BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

OPENING BRIEF
OF THE CONSUMER PROTECTION AND SAFETY DIVISION

HARVEY Y. MORRIS
TRAVIS T. FOSS
J. JASON REIGER

Attorneys for the Consumer Protection and Safety Division

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102
Phone: (415) 703-1998
Email: travis.foss@cpuc.ca.gov

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

CPUC Decisions

CPUC Regulations

California Public Utilities Code

Federal Statutes

Code of Federal Regulations

TABLE OF ACRONYMS

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASV	Automatic Shutoff Valve
BAP	Baseline Assessment Plan
Capex	Capital Expenditures
CFR	Code of Federal Regulations
COF	Consequence of Failure
DSAW	Double Submerged Arc Welding
ECDA	External Corrosion Direct Assessment
ERW	Electric Resistance Welding
FAQ	PHMSA Frequently Asked Question
GIS	Geographic Information System
GO	General Order
GPRP	Gas Pipeline Replacement Program
GSR	Gas Service Representative
HCA	High Consequence Area
ILI	In Line Inspection
IM	Integrity Management
LOF	Likelihood of Failure
LTIP	Long-term Incentive Plan
LTIMP	Long-Term Integrity Management Plan
M&C	Manufacturing and Construction
MAOP	Maximum Allowable Operating Pressure
MOP	Maximum Operating Pressure
MP	Mile Post
NACE	National Association of Corrosion Engineers
NTSB	National Transportation Safety Board
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	Potential Impact Radius
PLC	Programmable Logic Controller
PLSS	Pipeline Survey Sheets
PRMP	Pipeline Risk Management Program
PSI	Pounds per Square Inch
PSIG	Pounds per Square Inch Gauge
RCV	Remote Control Valve
RT	Reporters Transcript
ROE	Return on Equity
RMP	Risk Management Procedure
SCADA	Supervisory Control and Data Acquisition
SMYS	Specified Minimum Yield Strength
UPS	Uninterruptable Power Supply

Pursuant to Rule 13.11 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure and the Administrative Law Judges' Ruling Adopting Revised Schedule and Common Briefing Outlines (dated February 4, 2013), the Consumer Protection and Safety Division (CPSD) hereby submits its opening brief in this proceeding.[1]

I. INTRODUCTION AND SUMMARY

At 6:11 p.m. on September 9, 2010, a 30-inch diameter natural gas transmission pipeline owned and operated by Pacific Gas and Electric Company (PG&E) ruptured in San Bruno, California. Gas escaping from the rupture ignited, and the explosion was of such tremendous force that a crater approximately 72 feet long by 26 feet wide was created, and a 28-foot long section of pipe weighing approximately 3,000 pounds was blown approximately 100 feet from the crater. The ensuing conflagration continued for over an hour and a half, and required the response of 600 firefighting (including emergency medical service) personnel and 325 law enforcement personnel. The incident was catastrophic, resulting in the loss of eight lives, serious injuries to ten people, moderate injuries to 48 people, destruction of 38 homes, moderate to severe damage to 17 homes, and minor damage to 53 homes. (CPSD-1, p.1.[2]) The deaths, injuries, and damage to property were especially severe. (CPSD-6, CPSD-7, CPSD-8.[3])

Beginning on September 10, 2010, the day after the explosion, the National Transportation Safety Board (NTSB) began an investigation of the cause of this tragedy.

[1] On January 1, 2013, CPSD officially changed its name to the Safety and Enforcement Division (SED). However, in light of all of the references to CPSD in the previous rulings by the Commission and the Administrative Law Judges (ALJs), pleadings, exhibits, testimony and cross-examination of witnesses and corresponding transcript references, to avoid confusion we will continue to refer to SED as "CPSD" in this brief and through the remainder of this proceeding.

[2] "CPSD Incident Investigation Report into the September 9, 2010, PG&E Pipeline Rupture in San Bruno, California", hereinafter referred to by its hearing exhibit number, CPSD-1. CPSD's Staff Report was issued on January 12, 2012.

[3] CPSD obtained statements from survivors of the incident. The Declarations of Susan Bullis, Betti Magoolaghan, and Robert Pelligrini describe extreme pain and mental anguish caused by the terrible heat and duration of the explosion and fire, which continued for approximately 95 minutes before being extinguished.

The NTSB is a federal safety agency charged with the responsibility to investigate and determine the causes of various kinds of accidents in the United States, including accidents involving natural gas pipelines. The Commission is certificated under 49 U.S.C. § 60105 by the Pipeline Hazardous Materials and Safety Administration (PHMSA) of the U.S. Department of Transportation (DOT) to enforce the federal regulations contained in 49 Code of Federal Regulations (CFR) Part 192, *et seq.* CPSD investigators arrived at the accident scene on the evening of September 9, 2010, and participated actively and continuously in the NTSB investigation.

The NTSB[4] determined the probable cause of the accident was PG&E's (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing Line 132 to rupture during a pressure increase stemming from PG&E's poor performance of planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section. The NTSB report documents other contributing factors as well.

CPSD established in the evidence produced in this proceeding that the incident had several root causes. The overwhelming evidence demonstrates that the explosion was caused by PG&E's failure to follow accepted industry practice when constructing the section of pipe that failed, PG&E's failure to comply with integrity management requirements, PG&E's inadequate recordkeeping practices, deficiencies in PG&E's Supervisory Control and Data Acquisition (SCADA) system and inadequate procedures to handle emergencies and abnormal conditions, PG&E's deficient emergency response actions after the incident, and a systemic failure of PG&E's corporate culture to

[4] "NTSB Report on PG&E Natural Gas Transmission Pipeline Rupture and Fire San Bruno, CA September 9, 2010", hereinafter referred to by its hearing exhibit number, CPSD-9. The NTSB Report was issued by the NTSB on August 30, 2011.

emphasize safety over profits. CPSD has prepared a table of the violations uncovered in this proceeding, presented in Appendix C.

PG&E's severe (self-imposed) restraints on its Gas Transmission & Storage (GT&S) division's safety-related budgets, caused: 1) a drastic reduction in the replacement of PG&E's aging transmission pipeline; 2) insufficient funds for the safe operation of its pipelines, including using less effective and lower cost assessment methods, such as External Corrosion Detection Assessment (ECDA) over In Line Inspection (ILI, or "smart pigging"); and 3) a reduction in its safety-related workforce. PG&E's own engineers told management that they strongly preferred to use ILI on PG&E's higher stress transmission pipelines to obtain a better initial evaluation of the line, but that they were prevented by PG&E's budget constraints.[5] At the same time, PG&E management adopted a campaign to reduce operating costs, because "[i]f cost savings are greater than anticipated, such benefits would accrue to shareholders." (CPSD-1, p.140.) PG&E provided bonuses or "incentives" to management and employees, paid quarterly cash dividends to shareholders from retained earnings, repurchased $2.3 billion in stock, expended funds to enhance public perception of PG&E, and expended money to affect ballot initiatives.

This Opening Brief recounts the facts and violations established by the evidence in this proceeding. As described below, the Commission also instituted an Investigation into PG&E's system-wide recordkeeping failures, as well as an Investigation into PG&E's misclassification of pipelines in locations with higher population density. Pursuant to the Administrative Law Judges' ruling issued on September 25, 2012, CPSD's recommendations regarding administrative fines and remedies will be contained in a separate brief that will contain CPSD's consolidated recommendations for the three San Bruno-related OIIs, I.12-01-007, I.11-02-016 (PG&E Recordkeeping OII), and I.11-11-009 (PG&E Class Location OII).

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[5] CPSD-168 (Harpster), p.7-8, CPSD-186 (OC-68, Att. 3, p. 2); CPSD-230, (OC-264 and OC-264, Supplemental, Att. 6, p. 9).

II. BACKGROUND

A. Procedural Background

After the explosion on September 9, 2010, on September 13, 2010, the Commission's Executive Director ordered PG&E to reduce operating pressure in Line 132 to a level 20% below the pressure at the time of the explosion, where it remains today. (CPSD-1, p.2.)

On September 23, 2010, the Commission ordered PG&E to "review the classification of its natural gas transmission pipelines and determine if those classifications have changed since the initial designation." (Resolution L-403.) Resolution L-403 also created the Independent Review Panel (IRP) to gather and review facts, and make recommendations to the Commission for the improvement of the safe management of PG&E's natural gas transmission lines. On June 24, 2011, the revised "Report of the Independent Review Panel – San Bruno Explosion[6]" was issued.

On January 3, 2011, the NTSB issued Urgent Safety Recommendations P-10-2 and P-10-3 to PG&E (which the Commission subsequently made mandatory) to determine "the valid maximum allowable operating pressure" for its natural gas transmission lines "in class 3 and class 4 locations that have not had a maximum allowable operating pressure established through prior hydrostatic testing" through a "traceable, verifiable, and complete" search of its "as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records."

The Executive Director, in a letter to PG&E dated January 3, 2011 (the same date as the NTSB's Urgent Safety Recommendations), referred to the NTSB's Safety Recommendations, and ordered PG&E to complete compliance with the recommendations by February 1, 2011. The Commission ratified the directive contained in Executive Director's letter on January 13, 2011, in Resolution L-410 (which also extended the compliance report filing date to March 15, 2011).

[6] CPSD-10.

On February 24, 2011, the Commission launched an investigation[7] into whether PG&E violated applicable rules or requirements pertaining to safety recordkeeping for its gas service and facilities across its system, including Segment 180 (PG&E Recordkeeping OII). Also on February 24, 2011, the Commission initiated a statewide rulemaking proceeding[8] to consider a "new model of natural gas pipeline safety regulation applicable to all California pipelines."

On November 10, 2011, the Commission launched a related investigation[9] to determine whether PG&E's natural gas transmission pipeline system was safely operated in areas of greater population density, which resulted from PG&E's compliance reports issued in response to Resolution L-403 (PG&E Class Location OII).

On January 12, 2012, the Commission launched this Investigation[10], based on CPSD's Report and the NTSB's San Bruno Accident Report.

B. Summary of the Incident

On September 9, 2010, at approximately 6:11 p.m., a 30-inch diameter natural gas transmission pipeline owned and operated by PG&E ruptured in San Bruno, California. (CPSD-1, p.7.) Gas escaping from the ruptured pipeline ignited, resulting in the loss of eight lives, injuries to 58 people, destruction of 38 homes, moderate to severe damage to 17 homes, and minor damage to 53 homes. (CPSD-1, p.7.)

Energy released by the explosion created a crater about 72 feet long by 26 feet wide. A 28-foot long section of pipe weighing approximately 3,000 pounds was ejected from the crater and landed approximately 100 feet from the crater in the middle of Glenview Drive. (CPSD-1, p.8.)

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[7] I.11-02-016.

[8] R.11-02-019.

[9] I.11-11-009.

[10] I.12-01-007.

1. Description of PG&E's SCADA System And Events At PG&E's Milpitas Terminal

a) SCADA system

PG&E's gas SCADA system provides remote control of 6,438 miles of transmission pipeline. Parts of PG&E's 42,141 miles of gas distribution pipeline are also monitored by SCADA. (CPSD-1, p.71.)

Supervisory Control and Data Acquisition (SCADA) is the use of computers and communications networks to gather field data from numerous remote locations, perform numerical analysis, and generate trends and summary reports. These reports are displayed in a structured format to enhance Gas Control Operators ability to monitor, forecast and send commands to field equipment. Some pipelines span long distances and are usually operated from a central location using a SCADA system. SCADA is employed for many different processes, such as management of electric power lines, operation of oil refineries, and operation of automobile assembly plants. SCADA systems make it possible to control a process that is distributed over a large area with a small group of people located in a single room. (CPSD-1, p.70.)

