JACOBS Consultancy

Report of the Independent Review Panel
San Bruno Explosion

Prepared For
California Public Utilities Commission

June 8, 2011

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1.0 Executive Summary

1.1 The Incident and the Formation of an Independent Review Panel

On September 9, 2010, at approximately 6:11 P.M., a portion of the 30-inch diameter underground natural gas transmission system (Line 132) of Pacific Gas and Electric Company (PG&E) suddenly ruptured. Operating at approximately 386 pounds per square inch gauge (psig), the pipeline was located under the asphalt paving at the intersection of Glenview Drive and Earl Avenue in a residential area of San Bruno, California. Installed in 1956, the 28 foot long section of Segment 180 Line 132 that failed consisted of five segments which were propelled into the air and landed about 100 feet away. An explosion ensued, fueled by blowing natural gas. The explosion and fire resulted in the loss of eight lives and the total destruction of 38 homes. Seventy homes sustained damage and eighteen homes adjacent to the destroyed dwellings were left uninhabitable. The individuals who lost their lives were: Greg Bullis, Lavonne Bullis, William Bullis, James E. Franco, Janessa Greig, Jacqueline Greig, Jessica Morales, and Elizabeth Torres.

The operator, PG&E, is regulated by the California Public Utilities Commission (CPUC) in terms of rate-setting, overall service and safety. Safety matters associated with pipeline facilities are subject to state authority and an annual certification to the United States Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). After the incident, the National Transportation Safety Board (NTSB), an independent agency with oversight over transportation accidents, immediately dispatched investigators to the scene of the incident. The NTSB has since undertaken an investigation into the root cause(s) of the incident.[1]

The San Bruno Incident ranks among the most significant pipeline incidents in terms of loss of life and property in recent years. The fact that a large segment of pipe literally blew out of the ground in an urban neighborhood and the residents were generally unaware of the proximity of a high-pressure natural gas transmission system to their homes – raises significant public safety concerns. Not surprisingly, the San Bruno Incident garnered media attention and, in turn, the level of public concern has remained elevated.

On September 23, 2010, the California Public Utilities Commission (CPUC) approved Resolution No. L-403, which included the formation of an Independent Review Panel of experts. The Panel's purpose was to gather and review facts and make recommendations to the CPUC

[1] According to applicable regulations, an incident involves a release of gas from a pipeline and (1) a death, or personal injury necessitating in-patient hospitalization; or (2) estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more; or (3) an event that is significant, in the judgment of the operator, even though it did not meet the two previous criteria.

for the improvement of the safe management of PG&E's natural gas transmission lines. The report submitted herewith is the result of efforts undertaken by the Independent Review Panel over a seven-month period. The Independent Review Panel, operating under the charter described below, retained outside independent consultants to aid in our investigation. However, the opinions and evaluations contained herein reflect the unanimous views of the members of the Independent Review Panel.

The Panel's full Charter is provided as Appendix B to this report. In brief, our mandate was as follows:

> The investigation shall include a technical assessment of the events and their root causes, and recommendations for action by the Commission to best ensure such an accident is not repeated elsewhere. The recommendations may include changes to design, construction, operation, maintenance, and replacement of natural gas facilities, management practices at PG&E in the areas of pipeline integrity and public safety, regulatory changes by the Commission itself, statutory changes to be recommended by the Commission, and other recommendations deemed appropriate by the Panel. The latter shall include examining whether there may be systemic management problems at the utility and whether greater resources are needed to achieve fundamental infrastructure improvements.

Appendix D provides the biographical information on the Panel members and the professional qualifications of our consultants.

The Panel members recognize the high-pressure gas transmission infrastructure that serves California is an essential part of the quality of life our citizens enjoy. Natural gas heats homes and businesses, fuels power generation facilities and vehicles and serves as fuel and feedstock in industrial processes. If the public is concerned the natural gas transmission pipelines cannot be operated within the urban areas safely, then significant tensions among the competing parameters of industrialization, safety, and cost are likely to emerge. Emblematic of these tensions, in the aftermath of the explosion, legislators and regulators at the state and federal levels advanced a number of proposals intended to improve the safety of the infrastructure. With a fuller understanding of the San Bruno Incident, these proposals can be fully evaluated.

There are three purposes to our report. The first is to enhance the understanding of all parties as to what happened in San Bruno and what some of the underlying reasons for the incident were. The second is to delve into the complexities of how pipeline integrity management and the regulatory oversight thereof operate. The third is to offer recommendations for actions, which the operator and regulators can consider to reduce the likelihood of future incidents.

The Panel is mindful there is a great deal of interest in its findings by others involved in the natural gas pipeline industry. We do not intend our findings be applied more broadly to other regulatory jurisdictions or to the natural gas transmission industry in general. Rather, we

focused on the San Bruno event and, while our recommendations may be of use to others, we did not fashion them for industry-wide consideration.

1.2 Methodology

As a first step, the Panel members familiarized themselves with the incident and reviewed various materials described in the practices and standards by which natural gas pipelines are constructed, operated, and maintained. The Panel retained the following experts to assist us in understanding the various technical and legal/regulatory aspects of operating natural gas pipelines: Jacobs Consultancy, Van Ness Feldman P.C., Dr. Robert E. Nickell, and Dr. Ralph Keeney. Our consultants are all independent and acted as investigators on our behalf in interviewing various parties, analyzing data and acting as peer reviewers to each other's and the Panel's work.

The scope of our investigation was wide-ranging. The Panel and consultants traveled to the site of the pipeline explosion and met with San Bruno city officials and PG&E personnel. We heard presentations from eight members of the top management of PG&E. Interviews were conducted by our consultants with approximately 30 other individuals at PG&E who worked in various departments, including the front-line field employees. We met with three CPUC commissioners and the Executive Director, and our consultants held interviews with staff of both the utility safety and the ratemaking branches of the CPUC. To form a basis of comparison between PG&E and other operators, we contacted the two other natural gas utility companies who operate transmission pipelines in California and we and/or our consultants met with those companies. In addition, members of the Panel and consultants interviewed engineering leadership of two interstate natural gas pipelines. Staffs of regulatory commissions in several other states were contacted by our consultants for information on their respective frameworks. Consultants met with the staff of the California Office of the State Fire Marshal (OSFM), which has jurisdiction over the liquid petroleum pipelines which operate in California. The consultants interviewed the leadership of International Brotherhood of Electrical Workers (IBEW) Local 1245; the unit represents the field employees of PG&E. Almost without exception, we received excellent cooperation from all who spoke with the Panel directly or with our consultants.

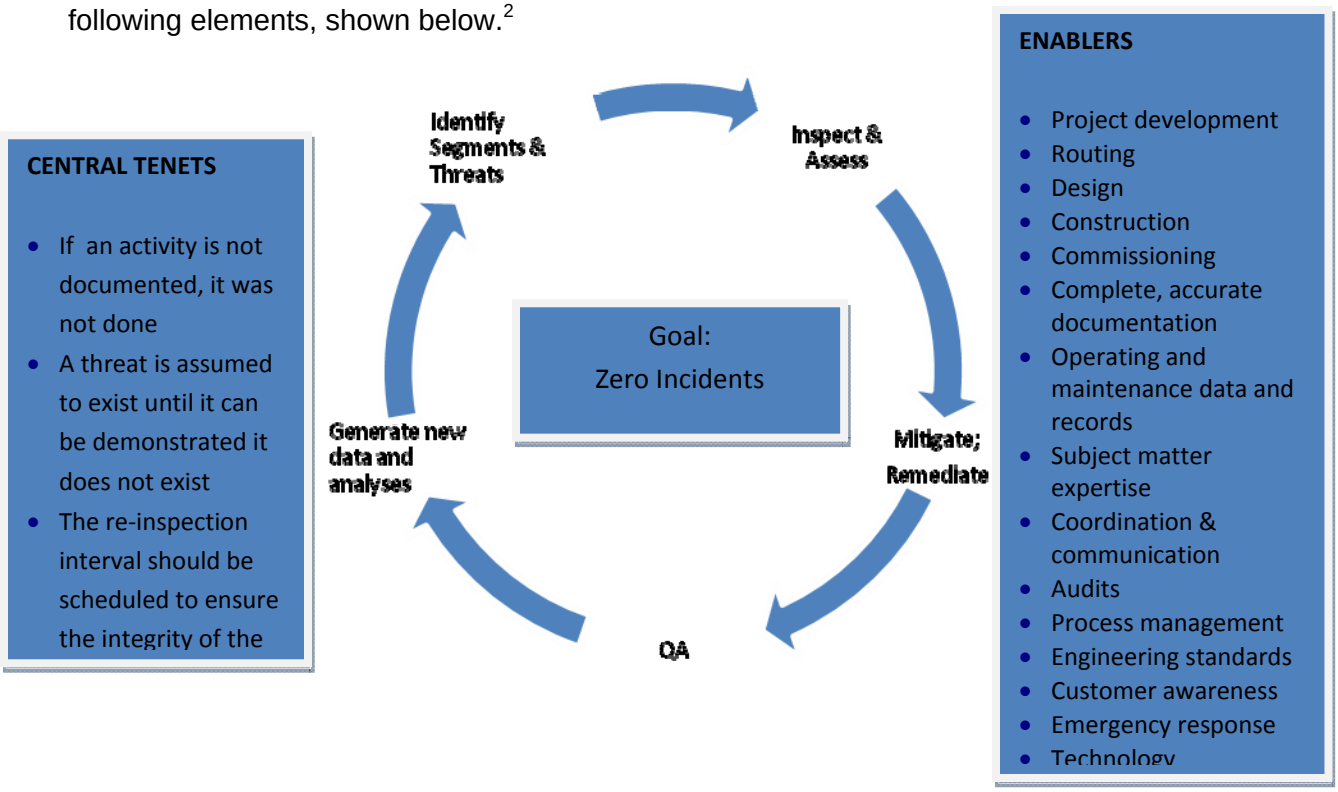
The Panel and consultants submitted over one hundred data and document requests to PG&E and eight to the CPUC staff. Although the quality of the responses varied, all of the requests were answered by the responsible individuals. The Panel appreciates the efforts of all the respondents to provide us with the information we requested. In PG&E's case, we recognize the company is facing multiple investigations and the Panel's questions were not the only requests which the company was obliged to answer.

As noted below, the NTSB has not yet made a final determination regarding the technical root cause of the explosion. Nevertheless, the Panel believes further time in the investigative stage

will not materially affect our findings and recommendations. Therefore, we respectfully submit this work to the CPUC as complete.

1.3 Our Central Focus: Pipeline Integrity Management

Natural gas pipeline engineering design employs, at its core, the goal of *zero significant incidents.* That is, if a pipeline is constructed, operated, and maintained according to its design, then it should operate without safety risk to the public – notwithstanding it transports a combustible product because the pipeline is buried, it is not susceptible to direct inspection on an ongoing basis. Thus, it is essential an operator maintain a virtuous cycle containing the following elements, shown below.[2]



While there is no absolute guarantee a failure will not occur, the probability of failure is materially reduced to the extent the cycle is scrupulously observed. Given this fundamental principle, the Independent Review Panel developed a detailed understanding of the *pipeline integrity management*. We immersed ourselves in the federal regulations and standards that set out integrity management requirements, how the regulations translate to practices across the industry, how integrity management is undertaken at PG&E and elsewhere, and how it is overseen by regulators in California and throughout the country. While *pipeline integrity*

[2] The schematic shown here is a variation of the materials developed by the Interstate Natural Gas Association of America and adopted by its board-level pipeline safety task force in December 2010. A paper summarizing the concept of zero incidents was presented before PHMSA in March 2011 entitled, "Building Confidence in Pipeline Safety, A Strategic Plan by the Members of the Interstate Natural Gas Association of America."

management is a specific term used in the natural gas transmission industry and in the regulations to which the operators are subject, it is comparable to the concept of *process safety management* in industrial facilities.

PG&E has the second highest amount of high pressure transmission pipeline located in so-called High Consequence Areas (HCA) compared to other utilities or pipeline companies in the U.S.[3] Thus, its public safety exposure is greater than most. Adherence to the zero incidents framework is essential for public safety. ***As a result of our investigation, the Panel concludes the explosion of the pipeline at San Bruno was a consequence of multiple weaknesses in PG&E's management and oversight of the safety of its gas transmission system. Furthermore, the Panel finds the CPUC did not have the resources to monitor PG&E's performance in pipeline integrity management adequately or the organizational focus that would have elevated concerns about PG&E's performance in a meaningful way.***

1.4 Observations Regarding Technical Root Cause

Before proceeding to our specific findings, it is important to discuss the technical root cause of the pipeline failure. The NTSB has principal jurisdiction over investigation of the failure and has extensive technical expertise. So the Panel members agreed it would not be productive or appropriate to duplicate the NTSB's efforts. Nevertheless, the Panel and its consultants have reviewed all the NTSB materials released to date. An analysis based on these materials was undertaken and we have reviewed a report released by the Interstate Natural Gas Association of America (INGAA) Pipeline Safety Committee ("Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of the PG&E San Bruno Incident" issued May 5, 2011).

NTSB's findings to date identified both the material and the fabrication welds of the section of pipeline that failed did not meet either: (1) the engineering consensus standards applicable to natural gas transmission pipelines at the time, or (2) the PG&E specifications in effect at the time of construction. However, the NTSB has not yet reached any conclusions about what triggered the material and fabrication weaknesses to destabilize the section and cause the explosion. (It is expected the NTSB will conclude its investigation later in 2011).

INGAA's analysis suggests the manufacturing defect by itself did not cause the incident. The pipeline, even with defective welds and substandard materials, was "stable" for the first 50 plus years of its existence. Despite the pressure exerted on the pipeline over time, including variations that episodically exceeded the maximum allowable operating pressure (MAOP), as defined in Title 49 of the Code of Federal Regulations Part 192 – Transportation of Natural and

[3] PG&E has 1,021 miles of pipeline within the urbanized or so-called high consequence areas. Sempra's Southern California Gas system and San Diego Gas & Electric have 1,320 miles of pipeline within high consequence areas.

Other Gas by Pipeline: Minimum Federal Safety Standards, such pressure fluctuations were not sufficient to have caused the failure.

As detailed in Appendix F to this report, our consultant had conducted independent parallel analysis to that conducted by INGAA. This work confirms INGAA's findings. Both INGAA and our consultant's analysis support the theory there was an external force that triggered the manufacturing defect to propagate, causing the pipe to fail; the force that most likely put the increased stress on the longitudinal seam was the force from a 2008 sewer replacement project undertaken by the city of San Bruno that utilized pipe bursting technology. Both the Panel and INGAA believe third-party activity (activity that was proximate to the pipe, but without direct contact would have led to visible immediate damage) could have played a key role in transforming a "stable" threat to an "unstable" threat, thus triggering the incident. **While the Panel takes no position regarding root case, we nevertheless urge the CPUC to submit Appendix F of our report to the NTSB for its consideration.**

Notwithstanding the above, the Panel emphasizes our investigation and findings are not tied to the sewer replacement project or to any other root cause. Rather, when a pipeline fails – for any reason – the zero significant incidents program that underpins public safety has failed. Thus, our focus was to understand whether and why: (1) the potential for failure was not identified by the operator during the normal course of managing system integrity; and (2) the regulator either did not detect weaknesses in the operator's management of the system or failed to take action that would have caused weaknesses to be remediated. Whatever the root cause(s) identified by the NTSB, our findings and recommendations are relevant.

1.5 How the Culture of an Institution Affects Everything It Does?

The Panel was mindful of the external criticisms that had been leveled at PG&E. While it was acknowledged the company has many talented professionals, the CPUC admitted it was less effective in dealing with PG&E than the other utilities because of the "culture" of PG&E.

Similarly, the "culture" of the CPUC came up in media accounts of the San Bruno Incident and in discussions with the regulators themselves. Specifically, the question surfaced of whether the CPUC was "tough" enough or inquisitive enough to provide vibrant oversight.

Whether it is the regulated entity or the regulator, the issue of organizational culture is an aspect the Panel felt could not be ignored. It is difficult to capture the full spectrum of factors that make an organization unique, such as history, hierarchy, mission, leadership, experiences, attitudes and values. Nevertheless, these intangible factors can often play as much a role in an organization's success as its processes and procedures. Therefore, our report offers perspectives on the cultures of both institutions we investigated. These perspectives necessarily involve our opinions rather than specific facts and so they will, no doubt, be subject

to challenge. However, the Panel felt compelled to make an effort to address the cultural backdrop in which these organizations operate. **The Panel believes both of these institutions must confront and change elements of their respective cultures to assure the citizens of California that public safety is the foremost priority.**

1.6 PG&E's Pipeline Integrity Management Program Has Numerous Shortcomings

The mindset of a prudent operator is to identify and cure defects through scrupulous attention to every activity in the integrity cycle. The following are the Panel's findings regarding gaps in PG&E's performance.

- Worker Safety versus System Safety - Management's focus in recent times appears to have been on the occupational safety of its employees and lacking an equivalent focus on the public safety aspects of its system. In extensive discussions with top management and in our evaluation of the company's goals, pipeline system safety was not substantively tracked, benchmarked, or otherwise a center of focus for the management. There was no evidence of any intent to compromise public safety, but there is the lack of management focus on how system integrity would be managed and assured that has significant consequences, as discussed below.[4]

- Data Management – It was extensively reported PG&E's first submission of incident data to the NTSB included information that incorrectly characterized fundamental aspects of Line 132. Based on discussions with PG&E staff, experienced piping engineers were well aware the San Bruno segment was double-submerged arc welded (DSAW), rather than seamless. However, it is not clear whether the process by which data was collected and examined for threat identification and the risk ranking of piping segments (which should include examination of construction and operating records by those experienced piping engineers) has been consistently undertaken.

  PG&E provided erroneous data because of a lack of: (1) robust data and document information management systems to archive historical data, and (2) processes to capture emerging information about the underground gas transmission system. There is

[4] That a company could emphasize personal safety and seemingly neglect system safety is not unique. This seemingly contradictory problem was reported by the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling regarding BP in January 2011. Namely, "BP has caused a number of disastrous or potentially disastrous workplace incidents that suggest its approach to managing safety has been on individual worker occupational safety but not on process safety. These incidents and subsequent analyses indicate that the company does not have consistent and reliable risk-management processes—and thus has been unable to meet its professed commitment to safety." (See page 218 of the Report to the President, at www.oilspillcommission.gov.)

a lack of coordination between field resources and engineering management regarding which data are to be collected and where and how records are to be preserved.

While we understand the entire pipeline industry has had challenges in digitizing and systematizing all the engineering design, construction and operating data, we find PG&E's efforts inchoate. **The lack of an overarching effort to centralize diffuse sources of data hinders the collection, quality assurance and analysis of data to characterize threats to pipelines as well as to assess the risk posed by the threats on the likelihood of a pipeline's failure and consequences.**

- Threat Identification – Given the questions raised about the completeness and correctness of the input data for integrity management, it appears PG&E's program is not identifying all threats, as required by regulation; is not identifying the segments of highest risk and remediating significant anomalies; and hence is not taking programmatic actions to prevent or mitigate threats. As described below, the company is now undertaking additional testing efforts, which the Panel fully supports.

  However, the Panel has observed some troubling issues with the company's implementation of its threat identification methodology. For example, while the company identifies individual threats and the assessment of those individual threats includes a weighted accumulation of the risk from those individual threats, the interaction or multiplicative effect of those threats appears not to be given adequate consideration.

  Another example, PG&E originally identified the San Bruno segment on Line 132 as seamless pipe (which was not possible given the vintage and diameter of the pipe). As noted below, there should have been a step whereby knowledgeable piping engineers could find and correct this misidentification during the annual internal review process for the integrity management program. But even if the misidentification had been caught, in PG&E's methodology the risk ranking for that segment would not have changed because of the way it ranks risks.

  As a practical matter, the portion of Line 132 that failed was installed across a ravine using very short segments ("pups") to deal with fitting up the welds across the terrain. This configuration is highly relevant for considering the riskiness of the segment. Three other threats should have been noted and evaluated: (1) the potential for one or more of the short pup segments (which were likely selected from pre-1950 vintage shop-welded inventory) to lack the quality of the more recently fabricated full-length, factory welded, and tested segments; (2) the potential for soil movement of the ravine fill from subsidence, seismic motion or other effects; and (3) the potential for third-party activity since the segment was in the city streets. Even without precise knowledge of the defective double submerged arc weld, such a combination of threats should have raised concerns about threat interaction and multiplicative increases in risk.

Had all of this information been integrated and analyzed to determine the cumulative threat, this segment should have been identified for additional assessment or for replacement sooner than 2012 when it was actually scheduled to be replaced by PG&E.[5]

- Spirit of Regulatory Compliance - PG&E appears to target its efforts to comply with pipeline safety regulations. But the goals it sets for management compensation purposes, its investments and its practices do not suggest its focus is on achieving an industry leading pipeline safety and integrity program. In 2010, a CPUC staff audit found PG&E was skirting the requirements of the integrity management regulations through use of an "exception" process, whereby critical repairs and other activities were delayed.[6] Further, the 2010 audit found there appeared to be insufficient company resource to complete pipeline integrity assessments. We observed numerous examples of PG&E asserting it was compliant with the regulations, but also learned about resource limitations that impeded its efforts. We saw minimal evidence of the company making efforts to analyze whether more or different investments would be appropriate to strengthen public safety. We do not opine about whether PG&E was technically compliant with the letter of the regulations (presumably, the CPUC will ultimately make a determination of whether the exceptions are legitimate or whether they actually constitute noncompliance), but we seriously question whether PG&E has embraced the spirit of the pipeline integrity regulations.[7]
- Organizational Effectiveness - At the time of the incident, PG&E's gas transmission operations were spread over several integrated electric and gas organizational units. Further, the organization did not have clear divisions of responsibility between gas transmission and gas distribution functions, resulting in the dilution of talent dedicated to transmission integrity management. In addition, some of these units were led by individuals without background in natural gas pipeline operations.

[5] Had PG&E been able to coordinate its integrity management with its field operations, it could have considered replacing this portion of Segment 180 in 2008 when the San Bruno sewer project was underway or in 1995 when portions the adjacent segments 181 and 178 were replaced nearby where the line failed.

[6] In PG&E's RMP-6 Section 18, Exception Process is the company's approach to instances where deviation from the integrity management program related procedures may be necessary. The same exception process is restated in other RPM's and includes the following language: "It is expected that all requirements of this procedure be met in conducting this Integrity Management Program. However, when this is not possible, then exceptions can be made by obtaining approval... from the Manager of Integrity Management or his/her designate prior to acting on the exception." The USRB audit noted various exception reports having been generated after the exception had been acted upon and that exception reports were routinely being generated to provide the basis for not performing procedural activities which PG&E has identified as being part of its IMP.

[7] In the National Commission report on the BP Deepwater Horizon Oil Spill, previously cited herein, the Commission discussed the character of safety culture which included the idea that "safety culture means doing the right thing even when no one is watching." (Page 218, www.oilspillcommission.gov).

We detected employee fatigue at the number and scope of reorganizations the company has undertaken in recent years. Frequently, employees cited poor communication and abundance of organizational silos that have impeded their ability to understand what work was being undertaken and hence the quality of the work. Moreover, over the past decade, there have been retirements and reorganizations that have undermined the continuity of institutional knowledge of the system. Current management has described recent efforts to ensure institutional knowledge is retained despite a wave of impending retirements. However, much of the knowledge and experience regarding transmission design, operation and maintenance has already been lost. For example, of the four principal architects of PG&E's pipeline integrity management program, only one is still an employee of PG&E.

During the course of our investigation, the gas business was reorganized and multiple management changes were instituted.[8] The Panel would have recommended a separation of the gas business from the electric business and the appointment of a top leader with qualifications in the natural gas transmission industry had PG&E not done so. To wit, the Panel recognized PG&E has taken meaningful action to bring focus to its gas operations, but additional segregated focus should be established for transmission assets and distribution assets.

- Resource Allocation - While PG&E repeatedly asserted its budgeting process was a "bottoms-up" process whereby every organization would get the resources it needed to assure a quality outcome, we found operational inconsistencies. PG&E generally did spend capital at or above the amounts it requested in its rate cases over the last several years, but we did not observe a coherent planning process to assure the system was being maintained and modernized with any urgency. In particular, the resource complement of qualified and experienced engineers and other professionals was limited throughout the period. Consequently, the staff size itself created bottlenecks in the process of how much integrity management the company could accomplish. While various integrity management policies were adopted and committees were formed pursuant to those policies, there were a number of competing priorities for the qualified engineers. One symptom of this problem of resources is employees did not hold required meetings on materials and designs -- meetings that could have improved the quality of analysis of threat identification to pipeline safety. Rather, work deemed more urgent supplanted work that was important for safety.

[8] On April 6, 2011, PG&E announced that it was creating separate gas and electric divisions (see http://www.pgecurrents.com/2011/04/06/pge-improves-safety-flexibility-by-creating-separate-gas-and-electric-divisions/). On May 5, 2011, PG&E announced it had hired a leader to head the gas division (see http://www.pge.com/about/newsroom/newsreleases/20110505/pgampe_names_nick_stavropoulos_to_lead_utility_natural_gas_operations_as_executive_vice_president.shtml).

- Quality Assurance – Integrity management must be constantly subject to a quality assurance and improvement process. Normally, gas transmission piping is designed and constructed with sufficient safety margin to accommodate some amount of uncertainty in such factors as materials, loadings, and operating environments. However, as defects or anomalies are identified, they must be remediated expeditiously. The scope of a quality assurance effort is designed to ensure, among other things, that objective is met.

  A foundation of quality assurance is that employees understand the requirements of pipeline integrity management – and how the various requirements work together to assure public safety. For example, interviews revealed several employees, while familiar with their specific role in integrity management, lacked the overall understanding required to make an effective program. This lack of knowledge manifests itself in silos of information and program ineffectiveness. Another example is PG&E's integrity management policies that require field supervision by the company during work in proximity to high-pressure lines. Interviews revealed that while some field supervisors understood the importance and connection of field supervision of third-party work near transmission facilities and to pipeline integrity, others did not.

  In the San Bruno situation, where the city was replacing the sewer system in proximate contact to the natural gas pipeline, there was no on-going field supervision by PG&E of the work. The individual who was responsible for the supervision had other priorities that day and was not present throughout as the pipeline was exposed and reburied.[9]

  No pre-construction engineering analysis was undertaken to determine if the sewer line work would impair the integrity of the gas pipeline. If such work had been undertaken, the company could have, at a minimum, detected the pipe had been mischaracterized. In turn, that observation should have triggered further analysis of the threats to the segment that failed. Having missed the pre-construction window, no post-construction threat analysis was conducted either. The PG&E standby person was not at the jobsite at the time the pipeline was crossed nor was the pipe re-exposed so that the company could have assured itself the pipe was properly seated in the trench and that other critical safety measures could have been verified.

  PG&E's internal audit of its processes in 2010 identified the field personnel were not adhering to the inspection policy during third-party construction, but no training was undertaken to remediate the nonconformance. Further, the company lacks a clear,

[9] At least two PG&E field employees told us or other interviewers that they suspected that the sewer line work could have adversely affected the gas transmission pipeline. Also during discussions or interviews, those employees demonstrated an understanding of why the requirement to be present during third party work existed.

disciplined communication process between field and general office engineering and between gas transmission engineers and integrity management personnel.

The capability of a piece of pipe with a manufacturing defect to operate for 50 years in a stable manner is a tribute to the margin of safety built into the system. But the margin remains only if there is no uncertainty about the condition of the infrastructure. If the operator does not know about changes in the condition of the pipeline, then assuming the margin of safety is still adequate is an exercise in hoping to be lucky. To fail to inspect during major adjacent earth disturbance and then to fail to analyze the effect of that earth disturbance after-the-fact are examples of the operator pushing its luck. **A strong quality assurance program must be an integral part of the integrity management program.**

- Strategic Integrity Plan - PG&E has no overall strategy to improve how it assesses the integrity of its system. It has done little to redesign its system to facilitate in-line inspection through the use of in-line inspection (ILI) tools.[10] Only 21% of PG&E's system is able to utilize in-line inspection. Yet, PG&E has substantial pipeline mileage in HCAs, which makes the significance of being able to inspect its system with the best available technology particularly important.

  The Panel learned there have been many technical advances in in-line inspection equipment over the last decade, but PG&E has not developed concrete plans to take advantage of these changes in technology. As we understand the federal pipeline integrity management regulations, operators are to identify their threats and then select the inspection assessment methods which can detect where the threat(s) is present. Operators must implement the appropriate assessment methods, or else they face the prospect of not accurately characterizing their pipeline facilities. If in-line inspection is the best method to detect the threat – which is clearly the case for many of the threats PG&E identified, then it is prudent to develop a plan to use the appropriate methods. Other companies we interviewed have already begun the work to modernize their systems to enable in-line inspection and/or have begun focused pipeline replacement efforts where the in-line inspection technology could not be readily used.

  In the absence of in-line inspection data, PG&E may not have made an accurate assessment of which pipeline segments should be replaced. In response to various

[10] An in-line inspection (ILI) tool, or "pig," (pipeline insertable gauge) is a mobile tool that incorporates one or more measurement instruments, such as non-destructive examination device, that is inserted at one point in the pipeline and recovered at some downstream point after traveling with the gas or liquid flow in the pipeline while recording and transmitting its measurements. A "smart pig" is designed to detect a number of pipeline defects, such as leakage, corrosion metallurgical anomalies, and deviations from the normal curvature of the pipe, such as from dents, bulges and ovality. The use of an ILI tool is a foundational technology for compliance with the federal pipeline integrity management regulations promulgated in 2004.

recent CPUC orders, the company has undertaken a program to hydrostatically test certain segments it has determined are "uncharacterized" and therefore at risk, but PG&E has not had an ongoing systematic program to deploy hydrostatic testing and it may not have sufficient internal expertise to meaningfully supervise its program and analyze the results at this time.[11]

Similarly, in the aftermath of the San Bruno Incident, PG&E was questioned by the NTSB as to its plans to re-examine the intervals on its gas transmission system through the high consequence areas where "smart valves" (valves that can be shutoff remotely or automatically) might be used. As discussed in our report, there are many considerations that would govern the expanded use of such valves.[12] We believe this is not a move that should be made hastily or in the absence of a detailed analysis of alternatives, but at this point, it is unclear as to how PG&E is approaching this question.

1.7 Pipeline 2020 Lacks Sufficient Analysis

Within a few weeks after September 9, 2010, PG&E announced a program to enhance pipeline safety it named "Pipeline 2020."[13] The program has five elements: (1) modernizing infrastructure, (2) installing automated or remote-controlled valves, (3) investing in next generation inspection technology, (4) developing industry best practices, and (5) building safety partnerships**.** In reviewing the Pipeline 2020 program, we did not find it to be well-reasoned or based on a thoughtful examination of alternatives. The plan appears to be reactive. A careful reading of the materials deepens the Panel's concerns the company has not underpinned its efforts with solid engineering and economic analysis.

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[11] PG&E is using outside consultants to design and conduct its hydrostatic testing program. But the company lacks internal resources with recent hydrostatic testing experience. Moreover, as a prerequisite to the current testing, PG&E does not appear to have analyzed how the NTSB findings on metallurgy (namely, there are anomalies in the content of the steel on the affected segments) might interplay with the hydrostatic testing regimen. To address this gap, one of the Panel's consultants recommends that PG&E take samples of the uncharacterized segments of the pipeline during hydrostatic testing.

[12] The issue of remote-controlled and/or automatic shut off valves is a major issue for the pipeline industry. These valves operate to shut off the flowing gas in a pipeline. There is safety and reliability trade-offs in deploying this technology. In the high consequence areas, the loss of gas supply may result in the loss of fuel supply to gas fired power plants or may require the relighting of all pilot lights in buildings and there is the potential for gas build up and spontaneous ignition within closed areas. In addition, the use of automatic or remote shut-off on high pressure lines of a downstream operator's system might trigger disruptions on upstream pipelines that could impair the ability of the interstate gas systems to operate as intended. The Panel has been persuaded by the arguments of industry experts that such technology should not be mandated across-the-board. See Appendix L for a fuller discussion of automated and remote control valves.

[13] See http://www.pge.com/about/newsroom/newsreleases/20101012/pge_announces_pipline_2020_program_for_enahncing_natural_gas_pipeline_safety_and_reliability.shtml

The Panel found PG&E has not produced a master plan for pipeline modernization. Moreover, in its testimony before the NTSB, the company conceded its work on the installation of remote valves was in the pilot stage. Thus, PG&E has not developed the analytical support for investments in either pipe or valves. The plan does not project any cost associated with the execution of the plan nor does it set any specific goals or key performance indicators to monitor the progress and effectiveness of the program.

We assume PG&E wants regulators to agree to hundreds of millions or billions of dollars in improvements to its system to assure public safety. The Panel believes for ratepayers to be responsible in the future for investments (some of which, arguably, should have been made already), PG&E must be prepared to support its request for rate recovery with a thorough delineation of its long-term capital program, including the specification of the alternatives considered and an appraisal of the tradeoffs among safety, effectiveness, and cost for each alternative approach**.**

We believe PG&E does need to invest in the future, but we are unimpressed by the company's pledge to invest in research and development of inspection technology. The industry has already made significant advances in in-line inspection technology and progress will be made with or without PG&E's investment. The fact remains PG&E has not devoted the resources to determining *how* it might adapt its system to use these emerging technologies. Rather than donating money to a research organization, we would respectfully suggest if PG&E is genuinely interested in advancing the technology of threat detection, that it would open up its pipeline system to some of the most promising new devices and vendors for testing and demonstration purposes.

The fourth element of Pipeline 2020 is for PG&E to become more active in developing industry best practices. Ironically, our discussions with other operators lead us to the realization that many applicable best practices already exist. If PG&E adopted those practices, perhaps it would find its fifth goal of promoting safety partnerships would naturally emerge.

1.8 Emergency Response - Another Area for Improvement

While our investigation concentrated on pipeline integrity management, the Panel did spend some time trying to understand what happened in the minutes and hours after the explosion occurred at 6:11 P.M. on September 9, 2010. Although emergency response is not a part of the integrity management plan *per se*, when it is invoked, it is essential to public safety. Therefore, the Panel did investigate the chronology of events regarding the emergency response.

PG&E conducts various training exercises in emergency preparedness. However, when this real-life emergency took place, there was confusion within PG&E as both its Gas Control Operations and its Gas Dispatch organization sought to identify the source and location of the

incident. The NTSB investigation conducted a number of interviews and a chronology of the evening is an exhibit in the matter.[14] Even with these materials and interviews with company employees, the Panel did not establish a definitive view of what did or should have transpired. Nevertheless, we observed had it not been for the experience and quick reaction of the first responders from PG&E, the San Bruno Incident could have been even worse. The field personnel who returned to duty after hours to close the pipeline valves – apparently without being dispatched by PG&E– are among the true heroes of this tragedy. These were tenured employees who had the training, experience, and mindset to take the initiative and respond.

It appears PG&E's Supervisory Control and Data Acquisition (SCADA) systems were not sufficient for the company to identify the location of the failure readily and quickly. Further, the automation available to the field force was not sufficient to respond more quickly or to have secured the situation more rapidly than actually occurred. PG&E's management acknowledged to the Panel the implementation of field force automation is not as advanced as what other companies in the industry have available. We believe it is likely the complex set of systems supporting the control of the gas transmission system deserves further investment as well.

1.9 The Role of Risk Management

Risk Management refers to the process by which an organization identifies and analyzes threats, examines alternatives, and accepts or mitigates those threats. An organization's maturity in the area of risk management is indicated by the priority, pro-active thought and serious effort it allocates to this process. To meet the challenge of addressing the complexities inherent in risk management, the leadership of the organization needs to establish and promote a thorough and honest company-wide communication system. Such a system ensures management it receives all of the information it needs to identify the key risk decisions it should be addressing and to make well-informed decisions about them in a systematic fashion. An organization with a mature risk culture is one willing and able to meet the challenge of making the organization's significant decisions in a thorough yet timely manner. The risk culture is set by the top management team, can be influenced by its Board of Directors, and is informed by a workforce engaged in a vibrant communication process and underpinned by subject matter expertise in the business.

The Panel learned PG&E had developed a process framework for an enterprise-wide risk management. In reviewing various materials provided to us, we found the framework reflected a comprehensive catalogue of the major threats the company faces, including the possibility of a San Bruno type event.[15] Given the amount of high consequence natural gas facilities PG&E operates, it was encouraging the company identified the potential threat of its exposure.

[14] Exhibit 2-B of NTSB Docket SA-534

[15] PG&E defined a major natural gas transmission incident as one that had any of the following consequences: financial exposure from $100-$500 million; significant injury, illness or environmental impact; and/or national or

In early 2007, the Enterprise Risk Management (ERM) program identified gas and electric system safety as one of the top 10 catastrophic risks facing PG&E. In examining this risk, PG&E demonstrated a high degree of intellectual understanding of the complex factors that impinge on system safety. The examination evaluated a number of business processes in the gas transmission operation and identified many items that should be improved. The Board of Directors was advised the company would apply its internal audit and quality assurance efforts to the key processes on which the safe operation of the system depends, and the work of mitigating the threats would begin in the first quarter of 2007. In July 2010, an ERM summary of the safety status of the gas distribution still described a number of items as "weak."[16]

Given this Panel's findings regarding gas transmission integrity management, one conclusion is inescapable. Simply put, "the rubber did not meet the road" when it came to PG&E's implementation of the recommendations of its enterprise risk management process.

1.10 Company Culture

When we met with the top utility management, the Panel found them to be committed to operational improvement. 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.

Ironically, the utility management described its vision to be "the leading utility in the United States." Management experts point out; however, inspirational goals must also be grounded in reality. In other words, leadership must have a realistic view of the current state in order to set goals which will mobilize the workforce to improvement. Thus, to set a vision of being "the best" and have that vision be credible, management must make sure it is on *terra firma*. In the gas transmission business, management made a faulty assumption. It did not make the connection among its high level goals, its enterprise risk management process, and the work that was actually going on in the company.

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international attention resulting in a severe negative consequence to the company's image or reputation with regulators, customers or the general public.

[16] Enterprise Risk Management Systems Safety Risk Review - 2009/2010, which is included as part of the material referred to as "EMC Systems Safety ERM Package Final.pdf." See Appendix G.

We think this failing is a product of the culture of the company – a culture whose rhetoric does not match its practices. The Panel is not trained in industrial psychology, but collectively, we have been leaders of large, complex organizations. As such, we would cite the following five factors as contributing to a dysfunctional culture.

- Excessive levels of management - In certain silos, there were as many as nine levels between the CEO and the front-line employee. As a result, the management that is setting the direction is distant from those who know the business the best.
- Inconsistent presence of subject matter expertise in the management ranks - Repeated reorganizations, the interchange of gas and electric supervisors and managers, the homogenization of gas transmission and distribution personnel, the large presence of telecommunications, legal and finance executives in top leadership positions, and the under representation of engineers and professionals with significant operating experience in the natural gas utility industry have impaired the effectiveness of the organization.
- Appearance-led strategy setting - In a business with the complexity of PG&Es, there is no substitute for long-term planning and careful execution, but there appears to be an elevated concern about the company's image that may get in the way of concentrating resources on the most important things. For example, PG&E announced Pipeline 2020 a few weeks after the San Bruno Incident, but the plan is grossly underdeveloped. We realize PG&E has to manage its relations with the media. However, putting forth a major initiative without having done the necessary work underneath ultimately undermines the company's credibility with its employees as well as the public.
- Insularity – In many instances over its long and storied history, PG&E has been an industry innovator and leader, but no company can maintain its edge without a certain degree of humility and an outward focus, both of which enable it to learn from and be influenced by others. As a large company with many different disciplines represented, it is a challenge to be sure one is listening to outside colleagues as attentively as it does to internal voices. Beginning in 2000, when PG&E went through its bankruptcy, much of the outside interaction – participation in industry conferences, committees, testing programs and colloquia – was curtailed. One consequence of this lapse is there appears to be an insular mindset in many of the individuals we interviewed. The mindset, if not addressed, can breed a corporate myopia that stands in the way of an honest assessment of the company's strength, weaknesses, and performance relative to others. Absent a realistic view of a company's performance, the drive for continuous improvement is diminished.
- Overemphasis on financial performance – While the company has multiple stated goals, top management may be overly focused on financial performance. Certainly the company must be financially healthy to fulfill its mission, but when top management focuses on financial performance and does not appear to be engaged in operational

safety and performance, leadership may dampen the willingness of the organization to challenge the priorities or resources put in place by upper management.[17]

It is difficult for a company to change its culture, but we hope the lessons of San Bruno will propel the Board and Management of PG&E to examine the process, by which it organizes its company, selects its leaders, sets its priorities, provides its resources, and evaluates its results. With the retirement of the incumbent CEO of PG&E on April 30, 2011, this juncture represents a singular opportunity for the company to get "back to basics" and re-establish its core competencies.

1.11 CPUC Regulation of Safety is a Struggle for Resources

If the task of implementing integrity management is challenging for the utility, the monitoring of utility compliance is fraught with its own difficulties. The CPUC derives its authority to regulate gas pipeline safety from the broad powers granted to it by the California Constitution and Public Utilities Code, and from federal pipeline safety laws. Pursuant to those authorities, the Commission has adopted PHMSA's federal pipeline safety regulations. Further, the CPUC has specific state statutory responsibility to regulate certain natural gas systems in mobile home parks and propane systems.

The gas section of Utilities Safety and Reliability Branch (USRB) of the Consumer Protection and Safety Division (CPSD) is currently staffed with 18 positions located in Los Angeles and San Francisco. This group has historically been responsible for performing audits of the natural gas utilities on a regular basis to ensure compliance with all DOT regulations. In addition to oversight of the three major gas operators in the state, this group must also inspect the small propane systems and the distribution systems of mobile home operators every five years. In total, this creates an additional inspection responsibility for over 3,200 small mobile home and propane operators once every five years.

However, since 2004, when the federal pipeline integrity rules were placed into effect, the gas safety staff must perform an in-depth analysis of the approach taken by the pipeline operators to know, evaluate, and assess the risks in their pipelines and take appropriate mitigation actions. This means, in addition to its normal audits of utilities' operations for compliance with federal

[17] In one interview with a top leader of PG&E, the question was asked about what change factor(s) would most positively affect safety in the future. The response given by the leader was that the provision for the recovery of costs for safety improvements would be the most important factor. We believe that while the recovery in rates of PG&E's prudently incurred costs for agreed-upon safety improvements must occur, the view articulated by the executive distracts from what should be the company's principal focus given the current situation – namely maintaining a safe, efficient and effective gas transmission infrastructure.

pipeline safety regulations on 11,000 miles of transmission pipeline,[18] the safety staff now has almost 2,350 miles of transmission pipeline in high consequence areas for which it must also assure compliance with federal integrity management requirements.

Conducting audits of performance-based regulations such as pipeline integrity management is a different skill set from that required to conduct audits of prescriptive regulations. Auditing of pipeline integrity management requires an understanding of the utility's system, the utility's threat identification process, and its risk management and decision processes. Thus, the very issues that surface regarding the quality of PG&E's pipeline integrity management are mirrored in the requirements for effective CPUC oversight. A CPUC auditor must have substantial expertise to understand and critically evaluate all the elements of the integrity and management processes in order to fulfill his role as a regulator. It is possible to become a PHMSA certified auditor for pipeline integrity, but the process can take years to achieve, represents a significant commitment of time for coursework, and requires out-of-state travel to Oklahoma City, Oklahoma for training classes.

The CPUC is funded predominantly (over 80%) via user fees assessed on customers' utility bills. In addition, the CPUC pipeline safety program receives annual grants from PHMSA to defray some of the costs of integrity management; grants cover approximately 60% of the cost of the gas safety program, including integrity management audit efforts. Presumably, as the responsibilities of the CPUC increase, the Commission could raise the user fees to cover the new costs that arise and are not otherwise reimbursed by PHMSA. However, in practice, the Governor's Finance Director has authority over the budget of the Commission. In the recent years of state budget austerity, it has been difficult for the Commission to increase its budget even though it has a revenue source separate from the general revenues of the state. Consequently, the safety staffing complement has remained generally unchanged despite the increased scope of its responsibilities.

Budget restrictions and state travel policy prevent all but the minimum amount of travel. The restriction limits the ability of staff to take PHMSA and other training courses. There is perhaps an equally important, albeit subtle, additional impact. With the travel limitation in place, the southern California and northern California personnel no longer meet to review and compare notes on their findings between different utilities. There is limited potential to rotate responsibilities. As a result, it becomes difficult to determine whether the various utilities' efforts at integrity management are comparable or whether differences have to do with the personnel assigned to the respective audits. The Panel and its consultants observed the integrity management efforts varied widely among the utilities; given the constraints under which the staff operates, to achieve a consistent regulatory approach appears challenging.

[18] This includes 6,034 miles of pipeline for PG&E, 4235 miles for Sempra, and 937 miles for Southwest Gas Company. For pipeline mileage within HCA's, and therefore subject to federal integrity management requirements, see data in Figure 1 of main report.

Arguably, the Commission management should have been more aware of the problem of priorities across the entire organization and made efforts to shift resources. However, even a shift would have been problematic given the training and expertise required for monitoring pipeline integrity management. The budget restriction is part of the exceedingly difficult environment in which our public employees must operate. While the taxpayers say, "Do more with less," in this case, the message also is, "Do more." **The Panel is mindful of the constraints the Commission faces in fulfilling its mission and believes the ultimate responsibility lies with the Finance Director to set budgets for the CPUC consistent with the responsibilities for public safety.**

1.12 Operational Challenges within the CPUC Safety Program

The struggle for adequate resources affects almost every aspect of the CPUC's program for monitoring pipeline construction, operations, and integrity. The following are some of the specific problems the Panel identified.

- Qualifications to Audit Integrity Management - The audit staff appears to be generalist engineers at a time when the PHMSA regulations militate for greater levels of specialization in the various disciplines associated with pipeline integrity management. Nevertheless, the staff has conducted two integrity management audits of PG&E and has raised substantive issues. (The CPUC has also twice conducted integrity management audits of the other gas utilities in the state.) However, the CPUC's ability to audit gas pipelines in the future will require not only greater technical and management skills, but enhanced information systems and analytical tools, including training in risk and integrity management. Moreover, we have not seen any evidence that the CPUC staff has the skills to perform quality analysis of operator risk management choices, either at an enterprise level or at the technical level specific to pipeline integrity management. The staff does not appear to have the skills necessary to perform an in-depth appraisal of any such analyses that might be offered by the operators. **At a minimum, there must be an effort to provide more engineers with PHMSA integrity management training. Further, CPUC employees must be encouraged and rewarded for outside continuing education in the area of integrity and risk management.**

- Use of Consultants – Given budget constraints, the CPUC has a very limited budget for the use of outside consultants, but as PG&E's activities of integrity management have increased, the CPUC staff does not have the internal resources to evaluate the activities, nor is it likely to develop the depth of expertise necessary for highly technical and management evaluation, except perhaps over an extended period of time. As an example of the problem, PG&E is now in the process of hydrostatically testing 152 miles

of its system. This is a complex testing regime involving many judgments that can only be validated by an experienced independent resource. **The CPUC has not previously monitored the design of a hydrostatic testing program, so its commentary and analysis are unlikely to be meaningful unless the staff is supported by a core set of highly qualified independent consultants with specialized expertise in gas integrity management.**

- Ability to Hire Talent – The CPUC needs to have talent on par with what is being hired in the industry, but the state pay scale is not comparable to either other governmental units or the private sector. (The CPUC has told the Panel this problem afflicts all of its hiring; recently it has made efforts in the Railway Safety Branch to raise compensation so experienced personnel would not leave the CPUC for federal government safety inspection jobs.) There are currently two vacancies in the gas safety group, which have been difficult to fill; between the pay scale and a long hiring cycle process used, even applicants who are interested in state service end up taking other jobs because they cannot afford to wait on an offer from the CPUC.

