12 and *et seq.,* available at http://emerginglitigation.shb.com/Portals/f81bfc4f-cc59-46fe-9ed5-7795e6eea5b5/r_El_Paso_Natural_Gas_Consent_DecreeFinal.pdf

suggestions or conclusions of PG&E, the Commission, or other interested parties;

- Quarterly public reporting by the independent monitors to a joint meeting of PG&E, the Commission, and other interested parties;
- The independent monitors will notify PG&E, the Commission, and other interested parties in writing within 10 days of discovery of any potential non-compliance with the requirements of the PSEP or presents a potential, but not immediate, threat to public safety;
- The independent monitors will notify PG&E, the Commission, and interested parties in writing within 24 hours of any condition that poses a potential and immediate threat to public safety; and
- PG&E's contracts with independent monitors shall prohibit an independent monitor from seeking work from PG&E while performing the duties of an independent monitor.

Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs necessary to implement this third party independent monitor proposal are set forth in Appendix A hereto.

VI. OTHER ALLEGATIONS RAISED BY TESTIMONY OF TURN

VII. OTHER ALLEGATIONS RAISED BY TESTIMONY OF CCSF

VIII. OTHER ALLEGATIONS RAISED BY TESTIMONY OF CITY OF SAN BRUNO

IX. CONCLUSION

For all the reasons set forth herein, the decision in this matter should disallow testing and replacement expenses for PG&E's gas transmission pipeline system that are the result of PG&E's errors and omissions. Further, the decision should adopt a process to ensure an independent third party monitor is appointed to oversee PG&E's testing, replacement, and recordkeeping activities to ensure they are performed in an appropriate manner. Appendix A, attached hereto, contains proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs necessary to implement these recommendations.

Respectfully submitted,

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APPENDIX A

PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

I. DISALLOWANCES FOR ERRORS AND OMISSIONS

A. FINDINGS OF FACT TO SUPPORT DISALLOWANCES FOR ERRORS AND OMISSIONS

PG&E Committed Unreasonable Errors and Omissions

1. PG&E has committed unreasonable errors and omissions in operating and maintaining its gas transmission system for which the remediation will cost far more than $50 million.

2. Based on the evidence presented in the NTSB Report and the evidence produced in this proceeding, the Commission concurs with the NTSB's finding that the San Bruno explosion was the result of "organizational failure," and thus there were many contributing causes of the explosion.

3. The San Bruno explosion was caused by a gas pipe that was defective when PG&E installed it in 1956, and the defects would have been visible when it was installed.

4. PG&E's inadequate quality assurance and quality control which allowed installation of the defective line in 1956, and its inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section in later years, were contributing factors in the explosion.

5. The San Bruno explosion was a consequence of multiple weaknesses in PG&E's management and oversight of the safety of its gas transmission system which resulted in PG&E's inaccurate records and a lack of a strong quality assurance program.

6. Every report on the San Bruno explosion concludes that PG&E's integrity management program was deficient.

7. The NTSB correctly found that PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective

because it relied on pipeline information that was inaccurate and incomplete, was missing mission critical information, and was not designed to consider the most relevant information – such as pipeline design, materials, and repair history – when determining how to prioritize repairs and replacements.

8. The NTSB correctly concluded that PG&E's integrity management program led to internal assessments that were superficial and resulted in no improvements.

9. The IRP correctly concluded that PG&E's integrity management program is not identifying all threats, as required by regulation; is not identifying the segments of highest risk and remediating significant anomalies; and hence is not taking programmatic actions to prevent or mitigate threats.

10. A form of PG&E's integrity management program has been in place for nearly 30 years.

11. PG&E's integrity management program lacked reliable data from the beginning.

12. The evidence shows that well before the San Bruno explosion, PG&E was put on notice of its significant record keeping deficiencies, and their impacts on its integrity management risk assessments.

13. PG&E's expert testimony that its integrity management program met regulatory requirements and industry standards is not credible and should be disregarded.

14. The evidence shows that PG&E was not complying with integrity management regulatory requirements or industry standards.

15. PG&E's expert witnesses intentionally ignored well-documented evidence that PG&E's integrity management records have significant errors and omissions.

16. PG&E's expert witness incorrectly asserted that accurate data is not important for integrity management purposes and is not necessary to operate a functional integrity management program.

17. PG&E's expert witnesses emphasized that integrity management was an iterative process requiring new and updated information to be added when pipeline assessments were performed and data became otherwise available.

18. The evidence shows that PG&E took no meaningful actions to systematically update its integrity management data, or correct the errors over time. It did not systematically update the integrity management data base when pipeline assessments were performed.

19. One of PG&E's integrity management witnesses joined PG&E after the San Bruno explosion and could not testify as an eye witness to PG&E's actual data collection and integration practices before San Bruno; nor could she testify regarding the actual functionality of PG&E's integrity management program at that time.

PG&E Received Sufficient Money In Rates To Operate and Maintain A Safe System

20. All of PG&E's integrity management work covering nearly three decades has been funded by ratepayers through rates.

21. All the experts, including PG&E's, agree that PG&E's GT&S operations have been extremely profitable for over a decade.

22. PG&E does not dispute that its GT&S operations made substantial profits over and above its authorized rate of return.

23. PG&E's ratepayers paid for maintenance and operation of a safe gas transmission system for decades, but PG&E did not invest that money into gas transmission safety.

24. Notwithstanding the significant profits earned by PG&E's GT&S operations, PG&E systematically underfunded GT&S integrity management and maintenance operations for the years 2008 through 2010, engaging in a "run to failure" strategy whereby it deferred needed maintenance projects and changed the assessment method for several pipelines from ILI to the less informative and less appropriate ECDA approach, to increase profits even further.