About 9,000 sensors and devices are installed along the length of the pipelines to enable the display of flow rates, equipment status, valve position status, pressure set points, and pressure control among other data. The current generation of SCADA used by PG&E is based on Citect software from Schneider Electric. (CPSD-1, p.71.)

PG&E's pipelines are controlled and managed from the Primary Gas Control Center (Gas Control) located in San Francisco. An alternate control center is located in Brentwood. Several compressor stations and local control stations, such as the Milpitas Terminal are situated along the pipelines, each with a separate local control system. (CPSD-1, p.72.)

The SCADA system is separate from PG&E's Geographical Information System (GIS). The GIS data is displayed on separate computer screens at each of the operator consoles at both the primary and alternate gas control centers. (CPSD-1, p.72.)

The SCADA system is programmed to register alarms when the pressure exceeds the Maximum Allowable Operating Pressure (MAOP) or if the value is less than a preset low level. It does not provide automatic control or intelligent alarming functions such as high rate of change alarms. The operational decisions are made by PG&E Gas Operators in charge of the five consoles at the Gas Control Center. (CPSD-1, p.73.)

Monitor valves act as limiting devices to protect against accidental overpressure for the outgoing gas pipelines. Regulator valve set points for outgoing lines can either be manually set at the Milpitas Terminal or remotely set through SCADA by PG&E Gas Control. (CPSD-1, p.74.)

b) Milpitas Terminal

The Milpitas Terminal has four incoming natural gas transmission lines and five outgoing natural gas transmission lines and is equipped with pressure regulation and overpressure protective devices to control incoming and outgoing pressure. The pressure regulating valves are electrically actuated with the SCADA system controls while the monitor valves are pneumatically controlled valves. (CPSD-1, p.73.)

Each of the incoming pipelines to the Milpitas Terminal has a regulating valve and a monitor valve to limit the pressure within the terminal. Pressure is further reduced with a second regulating valve and a monitor valve for overpressure protection before it is sent through the outgoing lines. The monitor valves are normally left fully open. When the downstream pressure starts to increase and exceed a pressure set point, the monitor valve moves to control the downstream pressure. (CPSD-1, p.75.)

PG&E's gas control system consists of Programmable Logic Controllers (PLCs), pressure controllers and related instrumentation which communicate with the SCADA computers in San Francisco. Redundant PLCs are provided with a fail-over switch so, if one fails, the other will pick up. The PLCs communicate with the 26 pressure controllers over a local Ethernet network. The PLCs execute a large program that calculates the flows and processes the inputs from many valve position sensors. The PLCs manage communication with the 26 pressure controllers and generate controller error alarms should a controller fail or lose communication. The PLCs also communicate commands issued by the Gas Operators located at Gas Control Center in San Francisco to control valves and to change pressure set points. Communication between the PLC software and the equipment is transmitted over individual wires connected to the PLC Input/Output (I/O) devices (also referred to as Genius Blocks). (CPSD-1, p.78.)

At the Milpitas Terminal, all of the pressure instruments have a full scale range of 0 to 800 psig. The pipeline at the Milpitas Terminal is rated up to 720 psig, therefore no pressure greater than 800 psig should ever occur. (CPSD-1, p.79.)

PG&E installed an Uninterruptible Power Supply (UPS) at Milpitas Terminal to power the SCADA and control equipment during a power outage and before the emergency generators start delivering backup power. (CPSD-1, p.80.)

In 2010, PG&E decided to replace the entire UPS system with a new one. The UPS at the Milpitas Terminal had been in service since the 1980s, with a three-phase system that was no longer needed and for which parts were no longer available. (CPSD-1, p.81.)

In February 2010, PG&E asked a Contract Engineer to offer a proposal to investigate and provide recommendations for UPS/battery problems at the Milpitas Terminal. In mid-March 2010, a Contract Work Authorization was approved for the Contract Engineer to perform the proposed work on the UPS at Milpitas Terminal. (CPSD-1, p.81.)

On March 31, 2010, the UPS at the Milpitas Terminal failed, exposing the gas control system to a short interruption of power and potential loss of pressure control. (CPSD-1, p.81.)

On April 1-2, 2010, PG&E installed three temporary mini-UPS units at Milpitas Terminal to provide temporary backup power. (CPSD-1, p.81.)

A clearance application to install the permanent UPS at the Milpitas Terminal was submitted on August 19, 2010 as Clearance Number MIL-10-09 and approved by PG&E Gas Control on August 27, 2010. (CPSD-1, p.83.)

System clearance is required for work that affects gas flow, gas quality, or the ability to monitor the flow of gas. All system clearances require authorization from

PG&E's Gas System Operations (GSO). PG&E Work Procedure (WP) 4100-10 issued August 2009 describes the two types of clearances required, depending on the work to be performed: (1) System Clearance and (2) Non-system Clearance. (CPSD-1, p.82.)

PG&E's WP 4100-10 requires a designated Clearance Supervisor for all clearances at all times. Clearance application MIL-10-09 marked the Clearance Supervisor as "TBD". Under the Description box is "GC M&C remove old UPS system and install new UPS at Milpitas Terminal", with the Special Instructions box marked "Yes". On the list of Special Instructions, it states: (1) "Technician to contact SF Gas Control prior to work and at the completion of work - Technicians will be on site with GC M&C during work"; and (2) the names and contact numbers of the technicians working on the project. The checkbox on the form which asks if normal function of the facility will be maintained was checked "No". The clearance application requires an explanation whenever this box is checked "No". However, there was no explanation provided on the clearance application as to how the work will affect normal function of the Milpitas Terminal. (CPSD-1, p.83.)

Under the Sequence of Operations, the clearance application states "Report On Daily and Report Off". It did not list any specific operations or key communication steps to be reported to Gas Control. PG&E's Work Procedure requires the Clearance Supervisor to report key communication steps identified in the Sequence of Operations to Gas Control, including operation of any piece of equipment that affects the flow and/or pressure of gas or ability of Gas Control personnel to monitor the flow and/or pressure of gas on SCADA. (CPSD-1, p.83.) One of the steps taken during the UPS work at the Milpitas Terminal was switching the controllers to manual, which locks the valve to its current setting and disables Gas Control's ability to change the valve settings remotely. (*Ibid.*) This should have been clearly stated on the clearance application as a key communication step within its Sequence of Operations. (*Ibid.*) Further, PG&E WP 4100-10 requires the Clearance Supervisor to fill in any steps in a system clearance with the time, date, and initials of the person completing the step and file the clearance as completed. (*Ibid.*) No record was provided by PG&E showing the specific steps taken and the time, date, and initials of the person completing each step in the system clearance. (*Ibid.*)

At 2:46 p.m. on September 9, 2010, the work to replace the temporary UPS was begun at PG&E's Milpitas Terminal. (CPSD-1, p.7.)

Between 2:00 p.m. and 4:40 p.m., the team installed mini-UPS units 5, 6, 7 and 8. The three Ethernet Switches that connect the pressure controllers to the PLCs were also placed on mini-UPS at this time. (CPSD-1, p.86.)

At 4:46 p.m., the PG&E Gas Technician[11] at the Milpitas Terminal called Gas Operator 2 to let him know SCADA communication with the Milpitas Terminal would be interrupted for a few minutes while they installed Mini-UPS unit 7, the last one of the day. (CPSD-1, p.86.)

The workers then discovered that an unidentified active circuit breaker remained in the Uninterruptible Distribution Panel (UDP). The Contract Engineer switched it off and the mimic panel went dead. After some research, he was able to identify power supply PS-C as the one which was connected to the unidentified breaker, and powered the indicators on the mimic panel. The Contract Engineer then installed mini-UPS unit 9 to power PS-C and the mimic panel. (CPSD-1, p.86.)

At that time, the system appeared to be operating normally. Alarm records show no activity from 5:09 p.m. to 5:21 p.m. The crew working in Milpitas was getting ready to wrap up, believing they had successfully completed the planned activities for the day. (CPSD-1, p.86.)

At 5:22 p.m., the SCADA center alarm console displayed over 60 alarms within a few seconds, including controller error alarms and high differential pressure and backflow alarms from the Milpitas Terminal. These alarms were followed by pressure alarms on several lines leaving the Milpitas Terminal, including Line 132. (CPSD-1, p.11.)

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[11] PG&E's workers are identified herein by title rather than by name.

At 5:23 p.m., records of SCADA alarms and pressure readings indicate valves opening and pressure increasing. The pressure readings measured at flow meters M31, M32 and M38 on Lines 132, 101 and 109, respectively, increased from 370 psig to 380 psig in about 90 seconds. (CPSD-1, p.87.)

The alarms were likely caused by an intermittent short circuit on a piece of wire in the pressure feedback circuit in the Control System equipment enclosure which contains hundreds of wires. The short circuit started a cascade of failures in the gas pressure sensors and pressure controls which lasted for over three hours. The Contract Engineer and Construction Lead began disconnecting and reconnecting circuits to find where the shorted wires loaded on the 24 volt current loops. At about 8:40 p.m., they eliminated the short and all the instruments and controls then resumed normal operation. The shorted connection was at a terminal block near the PS-A and PS-B where wires were possibly jostled during connection of the mini-UPS. (CPSD-1, p.87.)

Because of the malfunctions, PG&E's Gas Operators in San Francisco lost the ability to monitor and control the valves at the Milpitas Terminal with the SCADA system displaying inaccurate information. (CPSD-1, p.95.)

Loss of information and control over the pipelines caused various regulating valves to fully open. This caused gas pressure in lines leaving the Milpitas Terminal, including Lines 101, 109 and 132, to increase. According to telemetry data obtained during the investigation, the pressure on Line 132 leaving the Milpitas Terminal reached a high of 396 psig as measured manually. (CPSD-1, p.8.)

The Gas Technician at Milpitas began to manually apply valve pressure gauges to verify and report pressure readings and positions of regulating and monitoring valves to Gas Operators at the Gas Control Center. The Gas Technician was instructed to manually close certain valves and lower monitor valve set points. About 40 minutes after pressures began rising in the gas discharge header at the Milpitas Terminal, Line 132 ruptured. (CPSD-1, p.95.)

At 6:11 p.m., SCADA data indicated that a rupture had occurred when pressures on Line 132 upstream of the Martin station rapidly decreased from a high of 386 psig. (CPSD-1, p.11.)

It was after 10:30 p.m. when the Senior Gas Engineer was able to restore operation to the three PLCs which had malfunctioned. Those units suffered a rare type of malfunction and the manufacturer had to be contacted to advise how to correct it. PG&E did not determine if this malfunction was indicative of failing or defective units and they are still in service. (CPSD-1, p.87.)

The highest pressure recorded at an upstream location closest to Segment 180 just prior to the failure was determined to be 386 psig. Based on a review of historical pressure data, this was the highest pressure Segment 180 had experienced within the seven years preceding the rupture. (CPSD-1, p.8.)

2. Response to the Explosion

At 6:12 p.m., SCADA showed the upstream pressure at the Martin Station on Line 132 had decreased from 361.4 psig to 289.9 psig. At 6:15 p.m., SCADA showed a low-low alarm at the Martin Station that indicated a pressure of 144 psig on Line 132. Pursuant to PG&E's procedure, members of Gas Control attempted to troubleshoot the alarms by examining the pressures and conditions at different stations. (CPSD-1, p.108.)

At 6:12 p.m. the first police unit arrived at the scene. At 6:13 p.m., the first San Bruno Fire Department unit arrived at the scene. (CPSD-1, p.11.)

No outgoing calls were made by PG&E to fire or police officials upon discovery of the incident. (CPSD-1, p.118.)

