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, Laws, 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 CITY AND COUNTY OF SAN FRANCISCO

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I. INTRODUCTION AND SUMMARY

This proceeding concerns a utility's most fundamental obligation: to provide safe and reliable service. The California Public Utilities Commission (Commission) has an ongoing duty and obligation to protect the public by ensuring gas pipeline safety and gas service at reasonable rates. In order to do so, the Commission can impose penalties and other sanctions, and generally regulate PG&E's utility operations.

The federal regulations provide minimum safety standards, with which PG&E has not complied. In addition, Public Utilities Code section 451, among many other sections, empowers and requires the Commission to ensure PG&E's operations "promote the safety, health, comfort, and convenience of its patrons, employees and the public."

The evidence in this proceeding demonstrates that the San Bruno accident was the result of systemic and decades-long failure by PG&E to properly manage its gas pipeline system. The City and County of San Francisco's (San Francisco or CCSF) testimony[1], in particular, shows that:

- PG&E failed to act proactively to ensure the safe and reliable operations of its pipelines, by failing to comply with state and federal law or prudent utility practice.
- Prior to the accident and in the face of increasing uncertainty about the safety of its pipelines, PG&E failed to respond appropriately to all potential threats to its pipelines.
- This disregard for the potential threats to its pipelines was exacerbated by PG&E's spiking the pressures on its pipelines, in some cases repeatedly.

The Commission needs to look no further than the litany of actions PG&E has taken following the accident to determine that its conduct prior to the accident was insufficient to provide safe and reliable service. It is not credible to assert that the breadth of actions now required to ensure the safety of PG&E's gas pipelines is unrelated to PG&E's historical failure

[1] Exhibit CCSF-1(Testimony of John Gawronski) and exhibits attached thereto.

to operate its gas pipelines prudently and in compliance with state and federal requirements. The evidence shows that following the explosion on September 9, 2010, PG&E identified an additional 523 pipeline segments with unstable manufacturing defects, including over 1 mile of pipeline in San Francisco. These segments are some of the oldest segments in PG&E's system. As PG&E's own documents show, the safety mandate to carefully assess and remediate flaws on those segments has been in place for decades. Based on the evidence, the Commission and the public can have little confidence that PG&E provided safe and reliable service.

II. BACKGROUND

This Order Instituting Investigation (OII) was one of several Commission responses to the PG&E pipeline explosion in San Bruno that claimed eight lives, devastated a community, and raised the concern of everyone who lives or travels near gas pipelines. The OII clearly stated the genesis of this proceeding[2]:

> Because PG&E is entrusted to promote and protect the safety of its significant and complex engineering operations, the Commission expects PG&E to employ good safety engineering practices in operating and maintaining its potentially dangerous natural gas pipelines. The Commission's expectation applies to design, construction, operations, testing, maintenance, inspection, risk assessment, and pipe replacement.

III. LEGAL ISSUES OF GENERAL APPLICABILITY

A. The Commission Has the Responsibility to Ensure Pipeline Safety

In this investigation, the Commission seeks "to determine whether PG&E, and its officers, directors, and managers, violated any provisions of the California Public Utilities Code, Commission General Orders or decisions, or other applicable standards, laws, rules or regulations in connection with the San Bruno fire and explosion on September 9, 2010."[3] The Commission has ample jurisdiction, and in fact, the responsibility to undertake this

[2] I. 12-01-007 at p. 8.

[3] Order Instituting Investigation at p. 2.

investigation.[4] As described in more detail in below, the Commission has been granted safety jurisdiction in California pursuant to the Federal Pipeline Safety Act.

In addition, as the Commission itself detailed in its order instituting this investigation, the Commission has substantial jurisdiction, authority and responsibility under state law to regulate the safety of natural gas pipelines in California:

> The California State Constitution, Article XII, gives the Commission authority over natural gas operators in California. Public Utilities Code Section 701, and Public Utilities Code Section 222 which defines gas corporations, empower the Commission to do "all things…necessary and convenient" in the exercise of its powers and jurisdiction over natural gas operators. Section 768 authorizes the Commission to promote and safeguard the health and safety of the public by establishing uniform standards for construction and maintenance of utility equipment and plant. 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.[5]

B. Applicable Pipeline Safety Laws, Regulations, and Standards

In 1968, Congress enacted the Pipeline Safety Act (Act), which sets safety standards and provides for federal and state enforcement of those standards. The Act's purposes are " to provide adequate protection against risks to life and property posed by pipeline transportation and pipeline facilities by improving the regulatory and enforcement authority of the Secretary of Transportation."[6] To achieve these purposes, the Act requires gas pipeline operators to comply strictly with federal pipeline safety standards. The first iteration of the federal regulations were effective in 1970.

The Act also provides that a state may regulate and enforce the federal pipeline safety standards if a state authority certifies to the Department of Transportation (DOT) that, among other things, it has jurisdiction and authority to regulate such pipeline facilities, has adopted the

[4] See D. 04-04-065 at p. 48 (the Commission had jurisdiction to determine whether Southern California Edison violated GO 95 and GO 128 and to impose penalties).

[5] Order Instituting Investigation at p. 7 (citations omitted).

[6] 49 U.S.C. § 60102(a)(1).

federal safety standards, and is enforcing them.[7] The Commission has certified annually to the Pipeline Hazardous Materials and Safety Administration (PHMSA) that it has the jurisdiction and authority to enforce the minimum pipeline safety requirements. Although the federal regulations are the minimum standards, the Commission may enforce more stringent standards.[8]

Pursuant to its constitutional and statutory mandate, the Commission has enforced natural gas pipeline safety rules through its General Order (GO) 112. The first version of GO 112 was adopted in 1961. That version of GO 112 adopted the standards set forth in the 1968 version of ASA B.31.8. Following the promulgation of the federal regulations in 1970, the Commission incorporated the federal regulations into its General Order (GO) 112.[9] GO 112-E is the current version of GO 112 and was adopted in 2008. Although there was no version of GO 112 prior to 1961, PG&E has stated that it followed the requirements of the 1955 version of ASA B.31.1.8.

C. Applicable Provisions Of the California Public Utilities Code.

In addition to complying with applicable safety standards, "the Commission expects PG&E to employ good safety engineering practices in operating and maintaining its potentially dangerous natural gas pipelines."[10] This "expectation applies to design, construction, operations, testing, maintenance, inspection, risk assessment, and pipe replacement."[11] The Commission's expectations are grounded in California public utilities law.

Public Utilities Code Section 451 requires public utilities to "furnish and <u>maintain</u> such <u>adequate</u>, efficient, just, and reasonable service, instrumentalities, <u>equipment, and facilities</u>, . . . <u>as are necessary to promote the safety</u>, health, comfort, and convenience <u>of its patrons, employees, and the public.</u>"[12] Here, pursuant to Public Utilities Code Section 451, PG&E had an obligation to maintain the safety of its pipelines. Further, Public Utilities Code Section 702

[7] 49 U.S.C. § 60105(a) – (c).

[8] 49 U.S.C. § 60104 (c).

[9] See General Order 112-C.

[10] Order Instituting Investigation at p. 8.

[11] *Id.*

[12] Emphasis added.

requires every public utility to "obey and comply with every order, decision, direction, or rule made or prescribed by the commission in the matters specified in this part, or any other matter in any way relating to or affecting its business as a public utility," and to "do everything necessary or proper to secure compliance therewith by all of its officers, agents, and employees."[13] Thus, PG&E was required to comply with the Commission's detailed orders related to pipeline safety.

Moreover, as the Commission detailed in the Order Instituting Investigation, if the Commission finds that PG&E did not maintain the safety of its facilities consistent with California law, the Commission has broad authority to require PG&E to improve its practices.[14] As the Commission stated, "[w]e emphasize that the Commission's remedial powers are not limited to its authority to impose civil penalties. Pursuant to Public Utilities Code Section 761, if the Commission finds that PG&E's maintenance or operations practices were unsafe, unreasonable, improper, or insufficient, we may consider ordering PG&E to change or improve its maintenance, operations, or construction standards for gas pipelines, in order to ensure system-wide safety and reliability."[15]

D. Reasonableness Standard.

The Commission must determine whether PG&E acted reasonably to meet its obligations to maintain the safety of its equipment and facilities under California Law, including but not limited to Public Utilities Code Section 451, GO 112 and ASA B.31.1.8. A "utility is expected to take reasonable steps to ensure compliance with Commission directives, including regularly reviewing its own operations to ensure full compliance."[16] As the Commission explained in assessing Southern California Edison's compliance with GO95, GO 128 and Go 165 "[o]ur inquiries [are] into the reasonableness of a utility's conduct, and its compliance with relevant statutes and Commission orders . . . . The Commission is required to determine whether the

[13] Emphasis added.

[14] See Order Instituting Investigation at p. 10.

[15] Id.

[16] D. 04-04-065 at p.40.

service or equipment of a public utility *poses any danger* to public safety, and if so, to prescribe corrective measures."[17]

Moreover, in determining whether PG&E acted reasonably, the Commission's inquiry is not limited to determining whether PG&E violated a specific rule or guideline. Instead

> [u]tilities are held to a standard of reasonableness based upon the facts that are known or should be known at the time. While this reasonableness standard can be clarified through the adoption of guidelines the utilities should be aware that guidelines are only advisory in nature and do not relieve the utility of its burden to show that its actions were reasonable in light of circumstances existent at the time. Whatever guidelines are in place, the utility will be required to demonstrate that its actions were reasonable . . . .[18]

As the Commission explained in D.04-04-065, in assessing Southern California Edison's compliance with GO 95, GO 128 and GO 165:

> Edison has argued that if it has complied with the maintenance intervals of GO 165, it should be excused from liability for GO violations, for example, if a tree has grown enough since its last inspection that it is less than the minimum GO clearance from a power line. We do not agree. GO 165 sets minimum intervals for maintenance inspections. Circumstances may dictate that shorter intervals are required in particular cases. For example, an exceptionally wet or mild winter may result in faster vegetation growth. Simply complying with the minimum intervals set by our GO will not be sufficient to deal with that situation and the utility should be presumed to know that.[19]

E. Burden of Proof

In this investigation, the Commission is seeking to determine whether PG&E violated or failed to comply with state law and whether penalties should be applied pursuant to Sections 2107 and 2108. CPSD has the burden of proving that PG&E violated the law or an order of the Commission by a preponderance of evidence.[20] As will be detailed in subsequent sections of this brief, there is ample evidence that PG&E violated pipeline safety rules and California law. Moreover, where PG&E did not rebut evidence introduced by the parties with the burden of proof, it may not simply hide behind the "burden of proof" as a substitute for offering germane

[17] D.04-04-065 at p. 56 (citations omitted).

[18] D.90-09-088 p.22; see also D.05-08-037 at 9-10.

[19] D.04-04-065 at 16; see also D.97-03-070 at p.5 (The Commission in adopting inspection cycles for various types of distribution facilities and equipment, including wood poles provided "[i]In certain circumstances, it may be prudent to conduct more frequent inspections to assure high-quality service and safe operations. In those cases, the utilities are responsible to inspect facilities more frequently.")

[20] Decision 04-04-065 at p.3.

evidence on an issue. This is particularly true in this case, where parties cannot be blamed for a lack of direct evidence that stems from PG&E's deficient record keeping.