- Enforcement Regime – The CPUC operates under a regime of *Graduated Enforcement* whereby it has a four-step process of increasing severity when it finds safety violations. The four steps are: (1) Staff notice to utility of possible violations; (2) Staff investigation and notice to utility of noncompliance with a set time frame for remediation by the utility; (3) Staff requests Commissioners vote to open a formal Order Instituting Investigation (OII) which could result in fines and penalties; and (4) Staff requests CPUC Commissioners vote to refer the matter for civil or criminal prosecution by the Attorney General or the local District Attorney. The safety staff does have the ability to issue relatively small penalties and citations with respect to pipeline safety violations on the small distribution systems (propane and mobile home parks), but does not have authority to fine the large operators. Furthermore, enforcement is uneven across the Commission because utilities can be and are penalized by the Staff for billing errors (e.g., overcharging) while safety violations are, for the most part, only documented.

  Everyone with whom the Panel spoke supported the idea of graduated enforcement because it maintains an atmosphere of cooperation between the regulators and the operators. This atmosphere, in turn, encourages the utilities to self-report any violations. However, the Staff observed and we agree the levels of graduation may not be well calibrated. In particular, the OII process has rarely been invoked in pipeline safety cases.[19] Because the OII is a formal adjudicatory process that may involve administrative law judges, hearings, and pleadings, it is unwieldy for any but the most

[19] The only two safety cases which escalated to the OII level were the 2008 gas distribution system incident in Rancho Cordova where one person died and five were injured and the San Bruno Incident.

severe violations. As a result, the Staff has little flexibility to address significant violations that do not warrant an OII or judicial process.

Meanwhile, the Office of the California State Fire Marshal (OSFM), which has jurisdiction over liquid petroleum pipelines, has a different scheme of graduated enforcement. The State Fire Marshal staff has the ability to exact penalties of up to $500,000. (In addition, the OSFM has a framework to update its evaluation criteria for assessments, requirements for the use of in-line inspection, the ability to limit encroachment to pipeline easements, an inspection protocol for valves and the authority to take other preventative safety actions.). It is not clear why the two agencies have different enforcement schemes despite regulating pipelines with identical safety mandates.

The Panel did not undertake a full analysis of the differing capabilities of the OSFM relative to the CPUC. However, we have included Appendix P, which describes the organization, responsibilities, authority and expertise of the OSFM because we believe there may be lessons for the CPUC in understanding how the OSFM pursues its oversight of the pipelines under its jurisdiction.

- California Laws on Mobile Home Parks and Propane Systems - Under California law, the CPUC must inspect all 3,200+ mobile home park and propane gas distribution systems at least once every five years, and in some cases more often. As a result, the CPUC commits substantial pipeline safety inspection resources on these systems. In 2008, the CPUC spent 43% of its inspection days on these facilities. Large private distribution systems took up another 40% and only 17% of inspection days were spent on transmission pipelines. In our interviews, the CPUC staff indicated it would prefer to spend more time on integrity management and transmission lines, but is hampered from doing so by California mobile home park and propane requirements, which focus limited resources elsewhere.

The CPSD staff and the Executive Director generally recognize how problematic these limitations have become. Absent efforts to address the foregoing issues, it would be difficult for the gas safety staff to offer assurances on the quality of prevailing integrity management efforts they audit.

1.13 How Safety is Handled in the Rate Case Process

The Panel wondered if the regulatory process for setting rates had any influence on the level of safety pursued by PG&E. PG&E had told the Panel the company has a “bottoms-up” budgeting process and, via rate case settlements, it was being granted approximately 98% of what it had requested for compliance activities. PG&E operates under a regulatory regime of “future test year ratemaking.” Under this framework, PG&E forecasts its future expenditures and gains

approval for them before it actually spends the money. So, with an agreement that the company would be authorized rates sufficient to undertake 98% of what it planned, the ratemaking process affords the company a good deal of planning certainty. Further, one might conclude there was a high level of agreement among parties to the rate case PG&E was properly allocating resources to system integrity.

However, an alternative explanation was suggested to us by the CPUC Executive Director. Namely, he stated there was very little colloquy in the rate cases about safety. Hence, the rate case was not serving as an objective process by which PG&E's integrity management budgets were being scrutinized. With this in mind, our consultants interviewed a number of parties to PG&E's rate proceedings to gain an understanding of how ratemaking might influence the commitment to pipeline safety.

We found parties were only casually familiar with PG&E's safety programs; none had devoted resources to determining whether PG&E's proposed programs were appropriate. Although parties were aware there was a list of the top 100 riskiest segments, they did not monitor which of those pipeline segments were remediated before the next rate case. Occasionally, the safety branch of the CPUC did communicate with the CPUC Division of Ratepayer Advocates on selected matters, but there was, in no case, a critical assessment of whether PG&E's efforts were calibrated to the actual risk to pipeline safety.

Periodically, the CPUC has approved rate settlements that include so-called "one-way balancing accounts" for utilities that are designed to ensure the affected utility spends what has been agreed upon in the case. The purpose of such a mechanism is to: (1) ensure the utility doesn't "load up" safety given expenditure estimate and later spend less in order to enhance its returns; or (2) ensure expenditures deemed important are, in fact, made by the utility. The CPUC has recently approved such a mechanism for PG&E to assure the company spends all designated amounts authorized for safety integrity management expenses or else PG&E returns any excess revenues to the ratepayers. There is significant disagreement among the parties, including the other utilities in the state, about the efficacy of the one-way balancing account mechanism in general and its use for safety expenditures in particular. The Panel believes the underlying issue in PG&E's case, at least, is that the stakeholders do not trust one another – and no regulatory mechanism is going to solve that credibility gap.

On a related note, there is a proposal pending in another CPUC proceeding that would change existing regulations regarding reporting requirements for PG&E and which would involve the USRB safety staff. While reporting can create more transparency in the process, we would observe the safety staff does not have the resources to analyze the new reports on safety PG&E would submit. So we question the benefit of the new reporting requirements at this juncture. We do believe, though, as PG&E develops a longer term plan for investment, the safety staff's evaluation of that plan can provide useful input to the rate-setting process.

1.14 CPUC: A Culture of Compliance

The regulatory requirement for new reporting strikes the Panel as a visceral response to a problem with inherently more complexity. It is not an atypical response of government, by any means. Yet, we found in the CPUC – as we found in PG&E – an aspiration to be better than one's peers. However, if the CPUC is to rise above the standard of its peers, like PG&E, it must address its cultural issues.

By way of background, the CPUC can be thought of almost as two separate institutions: the Commissioners, who are appointed for six-year terms; and the Staff, which is chiefly comprised of career professionals. The role of the Executive Director is particularly important because it is that individual who must balance the changing policy orientations of the Commissioners (and the Governor who appoints them) and the roles, responsibilities, and capabilities of the permanent Staff.

The CPUC has a long-standing reputation for policy innovation. In recent years, the CPUC has been engaged in a number of policy initiatives that are far-reaching in their scope. These include climate change, renewable energy development, and innovative telecommunications policies.[20] There is some disagreement among the Commissioners, however, as to the Commission's priorities. The particular significance of this disagreement is that there is no unanimity of view regarding how the agency's resources should be allocated, what issues should become the primary agenda of the Commissioners, what skills are needed within the Commission, and what areas provide the best promotional paths for talented individuals. In general, however, it was acknowledged by all the Commissioners with whom we spoke that as commissioners they do not focus on the Commission's safety mandate – unless there is a problem escalated to them.

We found the Executive Director to be exceptionally adept at recognizing and navigating these cross-currents. He has recommended the appointment of a deputy director in charge of safety and has encouraged the Staff to reach out and attract outside experts to deepen expertise and recommends one Commissioner should be designated as a focal point for safety. He also believes the enforcement regime needs to change. These are good developments, and we admire his ability to think beyond the current state of the organization. He also recognized the importance of culture and made observations about the culture, which are consistent with our own views. Areas where the culture serves as an impediment to effective regulation are as follows.

- Operating with Ambiguity/Compliance Orientation – The technology for utility operations and the regulations regarding safe utility operations are constantly changing. It is

[20] See the CPUC's 2010 Annual Report at http://www.cpuc.ca.gov/NR/rdonlyres/5F23A699-5830-40DC-BD0D-7A335DD89C1A/0/AR2010_web.pdf for further discussion about its activities.

challenging for the Staff to keep up with all of these changes, particularly as training opportunities diminish. As individuals whose responsibility is to uphold the regulations, their oversight becomes increasingly prescriptive. The utilities reinforced this compliance-oriented mindset because it reduces the ambiguity of regulation for them. While Staff is conscientious, there are many forces that drive towards a "check the boxes" type of regulatory enforcement. To move to a regulatory model based on performance and effectiveness will require a shift in the mindset of the entire agency and will require courage and innovation to implement.

- Victim Mentality – State government has suffered many cuts in resources that have affected quality. This breeds a sense of hopelessness in the organization that things cannot get better and exceptional performance is not worth the effort. The current administration at the Commission has tried to avoid many of the restrictions to which other agencies have been subjected (e.g., furloughs), but there is the need for a renewal of commitment to the agency's mission and a re-examination of agency priorities.
- Where talent is rewarded – There is an unspoken reality at the agency that the path to greater responsibility is not in the compliance area of the Commission. Rather, one must be engaged in the policy-oriented roles if one wants to be recognized and given opportunities for more responsibility. This reality tends to create specializations and silos which limit creative thinking.

These are embedded attitudes, which are challenging to address. In the aftermath of the San Bruno Incident, the safety staff has been striving to be more engaged in the details of PG&E's integrity management program in real-time. However, it will take a concerted effort on the part of the Commissioners and the career leadership of the organization to address these cultural and organizational issues that face them.

1.15 Recommendations

Our full report includes detailed recommendations for the respective parties to consider. We refer readers to the "Recommendations" portion of Chapters 5-7 of our report for these specific recommendations, a number of which are technical in nature. What follows in this Executive Summary is the Panel's overarching recommendations, a number of which are policy-oriented in nature. The Panel believes that PG&E, the CPUC, and those legislators who have proposed or are interested in proposing legislation, may gain additional benefit in considering such recommendations.

Before listing our recommendations, however, the Panel offers several observations which we think must guide the various stakeholders as they take steps to ensure a San Bruno Incident does not occur again.

First, the natural gas infrastructure in North America, with all of its imperfections, represents a stable system. It is designed and built with a margin of safety so it should not fail without warning. A catastrophic incident such as the San Bruno tragedy is, therefore, a rare occurrence. In general, industry standards and government regulations are already designed to ensure the margin of safety will not be compromised to a point where there is a likelihood the pipeline will fail. What we have in the San Bruno situation is one operator, PG&E, who did not properly account for the threat of failure of a section of pipeline system and hence did not take appropriate remedial action. We must rely on the inherent safety margin of the infrastructure while the operator undertakes the painstaking effort to rehabilitate its processes and methodically recheck its pipeline system. *There is no one methodology, technology, or regulation for the CPUC to mandate -- nor legislation for lawmakers to enact -- that will immediately improve safety.*

Second, the breakdown in PG&E's pipeline integrity management is the result of a series of compromises made in the quantity and quality of resources dedicated to the transmission system. Similarly, the inability of the CPUC's safety organization to understand this breakdown and sound alarms is also the result of compromises made in the resources dedicated to oversight of the gas transmission pipelines of the state. Both organizations failed to understand the critical technical and managerial nature of the pipeline integrity mandate and neither created an environment in which excellence was demanded. However, the degradation of quality took place over a decade or more. The actions to rebuild these organizations will take time as well. *Urgency needs to be tempered with patience and realism.*

Last, successful implementation of the actions we recommend here will come only through the collective commitment of all the stakeholders. There will be arguments over which investments should be made, who will pay for them, and what represents an acceptable level of safety risk. *There must be fact-based discussion and civil colloquy among the stakeholders about the path to a safer gas transmission system.* In addition, the Panel is hopeful a commitment to future investments in infrastructure will bring with it an investment in the talents and capabilities of a next generation of engineers, technologists, and other energy professionals.

We recommend PG&E consider the following:

- Undertake an immediate and thorough review of the integrity management threat assessment methodology and consider changes to the default assumptions and interactive and cumulative threat analysis.

- Commission an independent operations and management audit of the gas transmission and gas distribution functions, including an organizational, staffing, and skills assessment of the two distinct functions.[21]
- Establish a multi-year program that collects, corrects, digitizes and effectively manages all relevant design, construction and operating data for the gas transmission system and which leads to a multi-year capital program, based on sound risk criteria (i.e., a methodology that addresses the likelihoods of various possible failures given competing alternatives), which leads to either the retrofitting of existing pipelines to accommodate in-line inspection technology or to pipeline segment replacement.
- Conduct a study of SCADA needs with the goals of improving: (1) the visibility of the transmission operations to system operators, (2) the ability of automation to sense line breaks, (3) the ability to model failure events; and (4) the capability to transmit schematic and real-time information to pipeline field personnel. When completed, establish a multi-year program to implement the results of the study.
- Review and restructure all division, regional, and company emergency plans for consistency and ease of use.
- Commence benchmarking of key natural gas transmission safety measures that are comparable to measures used by other operators in the natural gas industry.
- Ensure all individuals in top management, who have direct responsibility for managing the operation of the natural gas system, have thorough knowledge of gas transmission and distribution operations, and those individuals also have the management experience and style to engage with all levels of the organization in a meaningful way.
- Improve the risk management maturity of the organization by re-examining the entirety of the work done to date, including review by the Board of Directors, of the framework of management programs, actions, monitoring, and compensation that should be in place to ensure meaningful progress in reducing the risk of a catastrophic failure of the natural gas system.

The Panel recognizes the foregoing suggestions were not solicited by PG&E and the company has its own internal review underway. Nevertheless, we hope the company accepts these recommendations in the spirit in which they were intended – as constructive steps towards restoring the confidence of the public in the safety of the natural gas system.

We recommend the CPUC undertake the following:

- Adopt as a formal goal, the commitment to move to performance-based regulatory oversight of utility pipeline safety.

[21]During the pendency of this investigation, PG&E advertised in gas industry publications seeking job applicants with gas pipeline integrity management and engineering expertise. We recommend that the company first complete its assessment and then pursue actions to ensure that the staff is adequate and has appropriate skills.

- Commission an independent management audit of the USRB organization, including a staffing and skills assessment, to determine the future training requirements and technical qualifications to provide effective risk-based regulatory oversight of pipeline safety and integrity management, focused on outcomes rather than process.
- Retain independent industry experts in the near term to provide needed technical expertise as PG&E proceeds with its hydrostatic testing program, in order to provide a high level of technical oversight and to assure the opportunity for legacy piping characterization though sampling is not lost in the rush to execute the program.
- Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so there is an enhanced understanding of the costs associated with pipeline safety.
- If indicated, seek approval from the State Budget Director for an increase in gas utility user fees to implement performance-based regulatory oversight for all gas utilities.
- Require PG&E support its case for rate recovery of the costs of future investments in pipeline integrity by including state-of-the-art risk analysis of the full range of alternatives.
- Continue efforts commenced on January 3, 2011 to implement the NTSB's recommendations P-10-02, P-10-03, and P-10-04 regarding production of pipeline records by all the state's gas utilities.
- Revise the graduated enforcement framework to provide for the ability of the safety staff to levy civil penalties for violations.
- Institute a program for safety and pipeline integrity audits of the utilities that includes the following features: (1) posting of audit findings and company responses on the CPUC's website; (2) use of a "plain English" standard to be applied for both staff and operators in the development of their findings and responses, respectively; and (3) a certification by senior management of the operator that parallels the certifications now required of corporate financial statements pursuant to Sarbanes-Oxley.[22]
- Examine the pipeline regulatory authority, duties, and capabilities of the Office of the State Fire Marshal (OSFM), and determine, as part of the independent management audit of USRB described above, if and how the enforcement responsibilities of the gas safety group of the USRB could be aligned with OSFM, including consideration of whether a transfer of the CPUC's gas transmission safety function to OSFM would improve the overall quality of the oversight of gas transmission pipeline safety.
- Upon thorough analysis of benchmark data, adopt performance standards for pipeline safety and reliability for PG&E, including the possibility of rate incentives and penalties based on achievement of specified levels of performance.

[22] Section 302 of the Sarbanes-Oxley Act requires the principal executive and financial officers of a company filing periodic reports to certify in each quarterly and annual report, among other things, that the report does not contain any untrue statement of a material fact or omit to state a material fact and to present the company's financial condition and results of operations fairly present in all material respects.

- Request the California General Assembly enact legislation that would centralize the damage prevention authority in the CPUC by granting it the authority to adopt and enforce one-call notification.[23]
- Request the California General Assembly enact legislation that would replace the mandatory minimum five-year audit requirements with a risk-based regime that would provide the USRB with needed flexibility in how it allocates inspection resources.
- Request the California General Assembly enact legislation that would provide the state's gas utilities with the right to expedited permitting by counties and municipalities for pipeline inspection, remediation and replacement work undertaken pursuant to pipeline integrity management.
- Advise relevant lawmakers of the information contained in Appendix L regarding the complex issues associated with automatic shutoff and remote valves and request sponsors suspend legislative proposals that would require the use of such valves until such time as the detailed plans of the utilities for integrity management have been reviewed and approved by the CPUC.

It has been a privilege for this Panel to convene, to learn from experts in the industry and from one another. We believe our findings should serve as a source of useful information to parties in the Commission's pending gas pipeline safety rulemaking and can guide a renewed commitment to pipeline safety in the state of California.

In closing, the Panel hopes this report provides encouragement to the families of the San Bruno victims that this tragic incident has been thoroughly investigated, that stakeholders will be better informed as a result, and that it is within our collective capabilities to mitigate the chance such a catastrophic incident will ever occur again.

[23] Assembly Bill No. 56 as amended (Cal.Feb 23,2011) and Senate Bill No. 216 as amended (Cal. April 25, 2011)

2.0 Background

Pacific Gas and Electric (PG&E) is among the largest natural gas transmission pipeline operators in the United States and California's second largest natural gas distribution company. Figure 1 is a list of the top 20 companies that manage onshore natural gas transmission facilities. Of the top 20 companies, PG&E has the second highest percentage of its transmission located in what is defined by federal and state gas pipeline safety regulations as "high consequence areas," (HCAs).[24]

Figure 1 – 2009 Top 20 Companies
Miles of Gas Transmission Pipeline Operated in the U.S.

2009 Top 20 Companies - Miles of Gas Pipeline Operated in the U.S.

Rank	Company	Miles of Gas Pipeline Transmission	HCA miles	% HCA miles
1	Northern Natural Gas Co.	15,028	129	0.9%
2	Tennessee Gas Pipeline Co.	14,113	446	3.2%
3	El Paso Natural Gas Co.	10,235	224	2.2%
4	Columbia Gas Transmission Corp.	9,794	406	4.1%
5	ANR Pipeline Co.	9,579	315	3.3%
6	Texas Eastern Transmission LP	9,314	687	7.4%
7	Transcontinental Gas Pipe Line Corp.	9,225	981	10.6%
8	Natural Gas Pipeline Co. of America	8,939	549	6.1%
9	Southern Natural Gas Co.	7,563	202	2.7%
10	ONEOK Partners, L.P.	6,880	61	0.9%
11	Gulf South Pipeline Co, LP	6,565	288	4.4%
12	CenterPoint Gas Transmission	6,162	100	1.6%
13	Panhandle Eastern Pipe Line Co.	5,894	117	2.0%
14	Texas Gas Transmission LLC	5,881	261	4.4%
15	Southern Star Central Gas Pipeline Inc.	5,711	169	3.0%
16	Pacific Gas & Electric Co.	5,557	1,021	18.4%
17	Kinder Morgan Insterstate Gas Trans. LLC	5,258	485	9.2%
18	Sempra*	4,235	1,320	31.2%
19	Dominion Transmission	3,452	261	7.6%
20	DCP Midstream	3,113	34	1.1%
21	Enogex Inc.	2,433	152	6.2%
46	SouthWest Gas Corporation**	937	212	22.6%

Source:

Total Miles = 30th Annual 500 Report - Pipeline & Gas Journal - November 2010

HCA = Office of Pipeline Safety - 2009 Gas IMP Report

* Sempra's Miles - from San Diego Gas & Electric & Southern California Gas Co. - 2009 PHMSA Annual Transmission Data - Ranking Estimated

** SW Gas Miles - 2009 PHMSA Annual Transmission Data - Ranking Estimated

Over 18% of PG&E's total natural gas transmission infrastructure mileage is located in high consequence areas, locations which are typically urbanized and where

[24] Both Sempra and SouthWest Gas, the two other intra state pipeline companies in California, have a significantly higher percentage of their transmission pipeline located in HCA's.

transmission pipeline accidents could have a greater consequence to health and safety or the environment.[25]

Over 100,000 miles of intrastate transmission and distribution pipelines deliver natural gas supplies to California consumers. Natural gas pipelines are a critical infrastructure to the State of California, as well as the nation, and play an essential role in California's economy and quality of living. The state regulated natural gas operators deliver about 80% of the gas consumed in California. These operators deliver natural gas to over 10.5 million residential, commercial, and industrial customer in a safe, reliable, and efficient manner. While the natural gas transmission and distribution pipelines have an excellent record of transporting gas safely to end-users, incidents do occur.

2.1 Events Leading to the Independent Review Panel

On Thursday, September 9, 2010, at approximately 6:11 P.M., a portion of PG&E's natural gas transmission pipeline located near Glenview Drive and Earl Avenue, in the city of San Bruno, California, experienced a catastrophic failure. The pipeline failure and ensuing explosion resulted in a huge fireball, which led to the deaths of eight residents, caused numerous injuries, destroyed 37 homes, and seriously damaged 18 neighboring homes.[26]

When an incident occurs, it is responsibility of the pipeline operator, natural gas industry and the regulatory authorities to examine objectively the causes that contributed to the incident in an effort to prevent or mitigate the causes of the incident from recurring in the future.

On September 10, 2010, the National Transportation Safety Board (NTSB), an independent federal agency that investigates transportation accidents including those involving natural gas pipelines, commenced an investigation[27].

The California Public Utilities Commission initiated a series of actions immediately, including:

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[25] U.S. Department of Transportation (DOT) regulations require mandatory management procedures in these areas to en U.S. Department of Transportation (DOT) regulations require pipeline operators to have integrity management programs covering pipeline in HCAs. HCAs are defined in 49 C.F.R. § 192.903 to include all Class 3 and 4 locations and certain Class 1 or 2 locations. Generally, the greater the Class number, the greater the potential consequences of a failure.

[26] Data from NTSB preliminary report http://www.ntsb.gov/Surface/Pipeline/Preliminary-Reports/San-Bruno-CA.html; property damage subsequently reported included additional loss information.

[27] The NTSB is continuing to conduct its investigation into the root cause of the incident, and to date thousands of documents have been released. The NTSB will be releasing additional information regarding the San Bruno explosion at its website http://www.ntsb.gov/.

- September 9, 2010 - Shortly after pipeline failure, the CPUC's Consumer Protection and Safety Division had an investigator on site.
- September 10, 2010 - A toll free number and e-mail address for those with information on natural gas odors in the San Bruno area prior to September 9 was established.
- September 13, 2010 – The Commission ordered PG&E to take specific actions including: reducing pressure, inspecting the natural gas system, preserving records, reporting on authorized versus actual levels of spending on pipeline maintenance, and evaluating customer leak complaint records.
- September 17, 2010 - The Commission ordered PG&E to provide additional information, including a list of its top 100 maintenance projects as well as automatic valve information.
- September 23, 2010 - The Commission passed Resolution No. L-403 to investigate the facts surrounding the explosion and the general safety risks associated with PG&E's other gas transmission lines in the state.
- Resolution No. L-403 also created an Independent Review Panel of experts to gather facts, review these facts and make recommendations to the Commission for the improvement of the safe management of PG&E's natural gas transmission lines. The Commission established this Panel pursuant to its powers under Public Utilities Code Sections 451, 701, and 702. The Charter of the Panel, as appended in Resolution No. L-403 appears in Appendix B of this report.[28]

2.2 Scope of the Independent Review Panel

The scope of the Independent Review Panel, as stated in the Panel's Charter is as follows:

> "The investigation shall include a technical assessment of the events and their root causes, and recommendations for action by the Commission to best ensure such an accident is not repeated elsewhere. The recommendations may include changes to design, construction, operation, maintenance, and replacement of natural gas facilities, management practices at PG&E in the areas of pipeline integrity and public

28 Subsequent to the formation of the Independent Review Panel, the Commission has initiated numerous directives, filings, letters, press releases and other activities surrounding the San Bruno incident. The Commission's website - http://www.cpuc.ca.gov/PUC/events/sanbruno.htm - contains the various Commission initiatives and document responses.

safety, regulatory changes by the Commission itself, statutory changes to be recommended by the Commission, and other recommendations deemed appropriate by the Panel. The latter shall include examining whether there may be systemic management problems at the utility and whether greater resources are needed to achieve fundamental infrastructure improvements."

The Charter identifies the following specific questions to guide the Panel's fact-finding Investigation:

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

The Panel has been charged with investigating one event - the San Bruno explosion. While the Panel's findings and recommendations may be of broader interest, given the level of industry and national attention to this tragic event, it is confining itself to the San Bruno incident and PG&E.

On February 25, 2011, the CPUC issued an Order Instituting Rulemaking (OIR) to consider potential modifications to the Commission's regulation of natural gas transmission and distribution pipelines. The rulemaking may address pipeline siting, maintenance, inspections, best operating practices, ratemaking, and safety audits. The Order also proposes immediate rule changes addressing strength test requirements for certain PG&E-operated pipelines, and establishing revised reporting requirements and installation reports for new or reconstructed or reconditioned pipelines. In addition, the CPUC staff may develop rules for near-term implementation on 12 topics identified in the Order."[29] On May 10, 2011, the Administrative Law Judge presiding in the OIR issued a proposed decision that, if adopted by the CPUC, would require operators of natural gas

[29] Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms, R.11-02-019 at 1 (Feb. 25, 2011).

transmission pipelines in California (including PG&E) prepare and file comprehensive Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans to either pressure test or replace those pipeline segments that have never been pressure tested or that lack sufficient detail related to the performance of a test.[30]

On February 24, 2011, the CPUC issued an Order Instituting Investigation (OII) into PG&E's recordkeeping pertaining to gas transmission lines, including the San Bruno line. The CPUC will determine whether PG&E's pipeline safety-related recordkeeping violated good and accepted engineering standards and practices, and whether PG&E violated the Public Utilities Code or other laws and regulations.[31]

Because this report will become part of the record in the OIR, the Panel is aware our findings and recommendations may have possible implications for the other regulated pipeline operators in the State of California.

2.3 Organization of Report

The remainder of this report consists of six sections, a glossary of abbreviations and appendices. Each of the sections addresses specific aspects of the Panel's review of the San Bruno Incident:

Section 2.0 - Background - Addresses the incident in general terms and its significance, the National Transportation Safety Board's role, the various actions initiated by the CPUC and the specific role of the Independent Review Panel.

Section 3.0 - The Panel and Its Approach - Presents the Panel members, its Consultants, and the issues they needed to address in carrying out their investigation. This section also discusses and describes the methodology employed in conducting interviews, gathering data, and deliberating analysis.

Section 4.0 - The Pipeline Failure - Describes the Panel's understanding of the pipeline failure, how failures propagate, how stable, unstable and cumulative threats are dealt with, the configuration of the pipeline, where the rupture occurred, and a description of the National Transportation Safety Board findings to date.

[30] Proposed Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans, Filed in OIR 11-02-019 (May 10, 2011).

[31] Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company with Respect to Facilities Records for its Natural Gas Transmission System Pipelines, Filed in OII 11-02-016 (Feb. 24, 2011).

Section 5.0 - Review of PG&E's Performance as an Operator - provides background on PG&E's system from its profile to its integrity management plan; it further describes what issues have surfaced and identifies the key areas of focus. This section also describes the incident and PG&E's response to the emergency. In addition, this section reviews the PG&E's integrity management program, particularly the criticality of data management and what role the company's culture and its approach to risk management may have played in leading up to the incident.

Section 6.0 - Review of CPUC Oversight - Describes the CPUC's legal mandate for safety, PHMSA's roles and responsibilities and its relationship with state regulators, the CPUC's safety organization from its responsibilities to its auditing capabilities, and includes varying commissioner views and reforming ideas.

Section 7.0 - Public Policies in the State of California - Addresses the regulatory and ratemaking regime within California, from contrasting it to FERC and other states to balancing accounts.

This report contains numerous appendices and footnotes, which provide additional detail, analysis, and references to where additional information can be obtained. In addition, the glossary of abbreviations precedes the report's appendices.

3.0 The Panel and Its Approach

3.1 Panel of Experts

As specified by the Charter, the Panel is to retain no fewer than three experts, and no more than five, selected by the President of the Commission, and confirmed by a vote of the Commission. The President of the Commission shall select a leader for the Panel. The Panel may seek opinions and recommendations from expert consultants.

Following this process, the Commission created an Independent Review Panel of experts composed of the following members:

- Chair - Larry N. Vanderhoef, Chancellor Emeritus, University of California, Davis.
- Patrick Lavin, International Brotherhood of Electrical Workers 7th District International Executive Council Member; Co-chairman of the Pacific Council on International Policy, Energy Task Force.
- Karl S. Pister, Chair of the Governing Board of the California Council on Science and Technology; Chancellor Emeritus, University of California, Santa Cruz; Dean and Roy W. Carlson Professor of Engineering, Emeritus, University of California, Berkeley.
- Paula Rosput Reynolds, President and Chief Executive Officer, PreferWest, LLC; former Chairman, President, and Chief Executive Officer of AGL Resources, a Fortune 1000 Atlanta-based energy services holding company; former Chairman, President and Chief Executive Office of Safeco Insurance, a Seattle-based property and casualty insurer.
- Jan Schori, counsel to the law firm Downey Brand LLP; former General Manager and Chief Executive Officer of the Sacramento Municipal Utility District; North American Electric Reliability Council Board of Trustees; Climate Action Reserve Board of Director.

3.2 Consultant Expertise

Early on, Panel members recognized they would need to augment their knowledge and experience to explore fully the breadth and depth of the issues. Consequently, the Panel solicited the following firms and expert consultants to assist in the investigation:

- Jacobs Consultancy, Inc., an industry leader in conducting safety, operations, pipeline integrity and management investigations for regulatory agencies and utilities.
- Van Ness Feldman, P.C., is a law and policy firm focused on the inter-related areas of energy, the environment, and natural resources.
- Dr. Robert E. Nickell, an engineering consultant who provides applied science and technology and structural engineering services for both industry and government.
- Dr. Ralph L. Keeney, a professor at the Fuqua School of Business of Duke University, an expert on risk analysis and decision analysis with a focus on problems involving multiple objectives and life-threatening risks.

A brief background on each of the panel members, the firms and the expert consultants is included in Appendix D of this report.

3.3 Key Areas of Focus

Based on preliminary information on the incident, experience, and the wide variety of issues that were emerging in the media and elsewhere, the Panel identified a number of themes and established key areas in which to focus:

- Essentials of pipeline integrity management - system data, information, knowledge, data adequacy, accuracy and integration, threat identification, risk analysis, threat assessment methods, immediate repair, permitting, root cause, encroachment, risk- based field audits and independent operations/management audits.
- Organization and resources dedicated to safety by PG&E and the CPUC - reporting structure, goals, accountability and responsibilities, and staffing including adequacy, capabilities, specialization, and continuing development.
- Organizational culture of both PG&E and the CPUC – how history, attitudes, and other subjective factors influence performance.
- Utility investment in pipeline infrastructure - replacement reports, safety related budgets - especially in bankruptcy years, in-line inspection enhancement, R&D in safety-related enhancements, corporate vision and Pipeline 2020 Plan.
- Emergency response and preparedness - mock drills, first responder outreach, response time, community outreach and sectionalizing plans.

3.4 Approach

To identify the facts objectively and develop the findings and conclusions amidst the highly charged and dynamic environment surrounding this incident, the Panel employed a number of methods of discovery. These methods and approaches are described below.

3.4.1 Interviews and Discussions

A key element of the Panels' approach in addressing the explosion was to identify and interview key positions involved in all aspects of safety and integrity management at PG&E. In most cases, this iterative process resulted in the identification of data request questions, as well as additional individuals to be interviewed. The Panel and consultants carried out the following:

- A site visit to the location of the pipeline explosion and met with San Bruno city officials and PG&E personnel.
- Attended presentations from eight members of the top management of PG&E.
- Interviewed approximately 30 individuals at PG&E who worked in various departments, including the front-line field employees.
- Meet with three CPUC commissioners and the Executive Director.
- Interviewed staff of both the utility safety and the ratemaking branches of the CPUC.
- Met with the staff of the California Office of the State Fire Marshal (OSFM), who have jurisdiction over the liquid petroleum pipelines that serve the state.
- Interviewed the leadership of intrastate International Brotherhood of Electrical Workers (IBEW) Local 1245, the unit that represents the field employees of PG&E.

The Panel would like to acknowledge the cooperation afforded by all parties involved during this very trying time for all individuals concerned.

3.4.2 Data Requests and Analysis

Preliminary data requests were issued to PG&E to help identify key personnel and document work practices and policies involved in Integrity Management, as well as copies of the Commission's Integrity Management Audits of PG&E from 2005 and 2010 conducted by the Utility Safety and Reliability Branch. As the responses to the preliminary data requests were analyzed and interviews were conducted, supplemental

documents were requested. In total, 115 document requests were made to PG&E and the CPUC, all of which have generated responses.[32]

In addition, an extensive number of decisions and filings from state utility rate proceedings as well as industry organizations were reviewed. All of these documents were publicly available.

3.4.3 Knowledge from Other Operators and States

To form a broader basis of review, the Panel and/or consultants met with the two other major natural gas utility companies who operate transmission pipelines in California, Sempra, and Southwest Gas. In addition, members of the Panel interviewed engineering leadership of two interstate natural gas pipelines.

Consultants also had informal conversations with personnel in several states regarding state pipeline safety regulatory programs. Consultants also informally discussed the involvement of state safety personnel in utility rulemaking proceedings. States that were contacted include Georgia, Illinois, Kansas, Missouri, Minnesota, Oregon, Texas, and Washington.

3.4.3National Transportation Safety Board Hearings and Documents

Representatives from both Jacobs and Van Ness Feldman attended the NTSB Hearings held in Washington, DC on March 1 – 3, 2011. In addition, the Panel and its consultants reviewed the hundreds of documents generated by the NTSB in its investigation of the root cause of the pipeline rupture.

3.4.4Analysis – Expert Findings, Conclusions, and Recommendations

The major topics of this report evolved through iterative discussions between the Panel and its consultants of emerging themes and issues. Concerns and questions were brought forth by the interview and data request processes, as well as by PG&E's responses to ongoing Commission Orders.

As such, the analyses of all interviews and data are the foundation for arriving at the Findings presented in the body of this report. The Findings presented herein are based on data and information gathered from document responses and interviews, as well as industry experience. As noted above, where appropriate, references to a particular

[32] Due to the volume of these materials and the confidentiality that has been asserted by the company to certain of these materials, documents have not been included in this report, except to reference them.

interview or to a document response are provided to the extent the materials are not confidential.

Through the analysis of these Findings, we arrive at Conclusions. Conclusions can be characterized as statements of informed opinion, supported by one or more Findings. Conclusions are often a statement of a trend or a likely outcome.

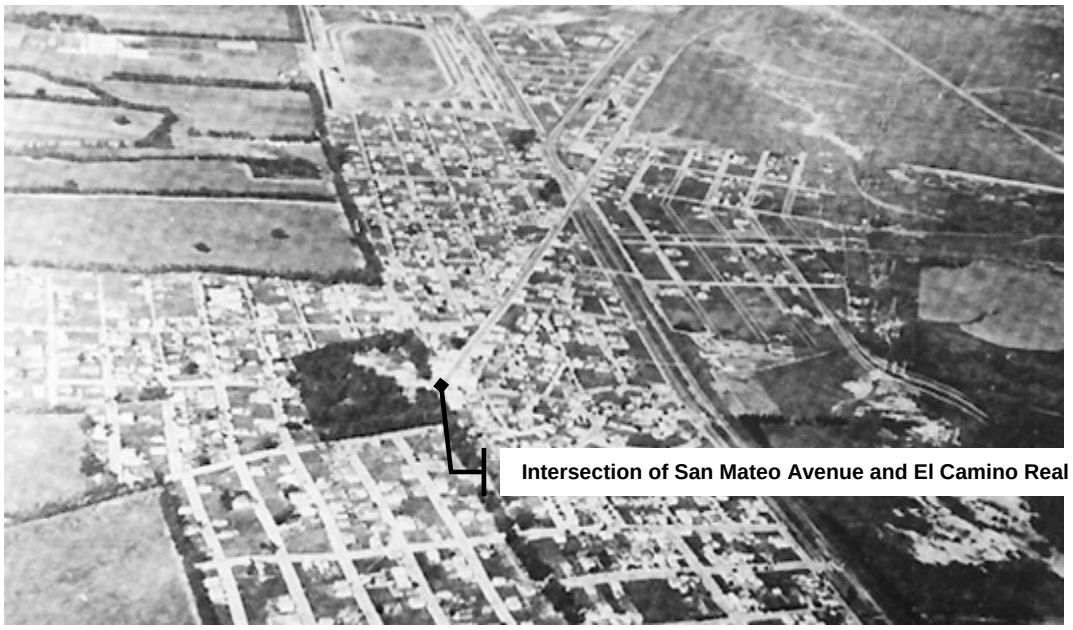
Finally, the analysis of the Conclusions and Findings is used to arrive at Recommendations. Recommendations are action items vetted by the Panel and its consultants, based on collective expertise, intended to engender the improvement to or remediation of negative conclusions.

4.0 San Bruno Incident

4.1 City of San Bruno

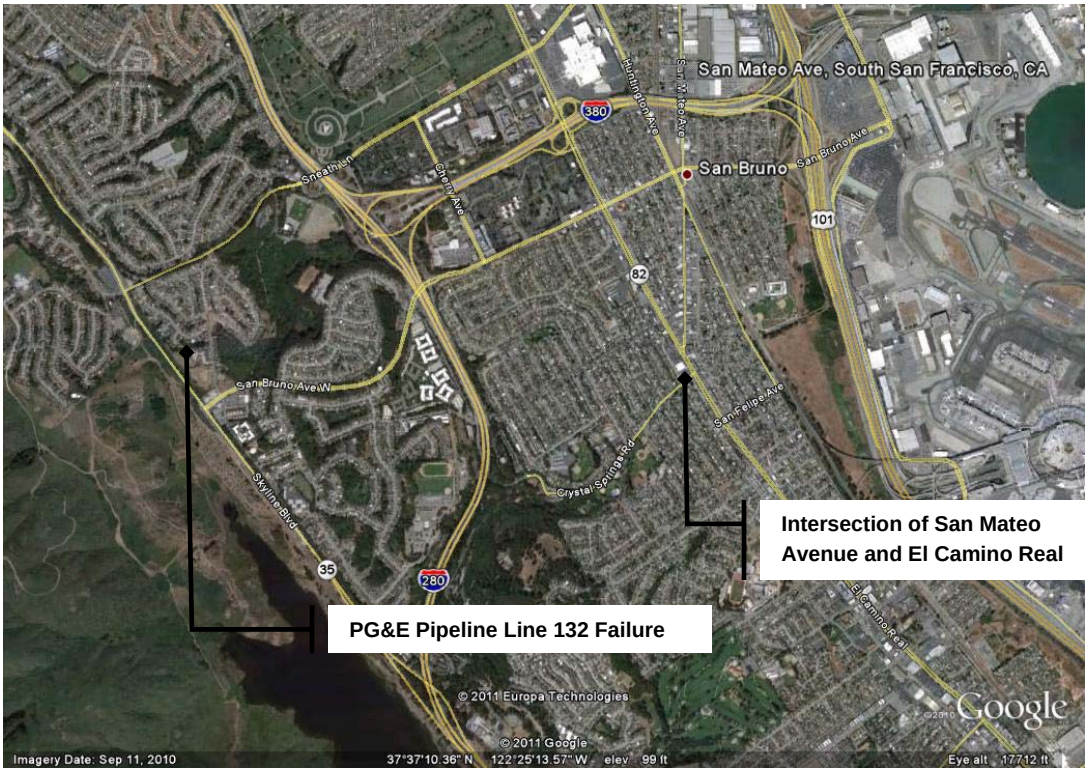
In 1914, the community of San Bruno was incorporated. At that time, San Bruno had roughly 1,400 residents. By 1930, there were about 3,600 residents (see Figure 2). San Bruno was known as a rural town until the 1940's. The housing boom that took place between the 1940's and 1960's transformed San Bruno from a town of about 6,500 in 1940 to a population of over 35,000 by the mid 1960's. An earthquake (5.3 magnitude) on March 22, 1957, caused minor damage throughout the city. Since then, the population has stabilized due to a lack of available land. The October 17, 1989 Loma Prieta earthquake (6.9 magnitude) caused some damage in the city. By 2010, there were about 41,000 residents in San Bruno (see Figure 3).

Figure 2 – San Bruno in the 1930's[33]



[33] Photo by Fred Beltramo. Source: The San Bruno Historical Photo Gallery.

Figure 3 - San Bruno Today



4.2 PG&E Gas Transmission Pipeline

In 1948, after the completion by El Paso Natural Gas Company of a 1,000-mile interstate gas pipeline from the Texas and New Mexico gas fields to California, PG&E began plans to construct a companion 502-mile high-pressure large diameter mainline to connect to this system. Along with this mainline infrastructure, PG&E built a large diameter pipeline to redistribute the natural gas in the San Francisco Bay Area, including Line 132 through rights-of-way it had acquired in conjunction with the pipeline construction project. Line 132 is a multi-diameter (24, 30, and 36 inch diameter) intrastate natural gas transmission line[34] that runs from Milpitas, which is located about 39.28 miles southeast of the San Bruno Incident location, to San Francisco.

In 1956, the city of San Bruno directed PG&E to replace an elevated portion of Line 132 at the intersection of Earl Avenue and Glenview Drive. Somewhere within the same general period, we understand the city converted PG&E's pipeline right-of-way from an

[34] A "transmission line" is defined in 49 C.F.R. § 192.3 as "a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS (specified minimum yield strength of the pipe); or (3) transports gas within a storage field."

easement to a franchise right as the community was growing and residential subdivisions were being laid throughout the area (see Figure 4).

Segment 180 of Line 132 was constructed from 30-inch diameter double-submerged arc seam-welded steel pipe (API 5LX) Grade X42 with 0.375-inch thick wall. The specified maximum operating pressure (MOP) for the ruptured pipeline was 375 pounds per square inch gauge (psig). According to PG&E, the maximum allowable operating pressure (MAOP) for the line was 400 psig.[35]

[35] See AGA White Paper on Verification of MAOPs for Existing Steel Transmission Pipelines, April 2011, a copy is provided in Appendix E. This paper describes how MAOPs were originally determined by pipeline operators and what types of records are useful in verifying this determination. The question of PG&E's MAOP has been the subject of some regulatory interest because of the method it uses to validate its pipeline pressure capabilities. The term used in the media was "spiking," but more precisely it may be thought of as a controlled increase in pressure beyond normal operating conditions but within the manufacturing tolerances of the pipeline. To our knowledge, PG&E is unique in the use of this type of process to validate its maximum allowable pressure.

Figure 4 - USGS September 1, 1956 San Bruno California Aerial Photograph[36]

As of April 2011, PG&E operated of 5,557 miles of gas transmission pipelines, of which 1,021 miles are in high consequence areas (HCAs). The backbone transmission pipeline portion is 2,027 miles, of which 187 miles are within HCAs. [37] PG&E refers to the transmission pipeline used to accept gas from its backbone transmission system and transport it to the distribution system as "local transmission."[38] The local transmission is 3,530 miles, of which 834 miles are within HCAs.

4.3 Pipeline Failure

The pipeline failure occurred on PG&E's Segment 180 of Line 132 at the intersection of Earl Avenue and Glenview Drive (see Figure 5) in the city of San Bruno. The pipeline failure occurred within a designated high consequence area.

[36] National Transportation Safety Board, Docket No. SA-534, Exhibit No. 2-DE

[37] PG&E refers to the large diameter transmission lines used to transport gas from interstate pipelines and California gas sources, such as underground storage sites to PG&E's local transmission system as "backbone" transmission pipe. The backbone refers to Lines 300, 400, and 401, as well as the network of Bay Area lines that serve to interconnect those major pipelines Lines 2, 107, 114, 131, and 303.

[38] "Local transmission" includes both local transmission and distribution feeder mains

Figure 5 - Aerial Location of the San Bruno Location[39]

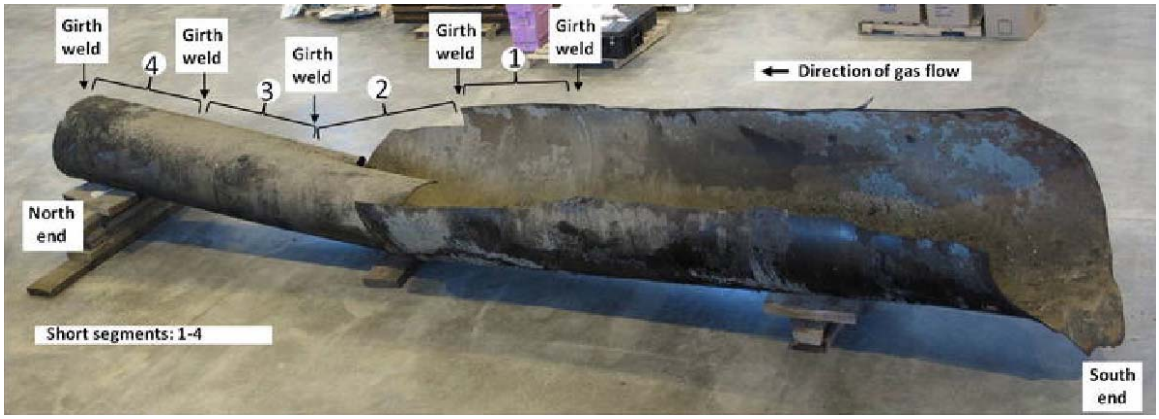
The rupture created a crater approximately 72 feet long by 26 feet wide. A pipe segment approximately 28 feet long was found about 100 feet south of the crater. Figure 6 below is a photo of the largest segment from the rupture.

As mentioned in Section 2 of this report, the National Transportation Safety Board has been investigating the cause of the pipeline failure since immediately after the event on September 9, 2010, and that investigation is continuing. It is commonly expected the NTSB will conclude its investigation and issue its report in late 2011.

As background to the deliberations by the Panel, the final determination of the root cause(s) and possible underlying contributing factors would be useful; however, the timing of the NTSB final report made it necessary for the Panel to proceed based on the available evidence found to date. To this end, the Panel's technical consultants analyzed the available technical information to guide the Panel's deliberations. That analysis in contained in Appendix F.