B. CONCLUSIONS OF LAW TO SUPPORT DISALLOWANCES FOR ERRORS AND OMISSIONS

1. The hearsay testimony of PG&E's integrity management witness should be given very little weight to the extent they were testifying to PG&E practices that they did not observe.

2. Section 463 of the California Public Utilities Code requires the Commission to disallow direct and indirect expenses related to the unreasonable errors or omissions of a utility costing more than $50 million.

3. The Commission has relied upon § 463 and its general ratemaking authority on many occasions to disallow costs resulting from unreasonable utility errors and omissions, and should do so here.

4. While ratemaking issues are not usually taken up in an OII, D.12-12-030, which addressed the ratemaking treatment for PG&E's post-San Bruno remediation plan, invited consideration of such issues here.

5. D.12-12-030 expressly provided for the possibility of refunds based on ratemaking adjustments adopted in this proceeding.

6. To the extent the parties to this proceeding have shown that PG&E has committed errors or omissions costing more than $50 million, all direct and indirect remediation costs should be disallowed.

7. Pursuant to D.12-12-030 and sections 451 and 463, the Commission should order disallowances for PG&E's errors and omissions in this proceeding.

C. ORDERING PARAGRAPHS TO SUPPORT DISALLOWANCES FOR ERRORS AND OMISSIONS

1. Pursuant to Public Utilities Code § 463, the costs related to pipeline testing and/or replacements performed because of PG&E's failure to maintain adequate records shall be disallowed. However, to the extent PG&E has records demonstrating that a replaced

pipeline was installed before January 1, 1956, the costs of such replacement shall not be disallowed to account for the fact that the ratepayers are receiving additional benefits from a newer pipeline.

II. ADOPTION OF AN INDEPENDENT THIRD PARTY MONITOR

A. FINDINGS OF FACT SUPPORTING ADOPTION OF AN INDEPENDENT THIRD PARTY MONITOR

1. PG&E's inattention to safety is pervasive and goes back over 50 years.

2. The evidence shows that PG&E has never had a gas safety culture, or systematic and effective quality assurance or risk assessment mechanisms in place to ensure the safe operation of a high pressure gas transmission pipeline system.

3. The Commission's failure to detect the inadequacies of PG&E's pipeline integrity management program contributed to the San Bruno Explosion.

4. Independent third party monitors are routinely used on large scale public works projects where independent monitors are on site, inspecting all aspects of the work being performed on a daily basis as an additional check to ensure the public is getting what it is paying for.

5. It is not uncommon for independent monitors to be employed in response to destructive oil and gas pipeline incidents.

B. CONCLUSIONS OF LAW SUPPORTING ADOPTION OF AN INDEPENDENT THIRD PARTY MONITOR

1. The various reports on the San Bruno explosion identify several contributing factors to the San Bruno explosion, which, when viewed holistically, demonstrate that PG&E's inattention to safety is pervasive and goes back over 50 years.

2. In light of this history, it is unrealistic to expect PG&E to change its culture successfully overnight.

3. In light of PG&E's historical lack of a safety culture, including failure to embody quality assurance practices, there is a need for ongoing "hands on" oversight of PG&E's work testing and replacing its gas transmission system, and updating its records with accurate information.

4. The Commission, as well as PG&E, must confront and change elements of their respective cultures to assure the citizens of California that public safety is the foremost priority.

5. The Commission, with the help of independent third parties, should adopt a qualitatively different type of oversight of PG&E at every level.

6. To restore public confidence in the Commission's ability to supervise PG&E, and to provide the expertise necessary to ensure that PG&E's work is implemented in a timely and competent manner, the Commission should establish an oversight process that employs independent monitors to actively monitor PG&E's remedial work and who report publicly on their findings until the Commission has found that PG&E has fully complied with its orders regarding testing, replacement, and database upgrades relative to its gas transmission system.

7. The Commission should maintain this stepped-up oversight until PG&E has demonstrated that it can operate its gas transmission system safely.

8. To establish an independent monitor process, the decision in this matter should direct the parties to meet and confer and, if possible, file joint comments proposing an independent monitor process acceptable to the majority of them. At a minimum, the decision should require the parties' joint proposal to include these elements:

- A hiring process for the independent monitors that ensures their independence, to the extent practicable;
- PG&E will hire and pay for the independent monitors;
- The independent monitors will conduct and present all analyses and recommendations independently of any suggestions or conclusions of PG&E, the Commission, or other interested parties;

- Quarterly public reporting by the independent monitors to a joint meeting of PG&E, the Commission, and other interested parties;
- The independent monitors will notify PG&E, the Commission, and other interested parties in writing within 10 days of discovery of any potential non-compliance with the requirements of the PSEP or presents a potential, but not immediate, threat to public safety;
- The independent monitors will notify PG&E, the Commission, and interested parties in writing within 24 hours of any condition that poses a potential and immediate threat to public safety; and
- PG&E's contracts with independent monitors shall prohibit an independent monitor from seeking work from PG&E while performing the duties of an independent monitor.

C. ORDERING PARAGRAPHS REGARDING ADOPTION OF AN INDEPENDENT THIRD PARTY MONITOR

1. The Parties shall meet and confer and, if possible, file joint comments proposing an independent monitor process acceptable to the majority. At a minimum, the parties' joint proposal shall include the following elements:

- A hiring process for the independent monitors that ensures their independence, to the extent practicable;
- PG&E will hire and pay for the independent monitors;
- The independent monitors will conduct and present all analyses and recommendations independently of any suggestions or conclusions of PG&E, the Commission, or other interested parties;
- Quarterly public reporting by the independent monitors to a joint meeting of PG&E, the Commission, and other interested parties;
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- PG&E's contracts with independent monitors shall prohibit an independent monitor from seeking work from PG&E while performing the duties of an independent monitor.