For example, in D.04-04-074, the Commission explained that once Southern California Edison (SCE)(the party with the burden of proof in that case) introduced evidence of its inability to buy sufficient power in the day-ahead market, Universal Studios had the burden of going forward. Instead, Universal Studios merely argued, without producing any evidence, that sufficient power would have been available if SCE had been willing to pay more. Since Universal Studios did not cross examine the SCE witness in question or introduce rebuttal evidence, Universal Studios could not complain when the Commission accepted the evidence proffered by SCE.[21]

In this investigation, the testimony of City witness John Gawronski identified important flaws with PG&E's natural gas pipelines operations. PG&E directly rebutted John Gawronski's testimony only on the limited issue of the purpose of the grandfathering provision in 192.619(c). While other witnesses asserted that they were responding to John Gawronski's testimony and in some cases claimed generally that they disagreed with him, they failed to identify any specific aspects of John Gawronski's testimony that were incorrect. Since the City introduced specific evidence by a credible witness, Mr. Gawronski, and since PG&E failed to meet its burden of going-forward by either cross-examining that witness or introducing specific evidence that is contrary to his testimony, the Commission can rely on this uncontroverted City evidence. For example, in responding to Mr. Gawronski's testimony on the threat of cyclic fatigues, PG&E's witness Mr. Kiefner discusses generally the industry perspective on the threat of cyclic fatigue but does not provide any specific analysis of PG&E's pipelines. Mr. Kiefner's general testimony on industry practices for addressing cyclic fatigue does not refute the specific concerns associated with PG&E's pipelines identified by CPSD and the other parties.

[21] D. 04-04-074 at p. 31-32, footnote 13, 2004 Cal. PUC LEXIS 173, *47 (2004); *See also* D. 07-11-037, footnote 4, 2007 Cal. PUC LEXIS 648, *47-48 (2007).

F. PG&E's Testimony on Industry Practices Does Not Excuse PG&E's Failure to Comply with Applicable Safety Laws

Throughout its testimony PG&E attempts to veil its pipeline operations and maintenance deficiencies by referencing "industry practices for complying with" the relevant safety laws. This investigation, however, is not concerned with whether industry practices for complying with safety laws violated those safety laws. The Commission's inquiry in this investigation is to "focus on PG&E's past actions and omissions, to determine whether PG&E has violated laws requiring safe utility gas system practices."[22] Thus, even if PG&E had provided credible evidence establishing actual industry practices, something it has not done with any specificity, such evidence would not excuse PG&E's failure to meet its obligations.

Much of PG&E's testimony provides little insight into what PG&E historically actually did or knew. Instead of trying to disprove the facts alleged by CPSD and other parties, PG&E's testimony focuses on trying to obfuscate the record by referencing industry practices for complying with safety laws. For example, as mentioned above, Mr. Kiefner's testimony discusses the industry perspective of the threat of cyclic fatigue but did not provide any specific analysis related to PG&E's pipelines. Aside from the issue of hiding the ball, PG&E's testimony on industry practices for addressing cyclic fatigue does not refute the allegations levied by CPSD and the other parties.

More broadly, even PG&E's witness admits that testimony on industry practices is irrelevant to the inquiry of whether an operator complied with the applicable safety laws.

> "Q: So just because Operators A, B, and C are violating the law doesn't mean that Operator D should also violate the law?
>
> A: Again, it's up to the operator, but I wouldn't use that as an excuse, if that's your question.
>
> Q: So industry practices are not an excuse for violating the law; isn't that correct?
>
> A: I would say that's true."[23]

As Mr. Zurcher characterized it, for natural gas operators, "Compliance with the regulations is the price of admission."[24] In this proceeding, the Commission must determine

[22] Order Instituting Investigation at p. 10.

[23] Joint RT 715:8-17 (Zurcher).

what PG&E did, not what other operators have done, and whether those actions comply with the applicable safety standards of the time. Thus, the Commission should disregard PG&E's testimony on the conduct of other operators.

IV. OTHER ISSUES OF GENERAL APPLICABILITY

A. PG&E's Testimony Lacks Credibility

In the OII the Commission noted that Rule 1.1 of its Rules of Practice and Procedure requires "utilities to provide complete and non-misleading answers to the Commission and its staff."[25] While the Commission has afforded PG&E many opportunities in this proceeding to present its evidence, PG&E has not done so in a manner that is convincing or consistent with Rule 1.1. PG&E's witnesses, both employees and consultants, broadly assert that the company followed all requirements of law, regulation, and prudence, while providing little evidence on what PG&E actually did. The evidence, however, as demonstrated below, belies these assertions. The Commission should not tolerate this deliberate failure to provide "complete and nonmisleading answers." The public expects and is entitled to such answers from the Commission, even if such answers are not forthcoming from PG&E.

A few examples illustrate this problem. First, PG&E's defensive and evasive testimony does not provide an objective assessment of PG&E's historical practices. For instance, PG&E's employee and expert testimony on its Transmission Integrity Management Program (TIMP)[26] asserts that PG&E met all regulatory requirements. Likewise, PG&E's testimony on its SCADA system and its emergency response find no shortcomings in PG&E's performance.[27]

Second, PG&E's expert testimony regarding TIMP is internally inconsistent and designed to obfuscate rather than elucidate. Prior to submitting his testimony in this case, Mr. Zurcher and his associates were retained by PG&E's Board of Directors to perform an

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[24] Joint RT 752:2-3 (Zurcher).

[25] I. 12-01-007 at p. 11.

[26] PG&E-1c and PG&E-1 (Chapters 4 and 5).

[27] PG&E-1 Chapters 9 & 10

independent review of PG&E's natural gas transmission and distribution practices from January through August 2011 (Blacksmith Audit).[28] This "review was intended to identify industry practices that PG&E could adopt to improve the operations and maintenance of its natural gas system."[29] Mr. Zurcher considered this to be a top to bottom examination of PG&E's Customer Care, Field Operations, Prevention and Maintenance, Damage Prevention, Information and Support, Capital and Expense Budgeting, Safety Culture, Public Awareness, and Emergency Response and Preparedness.[30] Mr. Zurcher was the lead for the Blacksmith Audit's review of PG&E's prevention and maintenance practices.[31] This included assessing PG&E's pressurization practices, and PG&E's integrity management.[32]

Despite the clear relationship between this aspect of the Blacksmith Audit and the scope of this investigation, Mr. Zurcher stated that he did not believe that any of the facts from the Blacksmith Audit were relevant to the San Bruno testimony.[33] Given that Mr. Zurcher's testimony in this proceeding concerns PG&E's compliance with the TIMP rules, it is inconceivable that no aspects of the Blacksmith Audit were relevant to his testimony in this case.

When asked specifically if he had been directed by PG&E to not consider the Blacksmith Audit when preparing testimony for this investigation, Mr. Zurcher did not provide a straight answer.[34] Yet, Mr. Zurcher's testimony suggests it was PG&E's intent to produce testimony that provides an incomplete picture of its practices. According to Mr. Zurcher, PG&E limited the scope of his testimony by providing him with a proscribed set of materials upon which he was asked to prepare testimony for this case.

> "Q: You didn't consider the Integrity Management Program aspects of the Blacksmith Audit when you wrote you testimony in the San Bruno case?

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[28] Joint 31 (PG&E Response Data Request CCSF_002-Q02, Attachment 1).

[29] *Id.*

[30] Joint RT 696:13-697:24 (Zurcher).

[31] Joint RT 703:3-22 (Zurcher).

[32] Joint RT 703:23-704:8 (Zurcher).

[33] Joint RT 699:8-17 (Zurcher).

[34] Joint RT 698:1-5 (Zurcher) ("Q: Were you directed to not consider this audit in your testimony for either case? A: Not that I recall. I am just not sure. I should say that. I'm not sure.").

> A: The testimony that I prepared for this case was based on the documentation that I was provided for this case. There was no cross-breeding or interrelation between the documents."[35]

The Commission is left to surmise that PG&E did not want Mr. Zurcher to provide a full and honest assessment of PG&E's TIMP practices in his testimony here. Given his experience and familiarity with PG&E's TIMP, Mr. Zurcher was uniquely situated to provide insightful testimony into PG&E's past practices and explain how those practices complied with or failed to comply with the natural gas pipeline safety regulations. Instead of providing this type of relevant and meaningful testimony, Mr. Zurcher's testimony contains generalizations about industry practices and assertions that PG&E complied with the law.

Third, a similar pattern emerges from the testimony of PG&E's expert on cyclic fatigue as a threat to pipeline integrity. In a few short pages, Mr. Kiefner testified that cyclic fatigue generally presented a low risk on natural gas pipelines.[36] He supports this conclusion with references to two studies on cyclic fatigue, in 2004 and 2007. Mr. Kiefner notes that the 2007 report is premised upon several key assumptions, and if the assumptions change, the conclusions contained in this report would change as well.[37] In Mr. Kiefner's view, in absence of specificity, the cyclic fatigue analysis is "somewhat arbitrary unless you actually do a study of a particular material in a particular environment…"[38] Mr. Kiefner asserts that his analysis and conclusions were based upon a review of PG&E's gas transmission pipeline system, with specific focus on data and records relating to the physical assets and operations of gas transmission Line 132; records related to PG&E's TIMP; and the testimony provided by other parties in this proceeding.[39]

In this testimony, however, Mr. Kiefner does not reveal that his firm, Kiefner and Associates Inc. (KAI), did just such a study for PG&E when it prepared a report (KAI Report) in

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[35] Joint RT 705:19-27 (Zurcher).

[36] PG&E-1 at p. 6-2 to 6-7.

[37] RT 780:22-782:1 (Kiefner).

[38] RT 687:6-9 (Kiefner).

[39] PG&E-1 at p. 6-2.

March 2012 applying the analysis from the 2007 study to the specific characteristics of PG&E's peninsula pipelines.[40] There can be no question that the KAI Report is relevant to the Commission's examination of PG&E's "past operations, practices and other events or courses of conduct that could have led to or contributed to the San Bruno explosion and fire."[41] Yet neither PG&E nor its expert provided the analysis to the Commission. Even though the KAI Report, containing "a detailed assessment of the threat of cyclic fatigue for Line 132"[42] was available to Mr. Kiefner, he did not consider the report prior to preparing testimony.[43]

The Commission can only surmise that PG&E and its experts either deliberately excluded relevant information on PG&E's gas pipeline system from its testimony here or prepared its testimony with a lack of care that is completely inappropriate in the circumstances of this proceeding. Either way, the only inference the Commission can draw from these facts is that PG&E's testimony has not provided the Commission with forthright answers to the Commission's inquiry into whether it violated applicable safety laws and standards.

Moreover, the credibility of PG&E's expert witnesses has been compromised beyond repair in this proceeding. An expert witness's opinion "is only as good as the facts and reasons on which it is based."[44] Expert testimony is limited to matters that are "sufficiently beyond common experience that the opinion of an expert would assist the trier of fact."[45] In addition, Commission Rule of Practice and Procedure 1.1 provides that any person who testifies at a hearing agrees to maintain the respect due to the Commission and never to mislead the Commission by an artifice or false statement of fact or law.[46] By ignoring relevant information at their disposal, and misleading the Commission through omission, these witnesses have failed

[40] CCSF-5 is the KAI Report.

[41] SB OII at p. 2. San Francisco discusses the findings of the KAI report in more detail in Section V.B., below.

[42] CCSF-5.

[43] RT 783:26-28 (Kiefner).

[44] *Howard v. Owens Corning*, (1999) 72 Cal. App. 4th 621, 633.

[45] Cal. Evid. Code § 801.

[46] Commission Rule of Practice and Procedure 1.1.

to provide testimony that would assist the Commission in making a determination regarding the alleged violations. Thus, the Commission should accord little weight, if any at all, to the opinions of Mssrs. Zurcher and Kiefner.