[39] NTSB's Operations Group Chairman's Factual Report, Docket No. SA-534, Exhibit 2A

Figure 6 - Photograph of 28-foot-long ruptured section of pipeline Segment 180[40]



The significant findings, as of today, are that the underlying cause of the San Bruno gas transmission pipeline failure appears to be a combination of:

- An incomplete Double Submerged Arc Weld (DSAW) that manifested itself as an initial manufacturing defect extending completely along the length and approximately half-way across the wall from the inside surface of a short pipe segment denoted as PUP 1 (see Figure 7). Abnormally low mechanical properties in the base metal, such as yield strength and fracture toughness, with high likelihood of similarly low mechanical properties for the weld metal and heat-affected zone, for several of the short pipe segments – including PUP 1 and PUP 2 in particular, which do not meet the nominal requirements for API 5L X-42 or API 5L X-52 specifications.
- Incomplete or missing fabrication and installation records for both the short pipe segments and the longer adjacent pipe segments that would have moved that portion of Line 132 into a higher-risk category.
- An event or events, such as third-party actions, that led to growth of the initial fabrication defect until reaching critical and unstable dimensions.

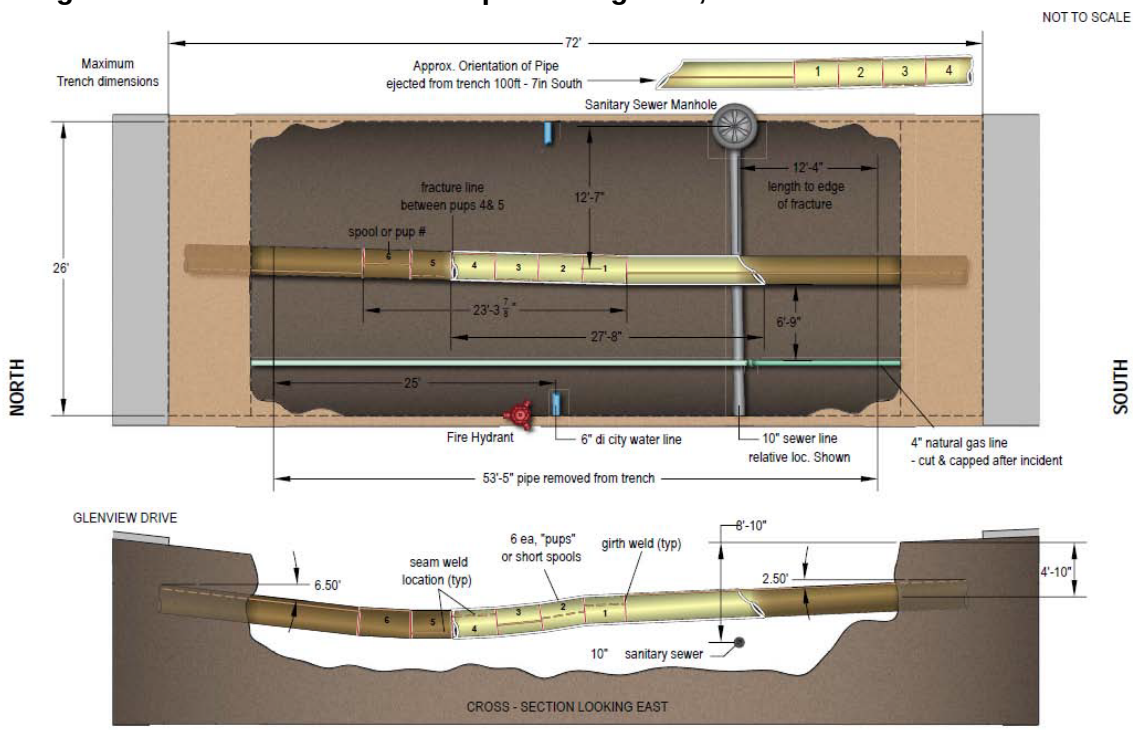
As the Panel was reviewing these findings, in May 2011, a white paper was issued by the Interstate Natural Gas Association of America (INGAA).[41] The paper analyzed the NTSB findings to date and concluded the supposition that defect growth stemmed from cyclic pressure changes was unlikely to be the sole growth mechanism for the initial manufacturing defect. INGAA suggested some other contributing factor led to initial defect growth and eventual failure, such as external stresses from a third party or soil

[40] National Transportation Safety Board, Docket No. SA-534, Exhibit No. 2-A

[41] Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of the PG&E San Bruno Incident, INGAA Pipeline Safety Committee, May 5, 2011, Interstate Natural Gas Association of America, Washington, DC.

movement. As discussed more fully in Appendix F, the work performed by our technical experts corroborates that view.

Figure 7 - Schematic of Failed Pipeline Segment, Plan and Elevation Views[42]



4.4 Pipeline Safety Regulation

Line 132 is an intrastate gas transmission pipeline regulated by the California Public Utilities Commission (CPUC) and inspected by the Utilities Safety and Reliability Branch (USRB) of the Consumer Protection and Safety Division (CPSD) of the Commission. The CPUC regulates intrastate gas transmission and distribution pipelines pursuant to both federal and state laws and regulations. The CPUC has adopted federal pipeline safety regulations and administers these through an annual certification to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA regulations include extensive safety requirements covering pipeline design, construction, testing, operations, maintenance, corrosion control, and integrity management. The CPUC's pipeline safety program is also authorized by the California Constitution and state public utilities laws, and the CPUC has adopted additional pipeline safety requirements beyond the federal regulations. The CPUC's program is funded through a combination of annual PHMSA grants and user fees levied by the CPUC.

[42] ibid

The integrity management regulations, in particular, are relevant to our analysis because they require pipeline operators to provide an extra layer of protection for pipelines in high consequence areas (HCAs), such as PG&E's Line 132 pipeline. As noted earlier, an HCA is an area along a pipeline in which a greater population density increases the potential consequences if an incident occurs. Integrity management requires operators to assess the threats to their pipelines, perform inspection and assessment, and take measures to prevent and mitigate the risks on pipelines in HCAs. The integrity management regulations are in addition to numerous other PHMSA requirements that apply to all gas transmission pipelines.

5.0 Review of PG&E's Performance as an Operator

5.1 Company Culture

5.1.1 Background

In evaluating an organization's effectiveness, one generally looks at the performance of the processes, the technology that support those processes, and the people who perform the work of those processes. When an organization is a high-performing one, we often think of it as somehow more than the sum of its parts. It is difficult to capture the full spectrum of factors that make an organization unique, such as history, hierarchy, mission, leadership, experiences, attitudes and values. Nevertheless, these intangible factors can often play as much a role in an organization's success as its processes and procedures, its technology and its people. The character of an organization very much affects its performance. Thus, as we discuss the specific technical and process findings, our report attempts to capture the elements of PG&E's culture and how that culture influences performance.

The product that a gas utility sells is safe and reliable service. Delivering this product is the key to sustaining a utility's franchise to service. It is also the basis for a utility's reputation. Values such as pipeline system safety, reliability, and process excellence are instilled in company personnel and its contractors through a corporate culture that continuously reinforces objective standards of expected performance. Because much of the work of safe and reliable service is highly technical in nature, continuity of personnel in key technical roles is critical and supervision must be able to administer a program of rewards based on objective evaluations of technical proficiency.

A number of concerns surfaced in the course of our investigation that go to this issue of whether PG&E has a high functioning organization, capable of fulfilling its mandate for safe and reliable gas service. The concerns about PG&E's performance culture start with the frequent management changes and dysfunction from excessive layers of management. They culminate with a concern that top management whose interests and expertise lie in financial performance which dilutes the company's focus on one of its core missions – that of safe and reliable natural gas service.

5.1.2 Findings

PG&E has been in a state of perpetual organizational instability for more than a decade.

- In 2001, the utility company, PG&E, filed for bankruptcy.

- Upon emerging from bankruptcy, PG&E Corp., including PG&E the utility, embarked at corporate "transformation" process.
- On January 1, 2006, the top leadership of PG&E Corp. and the utility changed.
- The Energy Delivery organization was created in 2006 at the utility company to perform the construction, maintenance, and restoration activities associated with combined PG&E's gas and electric transmission and distribution delivery assets.
- Throughout 2006, Energy Delivery was headed by a Senior Vice President. Within the Senior Vice President's organization was a Vice President for Gas Transmission and Distribution and numerous senior director and director-level positions.
- In August of 2006, a new President and COO of the utility was hired.
- In February of 2007, the President of PG&E announced a restructuring of the operating units, which affected Gas and Electric T&D, and resulted in the exit of the Vice President of Asset Planning.
- In April 2007, a new Senior Vice President of Engineering and Operations joined the company, with combined gas and electric engineering responsibilities.
- In July of 2007, the CEO of the utility resigned; he was replaced by the utility COO.
- In late 2007, an existing Senior Vice President moved into the lead role in charge of Transformation Initiatives and a new Senior Vice President of Energy Delivery was named to join a new Senior Vice President of Engineering and Operations. The President of PG&E created two new positions in Energy Delivery -- Vice Presidents of Maintenance and Construction, North and South.
- The year 2008 saw additional changes, including the retirement of the Senior Director of Gas and Electric Transmission and the hiring of a Vice President of Transmission and Substation, Maintenance, and Construction. In August, the CEO of the utility resigned and was replaced by the CFO of the parent company. By the end of 2008, the Engineering and Operations Organization determined the need for a vice president with responsibility for the Asset Planning and Engineering.
- In 2009, Energy Delivery realigned the Maintenance and Construction departments by commodity: gas and electric. The purpose of the realignment was to support improved line-of-sight and accountability.[43] A vice president of gas transmission retired.

[43] DR#81 – IRP_012-03 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_012-Q03-CONF.pdf - Energy Delivery organizational changes over the last six years – PG&E

- At the time of the San Bruno Incident, PG&E's gas transmission operations were spread over several integrated electric and gas organizational units. During the course of this investigation, a number of staffing changes were made. An announcement was also made that the gas business would be separately organized, reporting to a new position of the Senior Vice President of Gas Operations.

Through interviews, the Panel learned throughout this entire period, the system design, field engineering, pipeline integrity management and related operating functions were split among multiple officers, creating silos of expertise, but also creating difficulties in communications. In certain silos, there were as many as nine levels between the CEO and the front-line employee. As a result, the management that is setting the direction is distant from those who know have the responsibility for executing the work.

Among other things, to run a reliable natural gas transmission system, it is essential to ensure continuity of pipeline design expertise, preservation of design and operating data, and a disciplined process of analysis and planning. It is exceedingly challenging for employees to thrive in an organization with the sheer number and scope of changes in leadership, staffing, and direction that have occurred at PG&E.

As leadership changes occurred throughout the decade at PG&E, they included selection of a number of individuals in top management with little or no previous experience in the natural gas industry and/or no direct operating experience. The main training, experience and professional careers of many in PG&E's top management are in telecommunications, finance, and law, and they have not had operating roles where they could develop the requisite expertise in the reliability and safety aspects of a major gas or electric utility.

Among other things, organizational culture is a function of how people interpret what leadership deems important. In this regard, PG&E sends mixed messages regarding system safety when it brings its own financial performance into the equation.

- In an interview with a top leader of PG&E, the question was asked as to what factor(s) would most positively affect safety in the future. The response given was the provision for the recovery of costs for safety improvements would be the most important factor.
- In the high level corporate goals material which was presented to the panel and is included here as Appendix G, the company did not include any goals for safety as part of its long-term aspirations. It did include an aspiration for financial performance, however.

- PG&E stated it had a "bottoms-up" budgeting system where businesses were encouraged to request what they needed to get the work done as they saw fit. However, the actual process including justifying requests in the following categories: (1) Mandatory; (2) Priority 1 - work that is deemed critical to the company's operational goals and that could not be deferred without impact to system operations or reliability; (3) Priority 2 - work that is closely related to the company's operational goals, but that could be deferred; and (4) Priority 3 - work that would assist the company in achieving its long-term objectives to the fullest extent. Other than mandatory work, all other priorities were subject to internal debate among top executives for what was financially-driven amount of capital investment. In light of this framework, any work -- pipeline integrity management or otherwise -- that was not mandatory could arguably be deferred. In a company with a significant budget for its electric business, a natural tension is created when gas versus electric priorities are debated – particularly if the arbiters of the debate do not have experience in both disciplines.
- The panel learned from our first meeting with company representatives the amount of work the integrity management team could accomplish annually was largely a function of how many engineers had been assigned in the first place. Given the retirements, reorganizations and emphasis on cost controls in place in the company, it does not appear there was any encouragement of or support for a more comprehensive look at system integrity management. We found, for example, the vast majority of PG&E's transmission pipeline cannot be inspected using in-line inspection (ILI) tools. Since the inception of the program, the company has made some investment in modifying the lines to accommodate ILI tools; however, when compared to the industry, PG&E is significantly behind. As of 2010, approximately 17% of PG&E's overall pipeline transmission system can accommodate ILI tools and slightly more than 21% of its transmission pipeline system located in HCAs can be inspected using ILI tools.[44] This is dramatically less than the 60% in-line inspection average for cross-country natural gas transmission[45] and 40% average for utilities with transmission and distribution facilities. While it is difficult to compare efforts on the basis of percentages, all of the other utility companies with whom we spoke have made the investments to improve detection of threats. Meanwhile, PG&E's corporate materials state its vision is to be "the leading utility in the United States." (See Appendix H).

[44] DR#44 – IRP_10-08 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_010-Q08Atch01.pdf – Miles of Piggable Transmission Pipelines and HCA Transmission (2000-2010) – PG&E

[45] INGAA Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of PG&E's San Bruno Incident report dated May 5, 2011

5.1.3 Conclusions

PG&E is one of the nation's largest gas distribution system operators. It ranks in the top 20 gas transmission operators and has over 18% of the transmission lines located in high consequence areas. As will be more fully discussed in subsequent sections, the weaknesses in integrity management are not indicative of an industry-leading approach. This failure in integrity management is a product of a number of factors. Among them, the company's organization has been in a state of flux for over a decade with the following results.

First, there are excessive levels of management. In certain organizational subgroups in the gas transmission and distribution business, there were as many as nine levels between the CEO and the front-line employee. As a result, the management that is setting the direction is distant from those who know the business the best. Effective communications are challenging up and down the organization. The opportunity for a vibrant process to exchange views, question strategies and challenge decisions is denied by the sheer bureaucracy.

Second, there is inconsistent presence of subject matter expertise in the management ranks. Repeated reorganizations, the interchange of gas and electric supervisors and managers, and the homogenization of gas transmission and distribution personnel have taken a toll on the number of experienced individuals at every level of the company. The experience and knowledge base has been noticeably reduced over the last decade, partly due to retirements. Compounding this loss of knowledge of operations knowledge is the presence of telecommunications, legal, and finance executives in top leadership positions. There is an under representation of engineers and professionals with significant operating experience in the natural gas utility industry in leadership roles. In the organizational design, these less experienced senior leaders rely on their direct reports for technical advice. However, PG&E has had a practice of rotating the direct reports to various positions throughout the company, to fill in as vacancies arise. This constant shifting of personnel has resulted, over time, in senior management relying on a relatively small pool of talented individuals who lack experience and expertise in the positions they hold. These organizational dynamics send very mixed signals about what qualifications and performance will be rewarded.

Third, while the company has multiple stated goals, top management appears to be focused on financial performance. Certainly our utilities must be financially healthy to fulfill their respective missions, but when top management focuses on financial performance and does not appear to be engaged in operational safety and performance, it affects the willingness of the organization to challenge the priorities or resources put in place by upper management. The PG&E budgeting process, with its tiered structure, results in the company pursuing compliance activities and those projects authorized via ratemaking agreements. Compliance and expenditures for projects authorized in rates

are the driving forces affecting the infrastructure investment and maintenance program of PG&E's gas operations. A “compliant” company may or may not be running a safe system. Rather, only if the adherence to the letter of the regulation leads to an overall approach of process excellence is safety promoted.

Process excellence appears to be one of the victims of organizational instability. This was evidenced in the 2008 San Bruno sewer replacement project. Regardless of whether the sewer work led to the ultimate failure of the pipeline, the project was characterized by an ineffective communication process between the city’s contractor and PG&E’s field engineering, between the field employees and supervisors, between field engineers and pipeline engineers, and between the pipeline engineers and pipeline integrity management team. Individuals might know what one’s own role was in managing the integrity of the pipeline, but few understood how the individual roles fit into the larger framework of integrity management.

Further evidence of the breakdown in process excellence became apparent to the Panel when it asked the top utility management to describe the company’s safety program. In reply, the executives articulated their views on worker safety, with supporting data. They described how a program of personal safety improves productivity and saves money. Despite the opportunity to talk to the Panel about how the San Bruno situation related to or influenced its system safety program, the leaders did not address potential risks to the public or what the company was doing to make public safety central to the organization.[46] Management has embraced an occupational safety culture because it’s smart business, but seemed generally unaware of the quality of its pipeline integrity efforts.

When the integrity management regulations were being formulated, PG&E participated, along with other operators, with PHMSA in some of the early assessment protocol development. Perhaps in part due to the exigencies of bankruptcy, PG&E was introspective over the last decade, looking at its own performance as the benchmark to which it should manage. For example, when personal safety metrics were presented to the Panel, PG&E senior management benchmarked only against themselves, showing only PG&E safety trends.[47] More recently, it appears PG&E is becoming more active in what is going on in the industry via its participation in industry associations and committees. The Panel believes this is a positive development that needs to be encouraged, with the lessons gleaned from other industry participants elsewhere in North America being brought home to northern California.

[46] Independent Review Panel, discussion topics with COO of PG&E, PowerPoint presentation data January 12, 2011; shown as Appendix M.
[47] ibid

5.1.4 Recommendations

5.1.4.1 PG&E needs to create a culture of system integrity that enables every employee to recognize and understand how his or her day-to-day actions affect system integrity.

5.1.4.2 PG&E needs to streamline the organization, reducing layers of management and rebuilding the core of technical expertise.

5.2 Enterprise Risk Management

5.2.1 Background

Risk management concerns making decisions necessary to manage the risks faced by an organization. An organization's risk maturity is gauged by the priority, proactive thought, and serious effort allocated to manage the most significant risks facing an organization. Collectively, risk management and risk culture are the foundations that influence how well decisions about risk are made.

The review of PG&E's risk management practices focuses on two levels: strategic or policy risk management, and operational risk management. These levels are directly related in that the intent of operational decisions is to follow the policies set by the strategic choices of the organization. The management team has responsibility for the strategic and policy decisions, whereas operational decisions, which frequently involve following procedures and performing compliance activities, are conducted lower in the organization.

5.2.2 Findings

PG&E refers to the activities that comprise its strategic and policy risk management as Enterprise Risk Management (ERM).

In discussions the Panel had with top PG&E management, issues of risk management were essentially not mentioned. This was particularly surprising because the entire PG&E management team was well aware of the Panel's tasks, and therefore how keenly interested the Panel would be in the San Bruno pipeline explosion and with avoiding similar public health and safety risks in the future. Only near the conclusion of the interviews, when specifically asked about risk management, individuals interviewed agreed to provide information about risk management at PG&E. The company followed

up with data responses that provided background on PG&E's Enterprise Risk Program, which is discussed in the following finding.[48]

Because of the lack of information regarding risk management provided in the original interviews with top PG&E management, a subsequent meeting was held with the executives with responsibility and experience in this area. They discussed how PG&E develops and maintains a list of its top ten catastrophic risks. Managing these risks is the focus of PG&E's Enterprise Risk Program.

The process is essentially as follows. Potential catastrophic risks are suggested by many individuals. A group of senior executives selects the top ten at a given time through extensive discussion. Actions are taken to mitigate some or all of these risks and, as appropriate, a revised set of the top ten risks is periodically selected. The criterion for including a risk in the top ten is mainly the severity of the potential consequences of the risk. The likelihood (i.e. probability) of this risk was to some extent considered in the selection, but as it was stated, "probabilities are so difficult to know." The consequences of these catastrophic risks include public health and safety, financial impact, and reputation of the company.

For managing each catastrophic risk, PG&E identifies a risk owner who must be one of a senior officer team of 18 senior vice presidents. That officer typically works with an interdisciplinary team to decide what should be done to manage that risk. Once the team has a recommendation, this material is presented to the senior officer team for approval. Once approved, the decision then needs acceptance by top PG&E officers for implementation.

In early 2007, the Enterprise Risk Management program identified gas and electric system safety as one of the top ten catastrophic risks facing PG&E. In our review of the materials, it appears PG&E had a high degree of intellectual understanding of the complex factors that impinge on system safety. The examination evaluated a number of business processes in the gas transmission operation and identified many items that should be improved. The Board of Directors was advised the management would apply its internal audit and quality assurance efforts to the key processes on which the safe operation of the system depends and the work of mitigating the threats would begin in the first quarter of 2007. In July 2010, an ERM summary of the safety status of the gas distribution still described a number of items as "weak." Further, those findings were supported by PG&E's Internal Audit process which identified a number of weaknesses in the integrity management process. (See Appendix G.)

[48]Attachment 2 "Public Safety As Part of Company Goals," from Letter to Panel dated January 21,2011 from Thomas E. Bottorff, Senior Vice President of Regulatory Relations, PG&E

While the description of the risk factors showed insight, there was no evidence that state-of-the-art or even near state-of-the-art risk analyses were done at PG&E to address strategic or policy risk management decisions. In other words, the Board and the Management were advised of the risk of a catastrophic failure of the gas pipeline system and what factors might lead to such a failure, but we saw no evidence of any in-depth strategic discussion about the alternatives, level of investment, trade-offs, or other factors that would relate to mitigating the risk. Rather, the evidence provided supported the idea that achieving compliance with regulations was the path to safety. No analyses were provided to us that indicated the complexities of strategic risk management decisions discussed above were explicitly addressed.

Alternatives were selected based on internal PG&E discussion, but lacked insights from any risk analysis of the type described above. In none of the cases was it apparent that a distinct effort was undertaken, other than perhaps making a list, to produce innovative alternatives or a reasonably complete set of alternatives. In none of the cases were there references provided to any probabilities of possible events (e.g. a pipeline explosion on a particular segment of pipe) that could significantly affect consequences. In none of the cases were there descriptions provided of the possible consequences of potentially competing alternatives in terms of public health and safety, environmental implications, economic costs, and reputation implications. In addition, in none of the cases was a presentation provided of the pros and cons of the different alternatives, with or without the information and logic behind them that could have informed top management with the responsibility to make a decision.

5.2.3 Conclusions

Quality risk analysis to support strategic and policy risk management decisions at PG&E does not exist. There is no evidence top management has taken the steps necessary to be well- informed about the key aspects of decisions selected to manage major risks that concern PG&E, such as its top ten catastrophic risks. The main focus on safety risks at PG&E is on employee safety, which is managed by compliance and by following authorized procedures. There was no discussion of programmatic or strategic initiatives (e.g., reconfiguring the pipeline system to install in-line inspection capabilities) to improve safety.[49]

PG&E does not have a staff of professionals to produce quality risk analysis of the strategic and policy risk management decisions the company faces. Quality analysis could both facilitate two-way communication between top management and individuals

[49] Such strategic initiatives would fall into Priority 3 of PG&E's budget process. We were not provided with any materials suggesting that the organization had considered Priority 3 investments in integrity management.

with substantial knowledge about each of the relevant aspects of utility operations and provide a clear understanding of all the information available to make a key risk management decision. Management could then ensure a full range of alternatives were considered in the decision and examine how each measured up in terms of each of PG&E's relevant objectives. They could examine what assumptions and judgments were used in integrating the available information to indicate the pros and cons of the alternatives. A quality analysis would highlight any significant missing information and provide a basis to examine whether it would be worth gathering if possible.

5.2.4 Recommendations

5.2.4.1 PG&E should acquire and develop a staff of professionals with the skills necessary to do state-of-the-art practical analysis of risk management decisions that concern public health and safety, employee health and safety, environmental consequences, socioeconomic consequences, and financial and reputation implications for the company.

5.2.4.2 The Board of Directors of PG&E should require that state-of-the-art risk analysis be conducted on every problem included on PG&E's list of top 10 catastrophic risks. The Board should be assessing the quality of involvement of the members of the top management team in every one of these risk analysis, as all risk management decisions that concern the top ten catastrophic risk should be of direct concern to all top PG&E executives, including the President and CEO, as well as the Board.

5.3 Data Management

5.3.1 Background

Prior to the age of digital record keeping, pipelines used to record the relevant information about installed pipeline in bound journals called “pipeliners’ books.” The original developers of the systems understood that because the pipelines were buried and would not last forever, the operators needed to be able to locate facilities as well as determine their character. As an outgrowth of this history, one of the central tenets of modern day pipeline integrity management is that if an activity is not documented, then the operator must assume the activity was not conducted or completed. Similarly, if material, design, construction, operation, or maintenance data and information regarding a segment of pipeline is missing or insufficient to fully assess the presence of a threat, then the operator must assume it is a threat until proven otherwise. An effective approach to mitigate threats requires good data, good integration of data and risk assessment based on complete data.

Internal sources of data include pipeline design, construction, commissioning, operating, and maintenance records. External sources typically include manufacturers, industry associations, other operators, and governmental agencies. While information about a pipeline system or segment of a pipeline system is established and recorded at the time of initial design and construction, additional pipeline parameters are established after the facilities have been placed in service. Based on such information, an effective pipeline integrity management program requires a pipeline operator to review information regarding pipeline located in high consequence areas and identify the threats to such pipeline's integrity, assess the risks associated with those threats, and take actions to mitigate those risks. This activity is required by federal regulations.[50]

The pipeline "vintage"[51] is of concern to pipeline integrity managers not because of age alone. Rather, because of the developments in pipe coatings, construction techniques, manufacturing processes, and the ongoing maintenance and operation incurred over the pipeline's lifetime, one can develop a process by which to identify which segments are most in need of follow-up inspection and possible remediation or replacement. Pipe vintage is also a matter of concern if it is known in any given period that shortages of steel existed, which could affect pipe quality. For example, pipe fabricated during times of war are known to have different metallurgical composition than during normal times and hence have different integrity characteristics. Each of these conditions may affect threats and risks to the pipe, which in turn would generate the need to access particular data about the pipe manufacture, installation, operating pressure and in-service assessments.

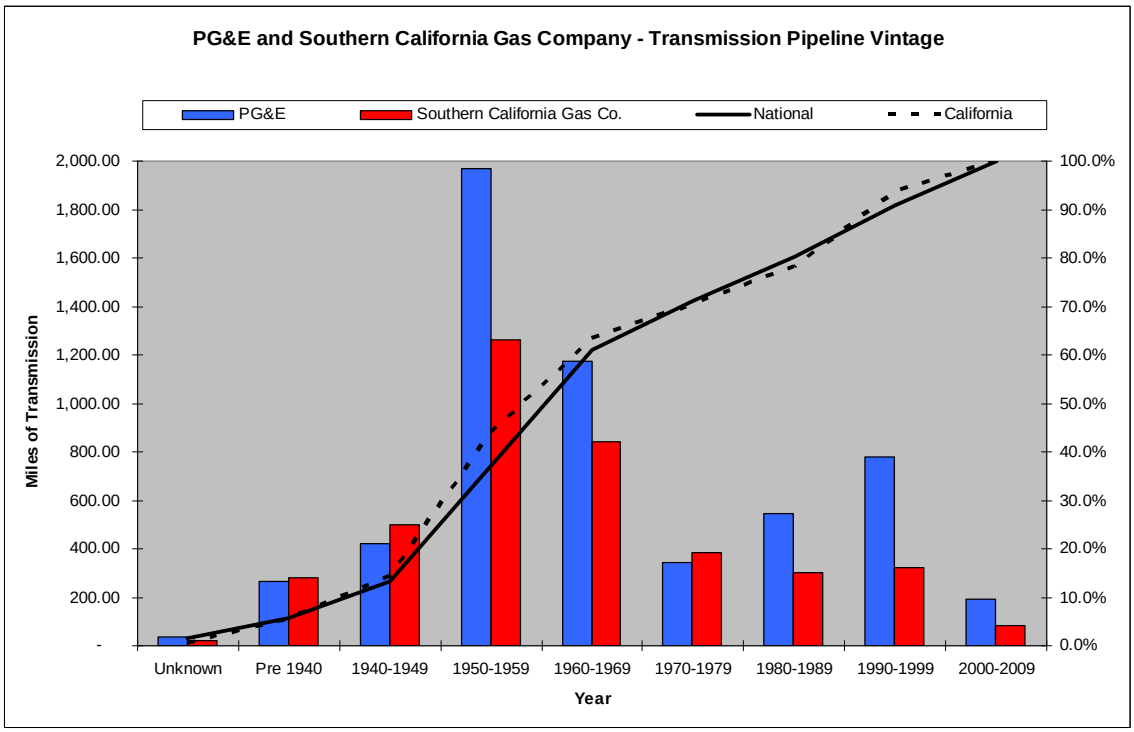
5.3.2 Findings

Availability and quality of data can be problematic for early vintage pipes, often varying depending on when the pipeline was constructed. Figure 8 compares the transmission pipe vintages of PG&E and Southern California Gas with national averages. PG&E has a significantly higher proportion of pre-1960 transmission pipe than the national average.

[50] Title 49 C.F.R. Part 192, Subpart O

[51] For purposes of this report, the words "legacy" or "vintage" refer to pipe installed prior to the promulgation of either Title 49 C.F.R. Part 192 or G.O. 112.

Figure 8 - Comparison of PG&E and Southern California Gas Pipe Vintages with National Average



PG&E stores data and information on gas transmission system assets in a Geographic Information System. The GIS database contains over 60 attributes/features. When information is updated in the GIS, the system maintains a log of changes. Appendix I contains a list of these attributes.

PG&E's Integrated Gas Information System (IGIS) is an application used to record, update, retrieve, and report on information for gas leaks, repairs, and inspections. This data includes information regarding the location and specifications of the type of cover over the gas facility, specifications about the type of the facility (operating pressure, diameter), repair information including pressure testing, pipe condition, and third-party damage information.

System data and records are retained in various formats and systems across the PG&E Divisions. For example, SAP is used in five of the company's 12 Divisions. SAP is typically used to store accounting records rather than digital or design records.

Data and information the operator needs to retain and be able to retrieve include: policies, processes, and procedures that involve engineering, design, construction, operations and maintenance of the gas transmission system. Changes to policies, processes, and procedures occur regularly and can have a direct effort on threat identification and risk assessment. For example, PG&E has revised its pipeline material

specification eight times since 1990. Copies of all of PG&E line- pipe material specifications have not yet been located.[52] Another example is PG&E's Design & Materials Management Committee, which is another integrity management control point regarding identification of materials and threats associated with design and materials, did not meet in 2008 and 2009. After the San Bruno Incident, the committee met on November 17, 2010, to characterize properly the materials and design from the affected pipe.

The American Petroleum Institute (API) standards first incorporated pipe toughness requirements in the 16th Edition (dated April 1969) as optional Supplementary Requirements SR-5 (Charpy Impact Testing) and SR-6 (Drop Weight Tear Testing). The earliest available PG&E document incorporating pipe toughness standards is a pipe specification document from the 1973 Construction of Line 57B, which was incorporated by reference to API 5L "Specification for Line Pipe," the industry standard for pipe specifications. This gap between published industry standards and company standards for pipeline integrity is an example of how threat characterization and the subsequent risk analysis are dependent on a complete understanding of both direct and indirect events that have occurred throughout the life of a pipeline.

Another example of the importance of having complete data relates to recent attempts by PG&E and Sempra to locate complete pressure test records on their transmission pipelines. CPUC General Order 112 has required transmission pipeline operators in the state of California to pressure test new pipelines since 1961.[1] Both utilities have reported they do not have complete records, but the results of the pressure test are one consideration used to establish the maximum allowable operating pressure (MAOP) of a pipeline system.[2] Combined with information on the pipe diameter, wall thickness, specified minimum yield strength (SMYS), the operator can establish the operating stress of the pipeline as a percent of the pipe's SMYS. The pressure test is, therefore, a key parameter in validating the workmanship and establishing a design margin of safety.

For PG&E, the unavailability of at least some legacy piping records and potential mischaracterization of other legacy piping records raises the issue of whether threats similar to the Line 132 San Bruno segment are currently unidentified. Based upon

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[52] DR#75 - IRP_011-Q22 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_011-Q22.pdf - Current Standard at time of incident and first standard where pipe toughness was incorporated – PG&E

[1] At the federal level, all pipeline operators were required to strength test all new transmission pipelines and maintain records of the pressure test for the life of the pipeline with the creation of Title 49 of the Code of Federal Regulations Part 192 in 1970. Operators with transmission pipelines constructed prior to the regulation were allowed to establish the maximum allowable operation pressure using the maximum-recorded operation pressure of the pipeline between 1965 and 1970, and to maintain a copy of the records used to establish the MAOP.

[2] Title 49 C.F.R. § 192.619 - Maximum allowable operating pressure: Steel or plastic pipelines.

discussions with PG&E staff, experienced piping engineers were well aware the Line 132 San Bruno segment was seam welded, rather than seamless. However, the process by which data were collected and examined for threat identification and the risk ranking of piping segments, which should include examination of construction and operating records by those experienced piping engineers, failed to correct the error.

Documentation of the MAOP of Line 132 was available in the form of a document substantiating the highest historical operating pressure as permitted by Title 49 CFR Part 192 Section 619, but records substantiating a pressure test of the pipeline or mill test have not been provided to the CPUC at the time of this report.

Records that could have identified the use of small pipeline segments across the ravine where the San Bruno Incident occurred and that made the pipeline across the ravine a potential candidate for additional inspection and replacement were not readily available.

Data used to establish the risk values for pipeline segments are missing. Where data were missing, PG&E used default values. The default values were replaced once the data became known. The default value resulted in higher pipeline segment risk scores, all other things equal, which is a seemingly conservative assumption, but in a ranking system where the highest risk segments are subject to inspection first and constraining the number of segments that would be inspected, PG&E's use of default values did not necessarily lead to inspecting the riskiest segments first. We are mindful of the tenet of pipeline integrity that if material, design, construction, operation, or maintenance data and information regarding a segment of pipeline is missing or insufficient to fully assess the presence of a threat, then the operator must assume it is a threat until proven otherwise. In the absence of data, threats not assumed to be present can lead to underestimating the potential risk of a pipeline segment.

In-line Inspection tools can provide a significant amount of data and information about the condition of pipelines. ILI data can provide information that cannot be obtained by hydrostatic testing or direct assessment inspection techniques. For example, comparing runs completed at different times of the same pipe can provide insight into the growth rate of an anomaly. As noted earlier, the vast majority of PG&E's transmission pipeline is unable to accommodate ILI tools and, therefore, the data and information is unavailable to make better informed inspection, prevention, and repair, replace, or rehabilitate decisions.

The Design & Materials Management Committee did not meet in 2008 and 2009. Since San Bruno Incident, the committee met on November 17, 2010 to characterize the materials and design for that segment based on the new information adduced in the NTSB investigation.

5.3.3 Conclusions

It has been extensively reported PG&E's first submission of pipeline data to the NTSB included information that incorrectly characterized fundamental aspects of the line (although our investigation indicated, as noted earlier, that experienced engineers were aware of the nature of the seamed fabrication). We understand the entire pipeline industry has had challenges in digitizing and systematizing all the engineering design, construction and operating data. However, having a plan for data management is a requirement of the pipeline integrity management regulations and is essential for assuring integrity threats are addressed. PG&E provided erroneous data because of a lack of: (1) robust data and document information management systems to archive historical data, and (2) processes to capture emerging information about the underground gas transmission system. There is a lack of coordination between field resources and engineering management regarding which data are to be collected and where and how records are to be preserved.

Data management is important, but it is just one process in the chain. Quality assurance is the framework that runs throughout the entire process. A review by experienced piping engineers who question assumptions and demand substantiation should be a part of the quality assurance for the threat identification and risk ranking process. At any number of process steps in PG&E's threat identification and ranking processes, a casual review by an experienced piping engineer should have flagged the mischaracterization of the pipe seam type for the Line 132 segments that are the subject of this investigation.

Threat identification and analysis of pipeline segments are limited by quality and accuracy of data and information, resulting in existing gas transmission piping segments, which are currently incompletely characterized or potentially mischaracterized, being at risk for unstable defect growth under nominal operating conditions.

In conclusion, PG&E lacks robust data and document information management systems and processes. These hinder the collection, quality assurance/quality control, and analysis of data to fully characterize threats to pipelines as well as assess the risk posed by the threats on the likelihood of a pipeline's failure.

5.3.4 Recommendations

5.3.4.1 PG&E should conduct a comprehensive review of its data and information management systems to validate the completeness, accuracy, availability, and accessibility to data and information and take action through a formal management of change process to correct deficiencies where possible.

5.3.4.2 Upon obtaining the results of the review, PG&E should undertake a multi-year program that collects, corrects, digitizes and effectively manages all relevant design, construction and operating data for the gas transmission system.

5.4 Pipeline Integrity Management Plan

5.4.1 Background

Natural gas pipeline engineering design employs, at its core, the concept of *zero significant incidents.* That is, if a pipeline is constructed, operated and maintained according to its design, then it should operate without safety risk to the public – notwithstanding that it transports a combustible product within its walls. Because the pipeline is buried, direct inspection on an ongoing basis is not capable of being carried out. Thus, it is essential that an operator maintain a virtuous cycle that contains the following elements, shown pictorially below.[53]

Figure 9 – Zero Incident Goal

To address the risk of pipeline failures, the Pipeline Safety Improvement Act of 2002 directed PHMSA to establish a Pipeline Integrity Management Program (IMP). In response, PHMSA issued Subpart "O" containing Sections 192.903 to 192.949 on May

[53] The schematic shown here is a variation of the materials developed by the Interstate Natural Gas Association of America and adopted by its board-level pipeline safety task force in December 2010. A paper summarizing the concept of zero incidents was presented before PHMSA in March 2011 entitled, "Building Confidence in Pipeline Safety, A Strategic Plan by the Members of the Interstate Natural Gas Association of America."

26, 2004. This subpart established a risk-based assessment pipeline integrity management plan that requires operators of gas transmission pipelines to:

- Identify all the segments located in "high consequence areas" (HCAs) - areas adjacent to significant population or frequently used areas, such as parks to reduce the risks to the public in such areas.
- Collect and analysis data and information to identify the threats to the pipeline and conduct a risk assessment.
- Undertake baseline integrity assessments at all segments located in the HCAs within 10 years.
- Develop a process for repairing any anomalies found in these inspections.
- Reassess these segments every seven years thereafter to verify continued pipeline integrity.

The central tenets of pipeline integrity management include:

- Integrity management decisions and activities must be documented.
- A threat should be assumed to exist until it can be demonstrated otherwise.
- The re-inspection interval should be scheduled to ensure the integrity of the pipeline between inspections.

5.4.2 Findings

Integrity Management Program

PG&E was an early adopter in the application of risk management principles to pipeline integrity. PG&E adopted risk management principles prior to the issuance of federal regulations in Title 49 CFR Part 192 Subpart O, as evidenced by the approval date of its program in November 2001. PG&E's Pipeline Integrity Management Program, referred to as the Risk Management Plan (RMP), is composed of 15 sections. RMP Sections 1 - 05 deal with identification of threats and were developed in the late 1990s, RMP - 06 addresses the overall IM Program procedures and remaining sections, and RMP 07 -15 deal with individual related risk management subjects. Furthermore, PG&E applied pipeline integrity principles beyond that required by these regulations. A risk assessment was undertaken on all PG&E defined transmission pipeline, which is broader than that of the federal and state definition of transmission pipelines.

PG&E indicated it has met all of the specified compliance milestones in the regulations by specifically meeting certain due dates including:

- Adopting an integrity management program by December 17, 2004.
- Initiating the baseline integrity assessment no later than June 17, 2005.
- Achieving at least 50% of the most risky segments being assessed no later than December 17, 2006.

In addition, PG&E has stated it is also on track to complete a baseline assessment on the all covered gas transmission pipeline segments by December 17, 2012.

However, the CPUC conducted an audit of PG&E's IMP in 2010, which had two overriding findings. First, PG&E was diluting the requirements of its IMP through its exception process. Second, it appeared PG&E was allocating insufficient resources to carry out and complete assessments in a timely manner. So while PG&E asserts it is on schedule, the CPUC has raised a question about whether this is compliance in form or substance.[54]

Approximately 60 individuals are part of PG&E's integrity management program-wide staffing, while the integrity management core staff consists of 17 individuals. These individuals are responsible for the integrity of both transmission and distribution pipe. Of the four principal architects of PG&E's Risk Management Plan, only one is currently employed at PG&E.

Threat Factors

"The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has been analyzed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes. Each of the 22 causes represents a threat to pipeline integrity that shall be managed."[55] PG&E has taken the individual threats, except for internal corrosion and stress corrosion cracking, and developed four threat categories: External Corrosion, Third-Party Threat, Ground Movement and Design/Materials. Pipelines with internal corrosion or stress corrosion cracking are prioritized as high risk. For each threat category, PG&E has identified specific threat factors which are significant in determining the likelihood of failure. Of particular interest to the San Bruno Incident are the Design/Material and Third-Party threat categories.

The Design/Material threat category in PG&E risk model carries a 10% weight, based on a point system devised by PG&E. Points are based on criteria the PG&E Design Management Committee feels is significant to determining the threat's likelihood of failure due to each factor and relative severity of failure (leak-before-break versus

[54] Assuming that PG&E has correctly assessed the segments of the highest risk.
[55] ASME B 31.8S – Managing System Integrity of Gas Pipelines

rupture)[56]. The likelihood of failure is comprised of the following factors: Pipe Seam Design, Girth Weld Condition, Material Flaws or Unique Joints, Pipe Age, MOP vs. Pipe Strength, leak rate, and test pressure.

The Third-Party threat category in PG&E's risk model is weighted 45%. Similar to design/material threat, points are based on criteria the PG&E Third-Party Threat Committee feels is significant to determining the threat's likelihood of failure due to each factor and relative severity of failure (leak-before break vs. rupture). The likelihood of failure is comprised of the following factors: Ground Breaking, Damage Prevention, Ground Cover, Pipe Diameter, Wall Thickness, Line Marking, MOP vs. Strength.

Neither the threat attributes nor the threat factors include pipe fracture toughness. However, the fracture toughness of the pipe is an important characteristic to establishing the critical flaw length associated with a pipe's leak vs. rupture failure mode. The greater the facture toughness the longer and deeper the flaw a pipe may tolerate without causing the pipe to rupture, all other variables being equal.

Appendix J provides a copy of the Design/Material Threat Factors and Attributes.

Third-Party Risk

In 2008, a project to replace an aged city sewer line crossed the segment of pipe that later ruptured at San Bruno. The fact a PG&E standby person was not at the jobsite at the time the pipeline was crossed, contrary to the integrity management policies of the company, was not reported at the time.

Even if the standby person had reported his absence, PG&E's third-party threat factor did not take into consideration the types of construction practice used by contractors crossing PG&E's gas transmission pipelines.[57] Regulations require operators to monitor for conditions that may affect the integrity of the pipeline and to take remedial action

[56] Severity of failure is described by the mode of failure, leak versus rupture. A pipeline leak results in a relatively small volume of gas escaping from the pipeline. A pipeline rupture is the process or instance of breaking open or bursting of the pipe resulting is a sudden and large release of gas. Whether a pipeline mode of failure is a leak or rupture depend on many factors including operating pressure, length of crack, depth of crack, material characteristics of the pipe and other factors.

[57] This project was undertaken by propelling a pipe bursting, and/or cracking and expanding device, and pulling a new pipe through an existing pipe. The process used a large cable that was hydraulically powered with a pneumatic percussive device that helped drive the pipe breaking device. Such winches and rod pushers/pullers can produce pulling forces of up to 75 tons and create significant vibration in the process. Residents in San Bruno reported that they could hear their windows vibrating during the time the work was going on. See Appendix N for additional information on pipe bursting construction technique.

whenever analysis indicates the need for corrective measures, but PG&E did not view the sewer line work as a threat.

PG&E considers third-party risk as risk imposed by direct contact with the piping. PG&E's third-party risk does not consider effects that might be caused by construction proximity without direct contact. In other words, it is possible a pipe can suffer structural damage even if there isn't a dent or damage to the coating or some other form of direct contact. Rather, external operations that cause excessive lateral or vertical deflection of the piping by incorrect back-filling procedures or by vibratory effects on soil movement and support can also threaten the integrity of a pipe. PG&E's methodology did not contemplate threats other than through actual third-party contact. Proximity disturbance effects such as vibration or deflection due to soil pressure were not considered.

The prevalence of third-party risk as a historical contributor to gas transmission pipeline failure and the known presence of a manufacturing or fabrication defect raise questions about the potential for threat interaction and subsequent risk quantification. The current additive approach to risk quantification in the PG&E IMP is inadequate to take into account the potential for multiplicative threat interaction. A simple example would be the potential for soil movement that might cause localized radial growth of a manufacturing seam weld defect. Third party or ground movement threats that interact with design or construction threats can be significant contributors to total risk; current risk model includes additive, but not interactive or multiplicative risk.

The breakdown in the field standby process deserves one further note. When the sewer contractor completed the project that crossed Line 132, he covered the pipe without a PG&E standby person present. Although the standby process failure was not discovered until after the incident, PG&E could have and should have required the contractor to re-expose the pipe. In interviews, PG&E staff was not certain that even if the sewer crossing had been immediately discovered, the company would have returned to expose the crossing. There was no way PG&E would know if the contractor damaged the pipe without re-exposing the pipe.

Multiple Threats

In PG&E's 2004 Baseline Assessment Plan, the threats identified for Segment 180 of Line 132 were external corrosion, third-party damage, incorrect operations, weather and other outside forces. Neither construction nor material threats were identified.

Materials specifications, construction practices, and knowledge of pipeline failure modes have evolved along with the industry. Much of this evolutionary knowledge is captured in changes to standards such as ASME (formerly ASA) B 31.8 and API 5L, regulations such as title 49 CFR Part 192, and industry practices such as Common Ground Alliance

and Gas Pipeline Technology Committees Guide for Gas Transmission and Distribution Piping Systems.

Where the susceptibility of a pipeline integrity threat is determined, PG&E's decision tree prescribes an appropriate threat assessment and mitigation per pipe segment. The process recognizes multiple assessment methods may also be appropriate for the same line-pipe segment depending on the number of, or type of threats being evaluated. Furthermore, multiple threats of concern on a single-pipe segment would increase the overall concern for the segment and thus raise its priority.[58] Figure 10 identifies which threats can be detected by various inspection methods.

[58] DR#96 – IRP_ 013-08 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_013-Q08Atch01-CONF.pdf - Description Of Pipeline 2020 Program Elements – PG&E

Figure 10 - Inspection Methods[59]

INSPECTION CONSIDERATIONS
(Based on ASME B31.8S-2004, Section 6)

Abbreviations:
EC – External Corrosion; IC – Internal Corrosion; SCC – Stress Corrosion Cracking
MFG – Manufacturer Defect; WLD – Welding Defect; EQP – Equipment Defect
TPD – Third-Party Damage; WEA – Weather Event; ICO – Incorrect Operations

Inspection Methods	Primary Threats								
	EC	IC	SCC	MFG	WLD	EQP	TPD	WEA	ICO
In-Line Inspection Tools									
Magnetic Flux Leakage, Std Res.	X	X							
Magnetic Flux Leakage, High Res.	X	X					X		
Transverse Flux	X	X		X					
Deformation or Geometry					X[1]		X		
Pressure Test	X	X	X	X	X	X			
Direct Assessment									
ECDA	X						X[3]		
ICDA		X							
SCCDA			X						
Confirmatory Direct Assessment[4]	X	X							
Other Methods									
Radiographic	X	X	X	X	X	X			
Ultrasonic	X	X		X	X	X			
Visual				X[2]	X[2]	X	X	X	X

Notes:
1. Detects wrinkle bends.
2. Should be combined with another assessment technique.
3. ECDA is an equivalent method to ILI.
4. Confirmatory Direct Assessment can be used for assessments conducted on no longer than seven-year intervals when re-assessments conducted using ILI, Pressure Test, or DA specified methods are scheduled to occur at intervals longer than 7 years, and when the threats of concern are external or internal corrosion.