At 6:18 p.m., an off-duty PG&E employee notified the PG&E Dispatch center in Concord, California, of an explosion in the San Bruno area. Over the next few minutes, the dispatch center received additional similar reports. (CPSD-1, p.11.)

At 6:18 p.m., PG&E Dispatch was notified of a fire in San Bruno by an off-duty PG&E employee who speculated a jet crash. The dispatcher responded that a supervisor would be notified. (CPSD-1, p.108.)

At 6:21 p.m., an off-duty a Gas Service Representative (GSR) called into Dispatch alerting them that there was a fire in San Bruno that appeared to be gas fed. The dispatcher responded that he would send a GSR out to investigate. (CPSD-1, p.108.)

At 6:23 p.m., PG&E Dispatch sent a GSR working in Daly City (about 8 miles from San Bruno) to confirm the report. About the same time, PG&E's Senior Distribution Specialist, who saw the fire while driving home from work, reported the fire to the PG&E Dispatch center and proceeded to the scene. (CPSD-1, p.11.)

At 6:25 p.m., PG&E's Dispatch called the Peninsula On-Call Supervisor to advise him of the incident. He responded, "I'm probably on my way." (CPSD-1, p.108.)

At 6:27 p.m., while Gas Operators 1 and 2 were still in the process of determining the cause of the alarm, PG&E Dispatch called Gas Operator 3 to inquire if they noticed a loss of pressure in San Bruno. PG&E Dispatch advised about large flames and that a GSR and a Supervisor were heading to the scene. Gas Operator 3 responded that they had not received any calls yet. (CPSD-1, p.108.)

At 6:28 p.m., the PG&E Gas Controllers discussed the low-low pressure alarms amongst themselves and associated the reports of the fire at San Bruno with the pressure drop at Martin Station. At 6:29 p.m., a PG&E Gas Controller mentioned to a caller that pressure on Line132 had dropped from 396 psig to 56 psig and that "we have a line break in San Bruno… while we have Milpitas going down." (CPSD-1, p.109.)

At 6:30 p.m., PG&E Dispatch called the GSR to check on his status. The GSR was still in traffic at the time. The Measurement and Control (M&C) Superintendent of the Bay Area, on-call 24/7 to respond to any gas event within his area, arrived at the scene just after 6:30 p.m., as the result of seeing news of the explosion and fire on television. (CPSD-1, p.109.)

At 6:31 p.m., Gas Operator 1 called PG&E Dispatch regarding the previous inquiry about the loss of pressure and speculated that PG&E's gas facilities may be involved in the incident. PG&E Dispatch responded to Gas Control that a radio news report claimed the fire was due to a gasoline station explosion. (CPSD-1, p.109.)

At 6:32 p.m., Gas Control left a message for San Francisco Transmission and Regulation Supervisor about the low-low alarm at Martin Station, and the possibility of a leak. (CPSD-1, p.109.)

At 6:35 p.m., the M&C Superintendent of the Bay Area called Gas Control to inquire about the fire and told them to call the superintendent of the region. He then proceeded to the scene. At about the same time, Mechanic 1 called Dispatch, saying that PG&E's transmission line ran through the scene of the fire and that the flame was consistent with ignited gas from a transmission line. As Mechanic 1 headed to the Colma yard (Yard), he was called by Mechanic 2, who was then told to head to the Yard. (CPSD-1, p.109.)

At 6:36 p.m., the San Francisco T&R Supervisor returned the Gas Control's call and told them to contact the Peninsula Division T&R Supervisor. The gas controllers had been coordinating with the Senior Gas Coordinator to make the appropriate contacts. (CPSD-1, p.110.)

At 6:40 p.m., after confirming the involvement of PG&E's facilities with Dispatch and Gas Control, the Peninsula On-Call Supervisor called M&C Mechanics 1 and 2 and told them to "get to the yard, get their vehicles and head in that direction (of the valves)." (CPSD-1, p.110.)

PG&E first responders at the scene of the incident could not identify the cause of the fire. (CPSD-1, p.102.) PG&E had not offered specific training for its first responders on how to recognize the differences between fires of low-pressure natural gas, high-pressure natural gas, gasoline fuel, or jet fuel. (CPSD-1, p.102.)

At 6:41 p.m., the GSR and the Senior Distribution Specialist were at the scene and reported to PG&E Dispatch that the fire department did not yet know the cause of the flames. The GSR made PG&E Dispatch aware that there were gas transmission lines in the area. PG&E Dispatch conveyed to the GSR that a jet might have struck a gasoline station, which in turn caused the gas line to blow with it. The GSR called the Gas Service On-Call Supervisor, and the Gas Service Night Supervisor, to let them know he was on site. The Gas Service Night Supervisor arrived on site later. (CPSD-1, p.110.)

At 6:48 p.m., the Senior Distribution Specialist told PG&E Dispatch, "We've got a plane crash" and "we need a couple of gas crews and electric crews." Dispatch acknowledged the request. (CPSD-1, p.110.)

Mechanic 1 arrived at the Yard at 6:50 p.m. Mechanic 2 arrived soon after. More internal contacts ensued. At 6:51 p.m., a Gas Control Operator claimed, "it looks like it might [be transmission], if anything, distribution." (CPSD-1, p.110.)

At 6:53 p.m., the San Francisco Division T&R Supervisor communicated to Gas Control that he had crews responding, but they might be heading to Martin Station. At 6:54 p.m., San Bruno Police called PG&E Dispatch requesting gas support. PG&E Dispatch replied, "We know, they're out there already." PG&E Dispatch then told the Troublemen Supervisor about a plane that had crashed into a gas station, and asked for gas and electric utilities in the area to be turned off. The Troublemen Supervisor replied that he was notifying the troublemen. (CPSD-1, p.110.)

At 6:57 p.m., PG&E's Operations Emergency Center (OEC) was opened. While watching the news on a television at the Yard, Mechanic 1 identified the location of the incident and the nearest valves to be shut to cut off fuel to the fire. (CPSD-1, p.110.)

At 7:02 p.m., the San Mateo County Sheriff asked PG&E Dispatch if they were aware of the plane crash; PG&E Dispatch responded, "I'll go ahead and relay that message." At around the same time, Mechanic 1 called Dispatch and notified them of his plan to shut valves to isolate the rupture. (CPSD-1, p.110.)

At 7:06 p.m., Mechanic 1 called the Peninsula Division T&R Supervisor for authorization to shut the valves. The Peninsula Division T&R Supervisor approved. Mechanics 1 and 2 proceeded to the first valve location (containing valve V-39.49). Gas Control was continuously making and receiving calls to gather and relay information. (CPSD-1, p.111.)

At around 7:07 p.m., a Gas Control Operator mentioned that the M&C Superintendent of the Bay Area was on site but could not get close enough to the actual location itself because of the extent of the fire and that "until the crew arrives, secures it and comes up with a plan, we're just going to continue to feed it." (CPSD-1, p.111.)

At 7:12 p.m., the Troublemen Supervisor told PG&E Dispatch about his plan to order a mandatory call out requiring all Colma Yard employees to report in. (CPSD-1, p.111.)

At 7:15 p.m., a Gas Control operator commented, "The fire is so big I guess they can't determine anything right now." At approximately 7:15 p.m., an FAA representative informed PG&E's M&C Superintendent of the Bay Area that there was no plane involved in the incident. (CPSD-1, p.111.)

At 7:16 p.m., PG&E Dispatch began to relay the Troublemen Supervisor's plan. Minutes later, the M&C Superintendent of the Bay Area instructed the Senior Distribution Specialist, who was with him at the time, to call Gas Control and tell them the fire was gas related and to declare it a reportable incident. (CPSD-1, p.111.)

Mechanics 1 and 2 arrived at the first valve location at 7:20 p.m. At 7:22 p.m., the Senior Distribution Specialist contacted PG&E Dispatch and said that while unconfirmed, it looked like gas was involved. At 7:22 p.m., Gas Control told the Senior Vice President that the incident was likely to be a Line 132 break, although nothing had been confirmed. At 7:25 p.m., PG&E Dispatch informed Gas Control that the M&C Superintendent of the Bay Area was on scene and confirmed that the incident was a reportable gas fire. Gas Control confirmed that Line 132 was the involved line. At 7:27 p.m., the SF Division T&R Supervisor requested that Gas Control lower the pressure set points as low as possible at the Martin Station to isolate Line 132 from the north. (CPSD-1, p.112.)

At 7:29 p.m., Gas Control remotely closed the involved Line132 valves at Martin Station to cut off the feed of gas north of the rupture. By 7:46 p.m., Mechanics 1 and 2 had traveled north of the rupture and closed valves V-40.05 and V-40.05-2 at Healy Station to isolate the rupture. (CPSD-1, p.112.)

PG&E took 95 minutes to isolate the location of the rupture. The time for isolation could have been reduced had PG&E installed remote control valves (RCVs), automatic shut-off valves (ASVs), and/or appropriately spaced pressure and flow transmitters throughout its system to allow them to quickly identify and isolate line breaks. (CPSD-1, p.102.)

By early morning on September 10, firefighters declared 75% of all active fires to be contained. By the end of the day on September 11, 2010, fire operations continued to extinguish fires and monitor the incident area for hot spots and then transferred incident command to the San Bruno Police Department. (CPSD-1, p.13.)

During the 50 hours following the incident, about 600 firefighting (including emergency medical service) personnel and 325 law enforcement personnel responded. Fire crews and police officers conducted evacuations and door-to-door searches of houses throughout the response. In total, about 300 homes were evacuated. Firefighting efforts included air and forestry operations. Firefighters, police officers, and members of mutual aid organizations also formed logistics, planning, communications, finance, and damage assessment groups to orchestrate response efforts and assess residential damage in the area. (CPSD-1, p.13.)

a) Post-incident Drug And Alcohol Testing

PG&E performed post-incident drug testing of three PG&E employees and a PG&E contractor working on the UPS Clearance at the Milpitas Terminal. The drug testing was administered by a third party independent laboratory on September 10, 2011 between 3:36 a.m. and 5:21 a.m., and all four individuals tested negative. The post-incident alcohol test of the same four individuals was performed on September 10, 2011 between 3:10 a.m. and 5:02 a.m. (CPSD-1, p.99.) PG&E did not perform any drug or alcohol testing of its SCADA staff. (CPSD-9, p.105.)

3. History of Segment 180

The section of pipeline involved in the incident was Segment 180, at Mile Post (MP) 39.28 of PG&E's Line 132, located at the intersection of Earl Avenue and Glenview Drive in San Bruno, California. (CPSD-1, p.7.)

The City of San Bruno is in a Class 3 location, and Segment 180 was intended to meet the design and construction requirements in effect at that time for a Class 3 location.

Class 3 refers to any location unit that has 46 or more buildings intended for human occupancy. (CPSD-5, p.6; CPSD-9, p.133.)

PG&E provided a pressure log from the Milpitas Terminal dated October 16, 1968, showing a recorded pressure of 400 psig for Line 132. This pressure log was used by PG&E as the basis for establishing a Maximum Allowable Operating Pressure (MAOP) of 400 psig for Line 132. (CPSD-1, p.23.)

Segment 180 was installed in 1956 as part of a relocation project of approximately 1,851 feet of Line 132 that originally had been constructed in 1948. The relocation of Segment 180 started north of Claremont Drive and extended south of San Bruno Avenue and moved the pipeline from the east side to the west side of Glenview Drive. (CPSD-1, p.15.) This relocation was necessary because of grading associated with land development in the vicinity of the existing pipeline. The construction was performed by PG&E personnel. (CPSD-1, p.15.)

Segment 180 originally was documented in PG&E records as being 30-inch diameter seamless steel pipe with a 0.375 inch wall thickness and having a Specified Minimum Yield Strength (SMYS) of 52,000 psi, installed in 1956. PG&E obtained this material specification information for Segment 180 from accounting records rather than engineering records. (CPSD-1, p.16.)