V. CPSD ALLEGATIONS

A. Construction of Segment 180

B. PG&E's Integrity Management Program Violates Federal and State Requirements

PG&E's TIMP has been heavily scrutinized following the explosion in San Bruno on September 9, 2010. The Independent Review Panel found many problems with PG&E's TIMP compliance. Specifically, the Panel found that PG&E "is not identifying all threats, as required by regulation; is not identifying segments of highest risk and remediating significant anomalies; and hence is not taking programmatic actions to prevent or mitigate threats."[47] The NTSB went further and found that "the PG&E gas transmission integrity management program was deficient and ineffective."[48]

CCSF's testimony examined PG&E's past operations, practices and other courses of conduct and highlighted several major flaws in PG&E's TIMP that "violate laws requiring safe utility gas system practices."[49] CCSF witness Gawronski found that "PG&E failed to proactively identify and assess potential threats to its pipeline system … PG&E failed to collect and analyze relevant data, failed to use conservative assumptions when it lacked pertinent data, underestimated the potential threat posed by manufacturing and construction defects and failed to appreciate the effect of cyclic fatigue and interactive threats on those pipeline threats."[50] As a general principle, where aspects of gas operations create uncertainty, the operator must take steps

[47] Independent Panel Report, June 8, 2011, at p. 8.

[48] CPSD-9 at p. 125 (Finding 19).

[49] Order Instituting Investigation 12-01-007, at p. 10.

[50] CCSF-1 at p. 2.

to ensure the safe and reasonable operations of its system.[51] The record in this investigation makes clear that PG&E placed the public at risk by failing to respond appropriately to the increasing levels of uncertainty present in its pipelines system and that PG&E's unlawful practices contributed to the explosion.

1. Federal Requirements for Transmission Integrity Management Programs

In 2004, the federal regulatory approach to pipeline safety was amended to introduce the TIMP.[52] The TIMP is a process in which natural gas operators must 1) assess and mitigate safety threats to sections of their pipeline systems where leaks or ruptures would have the greatest impact on public safety, 2) identify high consequence areas (e.g., densely populated areas), and then 3) systematically assess pipelines in such areas for safety risks, and repair or replace any defective pipeline segments. In other words, the TIMP requires operators toanalyze risks for each pipeline segment that could affect high consequence areas in order to identify actions needed to enhance public safety.[53]

To identify threats and prioritize the remediation of those threats, the TIMP requires an operator to develop a Baseline Assessment Plan (BAP).[54] The BAP must include a list of all identified potential threats to covered pipeline segments; the methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected; a schedule for completing the assessments; and a procedure to minimize environmental and safety risks.[55] In order to ensure the integrity and safe operations of the pipeline, "more than one method may be required to address all the threats to the covered segment."[56]

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[51] *Id.* at pp. 2-3.

[52] 49 C.F.R. § 192.901 et seq.

[53] *Id.*

[54] 49 C.F.R. § 192.919.

[55] *Id.*

[56] 49 C.F.R. § 192.919(b).

The foundation of proper threat identification is proper data gathering and integration. To perform the data gathering and integration required by the TIMP regulations, the operator must "consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline."[57] The operator must consider, for each system and segment, the operation, maintenance, patrolling design, operating history, and all specific failures and concerns.[58] "Relevant data and information also include those conditions or actions that affect defect growth (e.g. deficiencies in cathodic protection), reduce pipe properties (e.g., field welding), or relate to the introduction of new defects."[59] Record keeping is essential to this process because an operator must both consider all available information about the pipeline, and document each step of its decision making process.[60]

Identifying threats is important because the threats that are present in a particular case define the types of assessment technology that should be used and determine whether a threat needs to be remediated.[61] Operators are required to "identify and evaluate all potential threats to each covered pipeline segments."[62] The regulation states that "potential threats that an operator must consider include, but are not limited to the threats listed in ASME/ANSI B.31.8S (incorporated by reference, *see* § 192.7) section 2." The threats listed in section 2 of ASME B.31.8S include various corrosion related defects, manufacturing related defects, construction related defects, equipment related defects, and third party and weather related defects.[63] In

[57] 49 C.F.R. § 192.917(b).

[58] 49 C.F.R. section 192.917(b); See also Ex Joint-28 (ASME B.31.8S section 2.3.2).

[59] Ex Joint-28 (ASME B.31.8S section 2.3.2).

[60] 49 C.F.R. § 192.917(b).

[61] 49 C.F.R. § 192.917.

[62] 49 C.F.R. § 192.917(a) (emphasis added).

[63] Ex. 28 (ASME B.31.8S – 2004) section 2.2.

addition, "the interactive nature of threats (i.e. more than one threat occurring on a section of pipeline at the same time) shall also be considered."[64]

Federal regulations specifically highlight potential threats from third party damage, cyclic fatigue, manufacturing and construction defects, threats posed by older vintages of pipeline and corrosion. Regarding manufacturing threats, federal regulations state that an operator may deem a manufacturing and construction defect to be stable, and to hence require no further assessment, only "if the operating pressure on the covered segment has not increased over the maximum operating pressure [("MOP")] experienced during the five years preceding identification of the high consequence area."[65] If the pressure exceeds the five-year MOP, the Maximum Allowable Operating Pressure (MAOP) increases, or the stresses leading to cyclic fatigue increase, then the operator must consider that segment to be a high risk segment and prioritize the segment for assessment.[66]

In addition, federal regulations recognize that certain pre-1970's manufacturing or construction methods such as low frequency electric resistance welds ("ERWs") may be particularly susceptible to failure and therefore pose potential threats to pipeline integrity. These include ERW pipe, steel pipeline more than 50 years old, mechanically coupled pipelines, and pipelines joined by acetylene girth welds in areas where the pipeline is exposed to land movement.[67] Because these pre-1970 fabrication techniques are more susceptible to failure, the federal regulations state that if a pipeline segment is made with these construction techniques and the operating pressure exceeds the five year MOP, in addition to considering the segment as a high risk for the baseline assessment or subsequent assessment, the operator "must select an

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[64] *Id.*

[65] 49 C.F.R. § 192.917(e)(3).

[66] *Id.*

[67] 49 C.F.R. §§ 192.917(e)(3)(i) and (4) (incorporating by reference ASME Appendix 4.3. ASME Appendices incorporated by reference are binding requirements on pipeline operators. See PHMSA FAQ # 155. "Where sections of consensus standards are incorporated by reference into a rule, those sections become binding requirements the same as if the language were repeated in the rule. Operators must follow the requirements in the Appendices of ASME/ANSI B31.8S when those Appendices, or sections thereof, are referenced in the rule, even though the standard indicates that the appendices are non-mandatory").

assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies."[68]

Regarding cyclic fatigue, federal regulations are clear that "an operator must evaluate whether cyclic fatigue or other loading condition could lead to a failure of a deformation."[69] This "evaluation must assume the presence of threats in the covered segment that could be exacerbated by the cyclic fatigue."[70]

2. PG&E's Data Gathering and Integration Violated Section 192.917(b).

The NTSB and CPSD both identify PG&E's failure to properly gather and integrate data and information about its pipelines as required by section 192.917(b).[71] The result of this failure is that PG&E used inaccurate data, or had no data, to identify and assess the potential threats to its pipelines. Consequently, PG&E could not meet its obligations under the TIMP requirements and could not operate safely as required by section 451.

a. PG&E's Failure To Consider The 1948 and 1988 Weld Defect Reports Violates the Law and Is Evidence that PG&E's Data Gathering and Integration Is Deficient

As noted above, to comply with federal safety regulations, PG&E needed to gather and integrate existing data and information on the entire pipeline that could be relevant to covered segments, so that it could evaluate the potential risks to the pipelines.[72] Eight months after the NTSB requested all leak and repair information for Line 132, PG&E produced a 1988 inspection report[73] stating that Line 132 had experienced a longitudinal seam leak at mile post 30.44, approximately 8.78 miles south of the rupture.[74] This report included a March 1, 1989

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[68] 49 C.F.R. § 192.917(e)(4).

[69] 49 C.F.R. § 192.917(e)(2) (emphasis added).

[70] *Id.* (emphasis added).

[71] CPSD-9 (NTSB Pipeline Accident Report) at 39; CPSD-1 at 34.

[72] 49 C.F.R. § 192.917(b).

[73] The Report has been introduced in the record of this proceeding as Exhibit 2 to CCSF-1 and PG&E-7 (Tab 4-15).

[74] CPSD-9 (NTSB Report) at p. 38 and fn 61.

memorandum from PG&E's Technological and Ecological Services stating that a 30" section of Line 132 had been "removed for failure analysis because of a pinhole leak in the longitudinal seam weld."[75] The memorandum states that "[o]verall, the x-ray inspection showed the weld to be of low quality, containing shrinkage cracks and voids, lack of fusion, and inclusions. Although the actual leak could not be found, it is likely that it was related to one of the weld defects."[76] The memorandum also states that "the cracks are pre-service defects, i.e. they are from the original manufacturing of the pipe joint."[77]

The leak identified constitutes a failure under TIMP regulations.[78] Moreover, the document shows that PG&E should have been aware of both potential manufacturing and construction defects present on Line 132.[79] In response to this document, PG&E should have evaluated all similar pipeline for potentially unstable manufacturing and construction defects.[80]

The segment with the identified longitudinal seam defect was 0.375 inch wall thickness, X52, 30" DSAW pipe, installed in 1948.[81] PG&E admits that the pipe characteristics of this segment are essentially identical to the pipe characteristics of segment 180 as identified in its job files.[82] Because the cracks were noted as being pre-service defects, PG&E should have been concerned that its quality control was deficient at the time the segment was installed in 1948.[83] PG&E should have reviewed its records for other similar pipe segments installed at approximately the same time to determine the extent of the quality control issue.[84]

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[75] CCSF-1 (Exhibit 2: 1989 TES Memorandum).

[76] *Id.*

[77] *Id.*

[78] CCSF-1 at p. 5.

[79] CCSF-1 at p. 6.

[80] CCSF-1 at p.5.

[81] CCSF-1 (Exhibit 2 to Testimony of John Gawronski: 1989 TES Memorandum).

[82] Joint Evidentiary Hearings of I.11-02-016 and I.12-01-007, at p. 567:23-27 (Harrison/CCSF).

[83] CCSF-1 at p. 6.

[84] CCSF-1 at p. 6, 8.

PG&E, however, was unaware of this document. The NTSB found that "until May 6, 2011, the PG&E GIS had listed the cause of the leak as 'unknown.'"[85] Following the discovery of the memorandum, PG&E updated its database to indicate the pipe had been replaced due to a longitudinal defect.[86] PG&E's testimony indirectly concedes that it did not consider this report in its TIMP[87] and it provided no evidence that these reports were considered in its TIMP.[88]

The NTSB also found that PG&E did not consider radiography records of girth from the 1948 construction of Line 132 indicating longitudinal seam defects.[89] As the NTSB explained

> Because only 10 percent of the welds were radiographed as part of the 1948 construction, and those radiographs captured only a few inches of each longitudinal seam weld, less than 0.2 percent of the longitudinal seams on pipe segments installed in 1948 were radiographed. In light of the fact that five rejectable defects were found in the small percentage of longitudinal seam welds that were so examined, **it is probable that additional longitudinal seam weld defects have remained in service since 1948.**[90]

Both the 1948 and 1988 documents should have been reviewed as part of PG&E's TIMP. Given the similarities to characteristics of segment 180 and the fact that the segment with the longitudinal defect was on the same line, these reports are clearly "existing data and information on the entire pipeline that could be relevant to the covered segment",[91] and PG&E should have considered these reports as part of its TIMP. PG&E's failure to consider these reports demonstrates that PG&E did not perform the proper data gathering and integration required[92] and violates 49 C.F.R. § 192.917(b).

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[85] CPSD-9 (NTSB Report) at p. 38.

[86] *Id.*

[87] PG&E-1c at p. 4-15 ("Even if our data gathering process had located records following the 1988 leak…") (emphasis added).