PG&E's integrity management program is designed to assess for threats that exist or are anticipated to potentially materialize. Although manufacturing defects such as those associated with pre-70 electric resistance welded (ERW) pipe are known by the industry to exist; there is no public information prior to the accident in San Bruno of long-seam manufacturing defects in DSAW pipe. The inspection method that PG&E selected to affirm the presence of threats to and examine the integrity of Line 132 Segment 180, in both 2004 and in 2009, was direct assessment. Although this inspection method resulted in the direct examination of pipe, at selected sites along the segment, PG&E was not always able to validate the seam type[60].

Under the 2020 Pipeline Program, PG&E will go beyond current pipeline safety regulations by performing a strength test on all gas transmission segments, not just those required under the Code. Any pipe segment not previously tested will be tested under this plan or replaced if strength testing or an in-line inspection is not feasible. Any pipe segment tested, but not meeting the requirements of 49 CFR Part 192 Subpart J will be retested under this plan[61].

A portion of the section of pipe that failed at San Bruno was fabricated from several pups (short pieces of pipe). While PG&E is able to collect and retain data and information about the line

[59] ANSI/GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2009 Edition
[60] DR#32 – IRP_009-02 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_009-Q02Atch06-CONF.pdf - Write Ups From The Validation Digs (2004 – 2010) – PG&E
[61] DR#96 - IRP_013-08 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_013-Q08Atch01-CONF.pdf - Description Of Pipeline 2020 Program Elements - PG&E

pipe and other materials used in construction of pipelines, one issue that remains is inventory management, particularly material returned and stored by PG&E. Even today, whenever there are segments of pipe returned and removed from a location were pipe is stored; data about the newly installed pipe may be unavailable for integrity management purposes.

PG&E has not adequately monitored changes in design, material, construction, and operational consideration in its risk assessment. One example is line pipe. PG&E's Gas Standard A-34 – Piping Design and Test Recommendations, see Appendix K, provides specifications for commercially available steel pipe commonly used by PG&E today. Table B-4 reveals the current minimum wall thickness of 30", DSAW pipe, Grade X42 is 0.406[62]. The line pipe used to construct Section 180 of Line 132 was reported to be 30" diameter, DSAW seam, 0.375 wall thickness.

An internal Quality Assurance audit concerning PG&E's Damage Prevention Program revealed that "standing by" during construction was an issue.[63] It is a good industry practice to require a person from the utility be present whenever a contractor is crossing or working in close proximity to a gas pipeline in order to protect the public, employees, and pipeline from harm.[64] The audit assessed PG&E's system-wide fieldwork carried out in the second quarter of 2009 and disclosed numerous inadequacies, including the following findings:

- The damage prevention process to protect gas critical facilities is inadequate. There is no formal or consistent process to document standby activities, potentially leading to stand-bys not being performed.
- Fifty-seven percent (8 of 14) of tickets tested for "No Standby" showed data entry errors in IRTHnet. Additionally, due to incorrect IRTHnet entry, a required standby was not performed.
- There is no formal process for follow-up with excavator when a call for Standby is not received.

In addition, in an Engineering Operations, System Reliability & Sustainability, Quality Assurance (EO SR&S) Quality Assurance Final Report[65] dated March 18, 2010 concludes that Standby personnel did not inspect buried gas facilities when exposed and A-forms were not being

[62] PG&E Follow-up to questions posed during meeting held January 12 and 13, 2011, Letter dated January 21, 2011 to the Independent Review Panel.

[63] DR# – 46 – IRP_010-10 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_010-Q10Atch01-CONF.pdf - Internal QA Audit, Damage Prevention Program, CONFIDENTIAL

[64] Title 49 CFR §192.935 requires monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502–2008. This requirement became effective October 1, 2010

[65] DR#46 – IRP_010-10 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_010-Q10Atch01-CONF.pdf - Internal QA Audit, Damage Prevention Program, CONFIDENTIAL

completed when pipe is exposed during standby. Corrective action led to a revision of the A-forms, but no corrective action with respect to training Standby personnel about what to inspect or how to inspect was made.

In several interviews, it was mentioned that either there was inadequate field staff to perform standby activities properly (meaning being present throughout the entire time the pipeline was exposed during third-party construction) and/or that needed communications with the pipeline engineers was not taking place. These statements indicate that despite the standby process being a part of the integrity management, the resources are either not available to meet the requirement and/or employees do not appreciate the significance of the standby inspection requirement. Moreover, field communications are not differentiating the types of third-party work that are ongoing and how they might present new threats.

Automatic Shut-down Valves and Remote Controlled Valves

PG&E is required to conduct a risk analysis of all pipelines within HCAs, and determine for each applicable threat on each covered segment additional measures to protect the integrity of the pipeline and enhance public safety. Such additional measures include installing Automatic Shut-off Valves (RSV) or Remote Control Valves (RCV). If PG&E determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, PG&E must, at least, consider the following factors: swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.[66] Appendix L provides addition information about RSV and RCV, as well as references. As discussed in our review of the Pipeline 2020 plan, PG&E has not conducted sufficient analysis of alternatives to conclude that an investment in ASV's or RCV's would be the preferred way of enhancing safety.

5.4.3 Conclusions

PG&E's executives have not provided effective pipeline integrity leadership and have not established pipeline integrity as a core value horizontally and vertically across all of its utility operation. External and internal events over the last decade have undermined PG&E's initial industry leadership in pipeline integrity management. These events include the corporate bankruptcy, transformation initiative, numerous reorganizations and other efforts that streamlined its organization. The outcomes of these events stagnated the pipeline integrity management program and related process advancement.

[66] GPTC Guide For Gas Transmission And Distribution Piping Systems, Additional Preventive And Mitigative Measures (§192.935(a) and (c))

The old saying we "learn from our mistakes," is critical to understanding what has failed at PG&E. Many factors attributed to the longevity of Line 132 in San Bruno, such as pipeline coating, cathodic protection, regular surveys, and its operating pressure. However, this segment represented a number of threats throughout its life, such as:

- Inherent weakness due to field-fabricated bends using a series of pups.
- Failure to adequately inspect the construction and detect the incomplete weld.
- Decision to allow urban/suburban encroachment along the pipeline right-of-way.
- Failure to recognize the impact of changes in policies, processes, and procedures on vintage facilities.
- Failure to analyze whether adjacent construction posed a threat.
- Failure to standby when the pipeline was excavated and backfilled.
- Failure to collect, retain, and analyze data and information that would exclude threats.
- Failure to identify and model multiple threats to Segment 180 Line 132.
- Failure to select multiple inspection techniques to assess each identified threat.

The fact the line pipe DSAW seam type was incorrectly recorded as "seamless" is symptomatic of PG&E's inadequate quality control and quality assurance management. The failure to properly document the seam type designation as DSAW, rather than seamless is not sufficient in itself to have prevented this incident, but had the records been more complete and the characterization been part of a more refined threat identification process, then the tragedy might have been avoided. Without a quality assurance program embedded in the integrity management process– and a feedback loop when anomalies are uncovered or pipelines do fail, mistakes happen. Unheeded lapses in the end-to-end process of pipeline integrity can lead to accidents like San Bruno.

The lack of data to characterize a significant portion of PG&E's pipeline remains a critical gap. PG&E must do a better job of filling in the gaps in its data regarding material inventory management. This includes the ability to trace the location and specifications of any material used in the construction and the operation or maintenance of a gas pipeline throughout its life cycle, from requisition, manufacturing to retirement.

Finally, it is important PG&E as an operator with gas transmission and distribution systems tailor its integrity management efforts to address the threats on a more specific basis. Integrity management staffing appears to be adequate to handle the transmission system; however, mixing transmission integrity management and distribution integrity management in the same group has mixed benefits.

The recent reorganization to create a gas business reporting to a senior vice president of gas operations should raise the level of gas issues, concerns, and needs within the company. However, in the Panel's opinion, transmission and distribution integrity management programs should be separately developed and implemented. These two programs are not adequately mature to be integrated. Furthermore, the resources supporting these programs, including organizationally, should be separate, providing dedicated resources to manage and execute these programs. Program integration may be considered once both programs have matured and financial benefits of an integrated program will not outweigh program effectiveness.

5.4.4 Recommendations

5.4.4.1 The pipeline and distribution integrity management programs should be separated organizationally with dedicated resources to manage and execute both programs.

5.4.4.2 PG&E should conduct a staffing and skills assessment of the integrity management group to determine if the organization would be better able to maintain its focus and accomplish its complex mission that would with an alternate structure.

5.4.4.3 PG&E should establish a capital program, based on risk criteria, that includes retrofitting existing pipelines, as appropriate, to accommodate ILI tools. ILI surveys provide additional information about the condition of the pipe that enable better decisions regarding remediation, prevention, and mitigation such as monitoring, inspection, repair, replacement, and rehabilitation.

5.4.4.4 PG&E needs to establish a culture of pipeline integrity that enable field and staff to encourage self-reporting of deviations from company policies, processes, or practices. CPUC pipeline safety inspectors should view self-reported deviations as nonconformance rather than noncompliance.

5.4.4.5 PG&E should develop and adopt a maturity framework that reflects the importance and advancement of thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise, where progress is transparent and measurable, and is consistent with the best thinking on pipeline integrity and process safety management.[67]

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[67] The Capability Maturity Model framework has been applied in engineering, manufacturing and safety processes in other industries with high degrees of technical requirements and safety risk, such as in aviation and defense. See, for example, http://www.baesystems.com/CorporateResponsibility/Safety/OurSafetyMaturityMatrix/index.htm or http://www.spqa-va.org/Assets/2010ForumPresentations/EffectiveBenchmarking-IndustrialTourist.pdf or http://www.dtic.mil/ndia/2005cmmi/tuesday/banerjee.pdf

5.5 Gas Operations, Gas Control, and PG&E's Emergency Response Background

In this section, Gas Operations, Gas Dispatch, Gas Control, and PG&E's emergency response are discussed, with a focus on the respective organizational roles as well as the structure of PG&E's Emergency Response Plans.

Gas Operations is part of the Energy Delivery organization. Gas Operations responsibilities include scheduling work in construction schedules, ensuring prerequisites are met like material availability, permits or traffic control, completes assigned tasks, performs QA/QC and completes paperwork to prove completion and compliance.

Gas Dispatch is part of the Customer Service organization. Gas Dispatch is a centralized group that dispatches gas service representatives (GSR's) 24/7. GSRs are the first responders to calls of gas odors and gas leaks, but are not generally trained or qualified to work on the high-pressure pipeline system. If a situation where an emergency service is needed -- for example, the fire department -- the GSR will contact the gas dispatchers who will, in turn, contact the emergency service provider. If excavation or construction is required, Gas Dispatch will contact Gas Operations to dispatch a crew.

Gas Control is part of the Engineering and Operations organization. Gas Control is an organizational unit within Gas System Operations reporting to Engineering and Operations. Gas Control utilizes a supervisory control and data acquisition (SCADA) to monitor and control gas pressures, temperatures, flows, and quality throughout the transmission network and portions of the distribution network. Gas Control is also responsible for managing the pipeline systems inventories and coordinating clearances for maintenance, integrity management and other activities affecting the system. During an incident Gas Control analyzes data from surrounding SCADA sites to determine the location of the involved facilities, assesses its ability to take remote control action and the need to have field personnel on site to resolve the abnormal condition and initiates emergency call out communication to appropriate management and field personnel.

5.5.1 Findings

- Gas Control, when it becomes aware of an abnormal operating conditions situation through SCADA or some other means, analyzes the data from surrounding SCADA points to determine the location of the incident and facilities involved.
- During the San Bruno Incident, Gas Control used operating maps and diagrams, and data from the SCADA system along with input from the field to determine the location of

the ruptured pipe. Gas Control also worked with field personnel to determine which valves on Line 132 were to be closed to isolate the rupture.[68]

- In the response to the San Bruno Incident, PG&E activated the Emergency Operations Center (EOC) per the Company Emergency Plan. The EOC sets response priorities and objectives. In addition, PG&E activated the Peninsula Division Operations Emergency Center (OEC), per the Peninsula Division Gas Emergency Plan. The OEC implements the EOC objectives in the field and requests, as needed, assistance from the EOC for logistics, customer strategy, and coordination issues.
- PG&E activated the EOC, the Peninsula Division OEC, and the Gas Restoration Center (GRC) during the San Bruno Incident.
- One hour and twenty-nine minutes elapsed from the time of the incident until the first valve was closed at Martin.
- Based on a review of the Gas Control Operator Logs[69] from the NTSB investigation, there appears to have been a significant amount of confusion as to the location of the incident, its severity and the mitigation efforts required. For example:
    - Incident occurred at 6:11 P.M.
    - The first valve was closed at Martin at 7:40 P.M.
    - The mile point of the affected segment was identified at 7:53 P.M.
    - There seemed to be some level of difficulty in reaching involved personnel (messages were left on voicemails).
    - There is uncertainty there was a controlled process to dispatch resources to mitigate the effects of the explosion. Only the gas service representative who was in the San Bruno area was contacted initially by Gas Dispatch to move to the incident area. The supervisor reported he was not dispatched and the two valve technicians were already on their way to the work center when Gas Dispatch reached them.[70]

PG&E's corporate ERP is comprehensive, embodies many current best practices, and is revised and tested on a frequent basis.

As part of its incident command structure (ICS), PG&E has, in addition to the EOC, four Regional Emergency Command Centers and 19 Division Emergency Command Centers, plus San Francisco.

[68] DR_IRP_011-Q06
[69] DR_IRP_016-Q09Atch01.pdf
[70] DR_IRP_016-Q09Atch02.pdf

There appears to be fragmentation in coordination between the corporate ERP and those at the Divisional level. The plans are structurally different in look and feel. This could be a source of confusion during emergencies.

Some gas transmission lines transverse several Divisional territories, for example, lines L-101, L-109, L-132 traverse Peninsula and San Francisco Divisions. Without clear physical segment assignment, confusion could result during a major event.

There are also some inconsistencies between the corporate ERP and the Peninsula ERP; for example, the corporate ERP denotes three distinct levels of escalation, while the Peninsula refers to levels numbered with Roman Numerals up to Level IV.

- PG&E is evaluating emergency response best practices[71] including:
  - *Statewide Emergency Response Plan* – This concept is being evaluated to consider partnerships with public agencies, including the California State Fire Marshal, and other California utilities, including a sister utility.
  - *Enhanced Emergency Training and Training* Scenarios – PG&E has conducted initial benchmarks and analyses of programs or practiced utilized by other utilities and is reviewing training programs offered by Southwest Gas.
  - *Deployment of Mobile Command Center* – PG&E is investigating the benefits of adopting a mobile command center as utilized by a major Eastern utility.
  - *Integration of Public Safety and Damage Prevention, Emergency Preparedness and Emergency Restoration* – PG&E is considering an emergency response model that incorporates all these efforts; benchmark data suggests that other utilities have adopted such an approach.
- As part of Pipeline 2020, PG&E has issued an RFP for services related to enhancing their emergency response plan(s) both at the corporate level as well as at the divisional level.
- PG&E has requested the CPUC to schedule workshops intended to strengthen emergency response procedures, with attendance to include all affected stakeholders: first responders, local, and state agencies and other utilities, CPUC staff and concerned citizens to develop emergency response procedures that represent national models.[72] In this regard, PG&E has initiated expanded collaborations with first responders for both gas and electric.

[71] DR_IRP_012-Q08
[72] DR_IRP_016-Q05Atch01

5.5.2 Conclusions

PG&E's Company Emergency Plan at the corporate level is complete, thorough, and contains many best practices. However, when the regional and division plans are compared their structures are dissimilar and the content between the plans does not flow.

PG&E's ability to respond to the San Bruno Incident was hampered by a SCADA malfunction and the fact there are fewer than optimal SCADA pressure points on its transmission system adding to a delay in determining the location of the incident.

Gas Control by relying on operating maps and diagrams does not have the decision tools in place to quickly analyze the situation. This also added to the significant amount of confusion as to the location of the incident and PG&E's ability to respond.

PG&E was fortunate that conscientious workers took it upon themselves to respond without being dispatched to the area and to decide which valves needed to be closed to shut off the supply of gas.

5.5.3 Recommendations

5.5.3.1 Review and restructure all division, regional and company emergency plans for consistency in presentation and feel, while incorporating best practices observed from Pipeline 2020.

5.5.3.2 Conduct a study of SCADA needs to achieve enhanced gas transmission system knowledge that would enable improved shutdown capabilities in the event of a future pipeline rupture. Study to include: (1) the visibility of the transmission operations to system operators, (2) the ability of automation to sense line breaks, (3) the ability to model failure events; and (4) the capability to transmit schematic and real-time information to pipeline field personnel.

5.5.3.3 When study of SCADA needs is completed (described in Recommendation 5.5.3.2), establish a multi-year program to make implement the results of the study.

5.6 Capital Investment

5.6.1 Background

PG&E expenditures on gas transmission infrastructure were reviewed, primarily from 2000 to 2009. Over this period, the principal category of safety-related capital work on the transmission infrastructure was "Pipeline Safety and Replacement." This consists of the Major Work

Categories (MWC); Gas Transmission Reliability – Pipeline (MWC75)[73] and Pipeline Integrity Program Management (MWC98).[74]

Pipeline Safety and Replacement expense consists of three principal categories:

- Integrity Management Program - covers the expense portion of TIMP, including the cost of assessments and reassessments using ILI, direct assessment (ECDA), or pressure testing.
- Gas Transmission System Maintenance - covers a wide variety of safety and maintenance-related expenditures, including the expense portion of the RMP as well as other transmission pipeline, compressor, and storage field maintenance work.
- Mark and Locate - covers the costs associated with marking and locating gas transmission facilities to protect against third-party dig-ins and the costs for standby activities during third-party excavations in close proximity to gas transmission lines.

Through the above period, the principal pipeline safety related programs were:

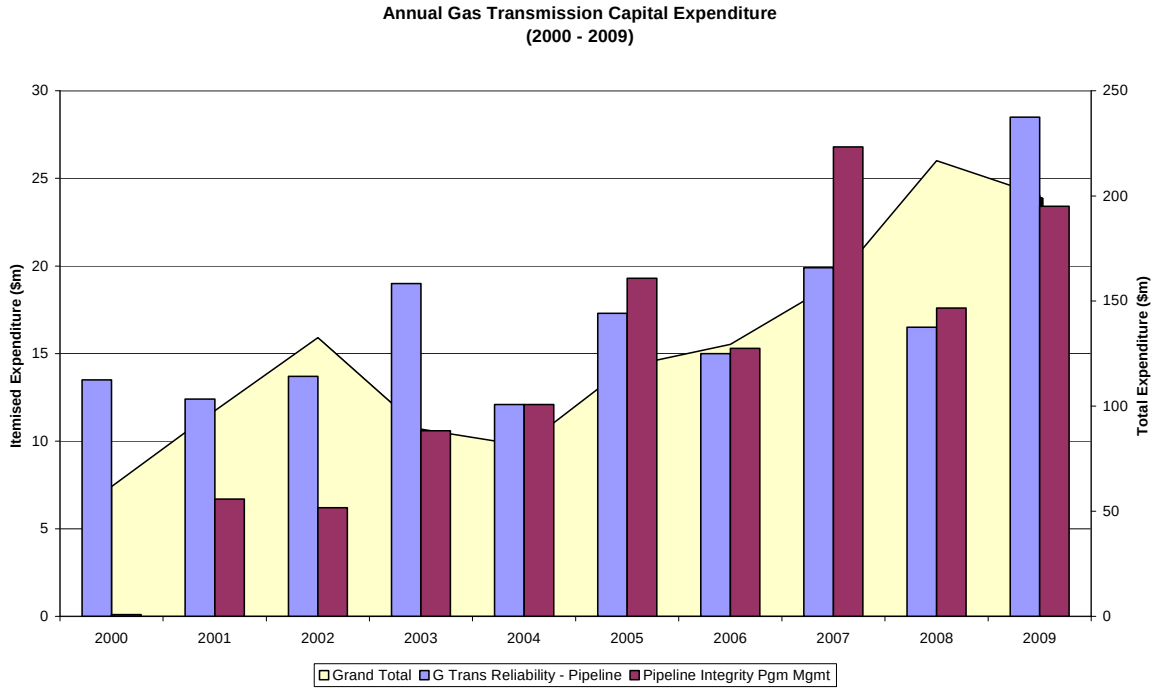
- The Gas Transmission Facilities Risk Management (2000-2006)
- Transmission Integrity Management Program (2004 forward)

Overall, capital spending under the above category alongside Pipeline Safety and Replacement spending is shown in Figure 11 below:

[73] MWC75 - covers a broad range of capital expenditures to improve the safety and reliability of the gas transmission system. This includes pipeline replacement under the RMP and the replacement of pipeline within an HCA; all other capital expenditures for the RMP (e.g. preparing non-HCA pipes for ILI); cathodic protection (e.g., replacing deteriorated or failed pipeline coatings); replacing equipment within gas regulator stations; and other pipeline reliability projects.

[74] MWC98 - covers capital expenditures for TIMP, including, in particular, retrofit work to prepare pipelines for ILI. The replacement of any pipeline within an HCA (or elsewhere on PG&E's gas transmission system) is included within MWC 75.

Figure 11 - Annual Gas Transmission Capital Expenditure

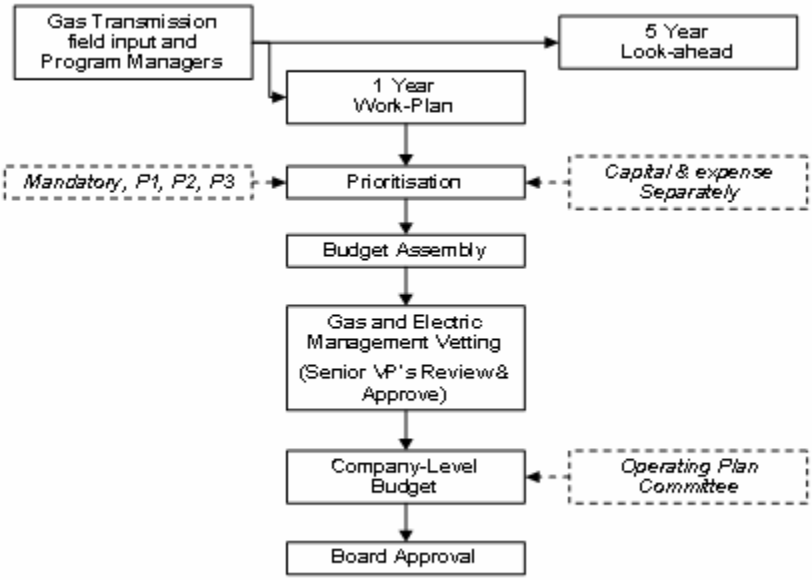


PG&E's general budgeting process is summarized in Figure 12 below. It should be noted, in the budgeting process, until the "budget assembly" step, gas transmission work is not combined with gas distribution or electric work. Also, PG&E budgets and prioritizes capital and expense requirements separately.

For the purposes of prioritization, work is categorized according to the risk of not funding as follows:

- Mandatory: Work that is required to maintain system safety, mandated by rule or regulation (e.g., CPUC or PHMSA), or is essential to maintaining the company's business operations.
- Priority 1: Work that is deemed critical to the company's operational goals and could not be deferred without impact to system operations or reliability.
- Priority 2: Work that is closely related to the company's operational goals but could be deferred.
- Priority 3: Work that would assist the company in achieving its long-term objectives fully.

Figure 12 - PG&E Budgeting Process



5.6.2 Findings

PG&E's reported transmission and gathering system mileage has remained reasonably constant across the whole period reviewed (5,900 miles +4% / -2%).

Replacement or retirement of transmission assets was ongoing through at least 2006, totaling 56 miles over seven years, and no data were available for years 2007-2009. Through 2006, replacement or retirement occurred at a relatively low level, averaging less than 0.2% of total system length per annum.

PG&E's future plans, as stated in Vision 2020, propose a significant acceleration of replacement through 2014, at an average of around 70 miles per annum.

Total transmission "risk reduction expenditure," which can be defined as transmission- related capital plus expenses rose over the period 2000 through 2006 from $14.1M to $36.2M.

Pipeline Safety and Replacement Capital accounted for 24% of capital expenditure over the period, averaging $30.6M per annum. Annual expenditure spanned a range from 15 to 33% of total Gas Transmission Capital expenditure. Annual expenditure on Pipeline Safety and Replacement Capital has grown at a slightly greater rate than total capital expenditure over this period.

The Gas Transmission Facilities Risk Management program transitioned to Transmission IMP 2004 forward; detailed reporting on transmission replacement or retirement under IMP is not currently available. It is not clear whether no transmission replacement has been carried in years 2007-2009, as those data were not available from IMP to clarify.

Pipeline Safety and Replacement Expense figures were available, but Mark and Locate figures only cover the period from 2003 through 2009 (note Mark and Locate accounted for less than 5% of total expense over the period 2003 through 2009).

Annual Transmission expense averaged $63.5M from 2003 through 2009 on a rising trend, increasing 44% over the period.

Integrity management program expenses accounted for 15% of expense overall, but expenditure was heavily biased towards the latter years of the period. Integrity management program expense rose from $1.6M in 2000 to $15.5M in 2009.

PG&E entered Chapter 11 bankruptcy in April 2001 and emerged from bankruptcy in 2004. Throughout this period, the company's budgeting and planning process did not materially change. The major additional requirements during the bankruptcy period were for PG&E to provide periodic information to the bankruptcy creditors' committee on several of its capital projects. PG&E also was required to obtain Bankruptcy Court approval for all new projects with an anticipated cost of $50M or more.

Pipeline Safety and Replacement spending as a proportion of total capital expenditure fell from 2000 through 2002, but more than recovered in the subsequent years of the bankruptcy period.

PG&E's budgeting processes operate on a "bottom-up" basis, where initial requests are generated by the originating organization. When projects compete for discretionary capital, those decisions are escalated to senior management in a competitive presentation process. In that process, gas versus electric projects compete for budget allocations.

5.6.3 Conclusions

Gas Transmission replacement or retirement was carried out at a relatively low level (< 0.2% of system total miles per annum) from 2000 through 2006. This low level of replacement is consistent with industry practice across North America based on consultant's knowledge and input from several other operators.

Transmission safety investment per mile (capital and expense) was on an increasing trend throughout the period.

No significant changes in spending trends were noted during the bankruptcy period of 2001 through 2004.

The capital investment by PG&E in the gas transmission pipeline system has been minimal. There was no plan to modernize the system and seek opportunities to improve the risk associated with operating the system. Instead, the focus was to provide funding to ensure compliance with the Pipeline Integrity rules.

5.6.4 Recommendations

5.6.4.1 PG&E should take a fresh look at the budgets for pipeline integrity efforts and make informed judgments about how to address the quality and timeliness of efforts to improve its system.

5.6.4.2 PG&E should establish a multi-year program that deals with all the capital requirements to assure system integrity, based on sound risk criteria (i.e., a methodology that addresses the likelihood of various possible failures given competing alternatives). This program would include:

- Investments to collect, correct, digitize and effectively manage all relevant design, construction and operating data for the gas transmission system.
- Investments to retrofit existing pipelines to accommodate in-line inspection technology, to test or replace uncharacterized or anomalous pipe has needed, and to reroute pipe in the HCAs where accessed.

5.7 Pipeline 2020 Program

5.7.1 Background

On October 12, 2010, PG&E announced Pipeline 2020 as a program to guide the utility's efforts to strengthen the natural gas transmission system and to advance industry best practices over the coming decade. The press release further described Pipeline 2020 as a program to augment a series of safety and reliability initiatives that PG&E had begun or expanded in the wake of the San Bruno Incident. The program was described as going well beyond regulatory requirements and "will guide PG&E in fulfilling our pledge to customers and the public to ensure the safety and integrity of our gas transmission system." The program is to focus in five areas:

- Pipeline modernization.
- Expansion of the use of automatic/remote shut-off valves.
- Advancement of state-of-the-art pipeline inspection technologies.
- Development and implementation of industry-leading best practices.

- Enhancement of public safety partnerships.

5.7.2 Findings

PG&E in its press release stated, "We're not waiting for the regulators, we are charging ahead, leading the industry once again in pipeline safety." In addition, the press release goes on to state "Pipeline 2020 raises the bar for the entire industry."

On PG&E's website, there is a video[75] of the public announcement of Pipeline 2020 where PG&E elaborates on the published press release. In the video, PG&E reasserts it will be "leading the industry once again in pipeline safety" and that the program "raises the bar for the entire industry." Pipeline 2020 is expressly stated to be a program for the entire industry, describing the speed of action as desirable. Despite the fact the root cause(s) of the incident had not yet been determined, the company stated, "these are no-regret actions, aimed at advancing best practices across the industry."

In the video, PG&E's stated its intention to dedicate $10M of shareholder money to establish a non-profit to begin work on research and development in the area of pipeline inspection techniques.

The video further indicates details are to be worked out with regulators, third-party experts and "others."

Given the scope of Pipeline 2020 that indicated in the press announcement, the panel requested a copy of the complete plan. The document was made available in response to the data request was entitled "Description of Pipeline 2020 Program" and addressed only two of the five areas of focus -- system modernization and automated valves.[76]

The document characterized itself as a "roadmap" as to how PG&E proposes to evaluate and implement the modernization of its pipeline system and the installation of automated valves. The plan defines PG&E's objectives, the criteria to be used, and the priorities it has set related to its pipeline assets. The plan includes:

- Extensive hydro testing of certain pipelines where safety factors may be unknown.
- Acceleration of the replacement of at-risk pipe.
- Improvements to the SCADA gas control system.
- Installation and upgrading of automatic and remote control valves.

[75] http://www.pgecurrents.com/video/pipeline-2020-program/

[76] DR#96 - IRP_013-08 - SanBrunoGT-LineRuptureInvestigation_DR_IRP_013-Q08Atch01-CONF.pdf - Description Of Pipeline 2020 Program Elements - PG&E

The plan does not project any cost associated with the execution of the plan nor does it set any specific goals or key performance indicators to monitor the progress and effectiveness of the program.

In the previous years where budget and planning documents were reviewed, there were no revenue requirements requests developed that would have supported Pipeline 2020 efforts. All pipeline investments for safety in prior years were for mandatory compliance with the applicable codes.

The plan announced is an approach as to how to assess and execute improvements to PG&E's pipeline assets, expand the use of automated valves, advance state-of-the-art pipeline inspection technologies, develop and implement "industry-leading best practices" and "enhance public safety partnerships."

Evidence in the NTSB hearing indicated PG&E's engineering department analysis did not support the use of automated shut-off valve. We saw no information PG&E has evaluated changes to the configuration of the transmission system to accommodate remote-controlled valves or has analyzed the other alternative investments that could be made to enhance system control.

The document presented only addresses a strategy for system modernization and the installation of automated valves. Further, it does not express any vision for PG&E's gas transmission system of the future, just a strategy for confirming compliance, and for expanding the use of automated valves.

5.7.3 Conclusions

PG&E has taken a proactive approach to the needs of its transmission system improvements; however, it is a reaction to the events of San Bruno and should be better defined.

Before the development of the Pipeline 2020 plan, there has been no evidence of any attempt or long-term investment strategy by PG&E related to these assets.

The Pipeline 2020 document is better described as an "execution" plan containing technical approaches and decision methodologies to provide guidance, but focused largely on confirming and exceeding regulatory code compliance.

There is no clear vision expressed by the senior management of PG&E as to what the PG&E transmission pipeline system of the future should look like, and, therefore, no overall guidance as to what objectives and measurable goals the 2020 Program is designed to deliver other than compliance.

The current approach does not ensure the monitoring of the program's effectiveness and cost by both PG&E management and the CPUC. It does not allow for shifts in the plan as results and targets are made or missed.

5.7.4 Recommendations

5.7.4.1 PG&E should restructure the Pipeline 2020 document to enhance effectiveness and assist in monitoring for both PG&E and the CPUC, by incorporating the following:

- Vision Statement, which will describe "the transmission pipeline system of the future." This should be a clear statement as to how PG&E sees the role of the transmission system of the future. This will facilitate decisions made in the strategic parts of 2020 that can be focused and relevant to more than just compliance. It should demonstrate the asset profile, and how it will support safety, and operational goals. PG&E should identify specific measures to define what an effective program will deliver.
- Delivery Strategies, which will set out the goals of the strategy and steps to deliver the vision. The delivery strategies should be fully developed based on other recommendations for pipeline integrity management and related improvements.
- Execution Plan, which will define the tasks to be accomplished, how they will be accomplished, an associated timeframe and projected costs.
- Analysis of Alternatives, which will document various alternatives considered, complete with costs and consequences. A thorough analysis of alternatives will ultimately result in support of the program.
- In lieu of or in addition to R&D funding for new technology, entertain reasonable opportunities to serve as a testing ground for improved ILI technology.

5.7.4.2 The CPUC or its designated consultant should review the plan and collaborate with PG&E in the development of clear objectives, measures, and schedule.

6.0 Review of CPUC Oversight

6.1 Introduction

There are three pipeline safety regulators in California:

- The CPUC, who regulates most intrastate natural gas pipelines, including distribution and transmission lines.
- The Office of the State Fire Marshal (OSFM), who regulates intrastate hazardous liquids pipelines.
- PHMSA, who regulates interstate gas and hazardous liquid pipelines, and municipally-operated intrastate pipelines.

CPUC Gas Pipeline Safety Program

The CPUC's Consumer Protection and Safety Division (CPSD), via the Utilities Safety Reliability Branch (USRB), regulates safety and inspects gas pipelines. The CPUC derives its pipeline safety authority from federal requirements as well as the California Constitution and Public Utilities Code. The USRB administers federal requirements pursuant to an annual certification to PHMSA and the additional state requirements contained in GO-112E.

The USRB gas section performs audits of gas transmission and distribution utilities, propane distribution systems, and master-metered gas systems in mobile home parks. USRB audits consist of tabletop records reviews and field inspections for compliance with PHMSA gas pipeline regulations, the additional requirements of GO-112E, and specific state statutory requirements for gas distribution systems in mobile home parks and propane systems.

Detailed information on the CPUC's pipeline safety authority is in Appendix O.

Office of State Fire Marshal's Program

The Office of the State Fire Marshal (OSFM) Pipeline Safety Division is directly responsible for regulating the safety of approximately 4,500 miles of intrastate hazardous liquid transportation pipelines. The Pipeline Safety Division performs inspections and investigations to ensure intrastate operators are in compliance with all federal and state pipeline safety laws and regulations. The Pipeline Safety Division consists of engineers, analytical staff, and clerical support located in Sacramento, Middletown, Bakersfield, and Lakewood.

The Division is mandated by state law[77] to exercise exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines and also to act as an agent of the PHMSA in the inspection of interstate pipelines. The OSFM regulates 46 intrastate operators and inspects nine interstate operators on behalf of PHMSA. The State Fire Marshal established a Pipeline Safety Advisory Committee for purposes of informing local agencies and every pipeline operator of changes in applicable laws and regulations affecting the operations of pipelines and reviewing proposed hazardous liquid pipeline safety regulations. The OSFM's pipeline safety program has been operated pursuant to a certification to PHMSA since 1981.

Every rupture, explosion, or fire involving a pipeline, including a pipeline system otherwise exempted, and including a pipeline undergoing testing, must be immediately reported by the pipeline operator to the fire department having fire suppression responsibilities and to the Office of Emergency Services. The Office of Emergency Services notifies the State Fire Marshal. The pipeline operator must, within 30 days of the rupture, explosion, or fire file a report with the State Fire Marshal.

Detailed information on the OSFM intrastate hazardous liquids pipelines is contained in Appendix P.

PHMSA's Role

PHMSA administers a national pipeline safety program pursuant to the Pipeline Safety Act. [78] PHMSA regulations apply to design, installation, construction, testing, inspection, integrity management, operation, replacement, and maintenance of pipelines, and the qualification of personnel who operate and maintain them.[79]

PHMSA has the authority to regulate both interstate and intrastate gas pipelines. However, through a state certification program, nearly all states, including California, regulate intrastate gas pipeline facilities pursuant to PHMSA's regulations. PHMSA also provides substantial grant funding and training to state programs; including the CPUC.

Detailed information on PHMSA's authority and role is in Appendix O

6.2 Responsibilities Resources and Staffing

6.2.1 Background

Below is the current organization chart for the Utilities Safety Reliability Branch.

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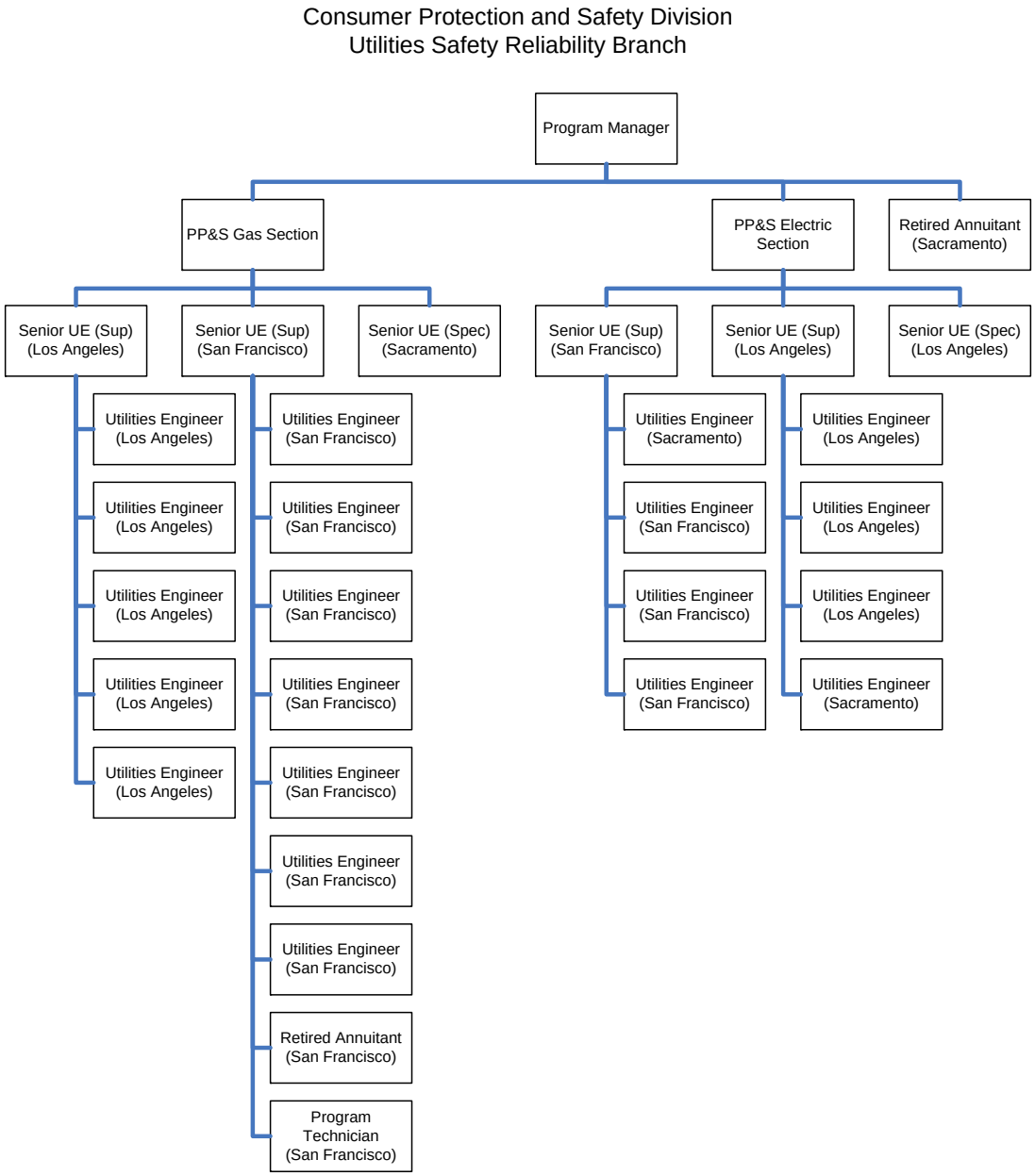
[77] CAL. GOVT. CODE §§ 51010-51019.1

[78] The Pipeline Safety Act, *as amended, codified* at 49 U.S.C. § 60101 *et seq.* (2006).

[79] 49 C.F.R. Parts 190-199 (2006).

Figure 13 - Utilities Safety Reliability Branch Organizational Chart



6.2.2 Findings

Within the past year, the USRB was reorganized into two distinct groups, gas and electric. Until this change was effectuated, the URSB staff was required to perform various aspects of regulatory oversight in both gas and electric utility operations. The rationale for this reorganization was due to the logical demands and different skills required for each of the utility areas.

The separation into gas and electric staff was achieved by soliciting who within the Division wanted to move to gas or electric. Thus, this process was not based on skills or performance, but the desire of the employee. The staff selections were divided as needed to fill the open positions in each area.

The USRB gas audits require a significant effort in both tabletop and field-related reviews on a regular basis. In addition, as discussed more fully in section 6.3, the branch must complete audits of approximately 3200 small mobile home operators and propane systems.

The CPUC Safety Division has currently allocated 18 positions, located in Los Angeles and San Francisco. The primary requirement for an applicant is possession of an engineering degree, but they do not need a professional engineering license.

There are currently two vacancies in the group, which have been very difficult to fill. Although the funding is available, the difficulty appears to be associated with the State of California's on-boarding process and the associated time delays, which can be as long as a year. In addition, the current financial issues within the state are a barrier to recruitment. Although the CPUC's funding is separate and not dependant on the state financial resources, the Commission is subject to the current mandates of the state and subsequent hiring freezes.

The 2004 implementation of PHMSA's Gas Transmission Pipeline Integrity Management regulations (49 C.F.R. Part 192, Subpart O) added significant new auditing requirements for the CPUC staff and a need for new skills and training. The audits, required under these new regulations, differ from the customary compliance audits required under the rest of Part 192. Most non-integrity management Part 192 requirements are prescriptive, and a well-defined compliance audit process is followed. The integrity management regulations are performance-based, requiring an in-depth analysis on the part of the auditor of the approach operators take to know, evaluate, and assess the risks in their pipelines and take appropriate mitigation actions.

To qualify for full PHMSA grant funding, USRB inspectors must eventually complete 24 PHMSA training courses on all aspects of Part 192. PHMSA offers the courses at no cost to state inspectors, but the CPUC must fund inspector travel to PHMSA's Oklahoma City training facility. In 2010, the USRB received all available points in its grant score for inspector qualifications. Nonetheless, due to state financial and travel restrictions and limited PHMSA course availability, it has been a challenge for USRB staff to obtain all necessary PHMSA integrity management training.

The training required to become a PHMSA-certified auditor for Pipeline Integrity can take several years to achieve and requires a significant time commitment. The staff currently has five

certified auditors. Although the Senior Managers in the organization are very experienced gas and electric engineers, neither has the pipeline integrity management certification.[80]

Training and resource needs are likely to increase in the near future, as the USRB will begin auditing operators for compliance with PHMSA's new Distribution Integrity Management Program (DIMP) starting in August 2011. In addition, the USRB may be expected to provide oversight for the hydrostatic testing program PG&E is initiating on 152 miles of transmission pipelines. The hydrostatic testing program resulted from PG&E not being able to document MAOPs on certain pre-1970 pipe.

6.2.3 Conclusions

Staff is dedicated and knowledgeable about integrity management concerns, despite lack of specific integrity management training.

Staff would like more resources and more expertise, which it believes can be gained by bringing on outside consulting support. Staff would like the ability to share its expertise among all utilities they audit.

To the extent the CPUC seeks to prioritize and improve integrity management oversight, additional funding resources for training are necessary. In addition, CPUC expertise could be improved if it could arrange for PHMSA to provide additional integrity management training opportunities, or training in different locations closer to California.[81]

Conducting audits of performance-based regulations like pipeline integrity management and distribution integrity management requires an understanding of not only the utility's system, but utility management and decision processes. The USRB engineers lack experience in current utility management and decision processes to enable them to ask the right questions. For example, while the engineers review processes and programs, they typically do not inquire at a detailed level about the utility's budgeting or resource allocation decisions, the information technology framework, or other aspects of the framework the utility uses to support its integrity management efforts.

The ability to audit gas pipeline integrity management programs effectively requires greater technical skills, knowledge of information systems, and more sophisticated analytical tools. The USRB has limited technical information systems and resources to enable them to manage, analyze, and trend data[82].

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[80] IRP Interview 01 USRB Staff

[81] PHMSA announced at a March, 2011 technical advisory committee meeting that it would be providing additional direct support to the CPUC with respect to pipeline risk assessment in California.

[82] IRP Interview 02 USRB Staff

The audit staff appears to be generalists. Greater specialization is necessary to perform comprehensive integrity management audits that will have meaningful impact on the companies audited. The recent reorganization of the group into gas and electric industry sectors is a good and important first step. Further specialization is necessary. Developing individuals to become specific subject matter experts in key areas of pipeline integrity, rather than general operations auditors, will increase the quality of the discourse between the regulators and the operators.

With the current staffing and recruiting issues, absent some major initiative, there is little evidence the focus on pipeline integrity management audits will increase and improve.

6.2.4 Recommendations

6.2.4.1 Adopt as a formal goal, the commitment to move to more performance-based regulatory oversight of utility pipeline safety.

6.2.4.2 Greater involvement by staff in industry groups such as the Gas Piping Technical Committee (GPTC) will better enable the CPUC staff to keep abreast pipeline integrity management advancements from a technical, process, and regulatory perspective. In addition, the CPUC can, through such forums, gain insight for pipeline operators, utilities, service providers, and professional services firms, as well as other federal and state pipeline safety professionals.

6.2.4.3 The CPUC should further divide gas auditing groups to create integrity management specialists.

6.2.4.4 Undertake an independent management audit of the USRB organization, including a staffing and skills assessment, to determine the future training requirements and technical qualifications to provide effective risk-based regulatory oversight of pipeline safety and integrity management, focused on outcomes rather than process.

6.2.4.5 Provide USRB staff with additional integrity management training.

6.2.4.6 Retain independent industry experts in the near term to provide needed technical expertise as PG&E proceeds with its hydrostatic testing program, in order to provide a high level of technical oversight and to assure the opportunity for legacy piping characterization through sampling is not lost in the rush to execute the program.