PG&E's identification of the entire length of Segment 180 as a seamless pipe was incorrect. (CPSD-1, p.7, p.47.) There was no American Petroleum Institute (API)-qualified domestic manufacturer of 30-inch diameter seamless steel pipe when the line was constructed. (CPSD-1, p.32; CPSD-9, p.61.) Segment 180 was in fact a 30-inch diameter Double Submerged Arc Welded (DSAW) pipe. (CPSD-1, p.7.)

PG&E believes the pipe was most likely produced by Consolidated Western in 1948, 1949 or 1953. (CPSD-5, p.21; CPSD-9, p.28.) According to PG&E, between 1947 and 1957, it purchased a total of 320,065 feet of 30-inch pipe from three suppliers. The pipe used for the 1956 project was assembled from multiple material procurement orders. (CPSD-5, p.21.)

The rupture of Segment 180 began on a fracture that originated in the partially welded longitudinal seam of one of six short pipe sections, which are known in the industry as "pups." (CPSD-9, p.x of the Exec. Summary.)

PG&E records for Segment 180 did not disclose the existence of the pups. The manufacturer of the pups is unknown. (CPSD-1, p.16.)

An NTSB metallurgical examination determined that the yield strength values of all six pups were lower than 52,000 psi, which is the designated yield strength for Segment 180. (CPSD-1, p.20; CPSD-9, p.28.)

Pup 1, the failed pup on which the facture initiated, was found to have yield strength of only 36,600 psi, and Pup 2 had the lowest yield strength of 32,000 psi. (CPSD-1, p.20.)

Longitudinally, Pups 1, 2 and 3 were partially welded on the seam from the outside and the weld did not penetrate through the inside of the pipe. No inside weld, required for a DSAW welded pipe, was found on the inside of the pipe. According to the NTSB metallurgical examination, the fusion welding process left an unwelded region along the entire length of each seam, resulting in a reduced wall thickness. (CPSD-1, p.20; CPSD-16, p.63.)

A visual examination of the pipe would have detected the anomalous and defective welds. The unwelded seam defects and manual arc welds ran the entire length of each pup and were detectable by the unaided eye and/or by touch. (CPSD-9, p.96.)

The girth welds and longitudinal seams associated with the pups had welding deficiencies related to incomplete fusion, burnthrough, slag inclusion, crack, undercut, excess reinforcement, porosity defects and lack of penetration. (CPSD-1, p.20; CPSD-16, p.6.)

The initial crack-like defect extended longitudinally along the entire length inside of the weld (the root) on Pup 1, resulting in a net intact seam thickness of 0.162 inches. With a nominal 0.375 inch wall thickness, the intact wall thickness was approximately 43% at the weld. There was also an angular misalignment on the inside of Pup 1. Given this initial defect, an additional 2.4 inch defect grew to failure. The initial crack-like defect first grew by ductile fracture (Stage 1). Then the crack grew by fatigue (Stage 2). The final stage was the rupture of the pipe, identified as a quasi-cleavage fracture (Stage 3). (CPSD-1, p.50; CPSD-9, p.41.)

All of the pups used for Segment 180 were less than 5 feet in length. (CPSD-1, p.22.)

PG&E was unable to produce records demonstrating that a strength test was performed on Segment 180 at the conclusion of its construction or at any time during its operation. (CPSD-1, p.22.)

The NTSB report found that the calculated burst pressure estimates were 594 and 515 psig for Pup 1; 668 and 574 psig for Pup 2; and 558 and 430 psig for Pup 3, respectively. The analysis was done assuming no crack growth in the weld defect in Pup 1 and no angular misalignment of the Pup 1 longitudinal seam. Based on the pipeline characteristics associated with the pups and the Class 3 location, if a strength test had been performed to 1.4 times MAOP (400 x 1.4 = 560 psig), it is highly probable that the pups in Segment 180 would have failed. (CPSD-1, pp.60-61; CPSD-9, p.49.)

4. Integrity Management of Segment 180

In 2004, PHMSA established the Gas Transmission Integrity Management Rule (49 CFR Part 192, Subpart O), commonly referred to as the "Gas IM Rule." The Gas IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect high-consequence areas within the United States. (CPSD-1, p.133.)

The Integrity Management (IM) requirements (49 CFR Part 192) for all pipelines in high consequence areas (HCAs) were effective with the signing into law of the 2002 Pipeline Safety and Improvement Act on December 17, 2002. This law required PHMSA to promulgate regulations concerning transmission pipelines in areas that could affect human safety no later than one year after enactment. PHMSA noticed the new regulations on December 15, 2003, and these regulations required that by December 17, 2004, operators were to have IM plans developed and to have identified all HCAs. (CPSD-1, p.25.)

The IM regulations include requirements for threat analysis, risk ranking, assessment methods and re-assessment timetables. (CPSD-1, p.25.) However, PG&E did not always use conservative default values for pipeline segments in Line 132 when the actual value was missing or unknown. (CPSD-1, p.26; CPSD-9, p.108.) PG&E did not always check the material specifications of pipeline segments in Line 132 for accuracy. (CPSD-1, p.26.) PG&E did not always gather all relevant leak data on Line 132 and integrate it into its Geographic Information System (GIS). (CPSD-1, p.26.)

The investigation discovered a number of examples where data from PG&E's GIS were in error, but not discovered by PG&E, including:

- the pipe wall thickness was an assumed value for 21.5 miles (41.75 percent) of Line 132;
- the manufacturer of the pipe was unknown ("NA") for 40.6 miles (78.81 percent) of Line 132;
- the pipeline depth of ground cover was also unknown for 42.7 miles (82.79 percent) of Line 132;
- three values were used for the SMYS of grade B pipe: 35,000 psi, 40,000 psi, and 45,000 psi;
- two segments with unknown SMYS were assigned values of 33,000 psi and 52,000 psi, not 24,000 psi;
- six consecutive segments, totaling 3,649 feet, specified an erroneous minimum depth of cover of 40 feet;
- several segments, including Segment 180, specified 30-inch-diameter seamless pipe, although there was no API-qualified domestic manufacturer of such pipe when the line was constructed; and
- the GIS did not reflect the presence of the six pups in Segment 180.

(CPSD-1, p.32; CPSD-9, p.61)

PG&E did not consider known longitudinal seam cracks dating to the 1948 construction and at least one other leak, which occurred in 1988, on a long seam of the 1948 portion of pipe. Closed leak information, such as the October 27, 1988, leak, which had been repaired, was not transferred to the GIS. (CPSD-1, p.26; CPSD-9, p.109.)

PG&E did not incorporate and analyze all of the known history of seam leaks or test failures. A number of defects were not incorporated into PG&E's analysis of the condition of the pipe for its 2004 Baseline Assessment Plan (BAP):

- 1948, Line 132: Multiple longitudinal seam cracks found during radiography of girth welds during construction.
- 1958, Line 300B: Seam leak in DSAW pipe.
- 1964, Line 132: A leak was found on a "wedding band" weld; the leak was the result of construction defect. The defect was found on segment 200.
- 1974, Line 300B: Hydrostatic test failure of seam weld with lack of penetration (similar to accident pipe).
- 1988, Line 132: Longitudinal seam defect in DSAW pipe.
- 1992, Line 132: Longitudinal seam defect in DSAW weld when a tie-in girth weld was radiographed.
- 1996, Line 109: Cracking of the seam weld in DSAW pipe.
- 1996, Line 109: Seam weld with lack of penetration (similar to accident pipe) found during camera inspection.
- 1996, DFM-3: Defect in forge-welded seam weld.
- 1999, Line 402: Leak in ERW seam weld.
- 2002, Line 132: During a 2002 ECDA[12] assessment, miter joints with construction defects were found on Segment 143.4.
- 2009, Line 132: A leak was found on Segment 189 that was caused by a field girth weld defect. Segment 189 was originally fabricated by Consolidated Western using DSAW and installed in 1948.
- 2009, Line 132: During the ECDA process, a defective SAW repair weld was found on Segment 186. As indicated in PG&E's pipeline survey sheet, the segment was originally fabricated by Consolidated Western using DSAW and installed in 1948.
- 2011, Line 300A: Longitudinal seam crack in 2-foot pup of DSAW pipe (found during camera inspection).
- 2011, Line 153: Longitudinal seam defect in DSAW pipe during radiographic inspection for validation of seam type.

[12] External Corrosion Direct Assessment (ECDA). This detection tool is described in more detail below.

(CPSD-1, pp.33-35; CPSD-9, p.39)

PG&E's 2004 Baseline Assessment Plan (BAP) did not identify a construction threat based on "wedding band" joints in its threat algorithms. (CPSD-1, p.34.) PG&E's Likelihood of Failure (LOF) algorithm did not include threats from internal corrosion, stress corrosion cracking, equipment failure, incorrect operations (including human error), and cyclic fatigue. (CPSD-1, p.38.)

PG&E dismissed cyclic fatigue as a threat based on a report prepared for PHMSA on the stability of manufacturing and construction defects. PG&E did not incorporate cyclic fatigue or other loading conditions into the segment specific threat assessments and risk ranking algorithm. (CPSD-1, p.38, p.50.)

PG&E increased the pressure on many lines, including Line 132, to a little over the line MAOP (referred to as "pressure spiking") so that it could eliminate the need to consider manufacturing and construction threats as unstable as a result of increasing the pressure above the 5 year maximum operating pressure (MOP). (CPSD-1, p.40.)

Identifying manufacturing and construction threats as unstable would mean that an assessment method capable of assessing seam, girth weld, and other manufacturing and construction anomalies would need to be used (hydrotesting or In Line Inspection). (CPSD-1, p.40.)

PG&E's risk-ranking algorithm in Risk Management Procedure (RMP)-06 does not consider DSAW pipeline as having manufacturing defects, including seam and pipe body defects. (CPSD-1, p.41.)

A report entitled "Integrity Characteristics of Vintage Pipelines", referenced by PG&E in its first revision of RMP-06, identifies DSAW as having manufacturing defects, including seam and pipe body defects. Table E-6 in the "Vintage Characteristics of Pipelines" report identifies Consolidated Western as a manufacturer of DSAW pipe that has had incidents for both pipe body (1950 and 1954-56) and seam welds during certain years (1947, 1950, 1954-56). (CPSD-1, p.41.)

PG&E's implementation of the ECDA process along Line 132 shows that some HCAs were identified and designated as such by PG&E before December 2003. (CPSD-1, p.43.)

PG&E operated Line 132 to approximately 400 psig in order to establish a maximum baseline value on two occasions. PG&E operated the line at 402.37 psig on December 11, 2003; PG&E also operated Line 132 at 400.73 psig on December 8, 2008. (CPSD-1, p.44.)

In the 2004 BAP, PG&E identified Segment 180 as not having any DSAW manufacturing threat. (CPSD-1, p.46.)

5. Safety Culture

PG&E's Board had full knowledge that portions of the gas pipeline system needed to be replaced. In 1978, the head of PG&E's Gas System Design, Charles J. Tateosian, recommended that a program should be initiated to test sections of pipe where there was a higher potential for failure and where there would be a high potential for injury and/or property damage should a failure occur. (CPSD-5, pp. 63-64 and CPSD-167 (Tateosian Deposition), Vol IV, pp 880 and 884). Mr. Tateosian had noted that 1.7 million feet of transmission line in populated areas that had no hydrostatic test records available. (*Id.*, Vol. IV p. 885.) He specifically noted that 163,213 feet, or 30.9 miles of Line 132 had not been strength tested. (*Id.*, Vol IV, p. 888.) He expressed concern that the foreseeable risk of failing to commit to the replacement of aging pipelines was death, injury and property damage to those living near the pipeline. (CPSD-5, pp. 63-64 and CPSD-162 (Tateosian Deposition) Vol. I, p. 92.)