[88] Joint 34 (PG&E Response to Data Request CCSF 001-Q05 in I.12.01-007 ("Mr. Zurcher has no personal basis for a conclusion as to whether PG&E was or was not aware of the referenced reports at the time it developed its TIMP.").

[89] CPSD-9 (NTSB Report) at p. 110-111.

[90] *Id.* (emphasis added).

[91] 49 C.F.R. § 192.917(b).

[92] CCSF-1 at p. 5, CPSD-1 at pp. 30, 32, and 37.

In its testimony, PG&E disputes the significance of these documents by asserting that they are irrelevant to its TIMP. When asked whether he knew if PG&E had considered these weld reports, PG&E witness Zurcher conceded that he did not know.[93] Instead, he asserted that PG&E did not need to consider 1948 and 1988 weld reports because they were irrelevant to PG&E's TIMP.[94]

> "Q: Shouldn't the operator at least document the consideration and if it chose not to act on it, explain why?
>
> A: Well, you would like to rule out the consideration, you know, based on value. I tend to do it the other way. I only look at those reports that are of value. If they're not of value to me, they're in a different bucket and I wouldn't even consider them."[95]

In essence, Mr. Zurcher's analysis begins with the conclusion that the reports are not relevant, and on that basis determines PG&E was not required to consider these reports, or even to document why it did not need to consider them. This conclusion flies in the face of the purpose and intent of the TIMP rules. For stable and time independent threats (such as manufacturing and construction defects), ASME B.31.8S states that an operator's data collection, review and analysis, should consider earlier data.[96] Operators are required to consider information on the operation, maintenance, patrolling design, operating history, and specific failures and concerns that are unique to each system and segment will be needed.[97] The leaks identified in these reports go directly to the maintenance, design and specific failure on Line 132. In addition, Mr. Zurcher concedes that under the TIMP rules, PG&E must have documented proof that an operator meets all the requirements of TIMP, "including data collection, review and analysis."[98]

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[93] Joint RT 779:17-21 (Zurcher).

[94] Joint RT 779:22-28 (Zurcher).

[95] Joint RT 780:23-781:5 (Zurcher).

[96] Joint 28 (ASME B.31.8S § 4.4 ("Stable and time-independent threats do not have implied time dependence, so earlier data is applicable."))

[97] 49 C.F.R. section 192.917(b); See also Ex. Joint-28 (ASME B.31.8S section 2.3.2).

[98] Joint RT 666:4-24 (Zurcher).

This assertion is also undermined by section 101.4 of General Order 112-E, which requires that "The utilities shall maintain the necessary records to ensure compliance with these rules and the Federal Pipeline Safety Regulations, 49 CFR, that are applicable. Such records shall be available for inspection at all times by the Commission or Commission Staff."[99] If an operator works from the conclusion that the records are not relevant and does not document that threshold consideration, it is impossible for the operator to prove compliance with General Order 112-E or any the data gathering and integration requirements of 49 C.F.R. Subpart O.

b. PG&E failed to consider additional weld defect reports from 1965, 1975, and 1996

In addition to the 1948 and 1989 weld documents discussed above, San Francisco's expert witness Mr. Gawronski identified four additional weld documents that PG&E should have considered as part of its TIMP.[100] These documents confirm the existence of manufacturing and construction defects on steel transmission lines over 50 years old in PG&E's service territory.[101] PG&E should have considered these documents as part of its TIMP when it developed its initial baseline assessment plan.[102]

First, there are laboratory test reports from 1975 discussing brittle failure on four unidentified segments of Line 101 constructed with oxyacetylene welds, and two unidentified segments of Line 109 constructed with arc welds.[103] For the segments removed from Line 101, the 1975 reports notes "weld defects present in fracture of all test specimens (porosity, lack of fusion, and slag includions (sic)). Some shear fracture present at all test temperatures."[104] For the segments removed from Line 109, the report notes "weld defects present in fracture of all test

[99] General Order 112-E § 101.4.
[100] CCSF-1 at p. 10.
[101] CCSF-1 at pp. 10-11.
[102] CCSF-1 at p. 11.
[103] CCSF-1 (Exhibit 6: 1975 PG&E Lab Test Report).
[104] *Id.*, at p. 16.

specimens (porosity, lack of fusion and slag inclusions). No shear fracture present in specimens tested at +70° or +100 ° F, some shear fracture present in specimens tested at +185° F."[105]

There are even earlier reports discussing issues with oxy-acetylene welds on Line 109. In 1965, PG&E issued an evaluation of an oxyacetylene weld from Main #109, San Francisco.[106] The report found that the oxy-acetylene weld on a section of 26 inch diameter pipe on Line 109 did not meet the minimum requirements of the (then) current A.P.I. Standard 1104, and that excessive carbon in the weld metal caused the failure.[107] This report should have raised concern regarding presence of oxy-acetylene welds in its system.[108] In fact, PG&E agrees that "these welding techniques are obsolete methods of fabricating larger diameter transmission pipeline girth welds."[109] Despite this acknowledgement of the obsolete nature of pipes with oxy-acetylene girth welds and PG&E's own documents discussing problems with these welds, PG&E continued to use pipelines with oxy-acetylene girth welds through out its system.

PG&E should also have been aware of two reports from 1996 that found cracking in longitudinal and girth welds on Line 109. In a metallurgical report, PG&E found evidence of cracking in its girth welds from 2 spools removed from Line 109.[110] Although the report did not identify which segments the sections of pipe were removed from, it states "the spools are believed to be from gas transmission line 109 which was installed in 1935."[111] One of the cracks was found to be 76.5% of the wall thickness.[112] Using in-pipe remote video inspection of 22-inch line 109 gas pipe along Miranda Avenue in Palo Alto, another report found "linear crack-like indication, about ½ inch long ... in the toe of a flush-ground, seam repair weld," "another

[105] *Id.*, at p. 17.

[106] CCSF-1 (Exhibit 7: 1965 PG&E Evaluation of Oxy-Acetylene Weld From Main #109 San Francisco) at p. 1.

[107] *Id.* at p. 1.

[108] CCSF-1 at p. 12.

[109] Joint-34 (PG&E Response to Data Request CCSF_001-Q05).

[110] CCSF-1 (Exhibit 8: 1996 Metallurgical Evaluation of Cracking in Line 109 Seam Welds) at p. 1.

[111] *Id.*

[112] *Id.*, at p. 2.

linear indication, 4 inches long, ... in the base metal about ½ inch away from the seam," and "[i]ncomplete root penetration ... in the seams of several spools. In two spools it extends intermittently for the entire spool length."[113]

These reports are evidence of potential manufacturing and construction defects on lines 101 and 109.[114] PG&E should have considered these weld documents when it evaluated and gathered, for each segment, "information to understand the condition of the pipe, identify the location-specific threats to its integrity, and understand the public, environmental, and operational consequences of an incident."[115] Relevant information to consider would have been the operation, maintenance, patrolling, design, operating history, and specific failures and concerns unique to each system and segment.[116] These reports should have raised concern regarding the stability of both girth and longitudinal welds in PG&E's system for these pipelines and other pipelines of similar vintage. Because these documents provide evidence of potential manufacturing and construction defects on Lines 101 and 109, PG&E should have taken extra precautions to ensure that it was providing safe service. Yet, PG&E apparently ignored these reports. CCSF asked PG&E to provide any documentation demonstrating how these reports were incorporated into PG&E's TIMP.[117] PG&E provided no documentation demonstrating that these reports were considered as part of PG&E's TIMP, rather, the response just notes how the reports *should have been incorporated*.[118]

3. PG&E's Threat Identification and Assessment Violated 192.917 and 192.921.

While the NTSB recommended that PG&E assess every aspect of its TIMP, it also recommended that, at a minimum, PG&E revise three facets of its TIMP related to threat

[113] CCSF-1 (Exhibit 9: 1996 In-Pipe Remote Video Inspection of Long Seam Welds 22-Inch Line 109 Gas Pipe, Miranda Avenue, Palo Alto) at p. 2.

[114] CCSF-1 at p. 12.

[115] Joint 28 (ASME B.31.8S-2004) section 2.3.2.

[116] *Id.*

[117] Ex. Joint-34 (PG&E Response to Data Request CCSF_001-Q05).

[118] *Id.*

identification and assessment: (1) revise its risk model to reflect PG&E's actual recent experience and data on leaks, failures and incidents, (2) consider all defect and leak data for the life of the pipeline, including risk analysis for similar or related segments, and (3) revise its risk analysis methodology to ensure that the proper assessment methods are selected for all applicable integrity threats, with particular emphasis on design/material and construction threats.[119]

As part of its TIMP, an operator's threat identification needs to be proactive and investigative in nature.[120] In addition to considering the nine threat categories identified by the ASME B31.8S, operators need to address all other threats that stem from the unique characteristics of their pipeline system.[121] In practice, if any additional threats are known, it is incumbent on the operator to identify and evaluate any threat to the integrity of the pipeline.[122] Evaluations must at least state why the operator chose to not evaluate any given threat listed in ASME B31.8S-2004, Section 2.2.[123]

Instead of being proactive and investigative, PG&E's threat identification and assessment was biased against properly assessing the manufacturing and construction threats on its pipelines. PG&E's Risk Management Procedure (RMP) 06, which embodies its TIMP,[124] makes clear that pressure testing was a last resort form of threat assessment. Section 5.1 of RMP-06 states

> "This section describes the tools and method selected to assess pipeline integrity and the process by which the assessment results are collected and integrated with other data."[125]

In the section for pressure testing, RMP-06 states

> "The Company does not plan to use pressure testing to assess the integrity of its pipelines unless it is a post installation test or up-rate test for an

[119] CPSD-9 (NTSB Report) at p. 114; see also CPSD-1 at p. 163 (noting that PG&E failed "to assess the integrity of Segments 180 and 181 (and other similar segments) using an appropriate assessment technology.")

[120] CCSF-1 at p. 3.

[121] *Id.*; Ex. Joint-28 (ASME B.31.8S) section 2.3.2.

[122] CCSF-1 at p. 3.

[123] *Id.*

[124] Joint RT 1106:7-26 (Keas).

[125] PG&E-6 (Tab 4-6) at p. 39.

HCA. However, during the course of assessing data for ECDA or ILI, it may become apparent that pressure testing is the only feasible option. If so, the Company will perform a pressure test."[126]

In its 2004 Baseline Assessment Plan, PG&E identified 456.6 miles of pipeline that had manufacturing threats, and 88.75 miles with construction threats.[127] As of September 9, 2010, PG&E's TIMP "had identified 11.15 miles of piping to be assessed for manufacturing seam threats."[128] Of these approximately 11 miles, PG&E had assessed 4.9 miles of piping using an in-line inspection tool called Transverse Field Inspection.[129] PG&E intended to inspect the remaining 6.2 miles using a similar tool.[130] According to PG&E's 2009 Baseline Assessment Plan, of the 1021 miles to be assessed by December 17, 2012 "zero miles will be assessed using pressure testing.[131] Clearly, PG&E was determined to not use pressure testing to assess the integrity of its pipelines. As discussed in more detail below, PG&E's modification of this plan following the explosion indicates that PG&E's threat identification sas historically under-calculated the potential seam-related manufacturing defect in its natural gas system.

Further evidence of PG&E's bias against assessing manufacturing and construction defects is contained in an April 12, 2010 memorandum.[132] That memorandum "documents that the operating pressure in a pipeline with a manufacturing seam threat, that has previously not been pressure tested, will not activate unless the historical operating pressure (MOP) plus 10 percent is exceeded.[133] As PG&E uses MOP in this context, it is the MAOP for the pipeline system, i.e. the entire line as opposed to one segment.[134] In the memorandum, PG&E acknowledges that section 192.917(e)(3), and ASME B31.8S do not specify any allowance past

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126 *Id.* at p. 40.