6.3 Auditing Capabilities

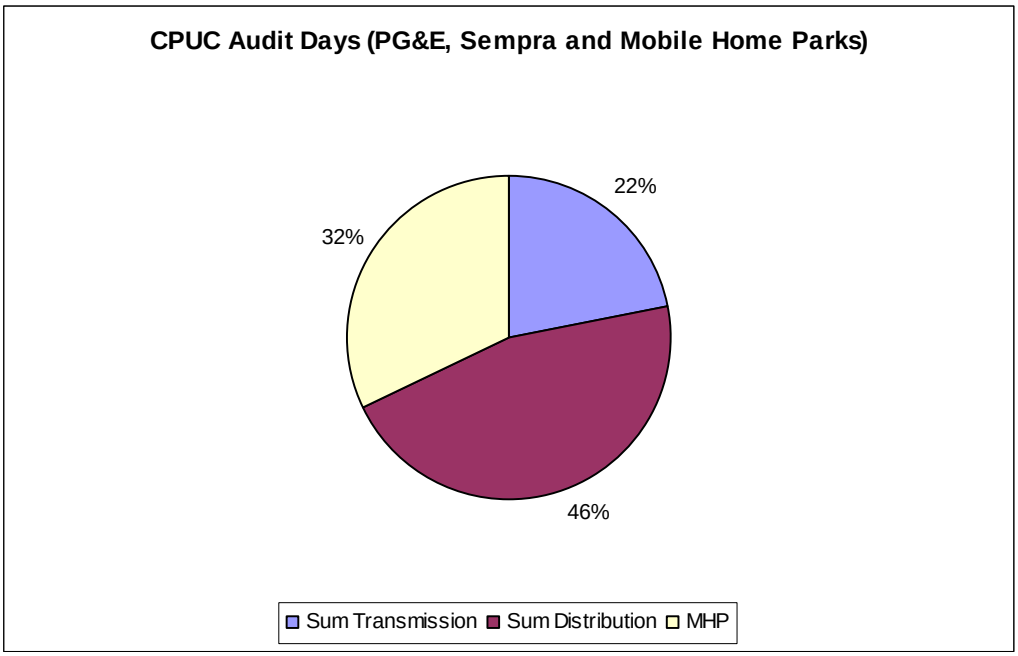
The CPUC regulates five intrastate transmission operators and more than 3,200 distribution operators in California.[83] The vast majority of distribution operators are mobile home park and

[83] 2009 CPUC Natural Gas Certification, Attachment 1.

propane systems. This large number of mobile home park and propane systems is unique to California. In addition, California law requires the CPUC inspect these systems on a minimum frequency of five years or less.[84]

The exhibit below shows the breakdown of how USRB staff is deployed across different types of pipeline systems. It depicts a strong emphasis on distribution systems and mobile home parks. Relatively fewer of the staff's scarce resources are currently focused on the transmission pipeline systems within the state relative to the small operator audits.

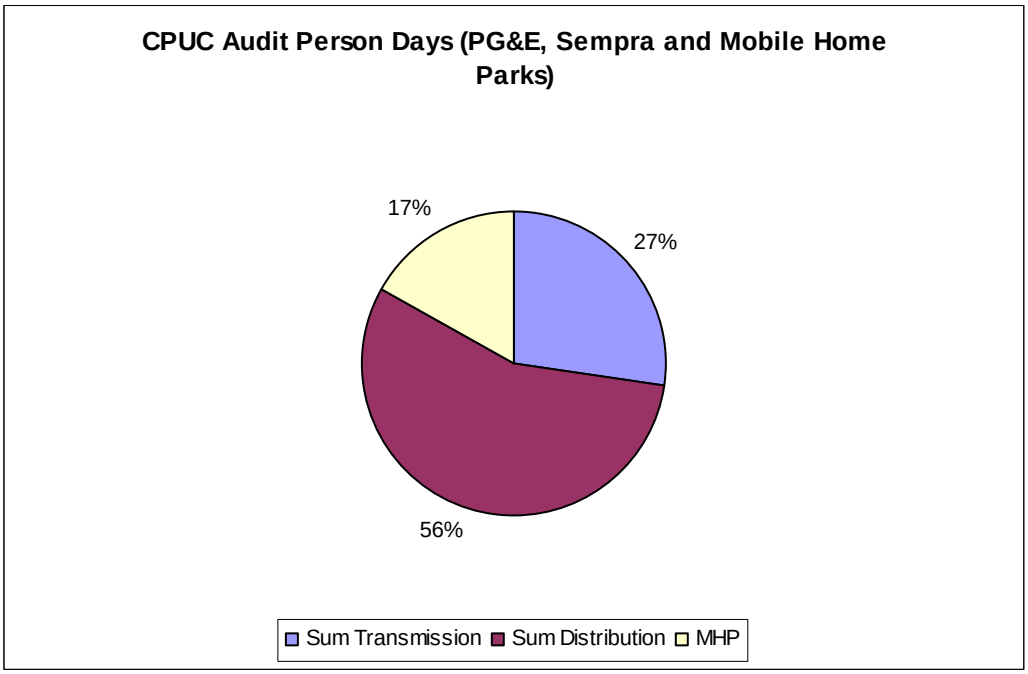
Figure 14 - CPUC Audit Days[85]



[84] CAL. PUB. UTIL. CODE §§ 4451-4465 (propane systems); §§ 4351-4361 (mobile home parks).

[85] DR#6 – San Bruno Independent Review Panel Data Request 3.doc – Number of days spent inspecting and auditing – CPUC.

Figure 15 - CPUC Audit Person Days[86]



As stated earlier, with the introduction of the new pipeline integrity rules in 2004, a new and more analytical type of audit process was added to the CPUC's auditing requirements. Since 2004, there have been two audits completed for each of the three major California intrastate pipeline operators.

The initial integrity management audit for PG&E was completed in 2005 and was characterized as a series of training exercises lead by PHMSA staff, which followed the PHMSA protocols. A second audit was completed in 2010, led by the CPUC staff that has been PHMSA-certified. The latter effort was described as a tabletop exercise, which focused on the compliance of the operators with their Integrity Management plans.

There were two overriding findings in the 2010 audit of PG&E. First, PG&E was diluting the requirements of its IMP through its exception process. The USRB audit noted various exception reports were routinely generated by the company to provide the basis for not performing certain activities which were required under PG&E's integrity management plan. Second, the staff noted it appeared PG&E was allocating insufficient resources to carry out and complete assessments in a timely manner.[87]

[86] DR#6 – San Bruno Independent Review Panel Data Request 3.doc – Number of days spent inspecting and auditing – CPUC.

[87] http://www.cpuc.ca.gov/PUC/events/110208_docs.htm

6.3.1 Findings

The existence of fixed, statutory USRB inspection intervals for propane and mobile home parks systems requires substantial inspection resources. No such intervals are required for other types of systems.

The scheduling of resources to perform audits is generally characterized as reactive.

The non-integrity management audits of operator compliance with the prescriptive requirements associated with transmission, storage, and distribution facilities lend themselves to traditional checklist audits, easy identification of noncompliance and issuance of noncompliance notices.

The current integrity management audits consist of predominantly tabletop exercises to assure compliance against a PHMSA checklist with little, if any, field related auditing.

The current frequency and nature of IM audits conducted by CPUC is consistent with those of PHMSA. PHMSA's approach to auditing interstate pipeline operators' integrity management programs was to first audit their written IM plans. The second wave of PHMSA audits, which the auditors are currently conducting, is moving towards more field-based audits of the program.

Pipeline integrity management regulations are a blend of technical (the integrity management plan) and management (performance plan, communications plan, change management plan, quality assurance plan) elements. While there is a prescriptive element in the pipeline integrity management regulations, the framework achieves pipeline safety through performance regulations. PHMSA has developed an audit protocol, which the CPUC follows in conducting pipeline integrity management program audits.

The audit methodology to date has been to follow the PHMSA guidelines and confirm the companies are in compliance. There has been discussion of migrating to an audit, which will define an "effective" program, but there is no plan to develop the process or what the plan should include.

The 2010 USRB Pipeline Integrity Management Audit was conducted in May of 2010. The audit results were presented to PG&E in late October, after the San Bruno Incident. The four-month turnaround to write up, to analyze the audit results, and make recommendations is unreasonable. The reason cited for the delay was USRB workload.

At the time of our interviews, the leadership of the USRB was considering accelerating the follow-up on integrity management audits from a previously planned five year to a three-year schedule. The specific rationale for the shorter intervals of the future audits was not clear. The content and approach for the future audits was not clear either, although it was stated those future audits should include more fieldwork.

Based on the relative inexperience of the staff in performing these audits and because there have been so few audits completed, it was noted there is a lack of historical data for each of the operating companies. Thus, there is little in the way of baseline information which can be used as to develop the focus for future audits. More importantly, there was no clear approach to development of a database or definition of the critical data that should be included in a data base for the purposes of analyzing the performance of the operators.

6.3.2 Conclusions

The CPUC conducts spot inspections of operator work. This can be an effective tool in assuring regulatory compliance, but less effective in achieving improvement in public safety and system integrity. A couple of additional approaches, which can be more effective, include:

- Selecting audits of locations presenting greater risk to public safety, property damage, pipeline integrity and environmental damage.
- Conducting a vertical audit where by an HCA or section of pipeline is assessed by following that HCA or pipeline section through a complete cycle of the operator's pipeline integrity management program.

California utilities periodically elect to undergo independent integrity audits. If these audits were performed annually and consistently, they could provide the basis for review by CPUC audits on a three-year basis.

There is no trending or history of the operating companies to draw on for future audits and improvements.

California law that requires inspection of propane and mobile home park systems on a fixed interval may be shifting inspection resources away from other types of infrastructure.

The pipeline integrity management rule is performance based making a determination of compliance more subjective and therefore making enforcement more difficult.

6.3.3 Recommendations

6.3.3.1 The CPUC should develop a plan and scope for future annual California utility initiated independent integrity management program audits. The results of these audits should be used to provide a basis for future CPUC performance based audits on a three-year basis.

6.3.3.2 Request the California General Assembly to enact legislation that would replace the mandatory minimum five-year audit requirements for mobile home parks and small

propane systems with a risk-based regime that would provide the USRB with needed flexibility in how it allocates inspection resources.

6.3.3.3 The CPUC should consider requiring the major regulated utilities operating in the State of California to submit the results of the independent integrity management audits as part of their respective rate case processes.

6.3.3.4 The USRB is currently understaffed and will be further understaffed as new programs such as Distribution Integrity Management are added. This understaffing problem must be relieved by a combination of an enhanced recruitment and training program to attract and retain qualified engineers plus a framework of supplemental support by outside consultants.

6.3.3.5 USRB should augment its current use of vertical audits that focus on specific regulatory requirements such as leak records or emergency response plans with:

- Horizontal audits that assess a segment or work order of the operator's system through the entire life cycle of the current asset for regulatory compliance.
- Focus field audits based on an internally ranking of the most risk segments of the gas transmission system assets in the state, regardless of the operator.

6.3.3.6 To raise the profile of the audits among all the stakeholders, add the following requirements to the safety and pipeline integrity audits of the utilities that includes the following features: (1) posting of audit findings and company responses on the CPUC's website; (2) use of a "plain English" standard to be applied for both staff and operators in the development of their findings and responses, respectively; and (3) a certification by senior management of the operator that parallels that certifications now required of corporate financial statements pursuant to Sarbanes-Oxley.

6.4 PHMSA Funding

6.4.1 Findings

Federal funding is critical to the viability of many state pipeline safety audit programs, including California's. On average, PHMSA grants accounted for more than 60% of state pipeline safety program budgets in 2010.[88] The agency allocates grant funds by scoring state performance out of 100 total points. PHMSA scores state programs by reviewing annual certification filings and through discussions with state program staff.

[88] Detailed information on the PHMSA grant process can be found in Appendix O.

In 2010, the CPUC gas program received 90.50 points out of 100, resulting in a grant of 63.70% of the cost of the program. With most state programs scoring in the mid- to high 90s, California received the lowest score of any state gas pipeline safety program, except for Puerto Rico.

The 2010 PHMSA scoring document indicates that the CPUC lost points because of a lack of state jurisdiction over municipal pipeline operators and for not meeting the recommended number of inspection days per inspector.

Because of California law, more than 80% of USRB inspection days are spent auditing mobile home park and other distribution systems.[89] While PHMSA collects data on the percentage of different system types that are inspected each year, PHMSA does not require state programs to inspect a certain percentage of system types annually. PHMSA's scoring on inspection time is based on whether a state program meets the recommended number of 85 inspection-person days annually.

In addition, although the CPUC is a self-funding agency, the agency is subject to state appropriations restrictions that currently limit its ability to augment its pipeline safety program budget through an increase in user fees charged to utilities and passed through on customer bills.

6.4.2 Conclusions

Absent the restrictions of California law, PHMSA's grant scoring system is unlikely to be an impediment to the USRB taking a risk-based approach, focusing more inspector resources on transmission pipelines.

Fiscal restrictions limit the ability of the CPUC to hire staff.

6.4.3 Recommendations

6.4.3.1 CPUC should consider seeking approval from the State Budget Director for an increase in gas utility user fees to implement performance-based regulatory oversight for all gas utilities.

6.4.3.2 Request the California legislature pass legislation that would replace the mandatory minimum five-year audit requirements with a risk-based regime that would provide the USRB with the needed flexibility in how it allocates inspection resources.

[89] 2009 CPUC Natural Gas Certification, Attachment 2.

6.5 Compliance Culture

There appears to be a sincere desire throughout the USRB organization to complete integrity management audits in a well-informed constructive manner. However, this is difficult given the priority of audits on mobile home parks and propane systems rather than integrity management audits on transmission pipelines. In an environment of state budget restrictions, these conflicting priorities present a conundrum for the employees of the USRB.

CPUC employees are very aware the state government cuts in resources have affected the quality of their efforts. Employees of the CPUC also recognize the current administration at the Commission has tried to avoid many of the restrictions to which other agencies have been subjected (e.g., furloughs). There is an undercurrent of discouragement within the organization that things will not get better. In addition, employees generally believe the safety branch does not customarily perform the type of high-profile work that is recognized and rewarded in the CPUC organization. These cultural norms undermine efforts at improvement.

Meanwhile, because the Integrity Management audits are performance driven, where risk must be assessed through a variety of means and mitigation plans and those results must be analyzed, the CPUC staff must be more deeply engaged in the review of the operators' plans and implementation. The type of audit that will be required to ensure program effectiveness is more than a check of the operators' conformance to their plans and compliance with the federal codes. These audits must be focused on the "effectiveness" of the operator's Integrity Management program and the measurable results of the implementation of the plan. Thus, a clear audit plan of how to and what to audit in the future is required. There needs to be a collection of relevant data and the development of a history of performance to serve as a baseline and a methodology to follow to achieve the required results. The context of these future audits is a concern of the CPUC and its ability to allocate resources to achieve future goals.

As noted above, there was no evidence of the availability of any benchmarking data, nor a plan to develop the necessary databases to accomplish this task. The need to capture the appropriate data was acknowledged by the CPUC, but there is currently no specific plan to develop the necessary processes.

The technology for utility operations and the regulations regarding safe utility operations are constantly changing. It is challenging for the staff to keep up with all of these changes, particularly as training opportunities diminish. Historically, the audit framework was prescriptive in nature. Given these realities, it is understandable the staff's "comfort zone" in its oversight is to be prescriptive. The utilities, in turn, reinforce this compliance-oriented mindset because it reduces the ambiguity of regulation for them. While staff is conscientious, there are many forces that drive towards a "check the boxes" type of regulatory enforcement. Thus, the CPUC's role in the auditing of Integrity Management must shift culturally to a destination beyond compliance. It must summon up the courage and resources to monitor the prudence of the

operator's program, its effectiveness and analysis of the program results to manage the system risks.

6.5.1 Findings

The desire of the staff from the top down is to complete the audits in a well-informed, constructive way.

Integrity Management audits are performance driven, where risk must be assessed through a variety of means and mitigation plans developed and analyzed. Consequently, the CPUC staff must be more deeply engaged in the review of the operator's plans and implementation.

There is no regular framework or plan to improve and expand the scope of integrity management audits.

6.5.2 Conclusions

The CPUC's role in the auditing of Integrity Management must shift culturally, beyond compliance driven. Compliance driven auditing historically has been the CPUC's approach to assessing utility regulatory conformance.

6.5.3 Recommendations

6.5.3.1 Adopt as a formal goal, the commitment to move to performance-based regulatory oversight of utility pipeline safety and elevate the importance of the USRB in the organization.

6.5.3.2 Develop a holistic approach to identifying pipeline segments for integrity management audits based on intrastate pipeline risk as opposed to simply auditing each operator's pipeline.

6.6 Risk Management

The CPUC has responsibility for setting rates that balance the needs of PG&E and its customers and significant efforts of the agency are engaged in this aspect of the regulatory process. The USRB must be equally, if not more vigilant, concerning PG&E's actions that affect the health and safety of the public to ensure the utility actions and programs are in line with those of a prudent operator. Public health, safety, and the appropriate rate structure to achieve expected results must be balanced by the CPUC. To achieve these results, the CPUC must coordinate the efforts of both the Utilities and Safety Reliability Branch and the Ratemaking Branch. There must be a clear objective and understanding regarding the approach the

operators are taking towards risk management and evaluation of the considered alternatives that appropriately address both safety and costs.

The CPUC currently does not require documentation from the operators that thoroughly explains the logic and motivation for addressing or not addressing specific significant risk management issues or for the subsequent choices of alternatives to address those risk management problems. The CPUC also does not require or receive information from the operators about their reasoning for why proposed risk management alternatives pertaining to public health and safety risks are the best of available alternatives or at least good alternatives compared to the other alternatives that could have been proposed. The new reporting requirements that are contemplated or have been ordered in the various recent and ongoing proceedings would not materially change the quality of PG&E's analysis of alternatives.

Moreover, there is no evidence the USRB or the ratemaking experts have the skills to perform quality analysis of risk management choices, either at an enterprise level or at the technical level specific to Pipeline Integrity Management. The CPUC collectively does not appear to have the skills necessary to perform an in-depth appraisal of any such analyses that might be offered by the operators. There may be individuals who have such skills or the potential to acquire them but in general, employees in the USRB have fewer opportunities and less access to CPUC management and commissioners than individuals concerned with rate cases, legal issues, and broader environmental and political policy issues.

6.6.1 Findings

There is no data collected on which to benchmark and identify risk management issues or alternatives.

The CPUC does not have the personnel to do quality analysis of risk management choices or to appraise in depth the quality of any such analyses that might be offered by PG&E.

Individuals in the USRB who may have such skills or the potential to learn them are currently undervalued and have fewer opportunities and less access to CPUC management and commissioners than individuals concerned with rate cases, legal issues, and broader environmental and political policy issues.

6.6.2 Conclusions

The CPUC currently does not have personnel with the skills to substantially review any risk analysis of risk management decisions submitted by utilities with rate requests related to risk management decisions.

6.6.3 Recommendations

6.6.3.1 The CPUC should significantly upgrade its expertise in the analytical skills necessary for state-of-the-art quality risk management work. The CPUC should have an organizational structure for individuals doing this work such that they have an equal stature and access to management of the CPUC as those who deal with rate issues or legal or political issues. Although the CPUC's role is to provide oversight of the operator's compliance with federal and state codes, its role should not be to provide management of risk direction to the utilities.

6.7 CPUC's Utility Safety "Graduated Enforcement" Program

6.7.1 Findings

If a pipeline does not comply with safety requirements, the USRB may issue informal inspection letters and reports and request the utility take action to comply. However, except for the ability to issue citations and small penalties to operators of propane distribution systems and master-metered natural gas systems in mobile home parks, the USRB may not assess civil penalties for noncompliance. Instead, the USRB must request the CPUC Commissioners institute a formal commission process called an Order Instituting Investigation (OII) or refer the matter to the Attorney General or local District Attorney for judicial prosecution. OIIs can involve public hearings and administrative law judges and can take a substantial amount of time to conclude. The only pipeline safety OIIs in recent history are related to PG&E's San Bruno Incident and another PG&E incident on a distribution pipeline in 2008. Both were instituted after the San Bruno Incident on the Commission's own initiative. CPSD staff views the OII process as administratively burdensome and has not historically invoked it for pipeline safety violations.

The ability of USRB staff to take a greater enforcement role appears limited, but not precluded, by CPUC policy and case law restricting the delegation of Commission authority. Although the Commission has delegated authority to the CPSD for smaller citation and fine cases related to propane and mobile home park systems, no delegations appear to have been sought for other kinds of pipeline safety violations.

Everyone with whom the Panel spoke supported the idea of "graduated enforcement" because it maintains an atmosphere of cooperation between the regulators and the operators. This atmosphere, in turn, encourages the utilities to self-report any violations. This view presented the Panel with the question of whether a system where the staff has greater enforcement latitude would adversely affect the relationship between the regulators and the operators in a way that was detrimental to safety.

So we first turned to the other agency in the State of California that has pipeline enforcement authority. The Office of the State Fire Marshal (OSFM) Pipeline Safety Division regulates the safety of approximately 4,500 miles of intrastate hazardous liquid transportation pipelines. The

Pipeline Safety Division has substantial authority to initiate and conclude enforcement actions, and assess civil penalties, without going through formal processes such as those at the CPUC.[90] The OSFM's model is based on and highly similar to PHMSA's informal enforcement process.

We also summarized the pipeline safety enforcement mechanisms at PHMSA and in several other states. This analysis is contained within Appendix O.

There is variability among the enforcement procedures across different states, and in how those procedures are implemented. In some states substantial authority is vested at the pipeline safety division level, others require commission involvement and approval.

Appendix O provides a detailed description of the USRB pipeline enforcement procedure and authority, a summary description of OSFM, PHMSA and other state pipeline enforcement procedures.

6.7.2 Conclusions

Compared to PHMSA, the OSFM, and a sampling of other states, the USRB's has limited, less flexible means for enforcing pipeline safety requirements. At the OSFM and in other state programs, more authority is vested at the pipeline safety division level.

There is no inconsistency between graduated enforcement where the staff has the authority to bring enforcement actions and positive relationships with the utilities that the staff regulates. There are many examples of agencies and industries where safety is regulated and enforcement actions are undertaken without any obvious deleterious effect on mutual cooperation or willingness of violators to self-report.

Limited USRB enforcement tools and flexibility may limit ability of the USRB to increase the visibility of safety to achieve compliance and increased performance from operators.

6.7.3 Recommendations

6.7.3.1 The CPUC should seek to align its pipeline enforcement authority with that of the State Fire Marshal's by providing the CPSD staff with additional enforcement tools modeled on those of the OSFM and the best from other states.

[90] CAL. CODE REGS. TIT. 19, §§ 2070-2075 (2011).

6.8 Reforming the Organization

The senior management of the CPUC sees the need to create a more proactive regulatory environment where the auditors and engineering staff are more inquiring as to why the operators are making the decisions and taking the various approaches to manage their systems.

6.8.1 Findings

It appears the staff currently relies on the operators to develop the plans for maintenance and capital expenditures to manage their assets in a prudent manner. The audit of PG&E found there was a shortage of resources, but the USRB did not take this finding to the next level. The approach needs to migrate from a monitoring and compliance mode to an inquisitive and challenging one.

6.8.2 Conclusions

Although the operator has the ultimate responsibility to manage its system and assets, the USRB should be using the knowledge gained in the audit process to challenge the utility about alternatives.

The ratemaking staff in the Division of Ratepayer Advocates may episodically challenge the level of spend, but that challenge is not informed by integrity management results the safety staff is auditing.

It is incumbent on the entire organization – safety and ratemaking branches -- to understand the need for investments in safety and reliability, the goals expected from the investments, the alternatives considered, and the progress in system improvements. The silos between the various disciplines in the agency must be dismantled

6.8.3 Recommendations

6.8.3.1 Consider a more proactive role for the safety staff in utility rate filings. Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so there is an enhanced understanding of the costs associated with pipeline safety.

6.8.3.2 Consider, as appropriate, transferring the USRB gas safety staff to the OSFM and with them the responsibility for inspection of gas operator safety and integrity management programs as required by federal and state gas pipeline safety regulations.

7.0 Public Policies in the State of California

7.1 Background

7.1.1 Regulatory and Ratemaking Regime

The CPUC is charged with ensuring that charges for service provided by a public utility are just and reasonable.[91] In a so-called "base rate" case, the CPUC determines a utility's revenue requirement (i.e., the revenues needed to cover the costs of owning and operating facilities to provide service and to earn a reasonable rate of return (profit) to shareholders).[92] The CPUC allocates the authorized revenue requirement among customers and approves rates for individual customer classes.[93]

PG&E's revenue requirement and rates for its gas transmission facilities (both backbone and distribution) and storage services are determined in "Gas Accord" proceedings. PG&E separately seeks approval of the revenue requirement for its gas utility distribution services in a General Rate Case (GRC) and determines customer rates in biennial cost allocation proceedings. Interested parties, including the CPUC's Division of Ratepayer Advocates (DRA), which advocates on behalf of customers, actively participate in these proceedings. Parties engage in discovery, file testimony, participate in hearings, engage in settlement negotiations, and execute settlements. The Energy Division staff is not a party, but provides technical assistance and advice to the presiding administrative law judge (ALJ) and the Commissioners, the ultimate decision makers. CPSD staff traditionally has had little involvement in natural gas utility ratemaking proceedings. In the aftermath of the San Bruno Incident, the safety staff has indicated a desire for increased interaction with DRA and Energy Division Staff to assist them in understanding utility maintenance requirements and expenditures in gas rate cases. The limited role of the CPSD staff in utility ratemaking in California is not unusual when compared to other states.

Most utility gas rate cases are resolved through settlement, often after the completion of evidentiary hearings. The CPUC approves a rate settlement if it is "reasonable in light of the whole record, consistent with the law, and in the public interest."[94] The CPUC has recently approved settlements that establish PG&E's transmission and storage rates for the 2011-2014 rate cycle[95] and set PG&E's revenue requirement for its gas distribution services for the 2011-2013 rate cycle (GRC 2011).[96]

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[91] Cal. Public Utilities Code § 451

[92] CPUC, Electric & Gas Util. Cost Report; Public Utilities Code Section 747 Report to the Governor and Legislature at 4 (Apr. 2011)

[93] More detail about PG&E's ratemaking proceedings in found in O

[94] CPUC Rule of Practice and Procedure Rule 12.1(d)

[95] Decision Regarding the Gas Accord V Settlement, D.11-04-031 (Apr. 18, 2011) (Gas Accord V Decision)

[96] Decision Regarding 2011 GRC, D.11-05-018 (May 13, 2011)

Both decisions approved negotiated levels of expenditures for new capital projects and new ratemaking mechanisms for expenses associated with pipeline safety and reliability. The Gas Accord V decision approved capital expenditures for new transmission pipeline and pipeline upgrades and provided PG&E with 100 and 98% of the capital investment it requested for pipeline integrity and pipeline safety and reliability, respectively.[97] The revenue requirement approved in the GRC 2011 decision includes $258 million for gas distribution capital expenditures in 2011. Capital expenditures may increase by $35 million in 2012 and in 2013.[98]

Both decisions also approve negotiated levels of operation and maintenance expenses for each rate cycle year, including expenses associated with compliance with federal integrity management regulations. As previously described, these regulations require that operators of transmission and distribution systems develop and implement comprehensive documented programs designed to enhance the safety of higher risk pipeline. Generally, operators must gain knowledge of their systems, identify threats, perform assessments and assess risks of those threats, rank identified risks and perform repairs pursuant to established timeframes, and implement preventative and mitigation measures to reduce risk.[99]

Under both decisions, PG&E is required to record expenses associated with integrity management programs in one-way balancing accounts, under which PG&E will record the aggregate difference between the authorized revenue requirement and expenses incurred over the term of the settlement. At the end of the settlement period, accumulated account balances are returned to customers, with interest. The one-way balancing accounts are designed to "help ensure that PG&E spends all of the designated O&M monies for pipeline integrity management activities."[100] There is no provision for PG&E to recover expenses that exceed authorized amounts, even if prudently incurred. However, all California utilities file for rate adjustments on a "future test year" basis where they forecast their capital expenditures and expenses in advance of incurring them. This framework provides a material amount of regulatory protection against earnings attrition between rate case filings. As a result, the restriction of a one-way balancing account for pipeline integrity is one exception to an otherwise liberal framework for utilities to recover prudently incurred costs. As explained in Appendix Q, one-way balancing accounts are not commonly used in state or federal ratemaking nor are the use of the one-way balancing account supported by all the parties in California proceedings.

PG&E is now required to submit a substantial amount of information regarding pipeline safety and reliability activities to the directors of the Energy Division and CPSD.[101] Specifically, the

[97] Gas Accord V Decision at 27

[98] PG&E GRC 2011 Settlement at Section 3.3.1 & Attachment 1, Appendix C

[99] 49 C.F.R. Part 192, Subpart O (gas transmission pipeline integrity management); 49 C.F.R. Subpart P (gas distribution pipeline integrity management). Transmission integrity management regulations became effective in 2004. Distribution integrity management regulations will become effective in August 2011.

[100] Gas Accord V Decision at 56

[101] Gas Accord V Decision at 58 & Settlement, Appendix C; GRC 2011 Decision at 26-31 & Settlement Attachment 5

Gas Accord V decision provides PG&E file adequate information to enable staff to: (1) monitor activities and expenditures related to storage and pipeline-related safety, reliability and integrity capital projects and maintenance; (2) determine whether PG&E is completing projects identified as high risk; (3) determine PG&E's reasons for any project reprioritization; and (4) monitor PG&E's compliance with federal integrity management regulations.[102] If the CPSD staff identifies problems with PG&E's prioritization or administration of projects, the CPSD shall notify the Commission.[103] The reports mandated in the GRC 2011 decision require similar information designed to permit the CPUC to exercise effective oversight of PG&E's pipeline integrity and reliability expenditures on its distribution facilities.

In addition, the GRC 2011 Decision requires PG&E submit information regarding the company's authorized budgeted amounts for 2011 and explain any differences with assumptions reflected in the Settlement Agreement. In subsequent years, PG&E must provide authorized budgeted amounts for the year and explain any significant deviations from the authorized budget for the prior year. In its next GRC, PG&E must fully describe any reprioritizations or deferrals, explain the reprioritization process, justify specific deferrals, and justify activities and projects given a higher priority or were not identified in the 2011 GRC.[104]

After the San Bruno accident, the ALJ established a Safety Phase for the Gas Accord V proceeding which will address how safety concerns on PG&E's system can be avoided over a four-year rate cycle and beyond. The ALJ will prepare a proposed decision recommending safety-related protocols and procedures that PG&E should be required to implement.

7.1.2 Order Instituting Rulemaking (OIR) on New Safety and Reliability Regulations

In response to the San Bruno accident, the CPUC has initiated a comprehensive review of its natural as pipeline safety regulations, including the role of ratemaking in utilities' implementation of pipeline safety programs. The OIR proposes several near-term modifications to existing pipeline safety regulations affecting strength testing and reporting requirements and identifies twelve topics on which the CPUC is considering new rules. With respect to ratemaking, the OIR expresses the need for certainty that expenditures authorized for maintenance and capital projects are carried out by the utility.

On May 10, 2011, the presiding ALJ issued a proposed decision that, if adopted, would require operators of natural gas transmission pipelines in California (including PG&E) to prepare and file comprehensive implementation plans either to hydrostatically pressure test or replace pipeline segments that have never been pressure tested or that lack sufficient detail related to the

[102] Gas Accord V Decision at 58 & Settlement, Appendix C
[103] Gas Accord V Decision at 58-59
[104] GRC 2011 Decision at 30

performance of a test.[105] The plans would be required to provide for testing or replacement as soon as practicable and include interim safety enhancement measures.

To enable the CPUC to fully consider the effects of the final adopted Implementation Plans, each plan would be required to provide cost estimates and information on rate impacts, along with a ratemaking proposal containing: (1) specific rate base and expense amounts for each year proposed to be included in the regulated revenue requirements; (2) proposed rate impacts for each year and each customer class; and (3) other facts and information necessary to understand the comprehensive rate impact of the Implementation Plan. PG&E's plan must also include a proposal for sharing costs between ratepayers and shareholders.

7.2 Findings

- The CPSD's limited role in utility ratemaking proceedings does not appear to be uncommon when compared to other states.
- In recent rate cases, the CPUC has authorized a large percentage of PG&E's requested capital expenditures for pipeline safety and reliability projects.
- The various parties in the gas transmission cases appear to have assumed PG&E's plans for pipeline safety and integrity management are generally appropriate and have thus supported the company's requests.
- One-way balancing accounts create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no less or no more than is authorized for a given activity.
- The extensive nature of new reporting requirements will require PG&E to commit substantial preparation resources; and will require the CPSD and Energy Division to commit resources to review and evaluate, which they do not have.
- Given the wide-ranging initiatives under consideration in the OIR, the CPUC will need significantly far more detailed plans and estimates before it can consider revenue requirement and ratemaking impacts.

[105]Proposed Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans, Filed in OIR 11-02-019 (May 10, 2011)

7.3 Conclusions

- Greater interaction between the CPSD, DRA, and the Energy Division could improve rate staff understanding of costs associated with pipeline maintenance, repair, integrity management, and reliability.
- It is not clear whether a one-way balancing account for expenses associated with a federally-mandated integrity management program improves the incentive for prudent utility decision-making regarding safety.
- The staffs of the CPSD and Energy Division do not currently have the resources to evaluate the information that PG&E and other utilities will be required to submit in an effective manner.

7.4 Recommendations

7.4.1 Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so that there is an enhanced understanding of the costs associated with pipeline safety.

7.4.2 Upon thorough analysis of benchmark data, adopt performance standards for pipeline safety and reliability for PG&E, including the possibility of rate incentives and penalties based on achievement of specified levels of performance.

8.0 List of Acronyms

AA	Associate Administrator
ALJ	Administrative Law Judge
ANSI	American National Standards Institute
API	American Petroleum Institute
ASA	American Standards Association (see ANSI
ASME	ASME - American Society of Mechanical Engineers
BS	Bachelor of Science
CA	California
CARCGA	California Regional Common Ground Alliance
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFR	Code of Federal Regulations
CGA	Common Ground Alliance
COF	Consequence of Failure
COO	Chief Operating Officer
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
DIMP	Distribution Integrity Management Company
D/M	Design Material
DOT	Department of Transportation
DPS	Department of Public Safety
DRA	Division of Ratepayer Advocates
DSAW	Double Submerged Arc Weld
ECDA	External Corrosion Direct Assessment
EO	Engineering Operations
EOC	Emergency Operations Center
ERM	Enterprise Risk Management
ERP	Emergency Response Plan
ERW	Electric Resistance Weld
EVP	Executive Vice President
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
GO	General Order
GPTC	Gas Piping Technology Committee
GRC	General Rate Case
HCA	High Consequence Area
IBEW	International Brotherhood of Electrical Workers

IGIS	Integrated Gas Information System
ILI	In-Line Inspection
IM	Integrity Management
IMEBA	Integrity Management Expense Balance Account
IMP	Integrity Management Program
INGAA	Interstate Natural Gas Association of America
JFK	John F. Kennedy
LEC	Likelihood of Failure due to External Corrosion
LGM	Likelihood of Failure due to Ground Movement
LNG	Liquefied Natural Gas
LTP	Likelihood of Failure due to Third Party
MAOP	Maximum Allowable Operating Pressure
MBA	Master of Business Administration
MHP	Mobile Home Park
MNOPS	Minnesota Office of Pipeline Safety
MOP	Maximum Operating Pressure
MPSC	The Michigan Public Service Commission
MWC	Major Work Categories
NACE	National Association of Corrosion Engineers
NAPSR	National Association of Pipeline Safety Representatives
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NPMS	National Pipeline Mapping System
NTSB	National Transportation Safety Board
OEC	Operations Emergency Center
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
OPS	Office of Pipeline Safety
OQ	Operator Qualification
OSFM	Office of State Fire Marshal
PG&E	Pacific Gas & Electric
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRP	Pipeline Replacement Program
PSI	Pounds per Square Inch
PSIG	Pounds per Square Inch Gauge
PU	Public Utility
QA/QC	Quality Assurance/Quality Control
RFP	Request for Proposal
RMP	Risk Management Plan
RRC	Railroad Commission
RSPA	Research and Special Programs Administration

SAP	Systems Application Programming
SCADA	System Control and Data Acquisition
SCC	State Corporation Commission
SCC	Stress Corrosion Cracking
SEC	Securities & Exchange Commission
SFM	State Fire Marshal
SMYS	System Minimum Yield Strength
SR	Supplementary Requirement
SR&S	System Reliability & Sustainability
SVP	Senior Vice President
TIMP	Transmission Integrity Management Plan
TP	Third Party
TQ	Training and Qualifications
US	United States
USGS	United States Geological Survey
USRB	Utilities Safety and Reliability Branch
WR	Welding Rod
WUTC	Washington Utilities and Transportation Commission

Appendix A

List of Recommendations

The recommendations included in this appendix should be read in conjunction with the recommendations included in the Executive Summary of this report.

No.	Recommendation
Section 2 - Background	
	None
Section 3 – The Panel and Its Approach	
	None
Section 4 – San Bruno Incident	
	None
Section 5 – Review of PG&E's Performance as an Operator	
5.1.4.1	PG&E needs to create a culture of system integrity that enables every employee to recognize and understand how his or her day-to-day actions affect system integrity.
5.1.4.2	PG&E needs to streamline the organization, reducing layers of management and rebuilding the core of technical expertise.
5.2.4.1	PG&E should acquire and develop a staff of professionals with the skills necessary to do state-of-the-art practical analysis of risk management decisions that concern public health and safety, employee health and safety, environmental consequences, socioeconomic consequences, and financial and reputation implications for the company.
5.2.4.2	The Board of Directors of PG&E should require that state-of-the-art risk analysis be conducted on every problem included on PG&E's list of top 10 catastrophic risks. The Board should be assessing the quality of involvement of the members of the top management team in every one of these risk analysis, as all risk management decisions that concern the top ten catastrophic risks should be of direct concern to all top PG&E executives, including the President and CEO, as well as the Board.

5.3.4.1	PG&E should conduct a comprehensive review of its data and information management systems to validate the completeness, accuracy, availability, and accessibility to data and information and take action through a formal management of change process to correct deficiencies where possible.
5.3.4.2	Upon obtaining the results of the review, PG&E should undertake a multi-year program that collects, corrects, digitizes and effectively manages all relevant design, construction and operating data for the gas transmission system.
5.4.4.1	The pipeline and distribution integrity management programs should be separated organizationally with dedicated resources to manage and execute both programs.
5.4.4.2	PG&E should conduct a staffing and skills assessment of the integrity management group to determine if the organization would be better able to maintain its focus and accomplish its complex mission that would with an alternate structure.
5.4.4.3	PG&E should establish a capital program, based on risk criteria, that includes retrofitting existing pipelines, as appropriate, to accommodate ILI tools. ILI surveys provide additional information about the condition of the pipe that enable better decisions regarding remediation, prevention, and mitigation such as monitoring, inspection, repair, replacement, and rehabilitation.
5.4.4.4	PG&E needs to establish a culture of pipeline integrity that enable field and staff to encourage self-reporting of deviations from company policies, processes, or practices. CPUC pipeline safety inspectors should view self-reported deviations as nonconformance rather than noncompliance.
5.4.4.5	PG&E should develop and adopt a maturity framework that reflects the importance and advancement of thinking of pipeline integrity and safety as a journey, which is coherently applied across the enterprise, where progress is transparent and measurable, and is consistent with the best thinking on pipeline integrity and process safety management.

5.5.3.1	Review and restructure all division, regional and company emergency plans for consistency in presentation and feel, while incorporating best practices observed from Pipeline 2020.
5.5.3.2	Conduct a study of SCADA needs to achieve enhanced gas transmission system knowledge that would enable improved shutdown capabilities in the event of a future pipeline rupture. Study to include: (1) the visibility of the transmission operations to system operators, (2) the ability of automation to sense line breaks, (3) the ability to model failure events; and (4) the capability to transmit schematic and real-time information to pipeline field personnel.
5.5.3.3	When study of SCADA needs is completed (described in Recommendation 5.5.3.2), establish a multi-year program to make implement the results of the study.
5.6.4.1	PG&E should take a fresh look at the budgets for pipeline integrity efforts and make informed judgments about how to address the quality and timeliness of efforts to improve its system.
5.6.4.2	PG&E should establish a multi-year program that deals with all the capital requirements to assure system integrity, based on sound risk criteria (i.e., a methodology that addresses the likelihood of various possible failures given competing alternatives). This program would include: • Investments to collect, correct, digitize and effectively manage all relevant design, construction and operating data for the gas transmission system. • Investments to retrofit existing pipelines to accommodate in-line inspection technology, to test or replace uncharacterized or anomalous pipe has needed, and to reroute pipe in the HCAs where accessed.

5.7.4.1	PG&E should restructure the Pipeline 2020 document to enhance effectiveness and assist in monitoring for both PG&E and the CPUC, by incorporating the following: • Vision Statement, which will describe "the transmission pipeline system of the future." This should be a clear statement as to how PG&E sees the role of the transmission system of the future. This will facilitate decisions made in the strategic parts of 2020 that can be focused and relevant to more than just compliance. It should demonstrate the asset profile, and how it will support safety, and operational goals. PG&E should identify specific measures to define what an effective program will deliver. • Delivery Strategies, which will set out the goals of the strategy and steps to deliver the vision. The delivery strategies should be fully developed based on other recommendations for pipeline integrity management and related improvements. • Execution Plan, which will define the tasks to be accomplished, how they will be accomplished, an associated timeframe and projected costs. • Analysis of Alternatives, which will document various alternatives considered, complete with costs and consequences. A thorough analysis of alternatives will ultimately result in support of the program. • In lieu of or in addition to R&D funding for new technology, entertain reasonable opportunities to serve as a testing ground for improved ILI technology.
5.7.4.2	The CPUC or its designated consultant should review the plan and collaborate with PG&E in the development of clear objectives, measures, and schedule.
Section 6 – Review of CPUC Oversight	
6.2.4.1	Adopt as a formal goal, the commitment to move to more performance-based regulatory oversight of utility pipeline safety.

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

6.3.3.4	The USRB is currently understaffed and will be further understaffed as new programs such as Distribution Integrity Management are added. This understaffing problem must be relieved by a combination of an enhanced recruitment and training program to attract and retain qualified engineers plus a framework of supplemental support by outside consultants.
6.3.3.5	USRB should augment its current use of vertical audits that focus on specific regulatory requirements such as leak records or emergency response plans with: • Horizontal audits that assess a segment or work order of the operator's system through the entire life cycle of the current asset for regulatory compliance. • Focus field audits based on an internally ranking of the most risk segments of the gas transmission system assets in the state, regardless of the operator.
6.3.3.6	To raise the profile of the audits among all the stakeholders, add the following requirements to the safety and pipeline integrity audits of the utilities that includes the following features: (1) posting of audit findings and company responses on the CPUC's website; (2) use of a "plain English" standard to be applied for both staff and operators in the development of their findings and responses, respectively; and (3) a certification by senior management of the operator that parallels that certifications now required of corporate financial statements pursuant to Sarbanes-Oxley.
6.4.3.1	CPUC should consider seeking approval from the State Budget Director for an increase in gas utility user fees to implement performance-based regulatory oversight for all gas utilities.
6.4.3.2	Request the California legislature pass legislation that would replace the mandatory minimum five-year audit requirements with a risk-based regime that would provide the USRB with the needed flexibility in how it allocates inspection resources.
6.5.3.1	Adopt as a formal goal, the commitment to move to performance-based regulatory oversight of utility pipeline safety and elevate the importance of the USRB in the organization.

6.5.3.2	Develop a holistic approach to identifying pipeline segments for integrity management audits based on intrastate pipeline risk as opposed to simply auditing each operator's pipeline.
6.6.3.1	The CPUC should significantly upgrade its expertise in the analytical skills necessary for state-of-the-art quality risk management work. The CPUC should have an organizational structure for individuals doing this work such that they have an equal stature and access to management of the CPUC as those who deal with rate issues or legal or political issues. Although the CPUC's role is to provide oversight of the operator's compliance with federal and state codes, its role should not be to provide management of risk direction to the utilities.
6.7.3.1	The CPUC should seek to align its pipeline enforcement authority with that of the State Fire Marshal's by providing the CPSD staff with additional enforcement tools modeled on those of the OSFM and the best from other states.
6.8.3.1	Consider a more proactive role for the safety staff in utility rate filings. Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so there is an enhanced understanding of the costs associated with pipeline safety.
6.8.3.2	Consider, as appropriate, transferring the USRB gas safety staff to the OSFM and with them the responsibility for inspection of gas operator safety and integrity management programs as required by federal and state gas pipeline safety regulations.
Section 7 – Public Policies in the State of California	
7.4.1	Improve the interaction between the gas safety organization and the Division of Ratepayer Advocates of the CPUC so that there is an enhanced understanding of the costs associated with pipeline safety.
7.4.2	Upon thorough analysis of benchmark data, adopt performance standards for pipeline safety and reliability for PG&E, including the possibility of rate incentives and penalties based on achievement of specified levels of performance.

Appendix B

CPUC Resolution L-403

Establishing an Independent Review Panel to assist in the Fact-Finding Investigation of the San Bruno Explosion and the Overall Safety of PG&E's Gas Transmission Lines in California

CPUC IRP Resolution L-403

Appendix C

Order Instituting Rulemaking

Order Instituting Rulemaking.pdf

Order Instituting Investigating

Order Instituting Investigation.pdf

PG&E GRC 2011 May 13, 2011 Decision with All Attachments

PG&E GRC 2011 May 13, 2011 Decision wit

OIR ALJ Proposed Decision Requiring Pressure Testing

OIR ALJ Proposed Decision Requiring Pr

Gas Accord V ALJ Proposed Decision on Safety Phase

Gas Accord V ALJ Proposed Decision on

Gas Accord V Order Accepting Settlement

Gas Accord V Order Accepting Settlement

JACOBS Consultancy

Gas Accord V Settlement Decision Appendix B

Gas Accord V
Settlement Decision A

Appendix D

Independent Review Panel Members Biographies

Larry N. Vanderhoef, Panel Chair

Larry N. Vanderhoef is Chancellor Emeritus, University of California, Davis. He joined the campus in 1984 as executive vice chancellor and provost and was appointed chancellor in April 1994. During his tenure as chancellor, the campus was invited to membership in the prestigious Association of American Universities; increased its extramural awards from $169.1 million to $622 million annually, earning a National Science Foundation research funding ranking of 10th in the U.S. among public universities; and made distinctive strides in recruiting a diverse and accomplished faculty and student body.

Mr. Vanderhoef was honored by the *Sacramento Business Journal* as one of the 20 people who have contributed most substantially to California's capital region over the past 20 years, and Valley Vision presented him with its 2009 Legacy of Leadership Award. As well, the Sacramento Metropolitan Chamber of Commerce named him Sacramentan of the Year in 2004, and the Arts and Business Council of Sacramento presented him with its Prelude to the Season Outstanding Contribution Award in 2003.

Mr. Vanderhoef has served on various national commissions addressing graduate and international education, the role of a modern land-grant university and accrediting issues. He holds B.S. and M.S. degrees in biology from the University of Wisconsin, Milwaukee, and a Ph.D. in plant biochemistry from Purdue University. Previously, he held faculty positions at the University of Illinois, where he also served as a department head, and at the University of Maryland, College Park, where he was appointed provost. Early in his career, he was named an Eisenhower Fellow, a recognition awarded to emerging leaders from around the world to promote positive relationships and interactions between countries. He was awarded honorary doctoral degrees by Purdue University and by Inje University in Korea, and an honorary professorship of China Agricultural University.

Patrick Lavin

Patrick Lavin started his International Brotherhood of Electrical Workers (IBEW) career at IBEW #9, Chicago, in June 1966 as a Groundman. In 1969, he enlisted in the United States Marine Corps and served on active duty in the Pacific with the Fleet Marine Force of the U.S. Navy's 7th Fleet until 1972. All the while, he was an active, dues paying member of IBEW #9.