Mr. Tateosian, PG&E's Head of Gas Design and Vice President of Gas Operations, subsequently presented to PG&E's officers and Board the need to replace PG&E's aging gas pipelines, and he proposed instituting the Gas Pipeline Replacement Program ("GPRP") to facilitate the replacement. (CPSD-5, pp. 63-64 and CPSD-162 (Tateosian Deposition), Vol I, p. 168.) The presentation specifically identified Line 132 as well as two other gas transmission lines that serve the San Francisco Bay Area region as needing to be replaced to be capable of operating at high pressures. (*Id.*, Vol I, pp. 82-

85, 152 161-162, 168-174.) Mr. Tateosian also expressed concern that due to questionable welding methods used prior to 1950 and recent pipeline failures, that PG&E should start looking at replacing the gas pipeline infrastructure. (*Id*., Vol I, p. 92.)

In 1985, the Commission approved PG&E's 20-year plan for pipeline safety improvements (i.e., PG&E's GPRP). (D.86-12-095 (1986) 23 CPUC 2d 149, 198-99; D. 12-12-030, slip op., p. 45.) In PG&E's GPRP, PG&E had planned to replace 2,467 miles of aging distribution and transmission pipeline. (*Ibid*.) In 1992, notwithstanding the Commission's Division of Ratepayer Advocates' (DRA) protest that PG&E had not spent all of the funds, which PG&E had previously forecast it needed for its GPRP and the Commission had approved, the Commission authorized all of the dollars PG&E had requested for its GPRP, and expressed its "fervent hope that PG&E spends all of the money on the program." (D.92-12-057 (1992) 47 CPUC 2d 143, 233-234.)

Under PG&E's GPRP, PG&E committed to replacing 15 miles of transmission pipeline a year. However, in 2000, PG&E replaced the transmission portion of the GPRP with its Pipeline Risk Management Program (PRMP). If the GPRP had remained in place, PG&E would have been required to replace 165 miles of transmission pipeline during 2000-2010. Instead, PG&E replaced only <u>25 miles</u> of transmission pipeline under the PRMP. (CPSD-168 (Harpster), p. 6-13, CPSD-186 (OC-68, Att. 12, p. 60), Table 6-14, CPSD-209 (OC-214).) PG&E's capital expenditures for its transmission pipeline were approximately $116 million lower than what the Commission had authorized between 1997 and 2000. (CPSD-170 (Harpster), p.8.)

PG&E cannot identify any PG&E requests for the recovery of costs for safety improvements to the natural gas transmission pipeline system that were denied by the Commission. (CPSD-1, p.131.)

Over the past 13 years prior to the San Bruno explosion, PG&E has focused on decreasing GT&S's operations and maintenance (O&M) expenses. (CPSD-1, p. 132; CPSD -168 (Harpster), p. 1-2.) Maintenance work generally increases as a gas system ages and throughput increases. (CPSD-168 (Harpster), p. 6-2.) But from 1998 to 2010, PG&E reduced the gas transmission union headcount for maintenance workers from a peak of 302 to 220. (CPSD-168 (Harpster), p. 6-1, Table 6-1, CPSD-176 (OC-35).) Over the period 1997 to 2010, PG&E spent approximately $40 million less than the Commission authorized for pipeline transmission O&M. (CPSD-1, p. 131.)

Part of PG&E's O&M is spent on its integrity management program. In 2000, PG&E's PRMP was also designed to justify using its less expensive and less effective ECDA method to verify pipeline integrity in lieu of the ILI method, such as smart pigging, in order to save millions of dollars. PG&E expected to save approximately $150 million over a 10-year period by using this cheaper assessment method. (CPSD-168 (Harpster), p. 7-2.) From 2000 to 2010 PG&E continued to change its integrity management assessment methods for some projects from the ILI method to ECDA to reduce costs. (CPSD-1, p. 134.)

PG&E deferred some integrity management expense projects to future years. (CPSD-1, p. 134.) PG&E changed the definition of the pipelines covered by integrity management rules in 2010 to reduce the scope of the integrity management program. (CPSD-1, p. 135.)

PG&E's reduction of its integrity management expenses, by changing assessment methods for some projects from ILI to ECDA and deferring some projects, was against the advice of its own engineers. (CPSD-168 (Harpster), p.7-8, CPSD-186 (OC-68, Att. 3, p. 2); CPSD-230, (OC-264 and OC-264, Supplemental, Att. 6, p. 9).)

PG&E's actual return on equity for gas transmission and storage operations averaged 14.3% during 1999 to 2010. PG&E's authorized return on equity averaged 11.2% over that period. (CPSD-1, p.140; CPSD-170 (Harpster), p.10.) Between 1999 and 2010, PG&E's gas transmission and storage (GT&S) revenues were at least $435 million higher than the amounts needed to earn the Commission-authorized return on equity (ROE). (CPSD-1, p.133; CPSD-170 (Harpster), pp. 5, 9).

On December 15, 2004, PG&E's board authorized a purchase of shares of the company's issued and outstanding common stock with an aggregate purchase price not to exceed $1.8 billion, not later than December 31, 2006. By June 15, 2005, the Company projected that it may be able to repurchase additional shares of common stock through the end of 2006 in an aggregate amount of $500 million and, as such, increased the amount of the common stock repurchase authorization for a total authorization of $2.3 billion. (CPSD-1, p.141.)

PG&E also authorized a cash dividend in 2005 of $476 million; in 2006, $494 million; in 2007, $547 million; in 2008, $589 million; and, in 2009, $624 million. (CPSD-1, p.140.)

On February 16, 2005, the Chairman of the Board, Chief Executive Officer and President presented the idea of "Transformation" to the boards of directors, a company-wide business and cultural transformation campaign to reduce operating costs and instill a change in its corporate culture. As stated in the 2006 Annual Report, the reason for the investment in Transformation was, "If the actual cost savings are greater than anticipated, such benefits would accrue to shareholders." (CPSD-1, p.135.)

PG&E's 2009 Investor Conference presentation included a slide on "Expenditures," which showed decreasing investments in gas transmission infrastructure; from $250 million in 2009 to $200 million in 2010. (CPSD-1, p.135.) PG&E Company's 2009 Annual Report discloses that the utility accrued $38 million, after-tax, of severance costs related to the elimination of approximately 2% of its workforce. (CPSD-1, p.139.)

PG&E's 2010 Annual Report stated that during each of 2008, 2009, and 2010, the utility paid $14 million of dividends on preferred stock. On December 15, 2010, the board declared a cash dividend on its outstanding series of preferred stock totaling $4 million that was paid on February 15, 2011. (CPSD-1, p.141.)

The 2010 Annual Report notes that $57 million was provided in each year of 2008 and 2009, and $56 million was provided in 2010 as bonus compensation to PG&E Corporation employees and non-employee directors. (CPSD-1, p.142.) PG&E provides a Short-term Incentive Plan, a "Pay-for-Performance" bonus, and a Reward and Recognition Program. (CPSD-1, p.142.)

III. LEGAL ISSUES

A. Applicable State and Federal Laws

The California State Constitution, Article XII and California Public Utilities Code Section 222, give the Commission authority over natural gas operators in California. In particular, Section 701 empowers the Commission to do "all things…necessary and convenient" in the exercise of its powers and jurisdiction. Section 768 authorizes the Commission to promote and safeguard the health and safety of the public by establishing uniform standards for construction and maintenance of utility equipment and plant. Section 451, which has been in effect since 1909 when California began regulating utilities, requires all public utilities to provide and maintain "adequate, efficient, just, and reasonable" service and facilities as are necessary for the "safety, health, comfort, and convenience" of its customers and the public.[13] A violation of the Public Utilities Code or a Commission decision or order is subject to fines of $500 to $20,000 for each violation, for each ongoing day, pursuant to Sections 2107 and 2108. As of January 2012, SB 879 increased the penalties to up to $50,000 for each violation.

Pursuant to the Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. §§ 60101 *et seq*., the federal government regulates the safety of transportation of natural gas pipelines. A federal rulemaking subsequently promulgated regulations set forth in 49 CFR Part 192, adopted in 1970. In order to enforce the federal regulations as to intrastate pipelines, state regulatory agencies, such as the Commission, must become certificated by PHMSA under 49 U.S.C. § 60105, providing the state adopts the minimum federal standards (but the states may adopt more stringent standards where appropriate).

The Commission has been certificated and applies the federal pipeline safety regulations contained in 49 CFR Part 192, *et seq.* The Commission approved General Order (GO) 112-C in 1971, which adopted the federal pipeline safety rules in 49 CFR Part 192. Prior to GO 112-C, the Commission had adopted GO 112-A and GO 112-B to

[13] The California Court of Appeals has upheld the Commission's authority to find Section 451 violations that are separate and distinct from any other rule or regulation. *PacBell Wireless v. PUC* (2006) 140 Cal.App. 4th 718, 743. Section 451 was in effect in 1956, when Segment 180 of Line 132 was built.

amend the original GO 112 to include the federal regulations. Pursuant to its constitutional and statutory mandate, the Commission had created the original version of GO 112 in 1960 (effective July 1, 1961) governing natural gas pipeline safety. GO 112 adopted the standards put forth by the American Society of Mechanical Engineers (ASME) that were followed by the industry at that time (ASME B31.1.8, in effect in 1955). General Order 112 has been updated several times; the current version is GO 112-E, last revised in 2008. General Order 112-E was substantially altered in order to automatically incorporate all revisions to the federal pipeline safety regulations, 49 CFR Parts 190, 191, 192, 193, and 199.

B. Public Utilities Code Section 451 Imposes An Obligation to Follow Safe Operating Practices and to Protect the Public

PG&E had an obligation created by Public Utilities Code Section 451 during its construction and maintenance of Line 132 to follow good utility practices, which PG&E failed to do. Section 451 requires all public utilities to provide and maintain "adequate, efficient, just, and reasonable" service and facilities as are necessary for the "safety, health, comfort, and convenience" of its customers and the public. Any unsafe condition or a violation of a utility safety practice may be a violation of Section 451. (CPSD-1, pp.3-4.)

Section 451, which has been in effect since 1909 (half a century prior to the installation of Segment 180[14]), is a broad and general requirement for utilities to create and follow safe operating practices. Section 451 is not prescriptive in the specific manner in which its obligations must be met. Without such specifics and because no set of regulations can cover every single possible unsafe condition, one looks to the industry standards and guidelines for guidance. When Segment 180 was constructed and installed there were industry standards in place; standards which PG&E failed to follow. Additional guidance was established in 1961 with the promulgation of the Commission's

[14] Section 451 was renamed in the 1950's; it was originally titled Section 13.

GO 112, and in 1968 with the Natural Gas Pipeline Safety Act. However, from 1909 forward the plain language of Section 451 has clearly stated that utilities must furnish and maintain equipment and facilities necessary to promote the safety of the public.

In 1961, when the Commission adopted GO 112, it recognized that utilities had a pre-existing responsibility to the public to provide safe service that goes beyond GO 112 because no code of safety rules can cover every conceivable situation. The Commission stated:

> Public utilities serving or transmitting gas bear a great responsibility to the public respecting the safety of their facilities and operating practices.
>
> It is recognized that no code of safety rules, no matter how carefully and well prepared can be relied upon to guarantee complete freedom from accidents. Moreover, the promulgation of precautionary safety rules does not remove or minimize the primary obligation and responsibility of respondents to provide safe service and facilities in their gas operations. Officers and employees of the respondents must continue to be ever conscious of the importance of safe operating practices and facilities and of their obligation to the public in that respect. (CPUC Decision No. 61269 (1960), p.12.)