127 Joint 46 (Coversheet and summary page of PG&E's 2004 Baseline Assessment Plan).

128 CCSF-1 (Exhibit 3: PG&E Response to Data Request CCSF_004-Q08 in R.11-02-016).

129 *Id.*

130 *Id.*

131 CCSF-8 (8/12/11 NTSB Factual Report Addendum) at p. 28.

132 Joint 9 (PG&E Response to CPSD Data Request 015-Q01, Attachment 692 in I.11-02-016).

133 *Id.*

134 *Id.*

the MOP (as it is used in that memorandum).[135] The memorandum states "although PHMSA FAQs further states (sic) that 'any pressure increase, regardless of amount' will require assessment, PG&E will interpret that an allowance of MOP + 10% is suitable before the pipeline with a manufacturing defect must be assessed."[136] This interpretation is not supported by the language of the regulatory standards. Most glaringly, despite acknowledging this fact, PG&E adopted an interpretation contrary to the regulations. This interpretation placed the public at risk by ignoring PG&E's obligations to assess potential manufacturing defects.

In addition, PG&E's own consultants identified PG&E's risk assessment methodology as a "weakness."[137] In 2009, PG&E hired an outside consultant to perform a high-level audit of its TIMP and identify its strengths and weaknesses.[138] RMP-06 was one of the documents considered in this audit.[139] Based on this review, the consultant found that PG&E's risk assessment methodology suffered from "significant weaknesses."[140] The two key weaknesses were weighting and awarding of points or scores.[141] Weightings "carry inherent risks of bias and masking" and some "reasons why weightings are currently out of favor and not used in robust risk assessment include the following: force pre-conceived results, difficult to support technically, potential for masking risk issues."[142] Using points or scores "often has inadequate defensible linkage to real world phenomena."[143] The Commission should find that PG&E's threat assessments were skewed by the bias inherent in the weighting and awarding of points.

Despite these findings from PG&E's own consultant, PG&E's witness Keas continues to state that its TIMP results were proper and that PG&E's TIMP was unaffected by the weightings

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[135] *Id.*

[136] *Id.*

[137] Joint 48 (October 20, 2009 WKMC Review of Pipeline IMP Documents).

[138] *Id.* at p. 1.

[139] *Id.*

[140] *Id.* at p. 3.

[141] *Id.*

[142] *Id.*

[143] *Id.*

and point scorings.[144] This view, however, is contradicted by the fact that PG&E's consultant actually considered RMP-06 as part of the scope of the audit. In addition, the fact that PG&E identified over 500 segments with unstable manufacturing threats following the explosion on September 9, 2010 does not support the assertion that PG&E's TIMP properly identified and assessed potential threats.

a. Based on the 1948 and 1988 weld documents, PG&E should have evaluated all similar pipeline for potentially unstable manufacturing and construction defects.

PG&E should have known that certain segments of Line 132 that had been installed in 1948 probably contained seam weld defects and that one such segment had even experienced seam failure.[145] In fact, PG&E admits that the pipe referenced in the 1989 memorandum has essentially the same specifications as those contained in the job file for the pipe that exploded.[146] In other words, the 1948 and 1989 memoranda demonstrate that PG&E should have been aware of both potential manufacturing and construction defects present on Line 132.[147]

This is clearly, "existing data and information on the entire pipeline that could be relevant to the covered segment."[148] Because of the similarity in vintage and type of pipe, PG&E had an obligation to evaluate all similar pipeline segments that are similarly over 50 years old and determine the need for assessing them via pressure testing or in-line inspection capable of detecting seam anomalies.[149] For example, segment 181, which was also installed in 1948, should have been considered to have a manufacturing defect.

In addition, the memorandum should have raised concern regarding a potential issue with PG&E's quality control during original construction.[150] Operators must address all other threats

[144] Joint RT 1122:15-18.

[145] CCSF-1 at p. 8.

[146] Joint RT 567:23-27 (Harrison).

[147] CCSF-1 at p. 6.

[148] 49 C.F.R. § 192.917(b).

[149] CCSF-1 at p. 8.

[150] *Id.*

that stem from the unique characteristics of their pipeline system.[151] Because the cracks are identified as pre-service defects, PG&E should have reviewed its records for other similar pipe segments installed at approximately the same time to determine the extent of the quality control issue.[152]

PG&E should also have had concern about the safety of DSAW pipe based on its age. As discussed above, the weld defect reports make clear that the older vintages of DSAW pipe in PG&E's system could be susceptible to seam-related manufacturing defects. The integrity of DSAW is largely dependent upon the age of the pipeline. As stated in the Integrity Characteristics of Vintage Pipelines (INGAA report),

> "a more detailed examination of the incident data for DSAW pipe shows a strong dependence on age. Over 44% of the incidents are attributed to pipe produced in 1950, another 17% in 1949, 1951, or 1952. These years represent the time period in which DSAW pipe was gaining widespread acceptance in the United States."[153]

PG&E admitted that it would take the findings in the INGAA report into consideration as part of its TIMP.[154] Had PG&E had considered this document, it might have recognized the need to assess the integrity of its 1948 DSAW pipe because it pre-dated the vintages identified in the INGAA report as being potentially susceptible to manufacturing defects.

In addition, based on the findings in this report and the Moody's engineering report, PG&E should have been on notice that Consolidated Western had poor quality control. The Moody's report states that some of the steel used for PG&E's purchase of pipe came from the Kaiser Company.[155] The Kaiser Company, in turn, is identified in the INGAA report as being the predominant supplier of SSAW and DSAW pipelines that resulted in reported incidents. "Again, several manufacturers dominate the reported incidents, with Kaiser accounting for

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[151] CCSF-1 at p. 3.

[152] *Id.* at p. 8.

[153] Joint 49 at p. E-6.

[154] Joint RT 970:21-26 (Keas).

[155] PG&E -7 (Tab 4-20: July 19, 1949 Moody's Report) at p. 2 ("the balance of the steel plates were supplied by Kaiser Company, Inc., and rolled at their plant in Fontana California.").

nearly half and U.S. Steel accounting for nearly 20 percent of the total."[156] Table E-6 of this report makes this conclusion very clear.[157]

PG&E attempts to dismiss the relevance of these documents by asserting that there was no reason to suspect that DSAW pipe was susceptible to potential seam defects. PG&E witness Keas asserts that these memoranda are not relevant to PG&E's consideration of manufacturing defects because the memoranda discuss pinhole leaks – which in PG&E's view do not constitute a structural integrity concern.[158] However, this statement is belied by the statement within the 1989 weld memorandum that the segment was removed for "failure analysis" and that there were "pre-service defects, i.e. from the original manufacturing."[159] It is also belied by PG&E's own course of conduct. Most tellingly, following the discovery of the leak in 1988, PG&E replaced the segment upon discovering the leak in the longitudinal seam.[160]

In addition, the research performed by PG&E witness Zurcher confirms that during the years 2002-2009, 6 out of the 17 reportable incidents involving longitudinal seam welds occurred on DSAW pipelines. Pinhole leaks accounted for all six reportable incidents.[161] Using the applicable definition of reportable incidents from 2002-2009, these pinhole leaks on DSAW pipelines resulted in death or personal injury necessitating in-patient hospitalization, estimated property damage, including cost of gas lost, of the operator or other, or both of $50,000 of more, or were otherwise significant.[162] While PG&E may take these types of incidents lightly, the Commission and the public should demand that PG&E use this type of information to proactively investigate all potential threats to its pipelines.

[156] *Id.* at p. E-6.

[157] Joint 49 (INGAA Study: Integrity Characteristics of Vintage Pipelines) Table E-6

[158] PG&E-1c at p. 4-14.

[159] CCSF-1 (Exhibit 2: 1989 TES Memorandum).

[160] Joint RT 885:19-886:2 (Zurcher)

[161] PG&E-1 at p. 5-10.

[162] 49 C.F.R. § 191.3 definition of incident (this section was amended in 2010 to include the "unintentional estimated gas loss of three million cubic feet or more" as an "incident.").

Based on the multitude of internal and external reports available at that time, PG&E should have identified its historic DSAW pipelines as having potential manufacturing defects and taken steps to remediate that potential threat.

b. PG&E Failed to properly consider the manufacturing and construction defects demonstrated by the 1965, 1975, and 1996 weld defect reports. 49 CFR § 192.917(e).

As discussed above, PG&E's TIMP was undermined by poor data gathering and integration, poor threat identification and assessment, and bias against pressure testing. The additional weld memoranda identified in CCSF's testimony demonstrate that from the beginning of its TIMP, PG&E should have been concerned with manufacturing and construction defects on Lines 101, 109 and 132.[163] PG&E should have documented how it evaluated and took action to address the fact that these reports suggest that defects could also be present on other pipe of similar vintages.[164] Because PG&E does not have records of post construction field pressure tests for many of these older pipes, PG&E had an obligation to evaluate all similar pipeline segments that are similarly over 50 years old and determine the need of assessing them via pressure testing or in-line inspection capable of detecting seam anomalies.[165]

If PG&E had properly considered the weld documents discussed in CCSF's testimony and integrated the information contained in those documents into its TIMP, PG&E likely would have had assessed many more pipelines for unstable manufacturing and construction threats. The clearest proof of PG&E's failures in this regard is that as of September 10, 2010, PG&E had identified 11.15 miles of piping to be assessed for manufacturing seam threats, but had only actually assessed 4.9 miles of pipeline using Transverse Field Inspection.[166] In terms of pressure testing, as of its 2009 Baseline Assessment Plan it did not have any plans to pressure test any of its 1021 miles of pipelines.[167]

[163] CCSF-1 at p. 12.

[164] CCSF-1 at p. 6.

[165] *Id.* at p. 8.

[166] CCSF-1 at p. 8.

[167] CCSF-8 at p. 28.

Yet, in March 2012, PG&E identified 523 pipeline segments (247,206 feet or over 46 miles of pipeline) that it admits have unstable seam-related manufacturing defects.[168] As of March 2012, PG&E had not yet assessed those defects.[169] In San Francisco alone there are 6 segments on Line 101, totaling approximately one mile (5,333 feet) in length, that have unstable manufacturing defects.[170] These segments were all installed in 1953.[171] These segments with oxy-acetylene welds in San Francisco, which have been identified as being susceptible to brittle like cracking, are not included in Phase I of PG&E's recently filed Pipeline Enhancement Safety Plan, and will not be addressed by 2014 under PG&E's current proposals.[172]

There are also 22 segments on Line 109, amounting to nearly 2 miles (9,781 feet) of pipeline, that have unstable seam-related manufacturing defects.[173] Most of these segments were installed in 1932, and many also have oxy-acetylene girth welds.[174] As the reports identified in CCSF's testimony indicate, these segments are potentially a threat to public safety based on the identified manufacturing and construction defects.

PG&E now proposes to assess over 46 miles of pipeline because those pipelines contain unstable seam-related manufacturing defects. Based on the characteristics of the segments proposed to be assessed, many of those segments should have been considered high risk and assessed by December 17, 2007. One reason that PG&E now needs to urgently assess such a large amount of pipe is that historically PG&E did not proactively investigate the manufacturing and construction defects on its system.[175] Because PG&E's knowledge and gathering of its records have proven to be unreliable, there may still be other segments that PG&E has not appropriately identified as having unstable manufacturing or construction defects.[176]

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[168] CCSF-1 at p. 9.

[169] *Id.*

[170] *Id.*

[171] *Id.*

[172] *Id.*

[173] *Id.*

[174] *Id.*

[175] *Id.* at p. 10.