Mr. Lavin is a Journeyman Lineman by trade and has been one for over 35 years. He has been elected to four terms as Business Manager & Financial Secretary of IBEW Local #47 and is serving his 3rd term as the IBEW 7th District International Executive Council member. He was elected as Secretary of that Council by the IEC in June 2003.

Of his 33 plus years in the field, Mr. Lavin has worked for numerous IBEW signatory contractors and four utilities out of various local unions around the U.S.

Mr. Lavin is the Treasurer of the Coalition of California Utility Employees (CCUE), a Board member of California Unions for Reliable Energy (CURE), an Executive Board Member of the California State Association of Electrical Workers (CSAEW), and a member of the Board of Directors of the California Foundation on the Environment and the Economy (CFEE). He is currently co-chairman of the Pacific Council on International Policy, Energy Task Force. He also serves as Chair of the IBEW #47 Retiree Medical Trust Fund, along with being the Chairman of the Cal-Nevada IBEW/NECA JATC Board.

As a member of the IBEW International Executive Council, he is a Trustee on the Pension Benefit Funds and all funds of the International Brotherhood of Electrical Workers. In addition to those duties, he serves on the National Employee Benefit Board (NEBB), which is the Board of Directors for the National Electrical Benefit Fund (NEBF), National Electrical Annuity Plan (NEAP), and the National Electrical 401k (NEFP).

Mr. Lavin holds a bachelor's degree in Organizational Management from Southern California College. He has been married to his wife, Ellen, for 36 years. They have two daughters, two sons, and 10 grandchildren.

Karl S. Pister

Karl S. Pister is Chair of the Governing Board of the California Council on Science and Technology, and Chancellor Emeritus, University of California, Santa Cruz, and Dean and Roy W. Carlson Professor of Engineering, Emeritus, University of California, Berkeley. He completed five decades of service to higher education, beginning his career in higher education as Assistant Professor in the Department of Civil Engineering at UC Berkeley. He served as Chairman of the Division of Structural Engineering and Structural Mechanics before his appointment as Dean of the College of Engineering in 1980, a position he held for 10 years. From 1985 to 1990 he was the first holder of the Roy W. Carlson Chair in Engineering. From 1991-1996 he served as Chancellor, UC Santa Cruz.

He received the Wason Medal for Research, awarded by the American Concrete Institute and was the recipient of Distinguished Alumni Awards from the University of Illinois and the University of California, Berkeley Colleges of Engineering. The American Society for Engineering Education presented him with the Vincent Bendix Award for Minorities in Engineering, and the Lamme Medal, the highest honor bestowed by the society, for his contributions to engineering education. He is also the recipient of the Berkeley Medal, awarded by UC Berkeley, the Presidential Medal of the University of California, and the Year 2000 Presidential Award of the American Society of Mechanical Engineers.

Mr. Pister is a member of the National Academy of Engineering and a Fellow of the American Academy of Arts and Sciences. He is also a Fellow of the American Academy of Mechanics, the American Society of Mechanical Engineers, the American Association for the Advancement of Science, and an Honorary Fellow of the California Academy of Sciences. He served as founding chairman of the Board on Engineering Education of the National Research Council.

Mr. Pister attended the University of California, Berkeley, where he received a bachelor's degree with honors and master of science degree in the field of civil engineering. After serving as an instructor in civil engineering at Berkeley, he completed graduate studies at the University of Illinois at Urbana-Champaign, where he received the Ph.D. in Theoretical and Applied Mechanics.

Paula Rosput Reynolds

Paula Rosput Reynolds has served as a senior executive in several prominent public companies. Most recently, Ms. Reynolds completed a one-year assignment leading a restructuring team whose goal was to stabilize the liquidity and capital needs of the world's largest insurance company, American International Group (AIG), which was a recipient of substantial support from the U.S. government.

Ms. Reynolds is the former chairman, president, and chief executive officer of Safeco Corporation, a Fortune 500 property and casualty insurance company that was acquired by Liberty Mutual Insurance Group in 2008. During her tenure, Safeco produced financial performance that was routinely in the top quartile of its industry peers. Under her leadership, Safeco increased its focus on technology and innovation, including the creation of the insurance industry's only research and development group.

Before joining Safeco, Ms. Reynolds was chairman, president, and chief executive officer of AGL Resources, a Fortune 1000 Atlanta-based energy services holding company. AGL's holdings include natural gas utilities along the eastern seaboard as well as energy facilities and trading in the Gulf Coast of the U.S. AGL Resources was named "Company of the Year" by its industry trade publication and launched major pipeline replacement programs throughout the states in which it operated.

Prior to moving to Georgia, Ms. Reynolds was an executive of Duke Energy Corporation and one of its predecessors, PanEnergy Corp. She served as the CEO of Duke Energy North America, an unregulated owner and operator of electric power. Earlier in her career, Reynolds held positions at PG&E Corp. including serving as an executive of PG&E's interstate natural gas pipeline subsidiary, which is now part of TransCanada Corp.

Ms. Reynolds has served as a director of various public companies and is currently on the boards of Delta Air Lines and Anadarko Petroleum Corporation. At present, Ms. Reynolds serves as a member of the Governor's Task Force on Financing Higher Education in the state of Washington.

Ms. Reynolds graduated with highest honors in economics from Wellesley College.

Jan Schori

Jan Schori is the former general manager and chief executive officer of the Sacramento Municipal Utility District (SMUD), the nation's sixth largest publicly owned electric utility. During her 14 year tenure as CEO, the utility earned a strong reputation for its renewable energy and energy efficiency programs as well as the national number one ranking in commercial customer satisfaction by JD Power & Associates in 2006-7 and 2007-8. Prior to serving as CEO, she spent 15 years on the legal staff at SMUD, the last five years as general counsel. She is past chair of the American Public Power Association, the Large Public Power Council, and the California Municipal Utilities Association.

Ms. Schori is also past chair of the Business Council for Sustainable Energy and served on the board of the Alliance to Save Energy. She was elected in 2009 to the North American Electric Reliability Corporation's (NERC) board as an independent trustee. NERC is responsible for the reliability of the U.S. and Canadian bulk power grid. She continues to serve as member of the board of directors for the Climate Action Reserve, which develops protocols and tracks greenhouse gas reduction projects, and the board of Valley Vision, a regional action tank seeking collaborative solutions to community issues in California's central valley. She is of counsel to the law firm Downey Brand LLP in Sacramento.

JACOBS Consultancy

Background of Expert Consultants

Jacobs Consultancy, Inc.

Jacobs Consultancy provides technical, economic, and management consulting services to clients in the electric, power, water, natural gas, refinery and petrochemical, and transportation sectors around the world. A selected listing of our typical energy utility services is shown below.

CONSULTING SERVICES	
• Operational reviews and audits • Reliability reviews and benchmarking • Due diligence merger reviews • Safety studies and audits • Business continuity audits and assessments • Pipeline Integrity Management • Risk management strategy development • Power and natural gas market analysis and forecasts • Litigation/expert witness assistance • Strategy consulting including planning, diversification, and acquisition assistance • Transmission engineering	• Economic assessments • Vegetation management audits • Rate and regulatory expertise • Partnering, alliances, and outsourcing advice • Project development and management • Workforce analysis • Asset appraisals and valuations • Business process improvement • Management audits • Project feasibility analysis – technical and economic • Environmental due diligence • Utility system planning • Fuel contract review

Specifically with respect to pipeline integrity, Jacobs Consultancy provides a comprehensive suite of advisory services including: program improvement; map, data and performance integration; gap assessment, program audits, communications outreach, rate case testimony and full-service pipeline integrity management program management.

Van Ness Feldman, P.C.

Founded in 1977, and now with over 90 professionals in Washington, D.C. and Seattle, WA, Van Ness Feldman provides strategic business advice, legislative and policy advocacy, legal, and regulatory compliance counsel, representation in administrative proceedings and litigation, and support for project development, permitting, and transactions in the inter-related areas of energy, the environment, natural resources, public lands, health care, and infrastructure.

The firm has one of the largest gas and electric practices in the country, augmented by a full network of complementary energy and environment-related disciplines, and have been described by *Chambers USA 2010* as "the best energy boutique in the USA." In addition, *U.S. News-Best Lawyers* ranked the firm in the top tier nationally for energy law, and in the top tier in Washington, D.C. for energy, environmental, and government relations.

A diverse range of clients – including leading electric utilities, natural gas and oil production and pipeline interests, renewable energy project developers, manufacturing and industrial concerns, financial institutions and investment funds, clean technology companies, health care services companies, federal lands concessioners, municipalities, trade associations, coalitions, and many others – rely on the firm's professionals for their substantive expertise and their practical, collaborative approach to complex, cutting-edge issues.

Van Ness Feldman's clients are involved in almost every aspect of the natural gas, oil, and refined products industries and have recently developed or are actively developing over $15 billion in new LNG import terminal, pipeline and storage infrastructure – including two of the largest, longest interstate pipelines in North America.

The firm provides legal, business, and strategic counseling on all matters arising under core regulatory statutes such as the Natural Gas Act, Natural Gas Policy Act, Pipeline Safety Act, Interstate Commerce Act, and many environmental statutes. Regarding oil and gas pipelines, the existing operational capacity on firm clients' U.S. pipelines exceeds 22 billion cubic feet per day (Bcf/d). Van Ness Feldman helps clients to anticipate and respond to the ever-changing market conditions and regulatory policies affecting the industry by providing strategic counseling and assistance with "day-to-day" regulatory matters.

Dr. Robert E. Nickell

Dr. Robert E. Nickell has provided engineering consulting services to private industry and government through Applied Science & Technology since 1984. In addition to consulting for the CPUC Independent Panel, his current consulting activity includes knife-edge corrosion assessment for Cook Inlet offshore platforms, expert testimony for the Indian Point Nuclear Power Plant Units 2 and 3 license renewal application, application of ASME Code rules to the design of controlled detonation chambers for chemical weapons destruction, aircraft impact assessment of new commercial nuclear power plants, technology readiness assessment for National Nuclear Security Administration capital construction projects, and risk assessment for medical, industrial and nuclear sources.

Dr. Nickell received his B.S. (1963), M.S. (1964), and Ph.D. (1967) degrees in engineering science from the University of California, Berkeley. Dr. Nickell has been involved in various ASME Boiler and Pressure Vessel Code activities for the past thirty-eight years, and is currently the Chair, Task Group on Impulsively Loaded Vessels, reporting to the Subgroup on High-Pressure Vessels (SG HPV) of Section VIII of the ASME Code. Dr. Nickell is a member of ASCE, ANS, and ASTM, and is a Fellow of the AAAS and ASME. He is a past Technical Editor of the ASME Transactions Journal of Pressure Vessel Technology and a past Chair of the Executive Committee of the ASME Pressure Vessel & Piping Division. He was elected and served as Governor of the ASME from 1992-1994, and he is currently a Past President of ASME, and served as the Secretary and Treasurer of the Society, with a three-year term that ended in June 2004. Dr. Nickell was elected to the National Academy of Engineering in 2007. He has authored or co-authored more than 100 papers in refereed journals.

Ralph L. Keeney

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JACOBS Consultancy

Appendix E

AGA White Paper on Verification of MAOPs for Existing Steel Transmission Pipelines

AGA MAOP White Paper

Appendix F

Analysis from Available Technical Information on Pipeline Rupture

By Dr. Robert E. Nickell

Introduction

The preparation of this appendix was a consequence of the Panel's deliberation process. Originally, the Panel's technical consultants were instructed to monitor the progress of the NTSB investigation of the San Bruno failure, using the Board's preliminary findings on potential contributing factors as the basis for assisting the Panel in framing its conclusions and recommendations. However, after reviewing the NTSB staff metallurgical results, reviewing the recollections and observations of the NTSB interviewees, and actually visiting the site of the incident with an opportunity to directly discuss those observations with some of the NTSB interviewees, the technical consultants determined the framework to be presented to the Panel was sufficiently complex to require formal articulation. The logical flow of that framework is provided in the following.

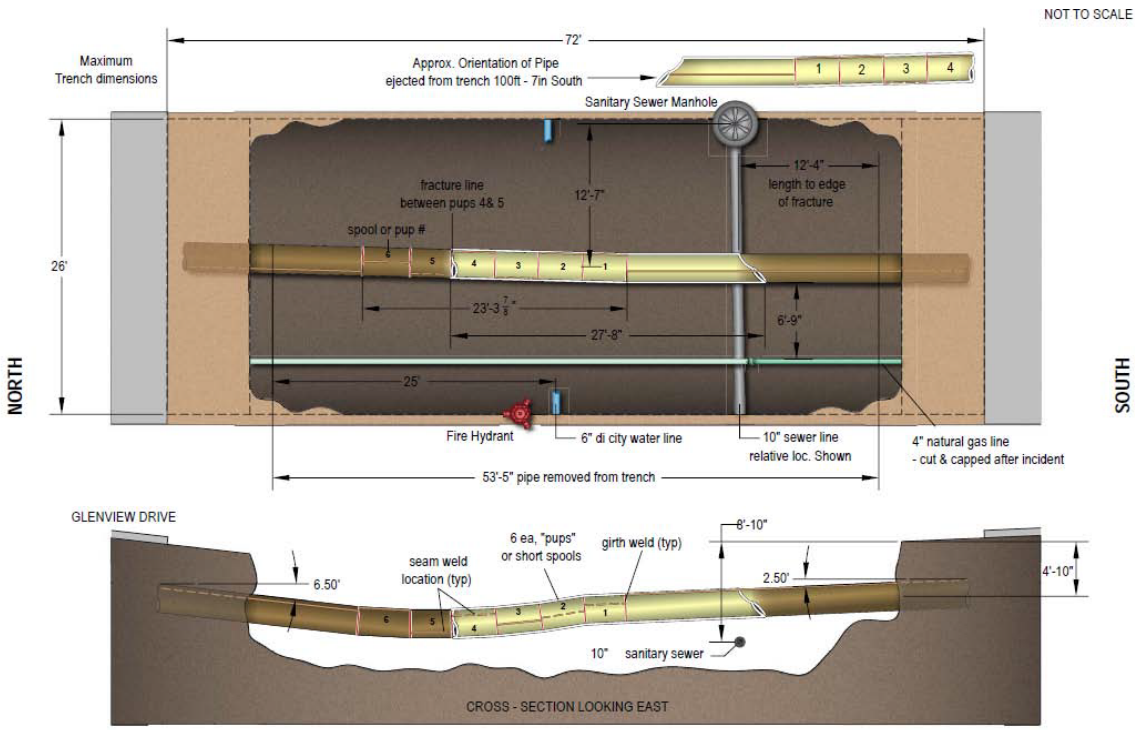
The Pipeline Geometry and Terrain Topography

The pipeline geometry and associated terrain topography are illustrated in the sketch of the segment used by the NTSB as a reference for their March 2011 hearings, as shown in Figure F-1 below. This figure shows both a plan view (on top) and an elevation view (on the bottom) that illustrates the relative location of the affected portion of the pipeline, the surrounding topography, and other relevant features such as the number of piping sections (referred to as PUPs) that were circumferentially welded together to form the total segment crossing the ravine on fill. From the figure, a relatively long piping run extends from the south end of the ravine and connects to PUP 1 at a point about 40% of the distance across the ravine and some ten feet or so north of the point where the June 2008 San Bruno city sewer replacement lateral crosses under the 30-inch-diameter, 0.375-inch-wall-thickness gas transmission line. PUP 1 connects to PUP 2 and then to PUP 3, and so on, until a final connection between PUP 6 and a relatively long piping run that extends out of the fill region into the north end of the ravine.

Two observations come to mind from the figure. First, the decision to place such a circumferential-weld-connected system of short piping runs together in a ravine fill section would normally trigger concerns about threats due to earth movement and possibly to the effects of water pressure during heavy rains. This concern would be amplified by knowledge about the location and orientation of the pipeline relative to seismic activity along the Daly City-Serramonte-San Bruno axis, with potential for lateral

motion and soil liquefaction. Second, knowing the location of PUP 1 relative to the lateral crossing of the San Bruno city sewer lateral, even if the seam weld defect was not known, should have triggered a significant concern during any excavation and related disturbances during the sewer replacement project in June 2008.

Figure F-1 Schematic of the failed pipeline segment in both plan and elevation view[106]



Very little information is available from fabrication and installation records for the placement of this pipeline segment in 1956, and the little amount of information tends to be anecdotal. For example, Exhibit No. 2-F, Docket No. SA-534 (the Maffei interview) provides anecdotal information about the problems encountered with fit-up of piping segments, because of the terrain, during the 1956 installation, resulting in considerable torch cutting of the piping segment ends to prepare circumferential weld joints. It seems likely the short PUP segments were introduced in order to minimize girth weld joint preparation, with the possibility that short piping segments with uncertain or unknown pedigree were located and used. Maffei also describes the visual examination he performed on approximately 1700 feet of the Line 132 piping run, crawling on his hands

[106] Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of the PG&E San Bruno Incident, INGAA Pipeline Safety Committee, May 5, 2011, Interstate Natural Gas Association of America, Washington, DC.

and knees through the 30-inch-diameter line. He was not looking up nor was he looking laterally to observe any potential defects in the longitudinal seam welds, being much more concerned with crawling across the protruding girth welds, where his knees could receive some degree of injury.

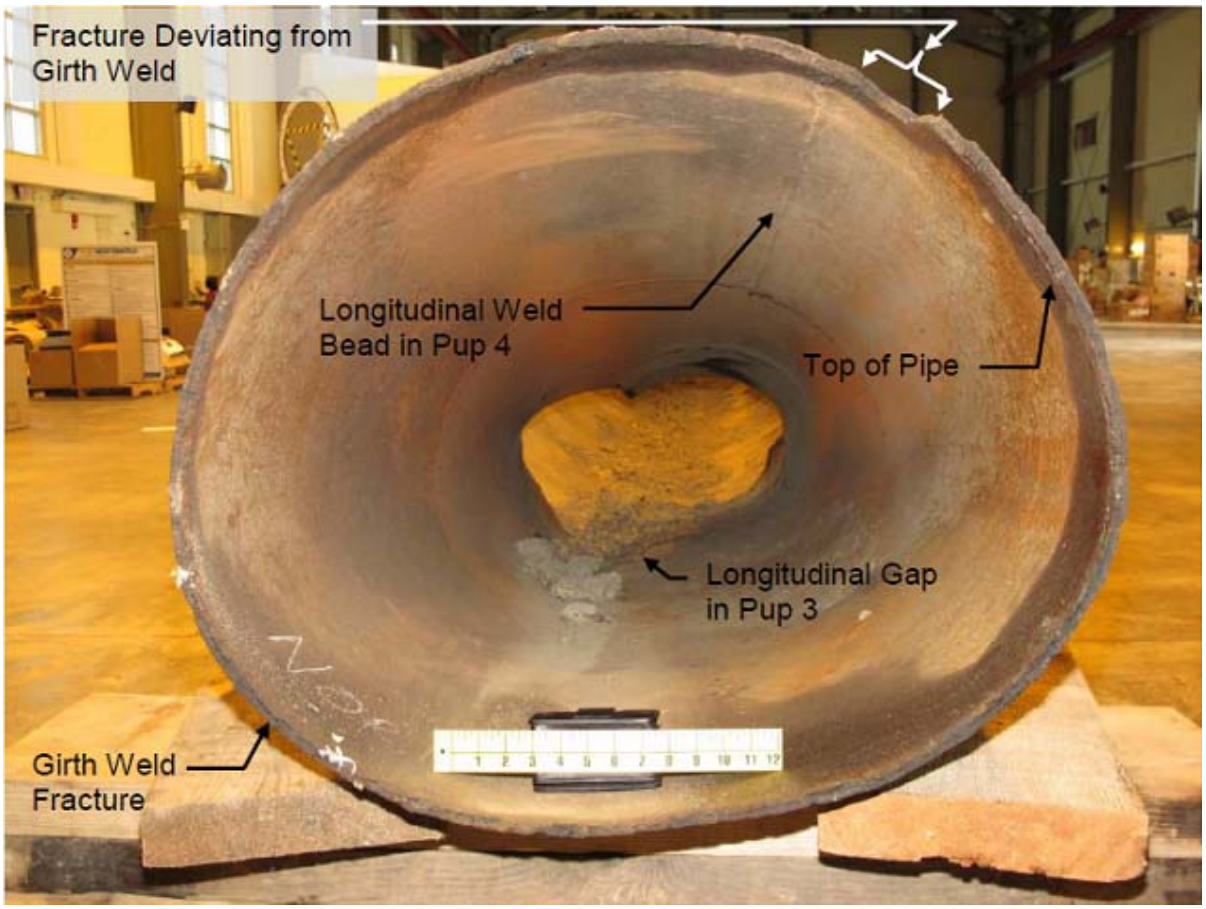
To confirm the Maffei statements, Table F1 (see below) of NTSB Metallurgical Report 1 (Report No. 10-119) provides the orientation of the longitudinal weld seams in the various pieces of pipe that constitute the failed San Bruno pipeline segments, as measured in the NTSB laboratory. The distances are given in inches measured circumferentially – clockwise or counterclockwise – from the top of the pipe looking north. In order to grasp the angular significance of those circumferential measurements, it should be noted the total circumference is greater than 90 inches. From the table it can be seen that, for the long joint south of PUP 1, the longitudinal weld seam is almost directly at the top of the pipe, only 2.88 inches clockwise from the top of the pipe. For PUP 1, the longitudinal seam fracture is located on the east side of that piece, roughly at 70 degrees from the top of the pipe. For PUP 2, the longitudinal seam fracture is also on the east side of that piece, almost at 90 degrees from the top of the pipe.

A good check on the longitudinal seam orientations is provided by Figure F2 from Report 10-119, which shows the longitudinal seam weld in PUP 4 looking south. The 15.25-inch clockwise measurement given in the table (about 58 degrees from the top of the pipe) can be directly compared to the angular location of the longitudinal weld bead shown in Figure F2, which appears to be a little more than 45 degrees counterclockwise (looking South) from the top of the pipe.

Table F1: Circumferential Distance of Longitudinal Seams and Longitudinal Fractures Measured from the Top of the Pipe

Pipe Piece / Feature	Circumferential Distance from Top of Pipe, inch
Long Joint South of PUP 1 – DSAW Seam	2.88 inch – Clockwise
PUP 1 – Longitudinal Fracture	18.50 inch – Clockwise
PUP 2 – Longitudinal Fracture	24.75 inch – Clockwise
PUP 3 – Longitudinal Fracture	27.25 inch – Counterclockwise
PUP 4 – Longitudinal Fracture	15.25 inch – Clockwise
PUP 5 – Longitudinal Fracture	34.25 inch – Counterclockwise
PUP 6 – Longitudinal Fracture	0.38 inch – Counterclockwise
Long Joint North of PUP 6 – DSAW Seam	11.50 inch – Counterclockwise

Figure F-2: Fracture through the Girth Weld between PUP 4 and PUP 5 at the North End of the Center Section. The View is looking south. PUP 3 and PUP 2 are also visible.



From the table and the figure, two features can be observed: (1) some attempt was made during installation to offset longitudinal weld seams from one piping segment to the next; and (2) most, but not all, of the longitudinal weld seams were located in the top portion of the pipe segments. With particular regard to the PUP 1 and PUP 2 segments, the location of the longitudinal weld seams are both fairly close to 90 degrees from the top of the pipe segments on the east side of the pipe run. This implies large, unbalanced pressure loads on the east side of the pipe run, such as could be caused by completely backfilling the east side after excavation, without corresponding backfill on the west side, would cause "flattening" on that side of both segments, placing the inside of the pipe segments at those locations (and the deepest portions of any internal defects) in tension.

Mechanical Properties

Chemical and mechanical property measurements for the removed San Bruno pipe segments were given in NTSB Metallurgical Report No. 2 also referred to as Report No. 11-005. Both sets of measurements showed consistent and anomalous behavior for several of the segments – notably PUP 2 – but also, to a lesser extent, PUP 1, PUP 3, and PUP 5. In order to discuss these anomalies, the first two data columns of the chemistry Table F2 have been extracted (see below), along with Tables F2A1 (yield strength), F2A2 (ultimate tensile strength), and F2A3 (total elongation).

Table F2 from 11-005. Chemistry Data for San Bruno Piping Segments

Sample	C	Mn
LS	0.29	1.02
P1	0.24	0.34
P2	0.12	0.35
P3	0.21	0.32
P4	0.18	0.8
P5	0.28	0.62
P6	0.27	0.95
LN	0.2	1.02
RW	0.1	0.49

The most startling anomaly is the combined low carbon content (0.12%) and the low manganese content (0.35%) for the chemistry of PUP 2, when compared to the API 5LX X42 specification of 0.33% and 1.28%, respectively, for carbon and manganese. Since these two alloying elements are largely responsible for the steel strength, it is not surprising the yield strength for all five mechanical property samples taken from PUP 2 gave very low yield strengths. It is also worth noting that, for the pipe segments with nominal carbon and manganese in the correct range (see both the long south segment

adjacent to PUP 1 and the long north segment adjacent to PUP 6), the yield and ultimate tensile strengths are quite acceptable without compromising the ductility (elongation). It is also worth noting the chemistry of the piece of welding rod (WR) that was found embedded in one of the pipe segments during the investigation is also unsatisfactory, which does not bode well for the girth welds.

Potential decarburization during service seems to be an unlikely explanation, since no other significant evidence of corrosion was found during the investigation. The poor strength of the PUP 1, PUP 2, PUP 3, and PUP 5 segments appears to be due to either low carbon or low manganese, or a combination of both. Whether such anomalous chemistry and strength is systemic throughout the 150 miles of uncharacterized legacy gas transmission piping in the PG&E system is unknown.

Table F2A1: Yield Strength Data Using the 0.5% Extension Under Load Method for Each Tensile Test Specimen

Source	Test 1, ksi	Test 2, ksi	Test 3, ksi	Test 4, ksi	Test 5, ksi
LS	56.0	57.0	57.0	57.5	57.5
P1	36.9	36.3	36.8	36.6	36.3
P2	32.1	32.0	31.9	32.0	32.1
P3	35.3	34.9	34.1	34.9	35.3
P4	47.7	49.1	47.9	48.3	48.4
P5	38.9	38.4	38.6	38.6	38.2
P6	48.5	51.5	50.5	50.0	52.0
LN	54.0	54.5	53.5	54.0	54.0

Table F2A2: Tensile Strength Data for Each Tensile Test Specimen

Source	Test 1, ksi	Test 2, ksi	Test 3, ksi	Test 4, ksi	Test 5, ksi
LS	83.5	83.0	83.0	83.0	83.5
P1	63.5	63.5	64.0	63.5	63.5
P2	52.0	52.0	52.0	52.0	52.0
P3	60.5	60.5	60.0	60.0	60.5
P4	79.0	79.0	79.0	79.0	79.0
P5	72.0	72.0	72.0	71.5	71.5
P6	78.5	78.5	79.0	79.0	78.5
LN	76.5	77.0	77.0	77.0	77.0

Table F2A3: Total Elongation for Each Tensile Test Specimen

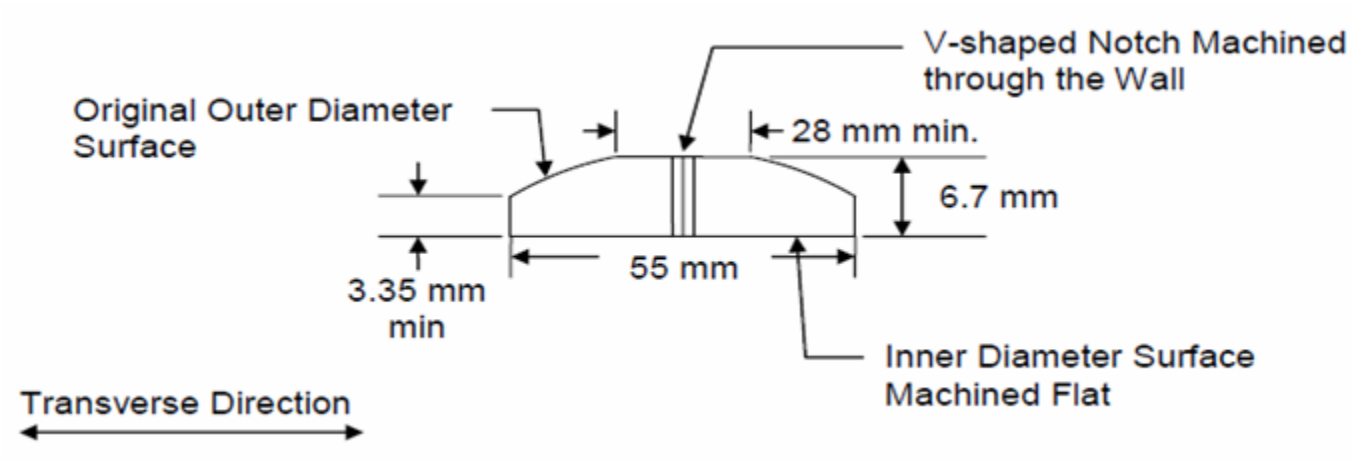
Source	Elongation, % in 2 inch	Elongation, % in 2 inch	Elongation, % in 2 inch	Elongation, % in 2 inch	Elongation, % in 2 inch
LS	30	31	30	29	30
P1	39	39	40	39	40
P2	49	48	48	50	49
P3	42	43	43	43	43
P4	33	34	34	34	35
P5	34	36	36	37	36
P6	31	31	30	30	32
LN	31	31	30	30	30

NTSB metallurgical report 11-005 also provided information on the impact energies of the base metal in the various Line 132 piping segments, which can be used to estimate the fracture toughness properties. The data are taken from Table A5, extracted and shown below. The samples used for Charpy impact testing were slightly sub-size, as shown in Figure F3 from 11-005, extracted and shown below.

Table F2A5: Impact Toughness Values for Each Charpy Test Specimen

Source	Test 1, ft-lbs	Test 2, ft-lbs	Test 3, ft-lbs	Test 4, ft-lbs	Test 5, ft-lbs	Test 6, ft-lbs
LS	10.0	11.0	10.0	10.0	11.0	10.0
P1	9.0	6.0	7.0	6.0	6.0	8.0
P2	76.0	25.0	99.0	52.0	27.0	18.0
P3	8.0	8.0	8.0	9.0	9.0	8.0
P4	13.0	10.0	12.0	11.0	11.0	14.0
P5	14.0	7.0	7.0	6.0	7.0	9.0
P6	10.0	11.8	8.0	8.0	10.0	10.0
LN	16.0	14.0	15.0	11.0	11.0	9.0

Figure F3: Schematic of Charpy Impact Test Specimens Taken from Each Piece of Pipe
The Longitudinal Axis of the Pipe Runs In and Out of the Page



Note LS and LN denote data for the south and north long pipe segments attached to PUP 6 and PUP 1, respectively. P1 through P6 denote data for the PUP piping sections. All of the specimens were taken from base metal and none of the data are for weld or heat-affected zone material. The impact data for PUP 1 (P1) show a variation from 6.0 to 9.0 ft-lb. The specimens are only slightly sub-size, since the full 10 mm dimension was available along the pipe axis, and 6.7 mm out of 10 mm was available through the pipe wall thickness (see Figure 3 from NTSB 11-005).

Various correlations can be used to scale the 6 ft-lb to 9 ft-lb sub-size Charpy data to full scale, and then to estimate the fracture toughness, with results that vary from as low as 35 ksi√in up to perhaps 45 ksi√in. The precise value is not as important as the knowledge that the fracture toughness is relatively low in comparison to the value that would normally be expected for typical piping base metal. It would be expected the fracture toughness of the weld and heat-affected zone would be lower, but perhaps not very much lower.

Initial Manufacturing Defect Assessment

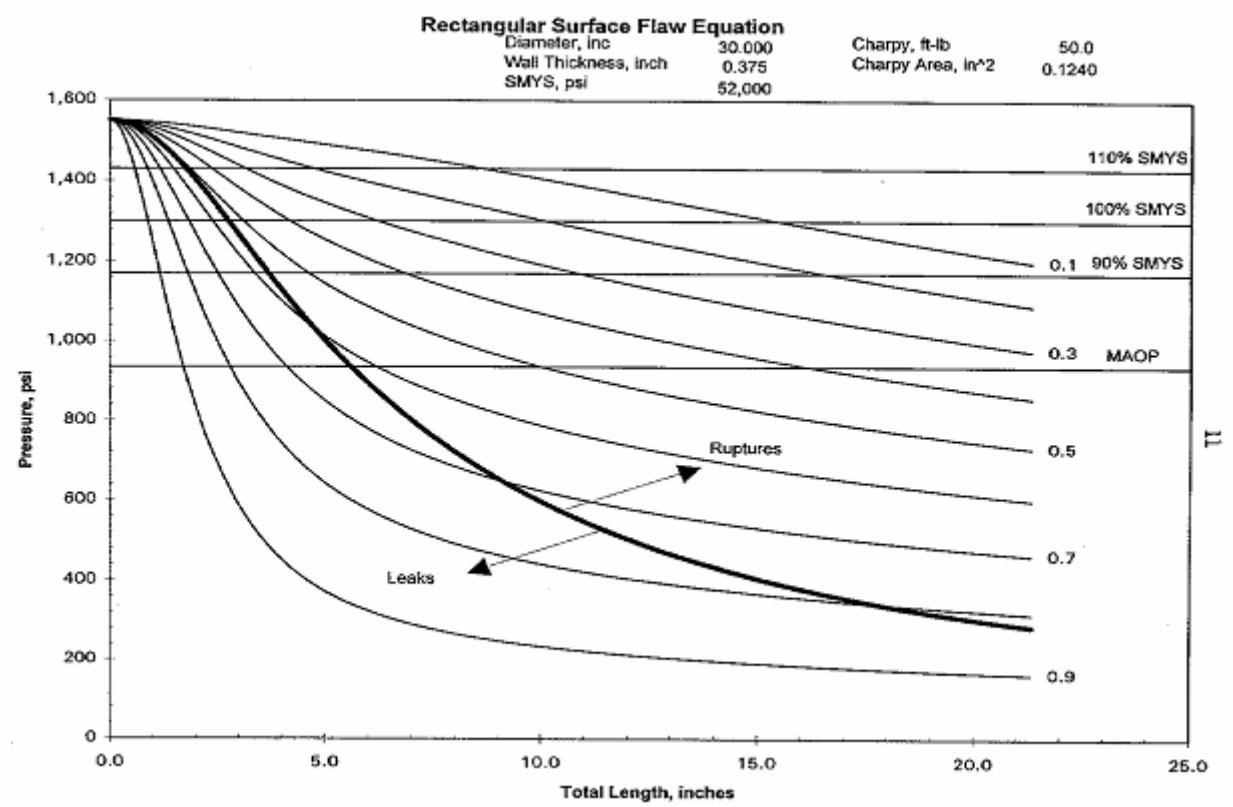
The NTSB metallurgical studies on the pipe sections removed from the San Bruno Incident site (Materials Laboratory Factual Report No. 10-119, National Transportation Safety Board, Washington, DC, January 21, 2011; Materials Laboratory Factual Report No. 11-005, National Transportation Safety Board, Washington, DC, February 9, 2011) provided clear evidence that an initial manufacturing defect was a significant contributor to the eventual failure. The failed piping segment (PUP 1) contained a longitudinal seam weld defect that appeared to extend the full length of that segment – approximately 44 inches – and extended at the worst location some 50 to 55% through the pipe wall from the inner surface. The failed piping segment had been operating at or near its Maximum Allowable Operating Pressure (MAOP) with that defect in place (the amount of defect growth from pressure cycling, either from relatively small pressure

fluctuations of 50 psi or so to full start-up/shut-down pressure cycling is small) for over 50 years, without any apparent manifestations of leakage. This successful operating history – albeit without any initial or in-service hydrostatic pressure testing demonstration of piping structural integrity – offers some evidence that such a defect was not sufficiently deep to be unstable, depending upon the assumed fracture toughness of the weld metal or heat-affected zone material.

In order to assess the stability of this initial manufacturing defect, Figure F4 (see below) from the paper by Kiefner and Maxey (The Benefits and Limitations of Hydrostatic Testing, by John F. Kiefner and Willard A. Maxey) is used for an initial evaluation. Note the graph has been prepared for a 30-inch-diameter, 0.375-inch-thick-walled pipe, with a yield strength of 52,000 psi and a Charpy impact energy of 50 ft-lb. Note also both the yield strength and the Charpy impact energy are far too high for the PUP 1 segment. Using these unrealistically high values, the figure shows that, for an operating pressure of 400 psi, even with a defect 50 to 55% across the wall and infinitely long, no leakage or rupture will occur.

Even with more realistic material property assumptions, an infinitely-long axial defect on the inner surface of the pipe that extends of the order of 50% across the wall can be shown to be stable. With an approximation to the Mode I fracture toughness established at around 45 ksi√in, or even slightly lower for weld metal and heat-affected zone material, that stability can be demonstrated, by using the stress intensity factor solutions in Annex C of API 579 (API 579-1/ASME FFS-1, Fitness-For-Service, Second Edition, American Petroleum Institute, July 2007), with an internal pressure of 400 psi. For an infinitely-long 40% through-wall defect, the applied stress intensity was calculated to be about 22 ksi√in; for an infinitely-long, 60% through-wall defect, the applied stress intensity was calculated to be about 50 ksi√in. In other words, for an infinitely-long internal surface defect, instability would be expected with a defect depth of the order of 60% of the wall thickness. Therefore, an initial longitudinal seam weld defect in PUP 1 that extended the full length of that piping segment (about 44 inches) and which extended through the wall on the order of 50 to 55% would have been marginally stable and have survived fifty or more years of service operating at MAOP.

Figure F4: Impact of Test Pressure Levels on Margin of Safety



Initial Manufacturing Defect Growth Assessment

The next logical question is: How does defects that has remained stable for so many years of operation at or near MAOP grow to critical dimensions? To answer this question, note growth rates of cracks in pipeline steels depend significantly on two parameters – the range of the applied stress intensity at the tip of the crack, called ΔK, and the ratio of the minimum applied stress intensity to the maximum applied stress intensity, called the R ratio or K_{min}/K_{max}. For the case of defect growth during a cycle of pressurization to MAOP, complete depressurization, and pressurization back to MAOP, the applied stress intensity range is relatively large; however, R = 0. For the case of defect growth during a pressure fluctuation of 10% of MAOP, the applied stress intensity range is relatively small; however, R could be close to unity.

To compare defect growth rates, the procedure used by Kiefner and Rosenfeld ("Effects of Pressure Cycles on Gas Pipelines," by John F. Kiefner and Michael J. Rosenfeld, Report No. GRI-04/0178, Gas Research Institute, Des Plaines, IL, September 17, 2004), can be followed. Kiefner and Rosenfeld used the Paris crack growth law constants from API 579. Using two different sets of cycles – a pressurization-depressurization-re-pressurization cycle every year with a stress intensity range of 35 ksi√in and a daily pressure fluctuation with a conservative

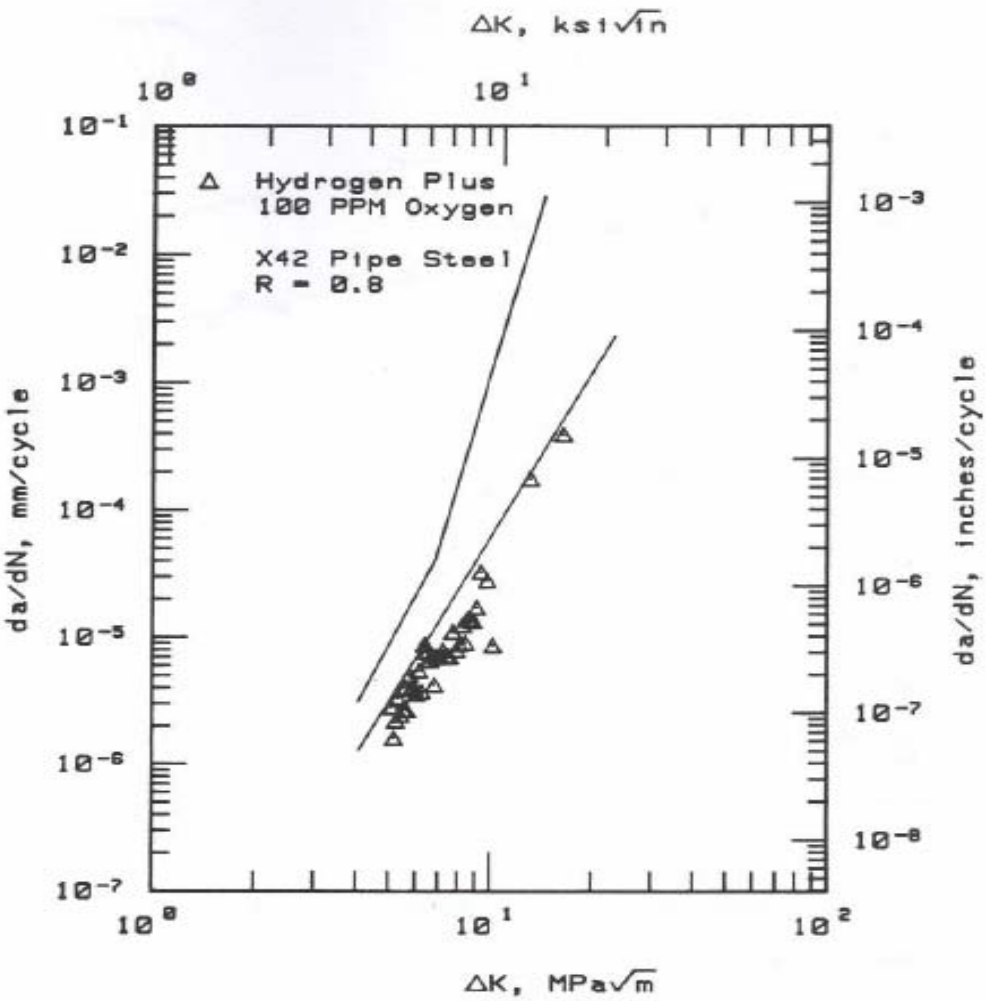
stress intensity range of 7 ksi√in – the total amount of defect growth over a 60-year period would be less than 0.01 inches. This growth would increase the depth of the original manufacturing defect from 55% of the wall thickness to no more than 57.5% of the wall thickness.

However, the Paris crack growth law constants used by Kiefner and Rosenfeld did not take the R ratio into account. Typically, the Paris crack growth constants are obtained from fully-reversed crack growth testing (R = -1). When R = 0, the crack growth rates are of the order of twice those for R = -1. For R ratios approaching unity, the crack growth rates are of the order of three times the crack growth rates for R = -1. Based on the figure below – taken from the paper "Assessing the Durability and Integrity of Natural Gas Infrastructures for Transporting and Distributing Mixtures of Hydrogen and Natural Gas," by I. Alliat and J. Heerings – crack growth data for X42 pipeline steel that is exposed to a benign nitrogen environment can be examined (the lower curve), with crack growth rates based on R = 0.8 (the crack tip is under moderately high tensile stress throughout the loading cycle).

In this case, for ΔK of 35 ksi√in (a full pressurization and complete depressurization cycle), the amount of defect growth for one cycle per year and 60 years of operation would be about 0.006 inches. For ΔK of 7 ksi√in, the growth for a daily cycle for 60 years would be about 0.018 inches. The combination of cycles could take a defect that is 55% through wall (0.206 inches deep in a 0.375-inch-thick wall) to a defect that is still less than 65% through wall.

Therefore, even assuming annual start-up/shut-down cycles and thousands or hundreds of thousands of modest pressure fluctuation cycles, the amount of stable propagation of the initial defect in the radial direction could possibly lead to a critical and unstable defect in PUP 1 only if the fracture toughness in the longitudinal seam weld and its heat-affected zone were of the order of 35 ksi√in. Such a scenario is certainly plausible, but no clear evidence of such growth is available from the NTSB metallurgical evidence.

Figure F5



Solid lines represent hydrogen (upper line) and nitrogen (lower line) data.

Alternative Piping Integrity Threats

Although failure from the presence of the initial manufacturing defect and its radial growth during cyclic pressure service is plausible, the possibility of failure from a combination of the initial fabrication defect and some other loading event or events seems to be a more likely scenario. In order to determine the most likely combination of threats, the historical record of natural gas transmission pipeline failures is a potential source of information. For example, the Pipeline Research Committee of the American Gas Association conducted a study of natural gas pipeline incidents that were required to be reported to U. S. federal authorities during the period

from 1985 to 1994[107] provides some evidence into the range of failure root causes and underlying contributing factors.

The most common cause (32.7%) was external force due to encroachment, which encompasses damage such as dents and gouges from third-party actions, or pipeline operator and contractor activities, and intentional malicious attack. The second most common cause (23.5%) is either internal or external corrosion; with such causes as external weather force (10.2%), which encompasses earth movement such as landslides, heavy rains and floods, and extremely cold temperatures; operator error (6.5%); equipment malfunction (5.2%); and defective welds (4.1%) and defective pipe (3.6%) provide much of the balance. Unattributed causes, or other (10.4%), complete the list.

This failure cause distribution is generally consistent with the Pipeline and Hazardous Materials Safety Administration (PHMSA) classification of both serious (causing at least one fatality) and significant (causing at least $50,000 in property damage) gas transmission pipeline incidents during the period from 1991 to 2010. For example, of the 132 serious incidents during this period, excavation damage was the cause of 43 incidents (32.5%), the largest grouping. Corrosion (22.8%) was the largest grouping among the 1,139 significant incidents, with material/weld/equipment failure (21.0%) a close second and excavation damage (18.3%) third.

These causes and a number of others are listed among the 22 different pipeline integrity threats that are provided as guidance in ASME B31.8S[108]. ASME B31.8S defines these threats in three categories:

- Time-dependent threats, such as loss of material from internal or external corrosion, and progressive stress corrosion cracking (SCC).
- Time-independent threats, such as third-party mechanical damage, incorrect operational procedures, weather-related phenomena, and earth movements.
- Stable[109] threats, which include a manufacturing-related defect (e.g., a defective longitudinal weld seam defect) or a fabrication-related defect (e.g., a defective pipe girth weld).

[107] Patrick H. Vieth, "Analysis of DOT Reportable Incidents," Ninth Symposium on Line Pipe Research, Paper 2, Houston, Texas, September 30-October 2, 1996.

[108] Managing System Integrity of Gas Pipelines, ASME B31.8S, American Society of Mechanical Engineers, New York, NY, 2010.

[109] The term "stable" is somewhat problematical since, while a manufacturing-related or fabrication-related defect may not be explicitly dependent on time, the sub-critical defect growth to potential instability may be implicitly cyclic loading time dependent.

All of these threats and combinations of threats are to be addressed by the gas transmission pipeline operator's Integrity Management Program (IMP).

One immediate observation from this list of threats is the prevalence of third-party risk as a historical attributor to gas transmission pipeline failure; however, the presence of a manufacturing or fabrication defect at the same time raises serious questions about the potential for threat interaction and the subsequent total risk quantification. For example, does the current *additive* approach to risk quantification in the PG&E IMP adequately take into account the potential for *multiplicative* threat interaction? A simple example to consider would be the potential for soil movement that might cause longitudinal seam weld defect growth. A second observation, based on the activity accompanying the June 2008 sewer replacement project, is the propensity for third-party risk to be characterized entirely by *direct* contact with the piping, as opposed to effects that might be caused by *proximity without direct contact*, such as causing excessive lateral or vertical deflection of the piping by incorrect back-filling procedures or by vibratory effects on soil movement and support.