In this OII, the Commission noted that Section 451 requires all public utilities to provide safe service. (I.12-01-007, p.7.) The Commission further noted that "the California Court of Appeals has upheld the Commission's authority to find Section 451 violations that are separate and distinct from any other rule or regulation. *PacBell Wireless v. PUC* (2006) 140 Cal.App. 4th 718." (*Ibid.*) In *PacBell Wireless v. PUC*, the Court quoted with approval the Commission's decision in *Carey v. Pacific Gas & Electric Company* (1999) 85 Cal. P.U.C.2d 682, 689:

> [I]t would be virtually impossible to draft Section 451 to specifically set forth every conceivable service, instrumentality and facility which might be "reasonable" and necessary to promote the public safety. That the terms are incapable of precise definition given the variety of circumstances likewise does not make section 451 void for vagueness, either on its face or in application to the instant case. The terms "reasonable service, instrumentalities, equipment and facilities" are not without a definition, standard or common understanding among utilities.

PacBell Wireless v. PUC, 140 Cal. App. 4^{th} at 741, n 10.

Similarly, in *PacBell Wireless v. PUC,* 140 Cal App.4^{th} at 743, the Court rejected an argument "that there *must* be another statute or rule or order of the Commission that has been violated for the Commission to determine there has been a punishable violation of section 451." In support thereof, the Court relied upon *Carey v. Pacific Gas & Electric Company, supra,* 85 Cal. P.U.C.2d 682, 683, stating that "the Commission fined the public utility for violating Section 451 (without finding a violation of any other specific statute) by failing to "'furnish and maintain such adequate efficient just and reasonable service, instrumentalities, equipment and facilities' when the utility permitted fumigators to turn off gas service to buildings before tenting them." (*PacBell Wireless v. PUC*, 140 Cal. App. 4^{th} at 743.) Accordingly, PG&E cannot claim that Section 451 does not create a duty separate from GO 112 for PG&E to provide safe service.

PG&E violated Public Utilities Code Section 451 by installing and operating its system in an unsafe manner. (CPSD-1, p.15.) This is true even though industry safety practices were not codified on the state level until 1961 and the federal level until 1968. Section 451 placed (and continues to place) an affirmative duty on the utility to act in a safe manner. That duty would apply today even if there were no specific guidelines, even if there were no General Order, and even if there were no federal law.

CPSD contends in this Opening Brief that PG&E created an unreasonably unsafe system in violation of Section 451 by failing to follow industry standards contained in ASA B31.1.8-1955, API 5LX, and API Standard 1104 during the construction of Segment 180 in 1956. CPSD further contends that PG&E's lack of a safety culture, by putting profits ahead of safety from 1997 until the San Bruno explosion occurred on September 9, 2010, constituted a continuing violation of Section 451.

IV. OTHER ISSUES

A. Mental State Is Irrelevant To A Determination Of PG&E's Compliance With Safety-Related Regulations

PG&E makes references to its mental state throughout its testimony.[15] PG&E appears to be claiming ignorance as a defense. However, it is well-established that public welfare offenses are strict liability offenses unless they specifically state a different mental state requirement. (D.97-10-063, 76 CPUC 2d 214, *9.) A strict liability offense is an unlawful act which does not require proof of mental state. (Black's Law Dictionary, 6th Ed.) Thus, CPSD is not required to prove PG&E's mental state with regard to the alleged violations.

PG&E's mental state is, however, one factor in considering the size of a monetary penalty, but it is not relevant to whether a violation existed or not. The duty to furnish and maintain safe equipment and facilities is paramount for all California public utilities, including natural gas transmission operators. Furnishing and maintaining safe natural gas transmission equipment and facilities requires that a natural gas transmission system operator <u>know the location and essential features of all such installed equipment and facilities</u>. (D.12-12-030, p.91.)

It should be noted that CPSD has developed evidence that PG&E's management made poor decisions that contributed to the unreasonably dangerous situation. This evidence is summarized in this Brief as it is relevant to PG&E's corporate safety culture. In addition, CPSD has also developed, in its Rebuttal Testimony, evidence demonstrating that despite PG&E's claim of ignorance, PG&E knew of the existence of threats posed by Line 132. PG&E was well aware of the fact that portions of Line 132 included the original, pre-1950 pipeline and had questionable welding, because Charles J. Tateosian, PG&E's Head of Gas Design and Vice President of Gas Operations, presented material to PG&E, and made a presentation to PG&E's Board which included this information when

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[15] *See, e.g.*, PG&E-1, pp. 2-1, 2-4, 2-5, 2-6. 2-7, 4-1, 4-12, 4-27, etc.

PG&E was preparing its GPRP. (CPSD-5 (Stepanian), pp. 63-64, CPSD-162 (Tateosian Deposition), Vol. I, p.82-85, 92, 152, 161-162, 168-189.)

V. CPSD'S ALLEGATIONS

CPSD's allegations of violations by PG&E are described in CPSD's Staff Report (CPSD-1), the focused audit by CPSD's retained expert witness Gary Harpster (CPSD-168), and the evidentiary hearings.[16] The Staff Report, Harpster Testimony and the OII place PG&E on notice of allegations relating to violations of the federal regulations (49 CFR Parts 190, 191, 192, 193, and 199), state regulations (Commission General Order 112), and state laws (Public Utilities Code Sections 222, 451, 701, 768, 2107, and 2108).

The CPSD investigation revealed that the incident was caused, not by one violation, but by many. But for each of these failures, the incident would have been prevented or vastly mitigated. The violations fall into six areas:

1) PG&E's failure to follow accepted industry practice when constructing the section of pipe that failed, Segment 180;
2) PG&E's failure to comply with integrity management (IM) requirements;
3) PG&E's inadequate recordkeeping practices;
4) PG&E's deficient SCADA system and inadequate procedures to handle emergencies and abnormal conditions;
5) PG&E's deficient emergency response actions after the incident; and
6) PG&E's systemic emphasis on profits at the expense of safety.

A. Fabrication and Construction of Segment 180

The segment of Line 132 that ruptured in San Bruno is referred to as Segment 180. Segment 180 was originally constructed in 1948, and then relocated in 1956 as part of a project to accommodate a real estate development. (CPSD-1, p.15.) The Segment 180 relocation project started north of Claremont Drive and extended south of San Bruno Avenue and moved the pipeline from the east side to the west side of Glenview Drive, in

[16] The OII, p.10, permits CPSD to "assert additional violations beyond those described herein and in CPSD's Report."

San Bruno. This relocation was necessary because of grading associated with land development in the vicinity of the existing pipeline. The construction was performed by PG&E personnel, not contractors. (*Ibid.*) A few engineering documents from job file 136471 have been located, but none of these documents show the existence of the pup sections. (Joint-10.[17] CPSD-1, p.65.)

The most direct cause of the explosion, but certainly not the only one, is that PG&E failed to follow industry safety standards during the construction of Segment 180 in 1956, creating an unreasonably unsafe system in violation of Section 451.

Industry standards exist to guide utilities in the safe construction of their natural gas systems. Examples of such industry standards in existence in 1956 are ASME B31.1.8-1955, API 5LX, and API Standard 1104. Industry guidelines are typically updated to stay current with modern practices. For example, ASME B31.1.8-1955 has been updated as recently as 2004. (CPSD-1, p.20.)

When the Commission adopted GO 112 in 1961, it explicitly codified the industry standards contained in B31.1.8-1955. When the Code of Federal Regulations superseded it in 1970 (49 CFR Part 190, *et seq.*), GO 112 was modified to track the federal regulations, which in turn were also based on the ASME industry standards.

Prior to the creation of GO 112, Public Utilities Code Section 451 imposed a duty on utilities to construct and maintain safe and reliable systems. Thus, PG&E had a duty to construct and maintain a safe and reliable system when it constructed Segment 180 in 1956. By installing pipe sections (pups) in Segment 180 that did not meet any known industry specifications for fabrication of gas transmission pipe, PG&E created an unreasonably unsafe system in violation of Section 451.

The general duty of reasonable care is also codified in Section 810.1 of ASME B31.1.8-1955, which states:

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[17] Several days of joint hearings were held that included the three San Bruno-related OIIs. Exhibits from those hearings are hereinafter referred to by their joint hearing exhibit number.

> It is intended that all materials and equipment that will become a permanent part of any piping system constructed under this code shall be suitable and safe for the conditions under which they are used. All such materials and equipment shall be qualified for the conditions of their use by compliance with certain specifications, standards, and special requirements of this code or otherwise as provided herein.

As described above, in Section II.B., the pups in Segment 180 were missing interior welds, poorly welded, lacking in sufficient yield strength, untested, and too short. In addition, the MAOP was set dangerously high for the poor quality of Segment 180. By installing pipeline sections that were not suitable and safe for the conditions under which they were used, PG&E violated the safe industry practices described in Section 810.1 of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

PG&E also has no records to show that Segment 180 ever underwent a hydrostatic test post-installation. Section 841.412(c) of ASME B31.1.8-1955 requires operators to hydrostatically test pipelines in Class 3 locations to a pressure not less than 1.4 times the maximum operating pressure.[18] PG&E alleges that the MAOP of Segment 180 was 400 psi, which means PG&E should have tested Segment 180 to 560 psi. PG&E thus violated Section 841.412(c) by not conducting a hydrostatic test on Segment 180 post-installation, creating an unsafe system in violation of Section 451. This is a serious safety violation, because Segment 180 would not have survived such a test had it been done, and the flawed pups would have been discovered. (CPSD-5, p.11.)

At the time of construction, a visual examination of the pipe would have detected the anomalous and defective welds. The unwelded seam defects and manual arc welds ran the entire length of each pup and were detectable by the unaided eye and/or by touch. (CPSD-9, p.96.) Section 811.27(A) of ASME B31.1.8-1955 states:

> All pipe shall be cleaned inside and outside, if necessary, to permit good inspection, and shall be visually inspected to

[18] In data request response CPUC_240-02 (CPSD-152), PG&E stated that Segment 180 "was designed and constructed to meet ASA B31.8 [sic] in effect at that time for a Class 3 location." (CPSD-5, p.8.)

> insure that it is reasonably round and straight, and to discover any defects which might impair its strength or tightness.

By failing to visually inspect for and discover the defects in Segment 180, PG&E violated Section 811.27(A) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

All 6 of the pups used for Segment 180 were less than 5 feet in length. (CPSD-1, p.22.) The purpose of API 5LX (4th Ed., 1954) was to "provide standards for more rigorously tested line pipe having greater tensile and bursting strength…" Chapter VI of API 5LX mandates that "no length used in making a jointer[19] shall be less than 5 feet." By installing sections in Segment 180 that were less than 5 feet in length, PG&E violated API 5LX Section VI, creating an unsafe system in violation of Section 451.

1. Yield Strength

Segment 180 was intended to meet API 5LX Grade X42 or X52 yield strengths, which indicate minimum yield strengths of 42,000 psi and 52,000 psi. Testing revealed the ruptured pups on Segment 180 had yield strengths below 42,000 psi. (CPSD-1, p.20.) Pup 1, the failed pup on which the facture initiated, was found to have yield strength of only 36,600 psi, and Pup 2 had the lowest yield strength of 32,000 psi. (CPSD-1, p.20.)

By installing pipe sections which did not meet the minimum yield strength prescribed by the specification under which the pipe was purchased, PG&E violated Section 805.54 of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451. Section 805.54 states: "specified minimum yield strength is the minimum yield strength prescribed by the specification under which pipe is purchased from the manufacturer (psi)." However, the pups were far below the required yield strengths.