[176] *Id.*

c. PG&E's Reliance on ECDA Violated Section 192.921(a)

PG&E's 2004 Baseline Assessment Plan states that PG&E believed that 100% of its pipelines were subject to the external corrosion threat.[177] PG&E used External Corrosion Direct Assessment (ECDA) to assess the external corrosion threat on its pipelines. ECDA, however, does not detect missing or cracked seams and the "code doesn't allow for the use of ECDA in the evaluation of manufacturing threats."[178]

In selecting an assessment tool, an operator is required to "select the method or methods best suited to address the threats identified" and if a pipeline segment is susceptible to more than one potential threat, the operator may be required to use more than one assessment tool to assess all threats.[179] Even if PG&E assessed a pipeline segment with ECDA because it believed that that a pipeline segment was susceptible to external corrosion, if that segment was also subject to a manufacturing threat or cyclic fatigue, it was required to assess that manufacturing threat using a pressure test or an in-line inspection tool capable of detecting cracking.

d. PG&E Admits That Segment 180 Should Have Been Considered to Have A Manufacturing Threat

PG&E has stated that it believes that segment 180 was constructed with DSAW pipe from Consolidated Western.[180] During the hearings, PG&E admitted that if segment 181 was identified as having a manufacturing threat in the 2004 BAP because it was identified as being over 50 years old, segment 180 should also have been identified as having a manufacturing threat because it was also over 50 years old in 2004.[181] When questioned why PG&E's TIMP did not

[177] Joint 46 (Coversheet and summary page of PG&E's 2004 Baseline Assessment Plan)

[178] Joint RT 960:3-961:7 (Keas)

[179] 49 C.F.R. § 192.921(a) and 192.919(b) ("more than one method may be required to address all the threats to the covered pipeline segment.").

[180] PG&E-1 (Chap. 2 Harrison) at p. 2-1:21-24, 2-3:9-20.

[181] Joint RT 966:20-26 (Keas).

identify segment 180 as having a manufacturing defect, PG&E's witness asserted that she believed it was because "we thought we knew what the installation was, which was in, I believe 1956."[182] In other words, PG&E's practice of using the installation date to determine the age of the pipe undermines PG&E's TIMP by understating the actual age of the pipe. These statements make clear that PG&E should have identified segment 180 as having a manufacturing threat, and that PG&E's practice of using the installation date to determine the age of the pipeline unnecessarily places the public at risk by understating the actual age of the pipeline.

4. PG&E Violated 192.917(e)(2) By Failing To Consider Cyclic Fatigue.

The NTSB found that fatigue cracking weakened the pipe segment that ruptured.[183] PG&E does not dispute this finding and admits the rupture of segment 180 was caused by a ductile tear that grew from "fatigue cracking [...] to a point that the relatively small increase in pressure on September 9, 2010 caused the Pup 1 longitudinal seam to rupture."[184] As part of its TIMP, PG&E should have been identifying and remediating pipelines in its transmission system that are susceptible to cyclic fatigue.[185] In addition, the CPSD report finds that PG&E did not incorporate cyclic fatigue or other loading conditions into its segment specific threat assessments and risk ranking algorithm in either its 2005 or 2010 Integrity Management Protocol Matrices.[186]

Under the Integrity Management rules, PG&E is required to consider the effect of cyclic fatigue on its pipelines. Section 192.917(e)(2) makes clear that all gas operators must consider the impact of cyclic fatigue on the integrity of their pipelines, and that this evaluation "must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue."[187] In addition, section 192.917(e)(3)(iii) requires an operator to know whether stresses leading to cyclic fatigue are present on its pipelines.

[182] Joint RT 967:5-7 (Keas).

[183] CPSD-9 at p. 124 (Finding 5)

[184] PG&E-1 at p. 3-7.

[185] CPSD-1 at p. 50.

[186] CPSD-1 at p. 51.

[187] 49 C.F.R. § 192.917(e)(2).

Taking into consideration that the MAOP may have been exceeded, a conservative operator would assume that the threat applies to the line being evaluated.[188] The implication of this requirement is that if a line is missing data specified in ASME B31.8S-2004, Appendix A, then the line must be assessed for that threat.[189]

PG&E lacks a documented record that it evaluated the pressure cycles on its pipelines.[190] Indeed, PG&E's RMP-06 does not even list cyclic fatigue as one of the threats to be considered.[191] When a pipeline operator concludes that a particular threat is not applicable to its pipeline, the threat evaluation must be documented and the basis for drawing such conclusions must be documented.[192]

To perform the cyclic fatigue analysis, an operator must track its pressure histories.[193] The operator must consider the changes or variations in pressures and related stress levels on the pipeline and track the percent increase or decrease caused by the change in pressure.[194] Next, the operator must identify what constitutes a significant threat due to severe or moderate pressure/stress cycles.[195] Operators must count the number of severe cycles experienced by the pipeline.[196] All operators must perform this analysis, and although failure due solely to cyclic fatigue is rare, the effects due to pressure cycling should be considered as part of an operator's evaluation of interactive threats.[197]

Based on this analysis, operators calculate an expected time to failure and time for reassessment. The expected time to failure is the "minimum amount of time that we would

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[188] CCSF-1 at p. 18.

[189] *Id.*

[190] *Id.*

[191] Joint RT 110:5-17 (Keas).

[192] ASME B.31.8S section 12.1.

[193] CCSF-1 at p. 17.

[194] *Id.*

[195] *Id.*

[196] *Id.*

[197] *Id.*

expect to see a failure."[198] This calculation is not 100% predictive, i.e. the pipeline could fail before or after that time.[199] The time for re-assessment is half the expected time to failure.[200] In other words, operators apply a safety factor of two by taking the calculated time to failure and dividing that number by two.[201] Upon reaching time for assessment, operators have two options: "one is to hydrostatically test the pipeline again to reset the clock. The other is to run in-line inspection with a crack detection tool that's capable of finding the defects."[202] The results of this analysis will vary depending on the specific characteristics of the pipelines subject to cyclic fatigue.[203]

a. PG&E's Failure to Identify and Assess Cyclic Fatigue On Its Pipelines Places The Public At Risk.

PG&E admits that cyclic fatigue was a threat to its pipelines even before the explosion on September 9, 2010.

> "Q: So even before the San Bruno explosion happened, based on the operating pressures, the threat of cyclic fatigue was present on PG&E's pipelines?
>
> A: Well, on the basis of these calculations, you could infer that."[204]

In March 2012, Kiefner and Associates wrote a report addressing the threat of cyclic fatigue on PG&E's peninsula pipelines based on the pressure histories for 10 years prior to September 9, 2010 (KAI Report).[205] The report finds that some segments in PG&E's gas transmission system have passed the time for reassessment and some have even passed their expected time to failure based on seam weld fatigue.[206] As PG&E's witness confirmed failure

[198] 704:13-14 (Kiefner).

[199] 706:21-28. (Kiefner).

[200] 707:3-22 (Kiefner).

[201] 707:3-12 (Kiefner).

[202] 708:7-12." (Kiefner).

[203] 780:7-10 (Kiefner).

[204] 801:16-21 (Kiefner).

[205] 801:16-21 (Kiefner).

[206] CCSF-5 (KAI Report.

due to seam-weld fatigue on high pressure transmission lines tends to lead to rupture.[207] Based on the pressure histories and pipeline characteristics of Lines 101, 109 and 132, PG&E's own expert witness agrees that cyclic fatigue is a threat that must be mitigated.

The report makes clear that several of the key assumptions contained in PG&E's testimony are inapplicable to the older vintages of PG&E's gas transmission system.[208] One key assumption is based on the vintage of the pipe. Pipelines of older vintage were not tested to as high a level, or possibly not even at all.[209] The record indicates that not all pipe PG&E purchased from Consolidated Western was subject to a mill test. In the NTSB's deposition of a former Consolidated Western employee, the employee stated that he believed only 1 in 50 pipes manufactured were subject to a mill test.[210] Mr. Kiefner's testimony further assumes a high level pipe grade (X52). Not all of PG&E's pipelines are constructed with X52 pipe, and pipelines made with lower grades have lower SMYS. Several types of lower grade pipe that are present in PG&E's system and are more susceptible to seam failure are PG&E specified grade, API 5L Grade A and Grade B pipe.[211] API 5L Grade A and Grade B pipe were subject to minimum test pressure of only 60 percent SMYS.[212] In some cases, the calculated fatigue life for these types of pipe is on the order of 50 years.[213] Based on these considerations, the manufacturing techniques and the lack of documented pressure tests, PG&E should have considered cyclic fatigue a threat to its pipelines before the September 9, 2010 rupture occurred.[214]

Based on the report's analysis, one segment of Line 109 made with PG&E Spec pipe, which was installed in 1936 had an expected time to failure of 139 years, and a time for

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[207] 797:16-18 (Kiefner).

[208] 780:22-25 (Kiefner).

[209] CCSF-08 (Based on the NTSB's interview of a former Consolidated Western employee it appears that not every piece of pipe made at Consolidated Western was subjected to a mill test.).

[210] CPSD-305 (Deposition of Arthur "Mike" Massaglia) at p. 11:4-5.

[211] CCSF-5 at p. 1.

[212] CCSF-5 at p. 2.

[213] *Id.*

[214] CCSF-05 (March 2012 Kiefner and Associates Inc. Final Report: Analysis of the Effects of Pressure-Cycle-Induced Fatigue-Crack Growth on the Peninsula Pipeline) at p. 2.

reassessment of 70 years.[215] Based on the ten year pressure history prior to September 9, 2010, the cyclic fatigue analysis shows that this segment should have been hydrotested or in-line inspected for crack growth in 2006.[216] It also appears that this segment has not been pressure tested as of March 2012.[217]

In addition, the KAI report finds that a segment of Line 132 installed in 1948 with a SMYS of 33,000 psi that has not been pressure tested passed the time to failure in 2008.[218] Yet another segment of Line 132 passed its time to failure in 1997.[219] Based on these findings, regardless of any decreases in MAOP, PG&E should have already assessed these pipeline segments for cracking based on potential seam failure due to cyclic fatigue.

The KAI report also makes clear that the threat of cyclic fatigue exists on DSAW pipelines too.[220] Table 3 of the report lists the estimated years to failure based on various proposed pressure reductions. Two of the pipe segments discussed contain DSAW pipe.

Despite the report's very clear findings, Mr. Kiefner asserted that cyclic fatigue was not a threat to PG&E's pipelines.

> "In real life the answer is probably still no because they haven't failed, they haven't failed in tests of some of the segments, and so evidence, really evidence is pointing to the fact that there isn't a fatigue problem."[221]

Mr. Kiefner attempted to downplay the severity of these findings by also asserting that "we are doing here is really a very conservative worst-case scenario. And that's what you should do."[222] Mr. Kiefner explained "the real evidence, which is the performance of the pipeline, suggests that this is over conservative, and we're glad that that's the case. There's only one case that we know of where it wasn't, and that was the incident pipe."[223] This statement regarding

[215] CCSF-5 at p. 2.

[216] 793:25-794:28 (Kiefner)

[217] 796:1-22 (Kiefner).

[218] 797:19-798:19 (Kiefner).

[219] 798:20-799:1 (Kiefner).

[220] 800:19-801:7 (Kiefner).

[221] 801:21-801:26 (Kiefner).

[222] 802:20-23 (Kiefner).

[223] 802:26-803:3 (Kiefner).

"the real evidence" exemplifies the type of analysis that led to the explosion in September 2010. Under this view, an operator should wait until its pipelines fail to determine that cyclic fatigue is a risk. This is the same type of conclusion-oriented analysis espoused by PG&E's other witnesses. Moreover, the suggestion by PG&E's expert that cyclic fatigue is not a "real life" problem because there has only been one explosion—on Line 132 in San Bruno—suggests that PG&E still lacks a safety culture and an understanding of its obligations as a public utility.