As a point of discussion of this effect, in the NTSB metallurgical Report No. 10-119, the longitudinal weld seam on the relatively long run south of PUP 1 is readily visible and would have been readily visible during the excavation for the sewer replacement project. That particular longitudinal seam was located near the top of the pipe segment (see Table 1), while the longitudinal weld seam for PUP 1, which probably would not have been visible, was located at about 70° from the top of the pipe on the east side of the piping run. NTSB Report No. 10-119 fixed the initiation point for the failure at the PUP 1 longitudinal seam roughly half way between the connections to the south end long run and PUP 2 (see Figures 33a and 33b from NTSB Report No. 10-119, shown below in Figure F6).

Figure F6

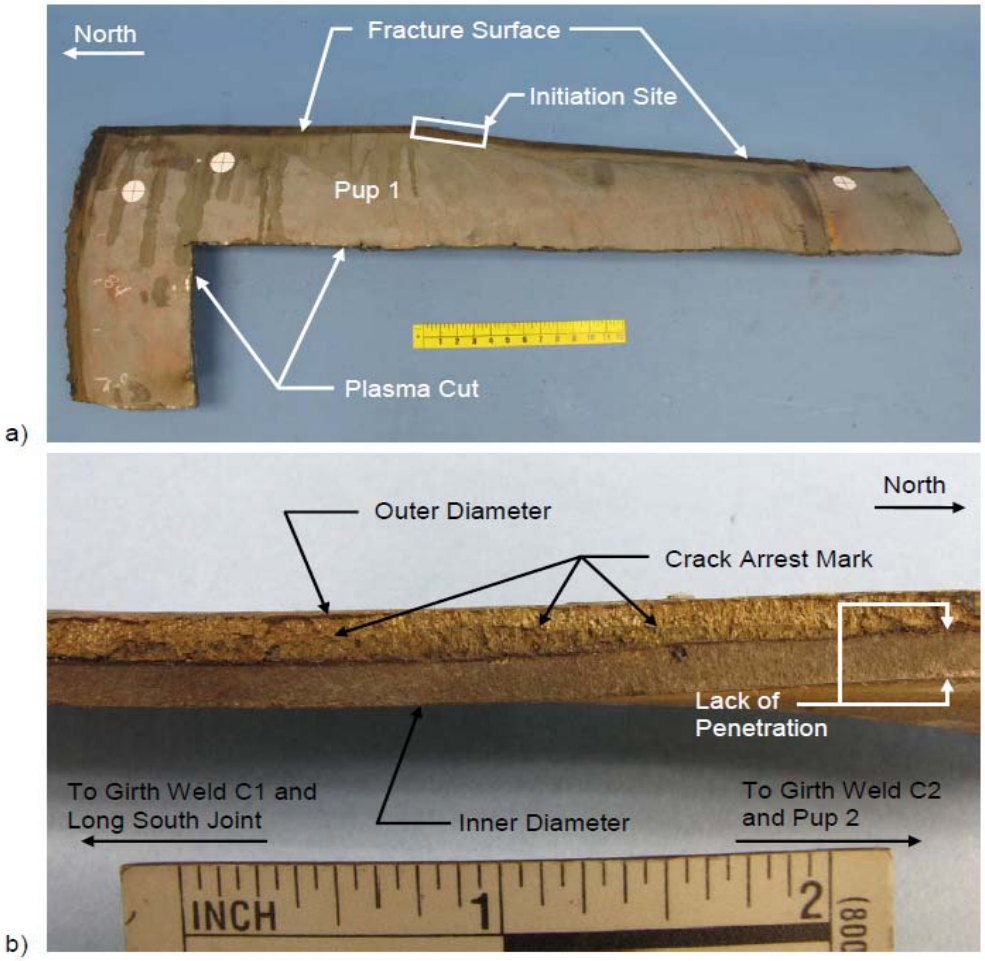


Figure 33: a) Counterclockwise half of pup 1 longitudinal fracture with the location of the crack initiation site indicated; b) cross section view of the longitudinal seam at the initiation site.

Note Figure 33b of the longitudinal weld cross section at the initiation site shows the initial 50 to 55% lack of weld penetration through-wall defect, with no clear evidence of cyclic crack growth extension of that defect. Also shown in the figure, without much explanation, are what are referred to as fairly localized “crack arrest marks” near the initiation site. These marks could be interpreted as stable extension of the initial defect, caused by a single event, out to somewhere in the neighborhood of 75 to 80% of the wall thickness.

If some type of localized effect, such as localized soil pressure or inadvertent third-party action, caused that additional defect growth, that growth would likely take place over a much shorter distance than the full 44-inch length of PUP 1. In order to investigate this possibility, an additional set of stress intensity factor solutions in Annex C of API 579 was evaluated for a finite-length longitudinal defect on the internal surface of a pipe under internal pressure (see Section C.5.10 of API 579). Only one such solution is discussed here – the case of a defect

that has grown from around 55 to 60% through wall to 80% through wall in a local portion of the incomplete PUP 1 weld.

Four different defect lengths were evaluated – 2.4 inches long, 4.8 inches long, 9.6 inches long, and 19.2 inches long. In all cases the driving pressure was assumed to be 400 psi. The evaluations showed that, for the 2.4 inch long defect, the applied stress intensity was only about 25 ksi√in, implying that such a short defect –although very deep – would not be unstable. For the 4.8 inch long defect, the applied stress intensity factor was about 36 ksi√in, which implies marginal but likely defect stability. Both the 9.6 inch long and 19.2 inch long defects were unstable.

Therefore, it would appear that localized acceleration of growth from the original manufacturing welding defect is an alternative and more likely failure scenario. At present, such localized growth must be considered anomalous absent some evidence of localized soil movement, or some phenomenon that locally increased soil pressure, or a third-party action that could have led to localized bending or ovalization of the pipe in the region near PUP 1. Localized bending or ovalization would be of particular concern if the stresses on the interior of the pipe caused by denting or ovalization were locally tensile at the azimuthal position of the longitudinal weld, adding to the circumferential pressure tensile stresses.)

NTSB Findings to Date

The NTSB investigation has not yet determined the root cause and any underlying contributing factors that led to the San Bruno pipeline failure, and will not issue its report on the incident for several months. However, the NTSB has recognized the failed San Bruno pipe section contained a longitudinal seam weld with a defect that extended the full length of PUP 1 and about 50 to 55% across the pipe wall. Because of this recognition, the NTSB recommended PG&E and other natural gas transmission pipeline operators should review their records to assure: (1) the mischaracterization by PG&E of the San Bruno pipe segment as seamless is not a systemic error, (2) any longitudinal seam-welded piping is properly characterized and appropriately classified in terms of risk, and (3) the risk associated with similar defects in other piping segments is appropriately mitigated.

The NTSB interim findings to date are both reasonable and useful, especially with respect to:

- Discovery that the failed piping was of longitudinal-seam-welded construction, rather than seamless.
- Discovery that the failed piping was composed of several short, girth-weld-connected segments.
- Identification of record keeping deficiencies by PG&E related to pipe characterization and MAOP determination.

- Production of useful metallurgical information on the failed piping, including relatively low Charpy V-notch energies for the base metal and some relatively low yield and ultimate strength values for some of the PUP segments.

All four of these interim findings raised significant issues with respect to legacy gas transmission piping in general and with respect to PG&E's legacy gas transmission piping, in particular. For PG&E, the unavailability of at least some legacy piping records and potential mischaracterization of other legacy piping records raised the issue of whether threats similar to the Line 132 San Bruno segment are currently unidentified.

Those legacy piping segments for which PG&E was unable to retrieve adequate documentation to confirm the piping characteristics are expected to undergo hydrostatic pressure testing over the next several months, with the test pressure planned to be 150% of the Maximum Allowable Operating Pressure (MAOP). The purpose of the relatively high test pressure is not only to expose any defects that threaten future operation at MAOP, but also to drive even smaller defects to instability (leakage or rupture), potentially generating a greater degree of integrity demonstration. The defects that threaten future operation are those that have been and are currently *stable*, but which have margins of safety that have been reduced to the point that uncertainties in material behavior, loadings, or environments could cause *instability*.

Hydrostatic pressure testing of uncharacterized legacy piping with potentially low fracture toughness may not be the optimum approach, depending upon whether the San Bruno Incident is viewed as an anomaly that is not likely to exist elsewhere in the PG&E transmission system, or whether the San Bruno Incident is viewed as evidence of potentially more systemic behavior. If systemic issues are suspected, another option is available that would either be a precursor to hydrostatic pressure testing, or which would replace some or even most of the hydrostatic pressure testing. That option would involve excavating and exposing any longitudinal seam welds along segments of uncharacterized legacy piping, probably at a frequency of every mile or every other mile, while using a tool such as the automated ball indenter to characterize the piping material. Such testing would include indenter determination of yield strength and "indentation energy to fracture," but could also entail a circumferential hardness traverse to locate the longitudinal seam weld and its heat-affected zones, with the potential for a volumetric non-destructive examination (e.g., ultrasonic testing) to determine any significant defect structure on the interior of the pipe. Destructive examination to remove an occasional section of the pipe (which would involve shutting down an occasional transmission line segment) to measure Charpy impact energy for confirmation of automated ball indenter results could be considered.

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Appendix G

EMC Systems Safety ERM Package Final

EMC System Safety
ERM Package Final

Appendix H

GE TD System Safety

GE TD System Safety

Appendix I

GIS Data Attributes

SanBrunoGT-LineRup
tureInvestigation_DR

Appendix J

Threat Factors and Attribute Tables

Pipe Seam Design Material Considerations[110]

Criteria	Points	Contrib.
Furnace Butt Weld (FBW) (Jef = 0.6)	100	30
Single Submerged Arc Weld SSAW (Jef = 0.8)	60	18
Low Freq. ERW* (Jef = 1.0)	90	27
A.O.Smith or Flash Weld (Jef = 1.0)	90	27
High Freq. ERW (Jef = 1.0)	20	6
Double Submerged Arc Weld (DSAW) (Jef = 1.0)	10	3
Seamless	10	3
Pre 1990 Spiral (Jef = 0.8)	90	27
1990 and newer Spiral (Jef=1.)	20	6
Other**	100	30
Default (Welds made prior to 1970)	100	30
Default (Welds made in 1970 and after)	20	6

* Welds made prior to 1970 using the ERW welding process are assumed to be made using low frequency.

[110] PG&E Procedure for Risk Management, RMP-05 Rev 4, Design/Material Threat Algorithm

Test Pressure vs. Pipe Strength

Criteria	Points	Contrib.
TP ≥ 100%PS (test is 5 years old or less)	-200	-40
TP ≥ 100%PS (test is more than 5 years old)	-150	-30
TP < 100% PS	-50	-10
No Pressure Test or TP/MOP <1.1	150	30

* Pipe Strength (PS) shall be determined to be equal to (SMYS)(2)(t)(Jef)/(OD).

** Pressure Tests performed earlier than 1950 will not be credited.

Third-Party Damage Prevention

Criteria	Points	Contrib.
None	0	0
Standby	-100	-10
Aerial Patrol	-20	-2

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Appendix K

PIPING DESIGN AND TEST REQUIREMENTS

PIPING DESIGN AND
TEST REQUIREMENTS

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Appendix L

Challenges and Benefits of Automatic Shut-off Valves and Remote Control Valves Installation

ASV-RCV White Paper AGA 3-30-11

Additional industry literature available on this subject:

- Eiber, R.J. and Kiefner and Associates, Review of Safety Considerations forNatural Gas Pipeline Block Valve Spacing (To ASME Standards Technology, LLC), July 2010.
- GPTC Guide for Gas Transmission and Distribution Piping Systems: 2009 Edition "§192.179 Transmission Line Valves", Gas Piping Technology Committee Z380.
- Sulfredge, C. D., "Scoping Study on the Safety Impact of Valve Spacing in Natural Gas Pipelines", Oak Ridge National Laboratory, September, 2006.
- Process Performance Improvement Consultants, (P-PIC), White Paper on Equivalent Safety for Alternative Valve Spacing, Draft April 18, 2005.
- Gas Research Institute 00/0189 "A Model for Sizing HCA's Associated with Natural Gas Pipelines", December 2001.
- Eiber, R., W. McGehee, P. Hopkins, T. Smith, I. Diggory, G. Goodfellow, T. Baldwin and D. McHugh, "Valve Spacing Basis For Gas Transmission Pipelines", PR-249-9728, January 2000, PRCI Report.
- U.S. Department Of Transportation, Research and Special Programs Administration, Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996), September 1999.
- Shires, T.M. and Harrison, M.R., Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implication for Today's Natural Gas Pipeline System, GRI-98/0367.1, December 1998.
- Sparks, C.R., Morrow, T.B. and Harrell, J.P., Cost Benefit Study of Remote Controlled Main Line Valves, GRI-98/0076, May 1998.
- Eiber, R.J. and McGehee, W.B., Design Rationale for Valve Spacing, Structure Count, and Corridor Width, PR249-9631, PRC International, May 30, 1997.

- Sparks, C.R. et al., Remote and Automatic Main Line Valve Technology Assessment, Appendix, B, GRI-95/0101, July 1995.

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Appendix M

Independent Review Panel

Discussion Topics with COO of PG&E - January 12, 2011

Appendix M - IRP
Discussion Topics with

- Background on President and tenure with company
- Executive management perspectives on gas department (size, expertise, business protocols, safety focus, culture)
- Key initiatives undertaken regarding people process, and technology in gas operations.

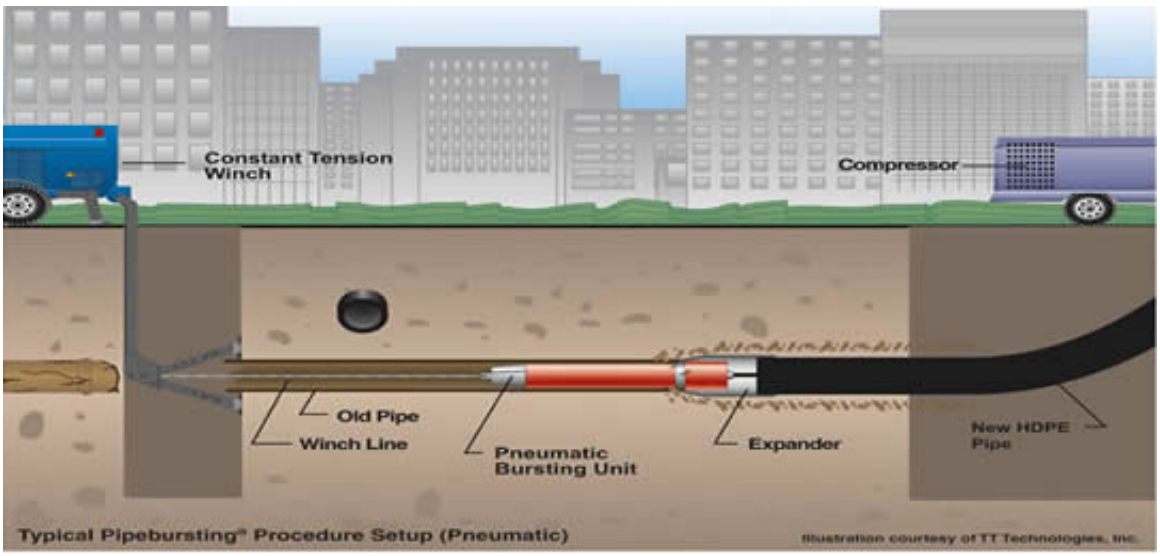
Appendix N

Pipe Bursting Construction Technique

Pipe bursting was first developed in the UK in the 1980s for the replacement of cast iron gas mains and has since been used more commonly for water and sewer pipes. An existing pipe is replaced size-for-size or up-sized with a new pipe in the same location.

Pipe bursting, which can be either pneumatic, hydraulic expansion or static pull, fractures a pipe, compressed the soil around the pipe and displaces the fragments outwards while a new pipe is drawn in to replace the old pipe.

The size of the pipe currently being replaced by pipe bursting typically ranges from 2 inches to 36 inches; although the bursting of larger diameters is increasing (pipes up to 48 inches diameter have been replaced). When cast iron is burst, a liner is inserted during the process to prevent damage to the new pipe. The process is very often used for service line replacement. A diagrammatic illustration appears below.



Source: TT Technologies, Inc.

Process

Typical pipe bursting involves the insertion of a conically shaped tool (bursting head) into the old pipe. The head fractures the old pipe and forces its fragments into the surrounding soil. At the same time, a new pipe is pulled or pushed in behind the bursting head. The base of bursting head is larger than the inside diameter of the old pipe to cause the fracturing and slightly larger than the outside diameter of the new pipe, to reduce friction on the new pipe and to provide

space for maneuvering the pipe. The rear of the bursting head is connected to the new pipe, while its front end is connected to a cable or pulling rod.

The bursting head and the new pipe are launched from the insertion pit, and the cable or pulling rod is pulled from the reception pit. The cable/rod pull together with the shape of the bursting head keeps the head following the existing pipe, and specially designed heads can help to reduce the effects of existing sags or misalignment on the new pipeline.

Strengths

- Pipes suitable for pipe bursting are typically made of brittle materials, such as clay, cast iron, or some plastics.
- Theoretically there is not a limit in size of pipe to be burst.
- Pipe bursting is typically carried out in 300 to 400 feet lengths, which corresponds to a typical distance between sewer manholes. However, much longer runs have been replaced, reportedly up to 1500 feet.
- The technique is stated to be more cost effective when there are few lateral connections or service connections, when the old pipe is structurally deteriorated, and when additional capacity is needed.

Weaknesses

- The bursting operation can cause ground heave or settlement above, or at some distance from the pipe alignment.
- Typical pneumatic pipe bursting may create considerable ground vibrations on the surface above the bursting operation.
- Difficulties can arise in expansive soils.
- The most critical conditions for ground displacement are when the pipe to be burst is shallow and ground displacements are primarily directed upward.
- Close proximity of other service lines, point repairs that reinforce the existing pipe with ductile material or a collapsed pipe at a certain point along the pipe will present issues.
- The bursting head should not pass closer than 2.5 feet from buried pipes and 8 feet from sensitive surface structures.
- The ground displacements tend to be localized, however, and to dissipate rapidly away from the bursting operation.
- The limit on pipe size depends on a cost effectiveness comparison to conventional replacement and the ability to provide sufficient energy to break the existing pipe and compress the soil while simultaneously pulling in a new pipe.

- It is sometimes necessary to install a sleeve with the burst head, so that pipe fragments do not damage the new polyethylene pipe.
- Ductile iron and steel pipes are not suitable for pipe bursting.

Appendix O

Pipeline Safety Regulation and Resources in California

PHMSA's Role

PHMSA is an agency within the U.S. Department of Transportation. PHMSA, through its Office of Pipeline Safety (OPS), administers a national pipeline safety program pursuant to the Pipeline Safety Act (Act).[111] The purpose of the Act is to protect "against risks to life and property posed by pipeline transportation and pipeline facilities."[112] To accomplish this purpose, PHMSA is authorized to prescribe and enforce minimum safety standards against owners and operators of pipeline facilities.[113] PHMSA regulations apply to design, installation, construction, testing, inspection, integrity management, operations, replacement, and maintenance of pipelines, and the qualification of personnel who operate and maintain them.[114] PHMSA's pipeline safety program is funded by an annual user fee assessed against gas transmission, liquefied natural gas (LNG) and hazardous liquid pipeline operators.[115]

PHMSA's broad jurisdiction reaches both interstate and intrastate gas and hazardous liquid pipeline transportation and facilities.[116] However, through a state/federal partnership nearly all states, including California, regulate intrastate gas pipeline facilities through an annual certification program.[117] Under this program, states must have regulatory jurisdiction, adopt and enforce the federal pipeline safety standards, and promote pipeline damage prevention.[118]

State/Federal Partnership

Although PHMSA has jurisdiction over intrastate pipeline facilities, all states except Alaska and Hawaii regulate intrastate gas pipeline facilities through an annual certification program.[119] Fifteen states, including California's OSFM, have certified programs for hazardous liquid

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[111] 49 U.S.C. § 60101 *et seq*. (2006). PHMSA's original authority to regulate natural gas pipeline safety comes from the Natural Gas Pipeline Safety Act of 1968, Pub. L. No. 90-481, 82 Stat. 720, as amended.
[112] *See id.* § 60102(a)(1).
[113] *Id.* §§ 60102(a)(2), 60118, 60120, and 60122.
[114] *Id.* § 60102(a)(2)(B)-(C).
[115] *Id.* U.S.C. § 60301.
[116] 49 U.S.C. § 60101(a).
[117] 49 U.S.C. § 60105 (2006). All states except for Alaska and Hawaii submit annual certifications to regulate intrastate natural gas pipeline facilities. http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=60dc8f4826eb9110VgnVCM1000009ed07898RCRD&vgnextchannel=a576ef80708c8110VgnVCM1000009ed07898RCRD&vgnextfmt=print#page1 (last accessed May 2, 2011).
[118] 49 U.S.C. § 60105(b)(1) – (4).
[119] 49 U.S.C. § 60105 (2006).

pipelines.[120] In addition to PHMSA regulations, most states also adopt additional, more stringent standards for intrastate facilities.

As long as state certifications comply with the requirements of the Act, PHMSA is precluded from prescribing or enforcing safety standards and practices for intrastate pipeline transportation and facilities.[121] PHMSA may reject a state's certification if it is not "enforcing satisfactorily compliance with applicable" federal standards.[122] Rejection of certification is rare and has only occurred once. In 1993, PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA) decertified Hawaii's state program due to a state budget shortfall that prevented the state from providing adequate technical staff.[123]

State pipeline safety programs share best practices, discuss emerging issues and influence policy through the National Association of Pipeline Safety Representatives (NAPSR).[124] NAPSR holds an annual meeting as well as several regional meetings each year. "State pipeline safety inspectors [comprise] more than 75% of the" pipeline safety inspection workforce.[125]

CPUC Authority

The Utilities Safety and Reliability (USRB) branch of the Consumer Protection and Safety Division (CPSD) of the CPUC regulates and inspects intrastate gas pipeline safety under federal and state authorities and pursuant to an annual program certification to PHMSA. The CPUC's structure, function and authority are set out in the California Constitution.[126] The CPUC derives its authority to regulate gas pipeline safety from the broad powers granted by the California Constitution and Public Utilities Code.[127]

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[120] List of states with intrastate hazardous liquid pipeline safety programs certified to PHMSA under 49 U.S.C. § 60105(a) for Calendar Year 2010. http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=60dc8f4826eb9110VgnVCM1000009ed07898RCRD&vgnextchannel=a576ef80708c8110VgnVCM1000009ed07898RCRD&vgnextfmt=print#page2 (last accessed May 2, 2011).

[121] *Id.* § 60105(a).

[122] *Id.* § 60105(f).

[123] Reauthorization of the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act: Hearing before the Subcomm. on Energy and Power of the H. Comm. on Commerce, , Serial No. 106-11, 106th Cong., 114 (Feb. 3, 1999), available at http://www.gpo.gov/fdsys/pkg/CHRG-106hhrg55149/pdf/CHRG-106hhrg55149.pdf (last accessed May 2, 2011).

[124] National Association of Pipeline Safety Representatives, http://www.napsr.org/who_we_are.htm (last accessed May 4, 2011).

[125] *Id.*

[126] CA CONST. art. XII.

[127] CAL. PUB. UTIL. CODE §§ 315 (investigations and reports of accidents), 451 (utilities must furnish safe service and equipment), 702 (utilities must comply with commission orders, decisions, directions or rules), and 761 and 768 (the commission may establish safety standards and issue orders and rules) (2010).

Pursuant to these authorities, the CPUC issued General Order 112-E (GO-112-E) adopting the Federal Pipeline Safety Regulations at 49 C.F.R. Parts 190, 191, 192, 193 and 199.[128] GO-112E provides that all revisions to the federal regulations are incorporated automatically.[129] GO-112E also includes additional requirements that are more stringent than the minimum federal standards. For example, it includes additional reporting requirements for incidents, new construction and changes in MAOP.

The commission also has specific statutory authority to regulate certain propane distribution systems serving multiple customers[130] as well as master-metered natural gas systems in mobile home parks.[131] These laws require the CPUC to conduct inspections of these systems at intervals of five years or less.[132]

PHMSA State Pipeline Safety Program Grants

States can apply to PHMSA for grants of up to 80% of the cost of a state's pipeline safety program. While 80% is allowed by law, appropriations from Congress have limited grant funds below 80%.[133] PHMSA allocates grant funds based on performance, as demonstrated in annual certification filings and through discussions with state program staff.

In 2010, the CPUC received 90.50 points out of 100, which resulted in a PHMSA grant representing 63.70% of the cost of the CPUC's natural gas pipeline safety program.[134] With most state programs scoring in the mid to high 90s, the CPUC received the lowest number of points of any state gas pipeline safety program, aside from Puerto Rico, which received a score of 73.20 points. The 2010 PHMSA scoring document indicates the CPUC lost points because of a lack of state jurisdiction over municipal pipeline operators and for not meeting the recommended number of inspection person days. The PHMSA recommended number of inspection-persons days is 85 days per inspector per year.[135]

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[128] CPUC General Order 112E, § 101 (as amended Aug. 21, 2008). While the CPUC has adopted PHMSA's inspection and enforcement regulations at 49 C.F.R. Part 190, it conducts enforcement pursuant to CPUC procedures. Given the delegation constraints within the CPUC, and existing CPUC procedural requirements, the CPUC does not employ the enforcement mechanisms set out in Part 190.

[129] *Id*. at § 104

[130] CAL. PUB. UTIL. CODE §§ 4451-4465 (propane systems).

[131] *Id.* §§ 4351-4361 (mobile home parks).

[132] *Id.* §§ 4353 and 4453.

[133] 49 U.S.C. § 60107(a) (2006). The most recent grant data for 2010 indicates maximum funding of approximately 70 percent of state program budgets. The 2006 amendments to the Pipeline Safety Act authorized an increase in grant funding from 50 percent to 80 percent of state program budgets.

[134] PHMSA 2010 Natural gas Scoring Document.

[135] Final Rule, Allocation Formula for State Grants, 58 Fed. Reg. 10985, 10988 (Feb. 23, 1993).

DOT uses the grant program to incentivize state responsibility for pipeline safety and to improve the performance of state programs.[136] To allocate grant funds PHMSA reviews and scores the performance of state programs on the basis of 100 total points, half of which come from PHMSA's review of the annual certification reports and the other half from discussions and interviews with state staff.[137] PHMSA allocates grant funds considering the following factors:

- Adequacy of state operating practices.
- Quality of state inspections, investigations, and enforcement/compliance actions.
- Adequacy of state recordkeeping.
- Extent of state safety regulatory jurisdiction over pipeline facilities.
- Qualifications of state inspectors.
- Number of state inspection person days.
- State adoption of applicable federal pipeline safety standards.
- Any other factor the PHMSA Administrator deems necessary to measure performance.[138]
- State adoption of a one-call damage prevention program.[139]

Each year, PHMSA notifies state agencies of specific performance criteria in light of the factors listed above, and the weights to be assigned to each.[140]

Training

PHMSA assesses state certifications and allocates grant funds, in part, on the basis of the qualifications of state inspectors.[141] A condition of full PHMSA grant funding is state pipeline safety personnel complete a series of courses offered by PHMSA's Office of Training and Qualifications (TQ). Most courses are offered only at TQs training facility in Oklahoma City, Oklahoma. The annual state certification forms for 2010 list 24 TQ courses that state inspectors must complete within three years of beginning employment.[142] PHMSA offers the courses at no cost to state inspectors. However, state programs must fund inspector travel to the Oklahoma City training facility.

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[136] Final Rule, Allocation Formula for State Grants, 56 Fed. Reg. 7636, 7637 (Feb. 25, 1991).
[137] 49 C.F.R. § 198.13(b) (2010).
[138] *Id.* § 198.13(c).
[139] *Id.* §198.35
[140] *Id.* § 198.13(e).
[141] 49 U.S.C. § 60107(d)(1)(C), (2), 49 C.F.R. § 198.13(c)(2).
[142] PHMSA Natural Gas Certification Attachments for 2010, *available at* www.regulations.gov in docket number PHMSA-2009-0304.

CPUC Enforcement

The CPUC currently takes a four step "graduated" enforcement approach to pipeline safety.[143] The CPUC describes the approach as follows:

- First, the CPSD notifies a utility of possible pipeline safety violations.
- Second, the CPSD investigates the matter and may give the utility a notice of noncompliance and order it to fix the issue within a specified timeframe.
- Third, the CPSD may request the CPUC Commissioners vote to open a formal Order Instituting Investigation, which could result in fines and penalties.
- Fourth, the CPUC staff may request "that the CPUC Commissioners vote to refer the matter for civil or criminal prosecution by" the Attorney General or a local District Attorney.[144]

CPSD may issue informal inspection letters and reports to utilities and request a utility take action to come into compliance.[145] However, except for small penalties for propane distribution systems and master-metered natural gas systems in mobile home parks (MHPs), the CPUC may only issue civil monetary fines and penalties for pipeline safety violations through a formal process called an Order Instituting Investigation (OII).[146] The CPSD may request the Commissioners vote to open an OII, or the Commission may do so on its own initiative. The OII is a formal adjudicatory process that may involve Administrative Law Judges, hearings and other formal proceedings.[147]

CPSD staff has, in the context of propane system enforcement, characterized OII proceedings as "lengthy, resource consuming and expensive proceedings for the Commission as well as for the operators."[148] The OII process has rarely been invoked in pipeline safety cases. The only two recent reported instances are the 2010 and 2011 OII proceedings against PG&E regarding the San Bruno Incident[149] and the 2008 gas distribution system incident in Rancho Cordova.[150]

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[143] CPUC Utility Safety Graduated Enforcement Program(Oct. 2010) (*available at* http://www.cpuc.ca.gov/NR/rdonlyres/B92CC9E9-48DF-4E8D-B8EB-2FBC9CD462A/0/GraduatedEnforcement102010.pdf).

[144] *Id.*

[145] Utilities Safety Reliability Branch, CPUC Gas Pipeline Safety Program GO 112-E Procedures Manual at 13-14 (Aug. 2008).

[146] CPUC Rules of Practice and Procedure, Rule 5.1.

[147] CPUC Rules of Practice and Procedure, Rules 5.1 and 7.1-.6 (2009).

[148] CPUC Resolution USRB-001 at 3 (Jul. 31, 2008).

[149] Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company with Respect to Facilities Records for its Natural Gas Transmission System Pipelines, I.11.-02-016, 2011 Cal. PUC LEXIS 69 (Feb. 24, 2011).

[150] Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company, Regarding the Gas Explosion and Fire on December 24, 2008 in Rancho Cordova, California, I.10-11-013, 2010 Cal. PUC LEXIS 505 (Nov. 19, 2010).

Both proceedings were initiated on the Commission's own motion and remain pending as of the publication of this report. The CPUC makes infrequent use of settlements in the pipeline safety context.

As noted above, the CPSD does have the ability to issue relatively small penalties and citations with respect to pipeline safety violations on propane distribution systems[151] and master-metered natural gas systems in mobile home parks (MHPs).[152] The CPSD requested and obtained this authority through limited delegations from the Commission.

Generally, the CPUC's delegation of citation authority appears limited, but not precluded, by Commission case law prohibiting the Commission from delegating powers that involve judgment or discretion, absent statutory authorization.[153] Other Commission cases have narrowed this principle to prohibit delegations only of the "power to make fundamental policy decisions or final discretionary decisions."[154] Such narrowing allows agencies to "act in a practical manner and delegate authority to investigate, determine facts, make recommendations, and draft proposed decisions to be adopted or ratified by the agency's highest decision makers, even though such activities in fact require Staff to exercise judgment and discretion."[155] This language suggests that the CPUC has some ability to delegate additional, limited citation authority for other types of pipeline safety violations.

Different Pipeline Safety Enforcement Frameworks: The Federal Model and Other States

States enforce pipeline safety requirements and achieve compliance objectives through a variety of different mechanisms. The PHMSA approach, as well as a sample of state pipeline safety enforcement frameworks, is set out below.

PHMSA

PHMSA conducts a compliance and enforcement program for interstate pipeline facilities nationwide. PHMSA Regional Directors have a large degree of discretion on whether and what type of enforcement action to take, and may initiate administrative enforcement cases and propose civil penalties through an informal process.[156] Operators may contest enforcement

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[151] CPUC Resolution USRB-001. Delegate's propane gas distribution system citation and fine authority to the CPSD. CPUC's authority to inspect and enforce propane master meter systems is found in CAL. PUB. UTIL. CODE §§ 4451-4465.

[152] CPUC Resolution SU-24 (Dec. 17, 1993). Delegate's mobile home park natural gas distribution system citation and fine authority to the CPSD. CPUC's authority to inspect and enforce propane master meter systems is found in CAL. PUB. UTIL. CODE §§ 4351-4361.

[153] *California School Employees Association v. Personnel Commission*, 3 Cal.3d 139, 144 (1970).

[154] *Union Pacific Railway Co.*, Order Modifying Resolution ROSB-002 and Denying Rehearing of Resolution, as Modified, A.08-12-004, 2009 Cal. PUC LEXIS 250, *5 (May 11, 2009).

[155] *Id.* at *6 (quoting *California Ass'n of Competitive Telecomm. Companies*, D02-02-049 (2002) __Cal.P.U.C.2d__ at pp.6-7 (slip. op.).

[156] 49 C.F.R. § 190.207.

cases and request an informal hearing or proceed on the papers.[157] Hearings are typically concluded in a day or less.

The PHMSA Associate Administrator (AA) ultimately decides and issues a final order in all cases involving a civil penalty or a compliance order, whether or not a hearing has occurred.[158] Operators may petition the AA for reconsideration of a final order.[159] Beyond the petition stage, appeal is to a District Court of the United States. PHMSA may also refer cases to the Department of Justice for civil or criminal enforcement, though this is somewhat rare.[160] Settlements are infrequent.[161]

PHMSA does not publish any official enforcement policy, though it views enforcement as a "key" part of its oversight mission.[162] The agency issues dozens of civil penalty cases each year and, in recent years, has assessed millions of dollars each year in penalties.[163]

California (Hazardous Liquids)

The Office of the State Fire Marshal (OSFM) regulates intrastate hazardous liquid pipeline safety.[164] Unlike the CPUC's General Public Utilities Code-based Gas Safety Program, the OSFM regulates hazardous liquids pipeline pursuant to specific statutory authority.[165] The OSFM enforcement mechanism is very similar to PHMSAs.[166] The Pipeline Safety Division may initiate and conclude informal enforcement cases on its own, including civil penalty actions, and may settle cases. Operators may request hearings, but they rarely do.

The OSFM has a large degree of flexibility to conduct informal enforcement proceedings and assess civil penalties.

Washington

The Washington Utilities and Transportation Commission (WUTC) regulate intrastate gas and hazardous liquid pipeline safety, according to a specific statutory mandate.[167] WUTC's enforcement policy is to provide technical assistance when an operator is first found to be out of

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[157] *Id.* § 190.209(a)(3), (b)(2).
[158] *Id.* § 190.213(a).
[159] *Id.* § 190.215(a).
[160] *Id.* §§ 190.231 and 190.235.
[161] Of several hundred cases initiated since 2002, PHMSA has issued six administrative consent orders. *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Cono_opid_0.html?nocache=6711 (last accessed May 4, 2011).
[162] http://primis.phmsa.dot.gov/comm/EnforcementProgram.htm?nocache=5108 (last accessed May 4, 2011).
[163] PHMSA Index of Final Orders issued: http://primis.phmsa.dot.gov/comm/reports/enforce/FOCP_opid_0.html?nocache=2676 (last accessed May 4, 2011).
[164] CA Office of State Fire Marshal: http://osfm.fire.ca.gov/pipeline/pipeline.php (last accessed May 4, 2011).
[165] CAL. GOV'T. CODE §§ 51010-51019.1 (West 2010).
[166] Cal. Code Regs. tit. 19, §§ 2070-2075 (2011).
[167] WASH. REV. CODE ANN § 81.88 (West 2011).

compliance, absent any risk to public safety.[168] Staff may also require an operator to submit a compliance plan.[169] WUTC will consider enforcement actions, including civil penalties, after repeated violations, failure to correct previous violations, for imminent threats and where circumstances otherwise warrant.[170] Staff may also propose relatively small administrative penalties for certain violations.[171] Administrative penalties must be approved by the commission and operators may request mitigation of the penalties or a hearing.[172] Pipeline safety staff may recommend the Commission issue a show cause proceeding or formal complaint including penalties and sanctions.[173]

Commission policy encourages negotiated settlements.[174] Staff may initiate settlement discussions with pipeline operators, and reach negotiated settlements, including civil monetary penalties.[175] The Commission must approve any settlement.[176]

Overall, WUTC pipeline safety staff has a degree of flexibility to pursue enforcement matters and conduct settlement negotiations without initiating formal adjudicatory processes.

Texas

The Railroad Commission of Texas (RRC) regulates intrastate gas and hazardous liquid pipeline safety, according to specific statutory mandates.[177] RRC staff attempt to solve many compliance issues informally, without enforcement actions. When enforcement is necessary, staff may propose enforcement cases and administrative penalties and operators have the opportunity for a hearing.[178] The RRC settles many cases and hearings are relatively rare. More substantial injunctive relief and civil penalties are available if the matter is pursued in court by the attorney general, on behalf of the RRC.[179]

The RRC has flexibility to use a variety of formal and informal means, including settlements, to achieve enforcement and compliance objectives.

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[168] WUTC Safety and Consumer Protection Division – Compliance and Enforcement Manual at 9.
[169] *Id.* at 51-52.
[170] *Id.* at 12.
[171] WASH. REV. CODE ANN § 80.04.405 (West 2011).
[172] *Id.*
[173] WUTC Safety and Consumer Protection Division – Compliance and Enforcement Manual at 55-56.
[174] *Id.* at 13.
[175] *Id.*
[176] Wash. Admin. Code § 480-07-750 (2011).
[177] Tex. Util. Code Ann. §121 (West 2010) (gas); Tex. Nat. Res. Code Ann. §117 (West 2010) (hazardous liquids).
[178] Tex. Util. Code Ann. §121.206 - 207.
[179] Tex. Util. Code Ann. §121.203 – 204.

Oregon

The Oregon Public Utilities Commission[180] regulates intrastate gas pipeline safety according to its general authority to regulate public utilities, as well as pipeline safety-specific authority.[181] Commission regulations give inspection priority to gas pipeline facilities with greater risk.[182] It is the policy of the pipeline safety division to resolve compliance issues informally.[183] Staff provides verbal notice of probable violations before concluding inspections.[184] Staff may also issue written notices of probable violation to operators.[185] Operators may request an informal settlement conference to discuss the probable violation and agree on corrective actions.[186] In order to obtain civil penalties, staff must refer probable violations the commission for formal action.[187]

The Commission has not issued any civil penalties for pipeline safety cases in the last ten years.[188] Oregon pipeline safety staff appears to have less enforcement flexibility than other states surveyed.

Minnesota

In Minnesota, the Department of Public Safety (DPS) regulates intrastate gas and hazardous liquid pipeline safety. Within DPS, the Office of Pipeline Safety (MNOPS) administers the pipeline safety program according to specific statutory authorities.[189] It is the policy of MNOPS to initially attempt to resolve compliance issues informally, before resorting to enforcement or penalty actions. MNOPS may initiate and conclude informal enforcement cases on its own, including civil penalty actions.[190] The MNOPS enforcement procedures are substantially similar to PHMSAs. The MNOPS may negotiate settlements of civil penalties[191] and may refer matters for judicial enforcement in state court.[192]

MNOPS has a large degree of flexibility and authority to initiate and conclude enforcement cases.

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[180] OR Public Utility Commission: http://www.oregon.gov/PUC/safety/index.shtml (last accessed May 4, 2011).
[181] Or. Rev. Stat. § 757.039 (2009).
[182] OR. ADMIN. R. 860-031-0005 (2011).
[183] OR. ADMIN. R. 860-031-0010 (2011).
[184] *Id.*
[185] OR. ADMIN. R. 860-031-0015 (2011).
[186] OR. ADMIN. R. 860-031-0020 (2011).
[187] OR. ADMIN. R. 860-031-0030 and 0035 (2011).
[188] PHMSA data on OR PUC enforcement: http://primis.phmsa.dot.gov/comm/reports/stenforce/StateEnfDet_state_OR.html?nocache=2768#_TP_1_tab_2 (last accessed May 4, 2011).
[189] MINN. STAT. §§ 299F.56 – 299F.641; 299J.01 – 299J.18 (2010).
[190] Minn. R. 7530.0100-5060 (2010).
[191] MINN. STAT. § 299F.60 (2010).
[192] MINN. STAT. § 299F.61 (2010).

Virginia

In Virginia, the State Corporation Commission (SCC) regulates intrastate gas and hazardous liquid pipeline safety. The SCC Division of Utility and Railroad Safety regulate pipelines safety according to specific statutory authority.[193] SCC pipeline safety staff may issue informal Notices of Probable Violation and often seek to enter into settlements with pipeline operators. Staff may negotiate settlements with operators and the Commission makes final determination in choosing to accept, modify, or reject the settlement.[194] Failing informal settlement, the pipeline or SCC staff may invoke formal adjudicatory proceedings before the Commission.

The ability of staff to initiate informal enforcement cases, propose penalties, and engage in settlement negotiations provides the pipeline safety division with significant flexibility.

A figure of enforcement statistics for these states is set out below.

Figure 16 - State Enforcement Statistics

*	CA (gas)	CA (liquids)	OR	WA	TX	MN	VA
Probable Violations	2626	42	207	92	2794	347	281
Probable Violations Corrected	2108	30	239	70	2634	386	172
Compliance Actions	554	13	25	11	632	94	20
Total Penalties Assessed	$3,744	$90,556	$0	$174,000	$84,383	$74,056	$249,864
Total Penalties Collected	$1,733	$40,556	$0	$174,000	$83,050	$35,389	$249,864

*All figures are annual averages for the period from 2001-2009.
Derived from PHMSA data, *available at* http://primis.phmsa.dot.gov/comm/states.htm?nocache=5544 (*last accessed* April 30, 2011)

[193] VA. CODE ANN. §§ 56-553 - 555 (2011) (hazardous liquids); VA. CODE ANN. §§ 56-257.2 (2011) (gas).
[194] VA. CODE ANN. § 12.1 – 15 (2011).

California One-Call

California's underground facility damage prevention law covers any underground pipeline, conduit, duct, wire or other structure, except non-pressurized sewers and drains.[195] Generally, the law requires excavators to contact a state one-call program at least two days before excavating.[196] If a facility operator receives notification of excavation near its facility, it must locate and mark the facility within two days of the notification.[197] There is no single entity in California responsible for administering or enforcing state damage prevention laws. Instead, the law allows enforcement by the Attorney General, a district attorney, or the state or local agency that issued any excavation permit.[198] Facility operators and excavators are subject to civil penalties for violations.[199] In addition, excavators can be subject to disciplinary proceedings, including loss of their contractor's license.[200] There are two separate one-call systems in California - Underground Service Alert (Northern) and Dig Alert (Southern).

The California one-call law imposes more stringent line locating requirements for "high priority" underground facilities, including gas pipelines operating at pressures above 60 pounds per square inch.[201] For such facilities, the excavator and facility operator must meet in person at the proposed excavation site.[202]

A recent PHMSA characterization of state damage prevention programs indicates that a key challenge in California is the lack of a single entity for dispute resolution and enforcement.[203] PHMSA also observed a weakness in the "process for fostering and ensuring active participation by all stakeholders in public education for damage prevention activities."[204] Proposed state legislation would centralize damage prevention authority in the CPUC, by granting it the authority to adopt and enforce a one-call notification program.[205]

Many state damage prevention programs have exemptions for certain categories of excavators, such as state and municipal excavators and their contractors. Pending federal legislation would require states to eliminate exceptions for state and local excavators as a condition of receiving damage prevention and state program grant funding.[206] PHMSA is also in the midst of a

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[195] CAL. GOV'T. CODE §§ 4216-4216.9 (2010).
[196] *Id.* § 4216.2 (2010).
[197] *Id.* § 4216.3 (2010).
[198] *Id.* § 4216.6(b) (2010).
[199] *Id.* § 4216.6(a) (2010).
[200] CAL. Bus. & Prof. CODE § 7110 (2010).
[201] CAL. GOV'T. CODE § 4216.2(a)(2) (2010).
[202] *Id.*
[203] PHMSA summaries of state damage prevention programs: http://primis.phmsa.dot.gov/comm/publications/StateProgramCharacterizationSummaries-20100514.pdf (last accessed May4, 2011).
[204] *Id.*; 49 U.S.C. § 60134(b)(5).
[205] Assemb. B. 56, as amended (Cal. Feb. 23, 2011); S.B. 216, as amended (Cal. Apr. 25, 2011).
[206] Pipeline Transportation Safety Improvement Act of 2011, S.275, 112th Cong. § 3 (referred to Comm. On Commerce Science and Transp. Feb. 3, 2011).

rulemaking process that will result in a procedure where by PHMSA can make a determination that a state damage prevention program is inadequate, and take federal enforcement action in the state.[207]

Aside from state damage prevention requirements, PHMSA's integrity management regulations require pipeline operators to consider the potential for external damage as a threat and take and monitor comprehensive additional measures to mitigate the threat.[208] In addition, PHMSA regulations require operators to have a written damage prevention program, a portion of which can be satisfied through participation in state one call programs.[209]

[207] Advanced Notice of Proposed Rulemaking, 74 Fed. Reg. 55,797 (Oct. 29, 2009).
[208] 49 C.F.R. § 192.917(e) (2010).
[209] 49 C.F.R. § 192.614 (2010).

Appendix P

CA State Fire Marshal Oversight

Intrastate pipeline and that portion of an interstate pipeline which is located within California is subject to the federal Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. Sec.2001 et seq.), the Pipeline Safety Reauthorization Act of 1988 (Pub. L.100-561) and federal pipeline safety regulations.

The Office of the State Fire Marshal (OSFM) Pipeline Safety Division is directly responsible for regulating the safety of approximately 4,500 miles of intrastate and approximately 1,200 miles of interstate hazardous liquid transportation pipelines. Pipeline Safety Division inspects, test, and investigate to ensure compliance with all federal and state pipeline safety laws and regulations. The Pipeline Safety Division consists of engineers, analytical staff, and clerical support located in Sacramento, Middletown, Bakersfield, and Lakewood.

The Division is mandated by state law[210] to exercise exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines and also acts as an agent of the federal Office of Pipeline Safety in the inspection of interstate pipelines. The SFM regulate 46 intrastate and 9 interstate operators. The federal government since 1981 has certified the program.

The OSFM established a Pipeline Safety Advisory Committee for purposes of informing local agencies and every pipeline operator of changes in applicable laws and regulations affecting the operations of pipelines and reviewing proposed hazardous liquid pipeline safety regulations.

Every rupture, explosion, or fire involving a pipeline, including a pipeline system otherwise exempted, and including a pipeline undergoing testing, must be immediately reported by the pipeline operator to the fire department having fire suppression responsibilities and to the Office of Emergency Services. The Office of Emergency Services notifies the OSFM. The pipeline operator must within 30 days of the rupture, explosion, or fire file a report with the OSFM.

The OSFM, every fifth year commencing in 1999, issues a report identifying pipeline leak incident rate trends, reviewing current regulatory effectiveness with regard to pipeline safety and recommending any necessary changes to the legislature.