As discussed above, PG&E did not conduct any pressure tests on Segment 180 after construction. Based on the pipeline characteristics associated with the six pups, it is

[19] At the NTSB's investigative hearing, the PG&E director of integrity management and technical support testified that he believed the accident segment of pipe was a jointer manufactured at a mill. (CPSD-9, p.29.) A jointer is defined as "two pieces joined by welding to make a standard length" (API 5LX, p.10) – essentially synonymous with a pup.

clear that, if a strength test that conformed to industry standards had been performed, it would have failed. (CPSD-1, p.22.) ASME B31.1.8-1955 specified detailed requirements for strength testing. Section 841.411 of ASME B31.1.8-1955 required that "All pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength of the pipe shall be given a field test to prove strength after construction and before being placed in operation."

a) Assumed Values for Yield Strength

PG&E acknowledges that it has no records showing the existence of the pup sections. (CPSD-1, p.16.) PG&E did not know the yield strengths for Pup 1, the failed pup on which the fracture initiated, which was found only after the rupture, to have a yield strength of only 36,600 psi. (CPSD-1, p.20.) The PG&E-designated yield strength for Segment 180 was 52,000 psi, when the yield strength was actually unknown. (CPSD-1, p.19.) Section 811.27(G) of ASME B31.1.8-1955 states:

> When the manufacturer's specified minimum yield strength, tensile strength or elongation for the pipe is unknown, and no physical tests are made, the minimum yield strength for purposes of design shall be taken as not more than 24,000 psi.

By assigning a yield strength value for Segment 180 above 24,000 psi when the yield strength was actually unknown, PG&E violated Section 811.27(G) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

2. Welding

Longitudinally, Pups 1, 2 and 3 were partially welded on the seam from the outside and the weld did not penetrate through the inside of the pipe. No inside weld, required for a DSAW welded pipe, was found on the inside of the pipe. According to the NTSB metallurgical examination, the fusion welding process left an unwelded region along the entire length of each seam, resulting in a reduced wall thickness. (CPSD-1, p.20.) By not completely welding the inside of the longitudinal seams on Pups 1, 2, and 3 of Segment 180 and failing to measure the wall thickness to ensure compliance with the procurement orders which required 0.375-inch wall thickness, PG&E violated Section 811.27(C) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

Section 811.27(C) of ASME B31.1.8-1955 requires proper measurement of the wall thickness of the pipe. Wall thickness is a key component of the design pressure formula in Section 841.1 of ASME B31.1.8-1955, which calculates the safe MAOP for a given pipeline. The intent of the minimum wall thickness requirement is to ensure its ability to withstand pressure. The ability of the pipe to withstand pressure is impacted regardless of whether the wall thickness reduction was on the plate or the seam weld. (CPSD-5, p.7.)

In addition to the missing weld, the pups' girth welds and longitudinal seams contained welding deficiencies related to incomplete fusion, burnthrough, slag inclusion, crack, undercut, excess reinforcement, porosity defects and lack of penetration. (CPSD-16, p.6; CPSD-1, p.21.) By welding the pups in a deficient manner PG&E violated Section 811.27(E) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

The shoddy and unsafe quality of the welds on the pups indicates the lack of a qualified welder and proper welding techniques. The lack of an inside weld, incomplete fusion, burnthrough, slag inclusion, crack, undercut, excess reinforcement, porosity defects and lack of penetration deficiencies violate the "Standards of Acceptability" in effect at the time, Section 1.7 of API 1104 (4th Ed., 1956), creating an unsafe system in violation of Section 451. The purpose of the industry standards in API 1104 is "to produce the highest quality welds obtainable on a commercial basis by skilled welders…" The poor quality of the welds created an unreasonably unsafe condition.

3. MAOP

PG&E provided a pressure log from the Milpitas Terminal dated October 16, 1968 showing a recorded pressure of 400 psig for Line 132. This pressure log was used by PG&E as the basis for establishing an MAOP of 400 psig for Line 132. PG&E did not produce evidence that it established an MAOP for Segment 180 at the time of construction. (CPSD-1, p.24.)

Section 845.22 of ASME B31.1.8-1955 describes the requirements for establishing the MAOP for pipelines. (CPSD-1, p.23.) Section 845.22 requires that the MAOP be established based on the lesser of either: 1) the <u>design</u> pressure; or 2) the <u>test</u> pressure. However, PG&E could not have relied on a test pressure value because it has no records showing that there was a pressure test on Segment 180. Thus, PG&E should have calculated the design pressure for Segment 180 at the time it was installed and established the MAOP based on that calculation. According to Section 845.22, the design pressure is the pressure of the "weakest element of the pipeline or main". PG&E clearly did not incorporate the pups, which were the weakest element of Segment 180, when it calculated the design pressure at 400 psi. This resulted in an unreasonably high MAOP, creating an unsafe system condition in violation of Section 451.

Without complete and accurate knowledge of the specifications or characteristics of the pup that failed, PG&E could not have accurately determined the weakest element of the pipeline, and consequently did not know the design pressure of the pups. Therefore, PG&E did not meet the MAOP determination requirements in Section 845.22 of ASME B31.1.8-1955, creating an unsafe system condition in violation of Section 451.

Had PG&E considered the pups in calculating MAOP for Segment 180, it would have found that the pups:

- Did not "conform to any known specification for pipe, including PG&E and API specifications". (CPSD-9, p.92.)
- Had "a yield strength below the SMYS for grade X42 and X52 pipe". (*Ibid.*)
- Was "partially welded from outside only". (*Ibid.*)
- Had "reduced cross sectional area" along the longitudinal seams. (*Ibid.*)
- Was "rolled in a manner inconsistent with industry standard line pipe". (CPSD-9, p.95.)
- Its assembly "did not meet the requirements of a mill-produced jointer". (*Ibid.*)
- "Was fabricated at an undetermined facility with no known specifications". (*Ibid.*)

If the presence of the pups in Segment 180 had been considered in determining a design pressure, it would not have substantiated an MAOP of 400 psig. (CPSD-9, p.106.) If PG&E had used an assumed yield strength of 24,000 psi (required for unknown pipe) it would have calculated the MAOP at 300 psi. (CPSD-5, p.18.) Based on the actual yield strength test data, the NTSB calculated that the MAOP for Segment 180 in a Class 3 location would have been 284 psi. (CPSD-9, p.106.)

B. PG&E's Integrity Management Program

CPSD's Report describes the federal rules for the ongoing maintenance of gas transmission pipelines that came into effect in the early 2000s, referred to as Integrity Management (IM). (CPSD-1, p.25.) The integrity management requirements apply to all gas pipelines in high consequence areas (HCAs), and were effective with the signing into law of the 2002 Pipeline Safety and Improvement Act on December 17, 2002. Segment 180 is in an HCA, and is thus a covered segment. (CPSD-9, p.36.)

This law required PHMSA to promulgate regulations concerning transmission pipelines in areas that could affect human safety no later than one year after enactment. The regulations referenced sections of ASME B31.8S-2001 and all of NACE RP0502-2002; these two standards became essentially part of the regulation. The law mandated that for time dependent threats (external corrosion and internal corrosion), the maximum re-assessment period was seven years from the completion of the initial or baseline assessment. (CPSD-1, p.25.)

PHMSA noticed the new regulations on December 15, 2003, and these regulations had the following requirements with regard to Integrity Management (IM) plans.

- No later than December 17, 2004, operators were to have IM plans developed and to have identified all HCAs.
- No later than December 17, 2007, operators were to have initially assessed 50% of the HCA segments by mileage, beginning with the highest risk segments.
- No later than December 17, 2012, operators were to have initially assessed all of their pipelines in HCAs.

The investigation found that PG&E did not comply with certain key integrity management requirements, including data gathering and integration, threat identification, and risk assessment.

1. Data Gathering and Integration

Potential threats to the integrity of Line 132 pipeline segments can only be identified through a detailed and thorough knowledge of each covered segment. (CPSD-1, p.27.) The requirements for data gathering and integration are stated in Part 192.917(b) and ASME B31.8S, Section 4, which is incorporated by reference in 49 CFR Part 192. Part 192.917(b) states:

> **Data gathering and integration**. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

Thus, operators are required to gather basic information about the pipeline as described in Appendix A of ASME B31.8S, as well as past incident history, maintenance history, etc. PG&E failed in many of these respects.

Appendix A sets forth the data sets required, including pipe material, year of installation, pipe manufacturing process, seam type, joint factor, and operating pressure history. When data is missing from the minimum data sets identified in Appendix A, the threat is assumed to exist. In addition, where there is missing data, "conservative assumptions should be used." (CPSD-1, p.28.)

However, with regards to yield strength, 49 CFR Part 192.107(b)(2) requires operators to use 24,000 psi if the data is missing. By routinely using yield strength values above 24,000 psi, PG&E violated Part 192.107(b)(2).

There are numerous examples of missing or inaccurate data in PG&E's records. Discussed in the previous chapter is the complete lack of any pressure test history for Segment 180. The investigation documents a number of examples where data from PG&E's GIS were in error, but not discovered by PG&E, including:

- the pipe wall thickness was an assumed value for 21.5 miles (41.75 percent) of Line 132;
- the manufacturer of the pipe was unknown ("NA") for 40.6 miles (78.81 percent) of Line 132;
- the pipeline depth of ground cover was also unknown for 42.7 miles (82.79 percent) of Line 132;
- three values were used for the SMYS of grade B pipe: 35,000 psi, 40,000 psi, and 45,000 psi;
- two segments with unknown SMYS were assigned values of 33,000 psi and 52,000 psi, not 24,000 psi;
- six consecutive segments, totaling 3,649 feet, specified an erroneous minimum depth of cover of 40 feet;
- several segments, including Segment 180, specified 30-inch-diameter seamless pipe, although there was no API-qualified domestic manufacturer of such pipe when the line was constructed; and
- the GIS did not reflect the presence of the six pups in Segment 180.

(CPSD-1, p.32; CPSD-9, p.61)

Not accurately gathering and integrating required pipeline data is a violation of 49 CFR Part 192.917(b).

With reference to data quality, ASME B31.8S (Section 5.7, p.14) states: "Risk Confidence. Any data applied in a risk assessment process shall be verified and checked for accuracy." By failing to check for and verify the accuracy of its pipeline data, PG&E violated Section 5.7 of ASME B31.8S.

As a policy, PG&E did not always seek the most accurate data. PG&E's Integrity Management process is governed by its Risk Management Procedure-06 (RMP-06). Under the heading in RMP-06 "Data Elements Selected for Initial Analysis," PG&E states:

> For the risk analysis process, the Company has chosen pipeline attributes based upon available, verifiable information <u>or information that can be obtained in a timely manner</u>. [Emphasis added.]

Thus, if pipeline data could not be verified, PG&E's policy allowed it to substitute information that can be obtained in a timely manner, which would not preclude assumed values. As a result, an in-depth understanding of the threats on Line 132 and Segment 180 was not achieved. (CPSD-1, p.30.)

2. Threat Identification

Another important step in the IM program is threat identification. 49 CFR Part 192.917(a) states: "An operator must identify and evaluate all potential threats to each covered pipeline segment."

The investigation documented a number of defects that were not incorporated into PG&E's initial analysis of the condition of Line 132 for its 2004 Baseline Assessment Plan (BAP), including:

- 1948, Line 132: Multiple longitudinal seam cracks found during radiography of girth welds during construction.
- 1958, Line 300B: Seam leak in DSAW pipe.
- 1964, Line 132: A leak was found on a "wedding band" weld; the leak was the result of construction defect. The defect was found on segment 200.
- 1974, Line 300B: Hydrostatic test failure of seam weld with lack of penetration (similar to accident pipe).
- 1988, Line 132: Longitudinal seam defect in DSAW pipe.
- 1992, Line 132: Longitudinal seam defect in DSAW weld when a tie-in girth weld was radiographed.
- 1996, Line 109: Cracking of the seam weld in DSAW pipe.
- 1996, Line 109: Seam weld with lack of penetration (similar to accident pipe) found during camera inspection.
- 1996, DFM-3: Defect in forge-welded seam weld.
- 1999, Line 402: Leak in ERW seam weld.