Further, there may have been additional over-pressurizations of PG&E's pipelines that could change the analysis.[224] PG&E has admitted that it lost records relating to over-pressurizations from 2005 and 2007, and although it was able to provide a partial list of lines that it over-pressurized, it "cannot confirm that this represents all such events."[225] Because it cannot confirm that it has located records of all such events, there are additional pressure cycles that may not have been considered and would provide for even shorter expected times to failure. In addition, it appears that PG&E did not track over-pressurizations prior to 2008[226] (as discussed in section 4a, below). The fact that PG&E did not track over-pressurization events prior to 2008 means that it cannot know the full extent to which cycling has affected the integrity of its pipelines and the stability of the manufacturing defects.[227] In sum, Mr. Kiefner's reliance on "the real evidence" should provide the Commission with little assurance regarding PG&E's identification and assessment of cyclic fatigue on its pipelines.

PG&E asserts that it appropriately considered the threat of cyclic fatigue.[228] It contends that it disclosed to PHMSA and CPSD that "cyclic fatigue was 'not considered a threat due to the level of increases and frequency of pressure increases in our system.'"[229] In addition, PG&E claims that its consideration of cyclic fatigue was consistent with the findings of Kiefner and

[224] 804:26-805:3 (Kiefner).

[225] CCSF-7 (PG&E Response to CCSF Data Request 004-Q01 and Q05 in I.11-02-016) See response to Q-01.

[226] CCSF-1 (Exhibit 13: PG&E Response to Data Request TURN_040-27 (A.09-12-020)).

[227] CCSF-1 at p. 18.

[228] PG&E-1c at p. 4-30.

[229] *Id.*

Associates' regarding pressure cycles on gas pipelines. As demonstrated above, however, this statement is belied by the specific application of Mr. Kiefner's analysis to PG&E's Lines 101, 109 and 132 in the KAI Report[230]. If PG&E had actually considered the nature of the threat of cyclic fatigue to the specific characteristics of its pipelines, it would have realized that cyclic fatigue was, in fact, a threat that needed to be remediated. Thus, it appears that these statements were actually untrue when made, and the Commission should place little weight on PG&E's representation that it appropriately considered the threat of cyclic fatigue.

Finally, PG&E's witness stated that he had no reason to believe that PG&E lacked the resources and ability to perform this analysis.[231] The Commission should be troubled that even though cyclic fatigue has been identified as one of the causes of the rupture, PG&E still has not asked Kiefner and Associates to perform a cyclic fatigue analysis for other lines that it over-pressurized.[232]

5. By Intentionally Over-Pressurizing Its Pipelines, PG&E Rendered All Manufacturing Threats On Those Pipelines Unstable And Increased The Risks Of Cyclic Fatigue.

As identified in the NTSB and CPSD reports, PG&E had a practice of intentionally over-pressurizing its pipelines. PG&E asserted that it over-pressurized its pipelines "to avoid [pressure testing] and any potential customer curtailments that may result."[233] Therefore, PG&E stated that it "has operated, within the applicable five-year period, some of its pipelines that would be difficult to take out of service at the maximum pressure experienced during the preceding five-year period in order to meet peak demand and preserve the line's operational flexibility."[234] Increasing the pressures in this way can affect the stability of manufacturing and construction (especially weld) defects in pipeline segments.[235]

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[230] CCSF-5.

[231] RT 741:6-10 (Kiefner).

[232] RT 809:8-18 (Kiefner).

[233] CCSF-1 (Exhibit 11: PG&E's Amended Data Response NTSB Exhibit 2-AI of the San Bruno Investigation (Docket No. SA-534)).

[234] *Id.*

[235] CCSF-1 at p. 16.

As described above, this practice of over-pressurizing pipelines to avoid the obligation to assess manufacturing defects not only places a low priority on public safety, it also increases the risk to the public by exacerbating the potential manufacturing threat that PG&E hopes to avoid assessing in the first place. Further, this interpretation actually contravenes the purpose and intent of section 192.917. As stated in the NTSB report "the PHMSA deputy associate administrator for field operations testified that, 'it was not the intent when the regulation was written that it would warrant the raising of pressures to avoid a certain assessment. If you're adjusting the pressure periodically, you need to … make that part of your overall assessment of the risk on that pipeline.'"[236] In addition, it appears that PG&E is the only operator who followed this practice.[237]

PG&E witnesses Keas and Zurcher assert in their testimony that such over-pressurizations were common in the industry and that no assessment is necessary following such an over-pressurization.[238] In addition, this statement is contracted by the findings of the NTSB, and should be given no weight.

Regarding whether an operator may exceed its MAOP on pipelines with manufacturing threats, PG&E witness Zurcher stated:

> "A: The fact that you had an excursion above the operating pressure or above MAOP does not kick in the need for an assessment for the manufacturing threat.
>
> Q: Can operators exceed MAOP?
>
> A: Yes. I have to clarify. It's not something that you do by choice, but it does happen. It happens every day on every pipeline that MAOP is exceeded.
>
> Q: Every day on every system?
>
> A: Yeah absolutely.
>
> Q: So right now, PG&E's exceeding MAOP?

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[236] CPSD-9 at p. 37.

[237] *Id.* ("PHMSA officials were unaware of any other operators following such a practice.")

[238] Regarding industry practices Mr. Zurcher admitted that industry practices are irrelevant for considering whether an operator has violated the applicable safety regulations. Joint RT 715:8-17

A: It's very possible. I don't know that for a fact, but I have seen enough operating records that to know that it happens."[239]

Similarly, Mr. Zurcher testified that "first of all, there is no regulation that says I cannot exceed my MAOP."[240] Later, he admitted that PG&E had exceeded the MAOP of the pipelines when performing planned pressure increases,[241] but then stated "I don't believe a prudent operator would exceed MAOP on purpose."[242]

Mr. Zurcher's prior testimony regarding MAOP is much clearer. In testimony before the Federal Energy Regulatory Commission, Mr. Zurcher testified that "49 CFR Part 192 (Pipeline Safety Regulation), requires pipeline operators to operate pipeline facilities in a manner so that they will not exceed Maximum Allowable Operating Pressure."[243] In fact, in Mr. Zurcher opined that "therefore, prudent pipeline operators manage system pressures to never exceed MAOP, which often means that a safety margin below MAOP is necessary."[244] When asked to reconcile these contradictory statements, Mr. Zurcher simply stated that it was his belief that even though an operator exceeded its MAOP, it could still be a prudent operator.[245] The Commission should disregard these contradictory and self-serving statements and find that PG&E's practice of intentionally overpressurizing its pipelines violated PG&E's obligation to provide safe and reliable service.

PG&E witness Keas' statements are even more troubling because they demonstrate that PG&E still has not learned from its prior mistakes. In her testimony, Ms. Keas stated that "applying John Kiefner's analysis to Line 132, even a 20-pound excursion (equivalent to 5% over the 400 psig MAOP) would not be enough to render a manufacturing threat unstable."[246]

[239] Joint RT 750:2-20 (Zurcher).

[240] Joint RT 713:14-15 (Zurcher).

[241] Joint RT 787:12-15 (Zurcher).

[242] Joint RT 788:7-8 (Zurcher).

[243] Joint 35 (Determination of Available Capacity and A Review of Maintenance on the El Paso Natural Gas Co. System for the Period November 1, 2000 through March 31, 2001) at p. 12.

[244] *Id.* at p. 13.

[245] Joint RT 791:8-13 (Zurcher).

[246] PG&E-1c at p. 4-26.

This not only contradicts the very clear language of the regulations, it also contradicts guidance from PHMSA. FAQ-221 very clearly states:

> **PHMSA FAQ-221**: Amount of pressure increase to trigger assessment of M&C defects
>
> **Question**: Relative to the requirement in 192.917(e)(3)(i), how much pressure increase (above the maximum experienced in the preceding five years of operation) will trigger the requirement to treat the segment as high risk for purposes of integrity assessments?
>
> **Answer**: The rule specifies that any pressure increase, regardless of amount, will require that the segment be prioritized as high risk for integrity assessment.

As described above, under section 192.917(e)(2)(3) and (4), PG&E's practice of intentionally over-pressurizing its pipelines exacerbated the threat of cyclic fatigue, and triggered an obligation to prioritize certain segments for assessment of the manufacturing threats on those pipelines. However, instead of properly prioritizing the assessment and identification of these potential risks, PG&E ignored the federal regulations.

Lastly, sections of Line 109 that run through San Francisco are identified as having manufacturing or construction defects and have been subjected to multiple over-pressurizations. Under sections 192.917(e)(2)(3) and (4), PG&E was required to prioritize and perform rigorous assessment of the integrity of these pipeline segments.

a. By Intentionally Over-Pressurizing Lines Within San Francisco, PG&E Rendered the Manufacturing Threats Unstable And Increased The Stresses Leading to Cyclic Fatigue.

Specific to pipelines in San Francisco, PG&E over-pressurized segments of Line 101 and Line 109 within the City and County of San Francisco on December 11, 2003.[247] Prior to December 11, 2003, the five-year MOP for the Line 101 segments in San Francisco (segment numbers 181 to 201) was 223.5 psi.[248] The five-year MOP for Line 109 segments in San Francisco (segment numbers 195.2 to 248) was 149.8 psi.[249] On December 3, 2011, PG&E

[247] CCSF-1 (Exhibit 11: NTSB Exhibit 2-AI of the San Bruno Investigation (Docket No. SA-534)), p. 4 of spreadsheet titled "NTSB_036-005 Amended.")

[248] CCSF-1 (Exhibit 12: PG&E Response to Data Request OII_DR_CCSF_003-Q05 in I.11-02-016).

[249] *Id.*

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raised the pressure on these segments of Line 101 to 249.42.[250] Similarly, PG&E raised the pressures on these segments of Line 109 to 150.01 psi.[251] By exceeding the five-year MOP of Line 101 and the MAOP of Line 109, PG&E should have identified the manufacturing threats on these lines as unstable and high risk.[252] Based on these facts alone, PG&E rendered segments with manufacturing defects on Lines 101 and 109 in San Francisco unstable and exacerbated the threat of cyclic fatigue on these lines. As a result, these segments should have been prioritized for a hydrostatic pressure test and in-line inspection assessment.[253]

In addition, the evidence indicates that PG&E did not track over-pressurizations prior to 2008. In a response to a TURN data request in PG&E Application 09-12-020, PG&E states that it "began tracking over-pressurization events in the Gas Events database in September 2008."[254] In that data request, PG&E states that prior to 2008 it experienced approximately 10 to 20 untracked over-pressurization events each year.[255] In response to a data request from CPSD, PG&E admitted that it does not have pressure histories for the entire year of 1999.[256] When asked to summarize how PG&E incorporated this lack of data into its operations, PG&E stated "PG&E did not incorporate the loss of the 1999 SCADA pressure records into its integrity management model as pipeline pressure and flow data are not directly incorporated into the integrity management risk model. The reason the risk model does not directly incorporate pressure and flow data is that the condition those records might provide information about, cyclic fatigue in a pipeline, is considered to be a low likelihood event for pipelines carrying natural

[250] CCSF-1 (Exhibit 11: NTSB Exhibit 2-AI of the San Bruno Investigation (Docket No. SA-534), p. 4 of spreadsheet titled "NTSB_036-005 Amended.")

[251] *Id.*

[252] CCSF-1 at p. 15.

[253] CCSF-1 at p. 15.

[254] CCSF-1 (Exhibit 13: PG&E Response to Data Request TURN_040-27 (A.09-12-020)).