Figure 17 below provides a summary of incidents, fatalities, injuries and property damage related to liquid pipelines failures in California from 2001 to 2010.

[210] TBP

Figure 17 - Summary of Liquid Pipeline Incidents, Fatalities, Injuries and Property Damage

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Incidents	6	8	12	9	13	13	7	11	2	6
Fatalities	0	0	0	5	0	0	0	0	0	0
Injuries	1	0	1	3	0	0	0	0	0	0
Property Damage*	$2498	$1619	$4432	$27164	$26893	$11050	$3812	$3088	$983	$5830

* Thousands of Dollars

Source: PHMSA

Figure 18 below provides a summary of probable violations issued, compliance action issued and dollars assessed by the SFM to liquid pipeline operators.

Figure 18 - Summary of Probable Violations Issued, Compliance Action Issued and Dollars Assessed

	2001	2002	2003	2004	2005	2006	2007	2008	2009
Probable Violations	32	40	10	23	21	60	46	84	59
Compliance Action	13	13	4	11	20	19	14	16	8
Dollars Assessed*	$ -	$ 200	$ -	$ 90	$ 500	$ -	$ 5	$ 20	$ -

* Thousands of Dollars

Source: PHMSA

The SFM maintains Geographic Information Systems (GIS)-based maps of all regulated pipelines and has been named as a state repository for pipeline data by the National Pipeline Mapping System (NPMS).

The OSFM assesses and collects from every pipeline operator an annual fee for carrying out this chapter. Funds are also provided by a grant from the federal government. All fees collected are deposited in the Pipeline Operations Account. The money in the account is available, upon appropriation by the legislature, to the OSFM for carrying out its mission.

Authority

The OSFM has adopted hazardous liquid pipeline safety regulations in compliance with the federal relating to hazardous liquid pipeline safety law. The regulations include, but not limited to, compliance orders, penalties, and inspection and maintenance provisions.

The OSFM can exempt the application of regulations to any intrastate pipeline, or portion thereof when it is determined the risk to public safety is slight and the probability of injury or damage remote. Exemptions are documented in writing and include a discussion of those factors, which the OSFM considers significant to the granting of the exemption.

Pipeline Safety Advisory Committee

The Pipeline Safety Advisory Committee is composed of eight members: two represent pipeline operators, three represent local agencies, one is a fire chief, and two are public members. The committee meets when requested by the OSFM, but not less than once a year. Some of the issues the Pipeline Safety Advisory Committee has been engaged in are:

- In consultation with the Pipeline Safety Advisory Committee and pipeline operators, the establishment of evaluation criteria for use by a pipeline operator when conducting any assessment.
- In consultation with the Pipeline Safety Advisory Committee, the development of criteria for identifying which hazardous liquid pipelines pose the greatest risk to people and the environment due to the likelihood of, and likely seriousness of, an accident due to corrosion or defect.
- In consultation with the Pipeline Safety Advisory Committee, the State Water Resources Control Board, the California regional water quality control boards, and local water purveyors, the OSFM at least once every five years reviews the regulations to determine if new measures that have been proven to be technologically feasible, practical, and operationally sound should be included in the regulations.

Operations

Cathodic protection of liquid pipelines was required on all hazardous liquid pipelines constructed after January 1, 1984. Hazardous liquid pipelines constructed prior to January, 1, 1984, were required to have cathodic protection on or before October 18, 1988, except pipelines that transport by gravity or operate at a stress level of 20% or less of SMYS of the pipe, which must have cathodic protection by January 1, 1991.

Hazardous liquid pipeline operators are required to file with the SFM an inspection, maintenance, improvement, or replacement assessment, although there is no intention to require the replacement of a pipeline. When preparing any assessment, priority is given to:

- Older pipelines located in densely populated areas
- Pipelines with a high-leak history
- Pipelines located near existing seismic fault lines
- Pipelines in areas with identified ground formations

A pipeline inspection, maintenance, improvement, or replacement assessment incorporates any information on regulatory requirements or existing public policies that could act as barriers to the inspection, maintenance, improvement, or replacement of pipelines. The assessment is required for the following:

- Any pipeline or pipeline segments built before January 1, 1960.
- Any pipeline installed on or after January 1, 1960, for which regular internal inspections cannot be conducted, or which shows diminished integrity due to corrosion or inadequate cathodic protection.

Any new pipelines must include a means of leak detection and cathodic protection the OSFM determines is acceptable. This does not apply to the replacement of valves and the relocation or replacement of portions of pipelines.

Any new pipeline on which construction begins after January 1, 1990, must be designed to accommodate the passage of instrumented internal inspection devices, and have leak mitigation and emergency response plans and equipment as the OSFM may require.

Any repairs to existing pipelines that can accommodate instrumented internal inspection devices are to be designed and constructed in a manner not to interfere with the passage of these devices.

For pipelines which cannot accommodate internal inspection devices, replacements of portions of the pipe is to be designed and constructed in a manner consistent, to the extent practicable, with the eventual accommodation of instrumented internal inspection devices.

A pipeline operator is required to make available to the OSFM, or any officers or employees authorized by the OSFM, any records, maps, and written procedures that are required to be kept by the pipeline operator including those which concern accident reporting, design, construction, testing, or operation and maintenance.

Higher Risk Pipeline

Each pipeline within the OSFM's jurisdiction that satisfies any of the following sets of criteria is placed on the OSFM's list of higher risk pipelines until five years pass without a reportable leak due to corrosion or defect on that pipeline. Pipelines that are found to belong on the list, but are not so reported by the operator to the OSFM, are placed on the list retroactively. The list includes pipelines that meet any of the following criteria:

- Have suffered two or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion or defect in the prior three years.
- Have suffered three or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion, defects, or external forces, but not all due to external forces, in the prior three years.
- Have suffered a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or defect, of more than 50,000 gallons, or 10,000 gallons of product in a standard metropolitan statistical area, in the prior three years; or have suffered a leak due to corrosion or defect which has resulted in more than 42 gallons of a hazardous liquid within the pipelines entering a waterway in the prior three years; or have suffered a reportable leak of a hazardous liquid with a flashpoint of less than 140 degrees Fahrenheit, or 60 degrees centigrade, in the prior three years.
- Are less than 50 miles long, and have experienced a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or a defect in the prior three years.
- Have experienced a reportable leak in the prior five years due to corrosion or defect, except during a certified hydrostatic pressure test, on a section of pipe more than 50 years old.

Pipelines on Higher Risk Pipeline list is tested by the next scheduled test date, or within two years of being placed on the list, whichever is first. If any pipeline becomes eligible for the list of higher risk pipelines after that date, the pipeline company must report that fact to the OSFM within 30 days and the pipeline is to be placed on the list retroactively to the date on which it became eligible for listing.

Testing

Hazardous liquid pipelines are periodically tested for integrity using procedures approved by SFM.

Every newly constructed pipeline, existing pipeline, or part of a pipeline system that has been relocated or replaced, and every pipeline that transports a hazardous liquid substance or highly volatile liquid substance is hydrostatically tested.

Every intrastate pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices are hydrostatically tested annually.

Every intrastate pipeline over 10 years of age and not provided with effective cathodic protection is hydrostatically tested every three years, except for those on the OSFM's list of higher risk pipelines, which shall be hydrostatically tested annually.

Every pipeline over 10 years of age and provided with effective cathodic protection is hydrostatically tested every five years, except for those on the OSFM's list of higher risk pipelines which shall be hydrostatically tested every two years.

The pressure tests required are conducted in accordance with Subpart E of Part 195 of Title 49 of the Code of Federal Regulations, except that an additional four-hour leak test, as specified in subsection (c) of Section 195.302 of Title 49 of the Code of Federal Regulations, may not be required.

When hydrostatic testing is required, the test results must be certified by an independent testing firm or person who is selected from a list, provided by the OSFM, of independent testing firms or persons approved annually by the OSFM.

The OSFM may require any intrastate pipeline to be subjected to a pressure test, or any other test or inspection, at any time, in the interest of public safety. Test methods other than the hydrostatic tests, including inspection by instrumented internal inspection devices, may be approved by the OSFM on an individual basis.

Notification, Outreach, Liaison

Each pipeline operator is required to notify the OSFM and the local fire department having fire suppression responsibilities at least three working days prior to conducting a hydrostatic test, which is required by this chapter.

Every pipeline operator must provide to the fire department having fire suppression responsibilities a map or suitable diagram showing the location of the pipeline, a description of all products transported within the pipeline, and a contingency plan for pipeline emergencies, which includes, but not be limited to any reasonable information, which the OSFM may require.

Every pipeline operator must offer to meet with the local fire department having fire suppression responsibilities at least once each calendar year to discuss and review contingency plans for pipeline emergencies.

With advice from the Pipeline Safety Advisory Committee, the State Water Resources Control Board, the California regional water quality control boards, and local water purveyors, the OSFM has adopted regulations for wellhead protection plans that provide guidelines to be used by the

pipeline operator to protect the public drinking water well from contamination should a pipeline rupture or leak pose a significant threat to a public drinking water well.

The OSFM reviews each wellhead protection plan submitted by a pipeline operator, and approves those plans that meet the criteria of the regulations adopted by the OSFM. The OSFM evaluates the plan at least once every five years to ensure the plan is in compliance with the current regulations.

Encroachment

As of January 1, 1987, no person, other than the pipeline operator, may do any of the following with respect to any pipeline easement:

- Build, erect, or create a structure or improvement within the pipeline easement or permit the building, erection, or creation thereof.
- Build, erect, or create a structure, fence, wall, or obstruction adjacent to any pipeline easement, which would prevent complete and unimpaired surface access to the easement, or permit the building, erection, or creation thereof.

No shrubbery or shielding may be installed on the pipeline easement, which would impair aerial observation of the pipeline easement. The regulation does not prevent the revegetation of any landscape disturbed within a pipeline easement as a result of constructing the pipeline and does not prevent the holder of the underlying fee interest or the holder's tenant from planting and harvesting seasonal agricultural crops on a pipeline easement.

The regulation does not prohibit a pipeline operator from performing any necessary activities within a pipeline easement, including, but not limited to, the construction, replacement, relocation, repair, or operation of the pipeline.

It is the position of the OSFM that “nothing shall encroach into or upon the pipeline easement, which would impede the pipeline operator from complete and unobstructed surface access along the pipeline right-of-way. Nor shall there be any obstructions, which would shield the pipeline right-of-way from observation. In the interest of public safety and the protection of the environment, it is imperative that the pipeline operator visually assesses the conditions along the easement to ensure the integrity of the pipeline.”

It is the responsibility of the pipeline operator to ensure they have unimpeded surface access and to be able to observe physically all portions of their pipeline rights-of-way. In cases where this is not possible, the pipeline operator informs the OSFM. The OSFM will, in conjunction with the pipeline operator, resolve the issue.

Data and Information

The Office of the State Fire Marshal has established and maintains a centralized database containing information and data regarding the intrastate pipelines. The database includes, but is not limited to, an inventory of the pipelines, including pipeline locations, ownership, ages, and inspection histories, that are in the possession of the owner or operator of the oil field or other gas facility.

The OSFM regularly updates the database and makes the information in the database available to the public, and to all local, state and federal agencies.

Any state or local governmental agency that regulates, supervises, or exerts authority over any pipeline is to report any information or data in its possession to the OSFM. That information is to be submitted to the OSFM in a computer compatible format.

The OSFM conducted a study of the fitness and safety of all pipelines, and investigated incentive options that would encourage pipeline replacement or improvements, including, but not limited to, a review of existing regulatory, permit, and environmental impact report requirements and other existing public policies, as may be identified by the Pipeline Safety Advisory Committee and adopted by the OSFM, that could act as barriers to the replacement or improvement of those pipelines.

The OSFM developed a comprehensive database of pipeline information that can be utilized for emergency response and program operational purposes. The database includes information on pipeline location, age, reported leak incidences, and inspection history, and has the capability of mapping pipeline locations throughout the state.

Utilizing GIS-based location information furnished by the State Department of Health Services and the State Water Resources Control Board, at least once every two years the OSFM determines the identity of each pipeline or pipeline segment that is regulated by the OSFM that transports petroleum product when that pipeline is located within 1,000 feet of a public drinking water well.

Risk Assessment

The OSFM conducted and prepared a risk assessment study dealing with intrastate and interstate hazardous liquid pipelines, which are located not more than 500 feet from any rail line and submitted to the Governor and the Legislature (around 1991).

In an effort to better protect public safety, the OSFM adopted regulations governing the construction, testing, operations, periodic inspection, and emergency operations of intrastate hazardous liquid pipelines located within 500 feet of any rail line. These regulations include provisions dealing with the following:

- Minimum depth of cover for newly constructed or reconstructed pipelines.
- Minimum hydrostatic testing requirements for newly constructed pipelines.
- Minimum requirements for testing existing pipelines, which may have been affected by a derailment.
- Minimum requirements for periodic inspections.
- Minimum requirements for installation and operation of safety or check valves.
- Procedures for developing, testing, approving, and implementing coordinated emergency contingency plans prepared by pipeline and rail operators. These procedures also provide for consultation with local affected agencies, and require pipeline and rail operations to develop and implement emergency training for their employees approved by the OSFM.

Valves

The OSFM adopted regulations that establish procedures for maintaining, testing, and inspecting mainline valves and check valves on intrastate hazardous liquid pipelines.

The OSFM study the spacing of valves, which would limit spillage into standard metropolitan statistical areas and environmentally sensitive areas from surrounding higher ground. If any existing pipeline system's valve spacing is deemed insufficient to protect California's uniquely situated population centers and environmental resources, the OSFM may require the addition of valves on existing pipelines. If the study indicates guidelines for valve spacing do not, in the OSFM's opinion, adequately protect these population centers and environmental resources, the OSFM may require new valves on new, existing, or replacement pipelines as necessary to protect the public interest.

Enforcement

The OSFM may issue orders directing compliance with state code or any regulations adopted. The OSFM will specify in the order the particular action which is required of the person issued the order.

The OSFM has adopted regulations for conducting enforcement proceedings consistent with the procedures specified in Sections 190.207 to 190.215, inclusive, and Section 190.227 of Title 49 of the Code of Federal Regulations.

If the OSFM determines, pursuant to the regulations, a person has violated any regulation adopted, that person is subject to a civil penalty of not more than ten thousand dollars ($10,000) for each day that violation persists, except the maximum civil penalty shall not exceed five hundred thousand dollars ($500,000) for any related series of violations.

- Any person who willfully and knowingly violates any provision or a regulation issued pursuant thereto upon conviction shall be subject, for each offense, to a fine of not more than twenty-five thousand dollars ($25,000), imprisonment for a term not-to-exceed five years, or both.
- Any person who willfully and knowingly defaces, damages, removes, or destroys any pipeline sign or right-of-way marker required by federal or state law or regulation upon conviction shall be subject, for each offense, to a fine of not more than five thousand dollars ($5,000), imprisonment for a term not-to-exceed one year, or both.

All civil penalties collected are deposited into the California Hazardous Liquid Pipeline Safety Fund and the money is used for providing hazardous liquid fire suppression training to local fire departments.

The California Hazardous Liquid Pipeline Safety Fund was also used to fund the comprehensive database of pipeline information that can be utilized for emergency response and program operational purposes.

Appendix Q

Public Policies in the State of California

Ratemaking Regulatory Regime

Background on Gas Utility Ratemaking in CA and PG&E

The CPUC's authority to regulate electric, natural gas, and other public utilities subject to its jurisdiction derives from the California state constitution.[211] The California Public Utilities Code requires that all charges for service provided by a public utility be just and reasonable.[212] Pursuant to this authority, the CPUC determines reasonable operational costs, customer cost allocations and rate design for the gas utility operations gas utilities, including PG&E.[213]

Costs incurred by California utilities to provide services to customers fall into the following major categories: gas procurement costs for core customers (primarily residential and small commercial customers);[214] utility operating costs, and gas public purpose program costs.[215] Each of these categories is subject to a different ratemaking proceeding. Discussed below are the ratemaking process and issues pertaining to costs PG&E incurs to operate its distribution, transmission and storage facilities.

The purpose of a rate case is to establish rates that will enable it to recover its authorized revenue requirement, *i.e.*, the revenues needed to cover the costs of operating natural gas distribution, transmission and storage systems and earn a rate of return (profit).[216] During the ratemaking process, costs are allocated among customer customers and then rates applicable to individual customer classes are developed.

PG&E uses two different proceedings to establish its authorized revenue requirement for its gas distribution and for its transmission and storage services. Its gas distribution revenue requirement is established in a general rate case (GRC), with cost allocation and retail distribution rates determined in a separate biennial cost allocation proceeding. The revenue requirement and rates for PG&E's transmission (backbone and distribution) and storage

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[211] CA Const. Art. XII, § 6.
[212] Cal. Public Utilities Code § 451.
[213] California Public Utilities Commission, Electric & Gas Utility Cost Report; Public Utilities Code Section 747 Report to the Governor and Legislature at 30 (Apr. 2011) (hereinafter referred to as the "Section 747 Report").
[214] Noncore natural gas customers, generally electric generators or industrial customers, generally purchase their gas supplies from third parties, rather than from the utility. Section 747 Report at 31.
[215] Section 747 Report at 30. Gas Public Purpose Programs fall into three main categories: energy efficiency and low income energy efficiency; the subsidy for California Alternative Rate for Energy (CARE); and the California Energy Commission's gas public interest research and development program. Costs associated with these programs are determined in various CPUC proceedings. Section 747 Report at 33.
[216] *See* Section 747 Report at 4.

services are established in "Gas Accord" proceedings. Gas Accord and GRC proceedings follow similar procedural tracks and establish rates for rate cycles extending three to four years.

When filing a rate case, PG&E projects future costs for the applicable rate cycle, which includes a "test year" and two or three "post test years," or attrition years. The utility provides five years of historical cost data.[217] Interested parties, including the CPUC's Division of Ratepayer Advocates (DRA) routinely intervene and actively participate. DRA, created under section 309.5 of the Public Utilities Code, "represents and advocates on behalf of the interests of public utility customers," with the goal of "obtain[ing] the lowest possible rate for service consistent with reliable and safe service levels."[218] Like other parties, DRA staff engages in discovery, files testimony, participates in evidentiary hearings, and engages in settlement negotiations.

The Energy Division is not a party to these rate cases, but provides technical assistance and advice to the presiding administrative law judge (ALJ) and the Commissioners. Energy Division staff keep apprised of developments in a rate case, but because of their role in assisting the ultimate decision-makers, do not interact with DRA.

CPSD staff of the CPSD traditionally has had little involvement in natural gas utility ratemaking proceedings. The CPSD staff has expressed its desire, however, to increase interaction with DRA and Energy Division Staff to assist them in understanding utility maintenance requirements and expenditures in gas rate cases. More recently, the CPSD staff has increased its outreach efforts to DRA and the Energy Division for the purpose of helping them to understand maintenance, repair, and replacement costs. The CPSD's limited role in gas utility ratemaking proceedings is not unusual when compared to practices in other states.[219]

Utility rate cases typically are resolved through settlement among the parties, often after the completion of evidentiary hearings. The CPUC approves a rate settlement if it is "reasonable in light of the whole record, consistent with the law, and in the public interest.[220]

Overview of PG&E's Ratemaking Proceedings

The Revenue requirement and rates for PG&E's transmission and storage services are established in its Gas Accord proceedings. On April 18, 2011, the CPUC accepted a settlement that will establish PG&E's revenue requirements for these services for the 2011–2014 rate

[217] Rule 3.2 of the CPUC's Rule of Practice of and Procedure set forth the information a utility must submit with an application for authority to increase its rates.
[218] Cal. Public Utilities Code § 309.5(a).
[219] Based on conversations with staff at several state agencies, formal involvement by pipeline safety staff in a utility ratemaking case appears to be rare. Rather, state safety personnel appear to generally serve as informational resources, with a couple states indicating that state safety personnel have limited or no involvement in utility ratemaking processes.
[220] CPUC Rule of Practice and Procedure Rule 12.1(d)

cycle.[221] A settlement approved on May 13, 2011 in PG&E's 2011 General Rate Case (GRC 2011) established the utility's distribution revenue requirements for the 2011-2013 rate cycle.[222]

Both settlements provide for capital project expenditures involving new pipeline facilities and contain new ratemaking mechanisms for expenses associated with pipeline safety and reliability. In addition, both settlements contain extensive new pipeline safety reporting requirements. Below is an overview of the two rate proceedings, particularly their treatment of costs related to pipeline integrity management and reliability and reporting requirements.

PG&E's Gas Accord V. PG&E submitted its Gas Accord V rate filing in 2009 and filed a proposed settlement in August 2010, one month before the San Bruno accident. Following the accident, the presiding ALJ added a "safety phase" to the proceeding to address pipeline safety measures and emergency response procedures that PG&E should be required to implement to ensure the safe and reliable operations of its transmission and storage facilities.[223] In addition, the Gas Accord V Decision modified PG&E's settlement to require extensive pipeline safety reporting requirements.[224]

The Gas Accord Decision approved a revenue requirement for 2011 of $514.2 million, which will increase to $581.8 million by 2014.[225] The decision also approves capital expenditures for new pipeline and pipeline upgrades, providing PG&E with 100% and 98% of the capital investment it requested for pipeline integrity and pipeline safety and reliability, respectively.[226] Major Work Category 98 (MWC-98) addresses "Gas Transmission Pipeline Integrity Management" and identifies capital funds needed under federal pipeline integrity management requirements,[227] especially to upgrade PG&E's transmission pipelines to accommodate in-line inspections.[228] Major Work Category 75 (MWC-75) addresses "Pipeline Safety and Reliability," and covers capital costs associated with PG&E's replacement of high-risk pipeline segments and pressure regulating facilities identified under PG&E's Risk Management Program.[229] The Gas Accord Decision also approves eight planned transmission capital projects that will be given "adder" treatment. If PG&E constructs these identified projects, the costs (up to a cap) will be added to PG&E's rates starting on January 1 following the project's in-service date.

The Gas Accord V Decision also approved a negotiated level of operation and maintenance expenses for each year of the rate cycle, including expenses associated with compliance with

[221] Decision Regarding the Gas Accord V Settlement, D.11-04-031 (Apr. 18, 2011) (Gas Accord V Decision).
[222] Decision Regarding 2011 GRC, D.11-05-018 (May 13, 2011).
[223] Revised Scoping Memo and Ruling Adding an Additional Phase, A.09-09-013, (Oct. 15, 2010).
[224] Gas Accord V Decision at 16
[225] Gas Accord V Decision at 23.
[226] Gas Accord V Decision at 27.
[227] 49 C.F.R. Part 192, Subpart O (2009).
[228] Gas Accord V Decision at 24-25 & Settlement Section 7.2.
[229] Gas Accord V Decision at 26-27.

the Department of Transportation's (DOT) transmission integrity management regulations.[230] For these costs, the decision approved a new Integrity Management Expense Balancing Account (IMEBA), which is a one-way downward balancing account in which PG&E will record the aggregate difference between the authorized revenue requirement and expenses incurred over the term of the settlement. At the end of the settlement period, accumulated account balances are returned to customers, with interest. Reflecting a concern that in the past, PG&E has not always spent all funds authorized for certain projects, the CPUC's decision explains that the one-way balancing account is designed to "help ensure that PG&E spends all of the designated O&M monies for pipeline integrity management activities."[231] There is no provision for PG&E to recover expenses that exceed authorized amounts, even if prudently incurred.

Reflecting the renewed focus on pipeline safety issues in the aftermath of the San Bruno accident and to establish a mechanism for verifying that PG&E spends authorized funds for their intended purposes during the rate cycle, the CPUC's Decision requires that PG&E submit a semi-annual "Gas Transmission and Storage Safety Report" to the directors of the Energy Division and CPSD.[232] The report must provide adequate information to enable staff to (1) monitor PG&E's activities and expenditures related to storage and pipeline-related safety, reliability and integrity capital projects and maintenance; (2) determine whether PG&E is completing projects identified as high risk or undertaking other high risk projects instead; (3) determine PG&E's reasons for any project reprioritization; and (4) monitor PG&E's compliance with federal integrity management regulations (Part 192, subpart O).[233] The CPUC's Decision further requires that, if the CPSD identifies problems with PG&E's prioritization or administration of projects, the CPSD shall notify the CPUC.[234]

The Safety Phase of the Gas Accord V proceeding remains pending before the CPUC and will address how safety concerns on PG&E's system can be avoided over 4-year rate cycle and beyond. In February 2011, the presiding ALJ issued a ruling stating that he would prepare a proposed decision recommending safety-related protocols and procedures that PG&E should be required to implement.[235]

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[230] Section 7.3.1 of the Settlement. In 2011, authorized O&M expenses associated with integrity management are $22 million and escalate each year of the rate cycle by up to 2.6 percent.

[231] Gas Accord V Decision at 56. The settlement provided PG&E with 92 percent of its requested expenditures for pipeline integrity operations and maintenance expenses. *Id.* at 27.

[232] Gas Accord V Decision at 58; Settlement, Appendix C.

[233] Gas Accord V Decision at 58; Settlement, Appendix C.

[234] Gas Accord V Decision at 58-59.

[235] Assigned Comm'r & ALJ's Ruling Confirming e-mail Ruling & to Address Whether Proposed Settlement is Adequate in Terms of Pipeline Safety, Integrity, & Reliability Efforts, A.09-09-013 at 3 (Sept. 15, 2010) (Safety Phase Ruling). Those protocols and procedures included the following: PG&E's disaster and emergency response plan (PG&E's Pipeline 2020 Program, which involves expanded use of automatically or remotely operated shut-off valves, and work with local communities, public officials and first responders); steps PG&E has taken to inform local emergency personnel about availability and location of transmission lines and shut-off valves and whether additional information needed; frequency of testing or monitoring of shut-off valves; procedures PG&E should have to ensure timely notification to the CPUC of any reprioritization of capital expenditures associated with transmission lines and

PG&E's GRC 2011 Rate Proceedings: On May 13, 2011, the CPUC issued an order approving, with modification, PG&E's proposed GRC 2011 settlement.[236] The settlement establishes a gas distribution revenue requirement of $1,131 million for 2011, reflecting a $47 million (4.3%) increase.[237] By 2013, the total distribution revenue requirement will increase by a total of $246 million, which is $540 million less than PG&E requested in its application.[238] The settlement reflects a revenue requirement of $258 million for gas distribution capital expenditures in 2011, and expenditures of $196 million for expenses.[239] Attrition year increases will be implemented through the CPUC's Advice Letter process.[240]

With respect to pipeline safety expenditures, PG&E's settlement creates a Major Work Category for expenses incurred to comply with DOT's distribution integrity management program (DIMP) regulations.[241] PG&E would be required to establish a new one-way balancing account mechanism with a $60 million cap over the term of the GRC rate cycle, 2011-2013. PG&E will track DIMP expenditures over the course of the rate cycle and return to ratepayers any portion of the $60 million not spent at the end of the period.[242] Like the Gas Accord V settlement, the GRC 2011 settlement is silent regarding PG&E's ability to recover DIMP expenditures over $60 million.

The CPUC's decision accepting the settlement expresses concern that PG&E will reprioritize contemplated programs and projects in a way that is neither reasonable nor consistent with expenditures contemplated in and approved by the settlement. While acknowledging the utility's prerogative and responsibility to reprioritize and defer activities as needed to ensure safe and

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procedures CPUC staff should adopt to review and monitor the reprioritization of these capital expenditures; other safety-related protocols/procedures that should be required; and the need for workshops and/or evidentiary hearings to determine protocols/procedures PG&E should be required to implement during rate cycle.

[236] GRC 2011 Decision at 88-89.

[237] GRC 2011 Decision at 15 & Attachment 1 at 1-4 (Settlement at Section 3.1).

[238] GRC 2011 Decision at 19.

[239] PG&E GRC 2011 Settlement at Section 3.3.1. By comparison, the settlement in PG&E's GRC 2007 rate case authorized PG&E's fully requested amount of $205.6 million in 2007 for gas distribution capital expenditures, including $66.953 million for its Gas Pipeline Replacement Program (GPRP) and $15.8 million to maintain and enhance the gas distribution infrastructure. The CPUC Decision approving the GRC 2011 settlement noted that, in the past, PG&E's actual expenditures sometimes had fallen short of those budgeted, and required that PG&E use all funds provided in the settlement. If it did not, PG&E was required to provide full explanation in its next GRC. Opinion Authorizing Pacific Gas & Electric Company's General Rate Case Revenue Requirement for 2007-2010, D.07-03-044 at 80-83 (March 15, 2007). In its GRC 2011 application, PG&E explained that it did not spend the full $66.953 during 2007 and 2008, because its risk analysis indicated a need to establish a Copper Service Replacement Project (CSRP). PG&E, therefore, allocated some funds from the GPRP to the CSRP. Application of PG&E for Authority, Among Other Things, to Increase Rates & Charges for Elec. & Gas Service Effective on January 1, 2011, Exhibit PG&E-3, Ch. 17 (Testimony of Robert T. Fassett) at 19-6 to 19-7 (Dec. 21, 2009).

[240] The CPUC's advice letter process provides a utility a "quick and simplified review" of non-controversial utility requests. CPUC General Order 96-B at 2, 8.

[241] 49 C.F.R. §§ 192.1001-15 . The federal DIMP regulations, which are discussed more fully in section 7.2.3, become effective August 2011.

[242] PG&E GRC 2011 Settlement at Section 3.3.2.

reliable service, the decision emphasizes that the CPUC must be assured that the utility spends the funds necessary to ensure such safe and reliable service. Moreover, the CPUC expressed concern that, even if reprioritizations and deferrals are justified, they may not have been tested in the GRC process and may not reflect the most efficient use of funds.[243]

Therefore, the CPUC required that PG&E provide detailed information about pipeline safety-related expenses and capital expenditures. In particular, in 2011, PG&E must submit to the CPUC the company's authorized budgeted amounts for 2011 and explain any differences with assumptions reflected in the Settlement Agreement. In 2012 and 2013, PG&E must provide authorized budgeted amounts for the year and explain any significant deviations between the authorized budget for the prior year. In addition, in its next GRC, PG&E must submit extensive information fully describing any reprioritizations or deferrals, explaining the reprioritization process, justifying specific deferrals, and justifying activities and projects given a higher priority that were not identified in the 2011 GRC. The decision cautions that, for activities deferred and then re-requested in the next GRC, the CPUC will be "critical in its evaluation."[244]

Finally, in light of the San Bruno accident, the GRC Decision requires that PG&E submit a substantial amount of pipeline safety-related information to the CPSD and Energy Division on a semi-annual basis. As more fully discussed below, the reports must include (1) a "thorough description and explanation" regarding the decision-making process for identifying/ranking capital projects, operation and maintenance activities, and inspections undertaken for gas distribution pipeline safety, integrity and reliability; (2) detailed information regarding amounts budgeted and spent and specific detail on capital and O&M projects; and (3) project descriptions and status.[245]

One-Way Balancing Accounts for Pipeline Integrity Management and Reliability Expenses

The settlements in the Gas Accord V and GRC 2011 proceedings permit PG&E to recover capital costs, including infrastructure replacement costs, associated with pipeline integrity programs and reliability improvements through base rates. To track integrity management expenses, however, the settlements establish new one-way balancing mechanisms. Under such mechanisms, PG&E records as a credit the annual revenue requirement authorized under each settlement and then debits expenses as incurred. At the end of the rate cycle, PG&E is required to transfer any accumulated credit balance to core and non-core customers. The purpose of one-way balancing accounts is to ensure that PG&E spends all designated amounts

[243] GRC 2011 Decision at 26-31.
[244] GRC 2011 Decision at 30.
[245] GRC 2011 Decision at 31 & Attachment 5.

authorized for these purposes.[246] One-way balancing accounts differ from two-way balancing accounts in that a one-way balancing account does not provide the utility opportunity to recover expenses above initial authorized amounts, even if such costs are prudently incurred.

According to CPUC staff, under a one-way balancing account, the parties establish an agreed-upon reasonable forecast of costs associated with a targeted program, such as integrity management.[247] Recognizing that a utility has the discretion to spend funds, a one-way balancing account is designed to ensure that money is spent for the purpose intended and that all of the designated funds are spent. A utility cannot recover any costs above those initially authorized. As such, from parties' perspectives, one of the attractive features of a one-way balancing account is that it avoids time-consuming prudence reviews of costs that exceed authorized amounts.

Order Instituting Rulemaking on New Safety and Reliability Regulations

In the wake of the San Bruno accident, the CPUC has initiated a comprehensive review of its natural gas pipeline safety regulations, including the role of ratemaking in utility's implementation of pipeline safety programs. The proceeding is intended to be "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[248] The scope of the OIR is broad and identifies several "primary objectives," including (1) "[d]evelop and adopt safety-related changes to the Commission's regulation of natural gas transmission and distribution pipelines, including requirements for construction, especially shut-off valves [sic], maintenance, inspections, operations, record retention, ratemaking, and application of penalties;" and (2) "[c]onsider available options for the Commission to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the 'nuts and bolts' details of prudent utility operations."[249]

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[246] Gas Accord V Decision at 56. Southern California Gas Company's 2008 GRC also contained a one-way balancing account for distribution integrity management costs. Southern California Gas Company is proposing to eliminate the account in its 2012 GRC.

[247] There is at least one proposal before the California legislature that would codify one-way balancing accounts. California Assembly Bill (AB) 56 would require, among other things that a public utility return ratepayer funds that were approved for expenditure for public safety if those funds are not expended within a reasonable period of time. A.B. 56, 2011-12 Reg. Sess. (Cal. 2010).

[248] Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms, R.11-02-019 at 1 (Feb. 25, 2011).

[249] OIR at 4. Other objectives include Provide the public with a means to make their views known to the CPUC; provide the public with the IRP's expert recommendations regarding the technical explanation for the explosion, assessment of likelihood that similar events may occur, and recommendations for preventive measures and other improvements; consider ways that the CPUC can undertake a comprehensive risk assessment for all regulated natural gas pipelines, and possibly for other industries that the CPUC regulates. consider the appropriate balance between the CPUC's obligation to conduct its proceedings in a manner open to the public with the legitimate public safety concerns that arise from unlimited availability of certain utility information; consider if the CPUC needs further

The OIR proposes several near-term modifications to existing pipeline safety regulations affecting strength testing and reporting requirements. In addition, the OIR identifies twelve topics on which the CPUC is considering new rules.[250] With respect to ratemaking, the OIR expresses the need for certainty that expenditures authorized for maintenance and capital projects are carried out by the utility. In this regard, the OIR indicated that one of the measures to be considered is whether "special ratemaking 'feedback loop' for safety-justified expenditures…" should be implemented to ensure that such expenditures are in fact made, or substituted only with higher priority safety projects.[251]

Comments on the ratemaking aspects of the OIR reflect two approaches. DRA, for example, appears to advocate expanding the use of one-way balancing accounts for "specific safety and/or maintenance related expense categories and investment programs."[252] Southern California Gas Company and San Diego Gas & Electric Company, on the other hand, urge a "balanced ratemaking framework" that encourages utilities to implement safety practices, while preserving shareholders' ability to earn a reasonable return.[253] In this regard, SoCalGas/SDG&E urge the CPUC to convene a "collaborative workshop" to explore potential proposals and their impact on, among other things, "alignment of utility incentives and Commission policies…"[254] As an interim measure, SoCalGas/SDG&E urge that the CPUC authorize a Pipeline Safety and Reliability Memorandum Account[255] to enable utilities to track safety and reliability costs that were not contemplated in their GRCs.[256]

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rules or other protection for whistleblowers to inform the Commission of safety hazards; and expand emergency and disaster planning coordination with local officials. OIR at 4-5.

[250] OIR, Attachment B. Those topics include: retrofitting transmission lines to allow in-line inspections; requiring evaluations for installing automatic or remote controlled valves on transmission lines; strengthening emergency response procedures; gas control monitoring (prevent liquid intrusion and sulfur buildup); test requirements for pipes below 100 psig and service lines; clearance between gas pipelines and other subsurface structures; incorporating one-call requirements for marking underground facilities; reporting CP deficiencies and providing a timetable for remedial actions; cover requirements for transmission lines; reporting problems associated with mechanical/compression couplings; assessment of meter set assemblies and other pipeline components to protect from excessive snow and ice loading; and require operators to identify threats along pipelines and develop plan to mitigate them, including R&D.

[251] OIR at 12.

[252] Comments of the Division of Ratepayer Advocates on Order Instituting Rulemaking, R.11-02-019, at 3 (Apr. 13, 2011).

[253] Comments of Southern California Gas Co. and San Diego Gas & Elec. Co. on Order Instituting Rulemaking, R.11-02-019 at 11 (Apr. 13, 2011).

[254] Comments of Southern California Gas Co. at 11.

[255] "A memorandum account allows a utility to track costs arising from events that were not reasonably foreseen in the utility's last general rate case. By tracking these costs in a memorandum account, a utility preserves the opportunity to seek recovery of these costs at a later date without raising retroactive ratemaking issues. However, when the Commission authorizes a memorandum account, it has not yet determined whether recovery of booked costs is appropriate, unless so specified." CPUC, Energy Division, Resolution G-3453 at 2 n.2 (May 5, 2011) (citing D.10-04-031 mimeo at pp. 43-44).

[256] Comments of Southern California Gas Co. at 11.

PG&E expresses similar views, in particular, its expectation that the CPUC will allow utilities to recover compliance costs in their rates. Like SoCalGas/SDG&E, PG&E recommends that the CPUC authorize memorandum accounts to track costs associated with compliance with the new rules.[257]

On May 10, 2011, the Administrative Law Judge presiding in this proceeding issued a proposed decision that, if adopted, would require that operators of natural gas transmission pipelines in California (including PG&E) to prepare and file comprehensive Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans to either pressure test or replace those pipeline segments that have never been pressure tested or that lack sufficient detail related to the performance of a test.[258] The required implementation plans would be required to provide for testing or replacement as soon as practicable and include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near MAOP values which result in hoop stress levels at or above 30% SMYS, and other safety enhancement measures.

Implementation Plans would be required to (1) list all transmission pipeline segments not previously pressure tested, with prioritized designations for replacement or pressure testing; (2) set forth criteria used to identify which pipeline segments will be replaced instead of pressure tested; and (3) prioritize replacements and explain prioritization criteria. Before Implementation Plans are filed, the CPUC would convene technical workshops, facilitated by an administrative law judge, to discuss and provide recommendations to inform the prioritization of pipeline segments for replacement or testing. The workshops also would be critical to developing a sound engineering approach to address the issue of aging transmission lines that have not been pressure tested.

Finally, to enable the CPUC to fully consider the effects of the final adopted Implementation Plans, each plan would be required to provide cost estimates and information on rate impacts. Each Implementation Plan would be required to include a ratemaking proposal that contains (1) specific rate base and expense amounts for each year proposed to be included in regulated revenue requirement; (2) proposed rate impacts for each year and each customer class; (3) other facts and information necessary to understand the comprehensive rate impact of the Implementation Plan. PG&E's plan must also include a proposal for sharing costs between ratepayers and shareholders.

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[257] Comments of Pacific Gas and Elec. Co. on Order Instituting Rulemaking, R.11-02-019 at 25-26 (Apr. 13, 2011).

[258] Proposed Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans, Filed in OIR 11-02-019 (May 10, 2011).

Contrast Recovery of Integrity Management Costs to FERC and Other States

A key characteristic of one-way balancing accounts is that they preclude the utility from recovering integrity management expenses that exceed authorized forecasted amounts, even if those costs are prudent. The practice of using one-way balancing account treatment for expenses associated with compliance with federally mandated integrity management safety programs does not appear to be widespread.[259]

The Federal Energy Regulatory Commission: Pursuant to section 4 of the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) is charged with ensuring that the transportation and sales rates of interstate natural gas pipelines are just and reasonable.[260] An interstate pipeline's revenue requirement is based on projected units of service.[261] A pipeline filing a rate case must submit cost and revenue data for a 20-month test period, which can be adjusted for known and measurable changes.[262]

Pipeline section 4 rate cases are vigorously scrutinized by customers and usually entail extensive discovery. In addition, the parties often may file written testimony. Most interstate pipeline rate cases settle before an evidentiary hearing is convened. Usually, rate cases do not identify expenses associated with integrity management programs. Rather, these costs are embedded in the pipeline's cost of service and recovered through generally applicable rates. PHMSA does not participate in pipeline rate cases at FERC.

Interstate natural gas pipelines are not required to file rate cases and years may elapse between rate cases.[263] In the meantime, a pipeline is at risk for under recovering costs, but also retains any over-recovery.[264] The Commission has found that this gives the pipeline an incentive to minimize costs and maximize service.[265] Pipelines do not report, and FERC does not audit, safety expenditures after the conclusion of a rate case or in a future rate case.

Interstate pipelines are at risk for cost recovery between rate cases, therefore, the FERC generally disfavors cost trackers because they would guarantee recovery.[266] Consequently, to

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[259] This section focuses on expenses related to integrity management activities, not capital costs. With respect to capital costs, the Gas Accord V and GRC 2011 settlements allow PG&E to recover the prudently incurred capital costs associated with pipeline upgrades and replacements and do not place PG&E at risk for these costs via a one-way balancing mechanism. Although a number of states have adopted statutory and regulatory mechanism designed to ensure that pipelines can recover capital improvement costs, to date, the CPUC has not placed PG&E at risk for recovering them via a one-way balancing mechanism.

[260] 15 U.S.C. § 717 et seq. (2006).

[261] 18 C.F.R. § 284.10(b)(3) (2010).

[262] *See generally*, 18 C.F.R. §§ 154.301-315 (2010).

[263] The FERC may, however, initiate a rate case under NGA § 5, in which FERC has the burden of demonstrating that the pipeline's existing rates are unjust and unreasonable.

[264] *Canyon Creek Compression Co.*, 99 FERC ¶ 61,351 at PP 14-15 (2002).

[265] *Canyon Creek*, 99 FERC ¶ 61,351 at PP 14-15.

[266] *canyon Creek*, 99 FERC ¶ 61,351 at PP 14-15; *ANR Pipeline Co.*, 70 FERC ¶ 61,143 (1995).

date, the Commission has approved tracking mechanisms for pipeline safety compliance expenses only in the context of settlements. For example, Equitrans, L.P. is authorized to recover via a tracker expenses, and return, taxes and depreciation expense on capital investments associated with compliance with the Pipeline Safety Improvement Act of 2002.[267] The Commission also has approved settlements containing "capital surcharge" trackers, allowing a pipeline to recover certain qualifying costs incurred for system security and pipeline integrity costs.[268]

State Cost Recovery Mechanisms. As at FERC, a significant number of rate cases at state commissions are resolved by settlement and orders approving settlements do not necessarily discuss treatment of integrity management expenses as a separate cost item. To the extent, however, that cases address integrity management expenses as a separate expense item, use of one-way balancing accounts does not appear to be common. In 2005, The Michigan Public Service Commission (MPSC) established this type of a provision for a utility's "uncharacteristic" and "extraordinary" safety and training-related expenses that were not known and measurable.[269] The MPSC required that the utility submit an annual report on the status of program expenditures specifically identifying those related to safety and training-related activities. The MPSC would then review the expenditures to determine if a refund were appropriate.[270] Importantly, the one-way balancing account approved by the Michigan PSC differs from those reflected in PG&E's settlements, in that refunds of expenditures are not automatic.

Tracker mechanisms also have been utilized to recover integrity management expenses. Since 2004, Indiana Gas Company has been authorized to adjust its rates via a Pipeline Safety Adjustment to recover prudently incurred, incremental non-capital expenses, up to a specified cap. The utility must demonstrate that costs are clearly and convincingly demonstrated to be incremental and caused by the Pipeline Safety Improvement Act of 2002 (*i.e.* transmission integrity management costs).[271] Costs exceeding the cap are deferred for subsequent recovery, without carrying costs, either in a subsequent tracker where costs are below the cap, or in a future rate case. The mechanism was extended and modified in 2008 and extended again in 2011, and now includes a provision allowing the utility to amortize certain deferred balances

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[267] *Equitrans, L.P.*, 115 FERC ¶ 61,007 (2006).

[268] *Florida Gas Transmission Co.*, 109 FERC ¶ 61,320 (2004) (authorizing reservation surcharge to recover certain capital costs incurred for system security and pipeline integrity). *El Paso Natural Gas Co.*, 120 FERC ¶ 61,208 (2007) (authorizing volumetric surcharge to recover the cost of service effect of capital and related Operation and Maintenance expenses in connection with pipeline integrity program). These surcharges have expired.

[269] *Michigan Consolidated Gas Co.*, Opinion and Order Granting Rate Relief, Case No. U-13898 at 74-76 (Apr. 28, 2005).

[270] *Michigan Consolidated Gas Co.* at 76.

[271] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 42598 (Nov. 30, 2004). The mechanism was modified and extended in 2008, Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43298 (Feb. 13, 2008), and extended again in 2011. Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43967 (Apr. 5, 2011).

identified three-year periods, without regard to the cap.[272] In 2010, the mechanism was modified to include deferred DIMP planning expenses.[273]

Current and Proposed Reporting Requirements

In the wake of the San Bruno accident and concerns that PG&E had reprioritized projects and deferred the completion of pipeline safety and reliability projects that had been identified during rate cases as "high risk," no fewer than three proceedings either propose or have adopted extensive reporting requirements for PG&E. The Gas Accord V decision requires that PG&E submit a semi-annual "Gas Transmission and Storage Safety Report" (Safety Report), and the GRC 2011 Decision requires that PG&E submit gas distribution reports. In addition, the OIR proposes to require the submission of reports to the CPUC.

The Gas Accord V and GRC 2011 settlements contain numerous reporting requirements applicable to PG&E's transmission and storage facilities and gas distribution facilities. The reporting requirements are similar. Generally, PG&E must:

- provide a "thorough description and explanation of the strategic planning and decision-making approach" used to determine and rank safety, integrity, and reliability projects, operation and maintenance activities and inspections;[274]
- provide specific information regarding funds budgeted and spent regarding pipeline safety, integrity and reliability capital expenditures and operation and maintenance expenses each year and throughout the rate period, and an explanation for any funds budgeted that are not spent;
- provide detailed information regarding projects undertaken; projects completed or not completed; costs of projects and how they compare to information contained in the Settlement Agreements; whether projects were completed pursuant to any federal requirement;
- provide its most recent Risk management Top 100 Report and identify any changes to it and reasons for them;
- provide its most recent inspections plans, explain progress of performing inspections, their results and inspection methods, and explain any discrepancies found in pipeline records; and
- discuss the status of compliance with federal pipeline integrity management regulations.

In addition, the OIR would require that pipeline operators report incidents that meet certain criteria, provide quarterly summary reports on gas leak related incidents,[275] submit installation

[272] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43967.
[273] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43885 (Sept. 8, 2010).
[274] Gas Accord V Decision Appendix C at 1; Proposed ALJ Decision Attachment 5 at 1.

reports regarding new pipeline construction and reconstruction or reconditioning of existing pipeline to be operated at a hoop stress of 20% or more of SMYS.[276]

Most, if not all, of this information is to be submitted to the directors of the CPSD and Energy Division. The staff's of both divisions indicated that they were involved in developing these requirements, but expressed concern about whether they have resources adequate to review and evaluate the information and take any action based on it.[277]

[275] OIR, Attachment B.
[276] OIR, Attachment C.
[277] Interview of CPSD, March 29, 2011; Interview with Energy Division, Mar. 29, 2011.