[255] *Id.*

[256] CCSF-1 (Exhibit 14: PG&E Response to Data Request CPUC_015-10 (I.11-02-016)).

gas."[257] This response is an admission that PG&E does not consider pipeline pressure and flow data in its integrity management model.

If PG&E did not track over-pressurization events until 2008, it would be unable to determine if it exceeded the five-year maximum operating pressure for the pipelines. In addition, if PG&E is not incorporating "pipeline pressure and flow data" into its integrity management risk model, it would be unable to perform the analysis required by sections 192.917(e)(3) (manufacturing and construction defect) and 192.917(e)(4) (ERW pipe). Both sections require knowledge of the operating pressure over the preceding five years in order to determine the risk of failure.

Moreover, because PG&E did not have the data to demonstrate that its operating pressure did not exceed the five-year MOP, using conservative assumptions, PG&E was required to assume that the threats of unstable manufacturing defects and cyclic fatigue applied to its pipelines.[258]

5. PG&E Has Not Considered Interactive Threats.

PG&E did not evaluate or analyze the interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time).[259] PG&E's RMP-06 does not account for interactive threats.[260] This is a mandatory requirement clearly spelled out in ASME B31.8S-2004, Section 2.2.[261] This is particularly important when considering manufacturing and construction threats as well as pipe seam threats.[262] Interacting threats can result in otherwise stable defects becoming unstable, requiring assessment.[263] It is clear that PG&E relied on the manufacturing and construction defects in its system being stable, and failed to consider the

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[257] *Id.*

[258] CCSF-1 at p. 18.

[259] CCSF-1 at p. 19.

[260] PG&E-6 (Tab 4-6 (RMP-06 lists threats that PG&E considered in its TIMP.). This RMP-06 does not include cyclic fatigue or interactive threats. Joint RT 1110:14-20 (Keas).

[261] CCSF-1 at p. 19; Ex Joint-28 (ASME B.31.8S) section 2.2.

[262] *Id.*

[263] *Id.*

interactive nature of the threats on its lines, or that changing pressures could affect the stability of the manufacturing and construction defects.[264]

C. Recordkeeping Violations

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

E. PG&E's Emergency Response

The federal regulations require that operators have, at a minimum, procedures that establish and maintain communication with appropriate first responders and other public officials in the event of a gas pipeline emergency.[265] In addition, the regulations require that employees be properly trained in implementing the procedures.[266] PG&E's emergency response on the evening of the San Bruno rupture did not meet these minimum standards. The evidence in this proceeding shows that PG&E's emergency response procedures were inadequate and its actual response was further flawed. Most glaringly, PG&E "did not notify emergency responders that the fire was being fed from a rupture in PG&E's natural gas transmission line."[267]

As the NTSB found, the GSR Emergency Response plan should have included some requirement to call 911. In addition, despite clear direction in its Gas Emergency Plan that PG&E should have called first responders very early on, PG&E failed to execute basic aspects of the plan that could have reduced the harm from the rupture. The following excerpt from the NTSB timeline[268] demonstrates this:

- The rupture on Line 132 occurred at 6:11 pm.
- At 6:18 Concord Dispatch was notified by an off-duty PG&E employee that there was a large fire in San Bruno.
- At 6:21 an off-duty Gas Service Representative called Concord Dispatch and stated that the fire appears to be fed by gas.

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[264] *Id.*

[265] 49 C.F.R. § 192.615(a).

[266] 49 C.F.R. § 192.615(b).

[267] CPSD-9 at p. 100; RT 284:22-23 (Almario).

[268] PG&E 40 (NTSB San Bruno Event Timeline, Exhibit 2-DX)

- At 6:23, Concord Dispatch called its GSR and instructed him to investigate the reported explosion.
- At 6:31 Gas Control calls Concord Dispatch and informs them that the explosion may involve a PG&E gas transmission line in the area.
- At 6:41, the GSR and off-duty supervisor are confirmed on site.
- At 7:46, PG&E closes the valves and isolates the rupture.

1. PG&E's Procedures For Gas Service Representatives Does Not Direct Them To Call 911.

PG&E's first responders to a gas incident are generally its Gas Service Representatives (GSRs).[269] The NTSB found that although GSRs are directed to evaluate the danger to life and property, assess damage, and make or ensure that conditions are safe, PG&E's emergency response procedures for Gas Service Representatives does not direct them to call 911.[270] This violates 49 C.F.R § 192.615(a).

2. Even Though Some Of PG&E's Procedures Require Notification to First Responders, PG&E Did Not Follow Those Procedures.

PG&E's Company Gas Emergency Plan[271] "defines the required procedures that all local gas operating departments must have in place to respond to gas emergencies."[272] The plan states that the first step in "GAS EMERGENCY RESPONSE POLICIES" is to "shut off gas if possible."[273] PG&E did not turn of the gas for 95 minutes.[274] Further, under External Notification Requirements, the Gas Emergency Plan states "local fire departments must be

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[269] RT 297:23-298:2 (Almario).

[270] CPSD-9 at p, 14, fn 25.

[271] This document is different than the document referenced in footnote 25 of the NTSB Report. RT 367:3-7 (Almario).

[272] PG&E-39 at p. Part I-1

[273] *Id.* at p. Part 1-37.

[274] I.12-01-007 at p. 6.

contacted whenever a gas emergency poses a threat of fire or explosion. Fire department can assist in fire suppression, evacuations, and traffic control."[275]

The Gas Emergency Plan also states that when there is a fire involving or near a gas pipeline facility, PG&E should "Call the local fire department at the same time a company representative is dispatched. Depending on circumstances at the scene, initiate a previously developed joint action to control the gas emergency."[276] Despite this direction, PG&E did not call the fire department when it dispatched its GSR at 6:23 pm,[277] even though it had knowledge that the fire was near a gas transmission line and may have been fed by gas.[278]

PG&E's witness stated that he did not believe that PG&E's failure to call 911 constituted a deficiency in PG&E's emergency response, instead suggesting that PG&E personnel lacked the information necessary to make such a call.[279] This view is contradicted by the record. As of 6:31 pm (20 minutes after Line 132 ruptured), PG&E's Concord Dispatch knew that the explosion may have involved a PG&E's gas transmission line in the area.[280] Although PG&E did not call 911 at that time, PG&E admits that first responders would have been aided by the knowledge that the fire possibly was being fed by a high pressure transmission line.[281]

F. Safety Culture and Financial Priorities

CPSD's Report, like the IRP report, notes that PG&E's ability to maintain safe and reliable gas pipeline operations is hampered by the overall corporate focus on image and

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[275] *Id.* at p. Part 1-40.

[276] *Id.* at p. Part 1-47.

[277] RT 360:24-27 (Almario).

[278] RT 361:2-12 (Almario).

[279] RT 349:7-20 (Almario). "In the event of the San Bruno event, one of the key pieces – you need information to be able to make a call with adequate information. You need information that is at least useful to provide to a 9-1-1 agency." ll. 15-20

[280] PG&E 40 (NTSB San Bruno Event Timeline, Exhibit 2-DX) at p. 8.

[281] RT 355:12-16 (Almario).

financial performance.[282] PG&E has been successful at generating revenues for shareholders and management,[283] but less so at fostering a safety culture within its gas pipeline operations.[284] These findings are not based on the performance of individual employees but on the priorities and performance measures established by management.[285]

The record in this proceeding provides little assurance that PG&E has restored its focus on safety, in part because the record does not demonstrate that PG&E recognizes or accepts it failure to do so in the past. Some examples of this are discussed above in Section IV. The Commission should be similarly concerned about PG&E's attempt to blame CPSD and PHMSA for PG&E's failure to comply with the data gathering and integration requirements.[286]

One of the more surprising examples of PG&E's refusal to abandon the mantra that PG&E did nothing wrong is PG&E's witness on emergency response who stated that PG&E needs to improve its response times to a major gas incident.[287] And yet also asserted that if PG&E were to respond to a situation identical to what occurred on September 9, 2010, taking 95 minutes to shut off gas would be "adequate."[288]

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[282] CPSD-1, Chapter IX; IRP at pp. 16-17. The IRP notes that PG&E's corporate culture promoted the company's image over substantive focus on safety matters and placed excessive emphasis on the company's financial performance.

[283] CPSD-1 at 129-130, 141-143.

[284] See, e.g., IRP at 16: "In recent years, the company has made strides in setting objective and measurable goals and rewarding employees based on achievement. However, as noted above, the management team did not mention system safety as a goal in its operational improvement drive. Thus, this is one obvious source of the problem. From 2007, when the risk management framework identified process safety concerns until 2010 when the San Bruno Incident occurred, the management's focus was elsewhere. This is not to say improvements in PG&E's integrity management did not take place, but the improvements do not appear to have been given the priority, resources, recognition and rewards that would have led to greater progress."

[285] Id. at 16-18.

[286] PG&E-1c (Keas) at 4-11.

[287] RT 347:28- 348:9 (Almario).

[288] RT 348:10-349:1 (Almario).

VI. OTHER ALLEGATIONS RAISED BY TESTIMONY OF TURN

The testimony submitted by The Utility Reform Network (TURN) recommends a comprehensive review and overhaul of PG&E's integrity management program.[289] The evidence presented here underscores the need for such a review.[290] The CPSD report, the testimony of John Gawronski, and the testimony of TURN all identify numerous failures of PG&E's TIMP. The need for such a review was identified by the IRP almost two years ago.[291] As the IRP noted, adhering to the tenets of Integrity Management can substantially reduce the probability of pipeline failure.[292] The foundation of natural gas transmission pipeline safety is the identification of risk of pipeline failure, and the prioritization of testing and remediation of threats to pipeline integrity on the basis of the expected impact of a pipeline failure on human life and property. In 2004, the regulatory approach to pipeline safety was amended to introduce the Integrity Management Program.[293] Under the TIMP, operators must continuously identify threats, select appropriate methods to assess those threats, properly test for those threats, remedy any problems or anomalies, and document the entire process.[294]

The evidence presented in this proceeding supports and amplifies the conclusions of the IRP regarding the failure of PG&E's TIMP, including poor data management,[295] ineffective threat identification procedures,[296] chaotic internal organization,[297] a lack of coherent resource

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[289] TURN-1 (Prepared Direct Testimony of Marcel Hawiger) at p. 1.

[290] See Section V.B, above.

[291] IRP at pp. 4-5. The Report describes the continuous review cycle utilized by pipeline operators to ensure integrity management. The elements of the cycle are to (1) generate data and analysis, (2) identify segments and threats, (3) inspect and assess, and (4) mitigate and remediate. The Report identifies three central tenets to pipeline safety:

- If an activity is not documented, it was not done.
- A threat is assumed to exist until it can be demonstrated it does not exist.
- The re-inspection interval should be scheduled to ensure the integrity of the pipeline between inspections.

[292] IRP at p. 5.

[293] 49 C.F.R. § 192.901 et seq.

[294] 49 C.F.R. § 192.937.

[295] IRP at pp. 7-8.

[296] IRP at pp. 8-9.

[297] IRP at pp. 9-10.

planning,[298] a complete breakdown in quality assurance,[299] and no strategic plan to improve its safety assessment capabilities.[300]

VII. OTHER ALLEGATIONS RAISED BY TESTIMONY OF CCSF

San Francisco has discussed all allegations from its testimony under the appropriate CPSD allegations in Section V.

VIII. ALLEGATIONS RAISED BY TESTIMONY OF CITY OF SAN BRUNO

IX. CONCLUSION

Appendix A – Proposed Findings of Fact

Appendix B – Proposed Conclusions of Law

Date: March 11, 2013

Respectfully submitted,

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By: /s/

[298] IRP at p. 10.

[299] IRP at pp. 10-12.

[300] IRP at pp. 12-13.