- 2002, Line 132: During a 2002 ECDA assessment, miter joints with construction defects were found on Segment 143.4.
- 2009, Line 132: A leak was found on Segment 189 that was caused by a field girth weld defect. Segment 189 was originally fabricated by Consolidated Western using DSAW and installed in 1948.
- 2009, Line 132: During the ECDA process, a defective SAW repair weld was found on Segment 186. As indicated in PG&E's pipeline survey sheet, the segment was originally fabricated by Consolidated Western using DSAW and installed in 1948.
- 2011, Line 300A: Longitudinal seam crack in 2-foot pup of DSAW pipe (found during camera inspection).
- 2011, Line 153: Longitudinal seam defect in DSAW pipe during radiographic inspection for validation of seam type.

(CPSD-1, pp.33-35; CPSD-9, p.39.)

PG&E's failure to analyze the data on these weld defects resulted in an incomplete understanding of the manufacturing threats to Line 132, in violation of 49 CFR Part 192.917(a) and ASME-B31.8S Section 2.2. ASME-B31.8S Section 2.2 states that "The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered."

a) Cyclic Fatigue

PG&E did not incorporate cyclic fatigue or other loading conditions into their segment specific threat assessments and risk ranking algorithm. Essentially, PG&E dismissed cyclic fatigue as a threat. (CPSD-1, p.38, p.50.)

However, the investigation found that fatigue was a major factor in the failure of Segment 180 and was a threat on Line 132. (CPSD-1, p.50.) The crack initiation section of the NTSB report describes the initial defect, and the stages by which the defect grew to failure. (CPSD-9, p.43.) The initial crack-like defect extended longitudinally along the entire length inside of the weld (the root) on Pup 1, resulting in a net intact seam thickness of 0.162 inches. With a nominal 0.375 inch wall thickness, the intact wall thickness was approximately 43% at the weld. There was also an angular misalignment on the inside of Pup 1. Given this initial defect, an additional 2.4 inch defect grew to failure. As noted in the photo from Figure 21 of the NTSB report (p.45), the initial crack-like defect first grew by ductile fracture. Then the crack grew by fatigue. The final stage was the rupture of the pipe, identified in the photo as quasi-cleavage fracture. (CPSD-9, p.45.)

49 CFR Part 192.917(e)(2) unequivocally calls for cyclic fatigue to be evaluated as a threat, which PG&E did not do on Segment 180 or any of its lines. PG&E should have undertaken the analysis required by Part 192.917(e)(2) on Line 132, and more broadly on all transmission lines, particularly for line segments that had not undergone hydrostatic pressure testing per Part 192, Subpart J.

b) DSAW Pipe

PG&E's records show that the 1948 DSAW pipe from Consolidated Western had seam quality issues based on the rejection of some seam welds noted in the limited girth weld x-rays taken during installation and seam leaks and cracks found since the installation date. (CPSD-1, p.41.)

The "Integrity Characteristics of Vintage Pipelines" report, a report referenced by PG&E in its first revision of RMP-06, identifies DSAW as having manufacturing defects, including seam and pipe body defects. Table E-6 of that report identifies incidents associated with certain manufacturers during certain years related to pipe body and seam weld defects for DSAW pipe, including seam issues on Consolidated Western pipe pre-1960. (CPSD-1, p.41.)

PG&E's procedure should have considered the category of DSAW as one of the weld types potentially subject to manufacturing defects. As a result of ignoring this threat, PG&E failed to determine the risk of failure from this defect in violation of 49 CFR Part 192.917(e)(3).

In addition, pursuant to Part 192.917(e)(3)(i), if the pressure increases above the maximum pressure reached in the 5 years preceding identification of HCAs, any defects must be considered unstable and must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. (CPSD-1, p.42.)

PHMSA FAQ-221[20] states that any pressure increase, regardless of the amount, above the 5 year MOP would cause manufacturing and/or construction defects be considered unstable. PG&E operated the line at 402.37 psig on December 11, 2003; PG&E also operated Line 132 at 400.73 psig on December 8, 2008. (CPSD-1, p.44.) The December 2008 pressure increase was clearly after the identification of HCA areas. The December 2003 pressure increase occurred after the actual identification of Segment 180 as an HCA, although before the formal designation. (CPSD-1, p.43.) Thus, both of these pressure increases legally required PG&E to consider potential defects on Segment 180 to be unstable.

Pursuant to Part 192.921(a), an operator must select the method best suited to address the threats identified. Assessment technologies proven to detect seam issues include In Line Inspection (ILI) and hydrostatic pressure testing, but not ECDA. (CPSD-1, p.47.) PG&E's engineers stated that they strongly preferred to use ILI on higher stress pipelines in order to obtain a better initial evaluation, but that using ILI was not financially viable given PG&E's funding of its GT&S. (CPSD-168, p.7-8.) By not performing pipeline inspections using a method capable of detecting seam issues, PG&E violated Part 192.921(a).

c) ERW Pipe

49 CFR Part 192.917(e)(4) specifically recognizes the threat posed by ERW pipe manufactured pre-1970. If a pipeline contains ERW pipe and is subjected to a pressure increase above the 5 year MOP, Part 192.917(e)(4) requires an operator to "select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies."

Line 132 includes several ERW segments. (CPSD-9, p.36.) By not conducting appropriate testing such as hydrostatic testing or in-line inspections after exceeding MOP

[20] PHMSA states that its FAQs are intended "to clarify, explain, and promote better understanding of the pipeline integrity management rules." (CPSD-1, p.42.)

on segments of Line 132 that contained electric resistance welded (ERW) pipe, PG&E violated 49 CFR Part 192.917(e)(4).

PG&E simply failed to identify that Line 132 had design and materials threats, and did not consider any possible threats to have become unstable as a result of the overpressurization events. (CPSD-9, p.111.) Thus, PG&E selected ECDA as its assessment tool for Line 132. (*Ibid.*)

However, ECDA is not the appropriate tool. Pressure testing and in-line inspection both assess the integrity of the entire pipe section to which they are applied. (*Ibid.*) ECDA assesses only the integrity of selected pipe areas where the operator suspects a problem. (*Ibid.*) ECDA provides information only about threats that the operator is specifically looking for, while in-line inspection and hydrostatic testing can identify critical threats that the operator might not have been looking for. (*Ibid.*) In this regard, PG&E's treatment of ECDA as an equally acceptable method is flawed. (*Ibid.*)

Thus, PG&E not only violated Part 192.921(a), but also created an unreasonably unsafe system in violation of Section 451, by failing to use an appropriate tool capable assessing the threats identified to the covered segment.

3. Risk Assessment

Risk analysis is the process by which each individual pipeline segment in PG&E's system is given a risk score that is used to rank the segments for assessment (physical examination). (CPSD-1, p.53.)

ASME-B31.8S Section 4.4 states: "Records shall be maintained throughout the process that identify where and how unsubstantiated data is used in the risk assessment process, so its potential impact on the variability and accuracy of assessment results can be considered." As discussed above, PG&E repeatedly used assumed values where it did not have verified and accurate data. It was impossible for PG&E to know the variability or accuracy of assessment results as a consequence of failing to identify where and how such unsubstantiated data was being used, in violation of ASME-B31.8S Section 4.4.

49 CFR Part 192.917(c) and ASME-B31.8S Section 5.7 prescribe the characteristics of a risk assessment program. Section 5.7 states that these characteristics

shall (among other things): contain a defined logic and a structure to provide a complete, accurate, and objective analysis of risk; consider the frequency and consequences of past events, including the subject pipeline system or a similar system; and determine and document the default values that will be used and why they were chosen.

As described above, PG&E failed to conduct risk assessment that considers the identified threats, failed to consider the consequences of past events on Line 132, and failed to account for missing or questionable data. PG&E was therefore in violation of 49 CFR Part 192.917(c) and ASME-B31.8S Section 5.7.

Risk assessment is intended to provide a measure that evaluates both the potential impact of different incident types and the likelihood that such events may occur. (ASME B.31.8S, Section 5.3.) A risk algorithm is used to develop a risk score, determined as the product of the LOF and COF factors (Risk = LOF *COF). If either of these factors is inaccurate, the risk score and risk ranking will be inaccurate. (CPSD-1, p.54.) To the extent that PG&E's risk algorithm does not incorporate certain factors, or does not reflect them in an appropriate way, the risk ranking algorithm is less accurate. (CPSD-1, p.55.)

However, PG&E did not properly weigh the threats to Line 132, because PG&E did not include its actual operating experience, instead substituting industry experience. (CPSD-1, pp. 55-56.) PG&E's algorithm weighted external corrosion 25%, third-party threat 45%, ground movement 20%, and design/materials 10%. However, PG&E's incident statistics for the years 2004-2010 show that external corrosion was 51% of combined leaks, design/materials accounted for 24% of combined events, third-party accounted for 24% of incidents and ground movement accounted for 0% of incidents. While PG&E weighting factors may have generally reflected industry experience, they did not reflect PG&E's actual operating experience. (CPSD-1, p.56.)

The investigation identified certain systemic issues along with specific examples along Line 132:

- In the third-party threat algorithm, an unknown depth of cover is assigned the same value as ground cover meeting new construction depth requirements. However, the depth of cover for more than 82% of Line 132 is unknown.

- In several threat algorithms, non-conservative values are used for pipe wall thickness.
- PG&E uses MOP as a percent of pipe strength, calculated from the pipe diameter, pipe wall thickness, weld joint efficiency, and specified minimum wall thickness. However, the pipe wall thickness for Line 132 is an assumed value for 41.75% of Line 132.
- The use of "wedding band" joints in place of a girth weld is not considered as an element of any of the threat algorithms, despite the fact that this type of joint is not as strong as a full penetration butt weld.
- Prior to the San Bruno incident, PG&E did not consider missing girth weld radiography records as an element of any of the threat algorithms.
- Construction damage is not considered as an element of any of the threat algorithms.
- Leaks resulting from manufacturing defects are only considered in threat algorithms if they occurred on the segment in question or on an adjacent segment with the same pipe properties and within 1 mile of the leak. Leaks on more distant pipe segments of the same vintage, same characteristics, and same manufacturer are not considered.

(CPSD-9, pp.108-109.)

PG&E also failed to: properly identify the Potential Impact Radius of a rupture, by using a value of 300 feet where the PIR is less than that (CPSD-1, p.57); identify the proper Consequence of Failure formula, by not accounting for higher population densities (CPSD-1, p.58); use conservative values for electrical interference on Line 132, which created an external corrosion threat (CPSD-1, p.58); include any consideration of one-call tickets, which indicates third party damage threats (CPSD-1, p.58); include any consideration of historic problems with the type of pipe used on Segment 180 (CPSD-1, p.59).

PG&E thus violated 49 CFR Part 192.917(c) and ASME-B31.8S Section 5 by using dangerously inaccurate risk algorithms, resulting in risk assessments that underplayed the danger of leaks and overstated the threat from third-parties, among other things.

a) PG&E's Practice of Pressure Spiking

As noted in the public hearing transcript from the NTSB hearings on March 1, 2010, PG&E engaged in a practice of "spiking" certain transmission lines to "maintain operational flexibility." (Joint-41; CPSD-1, p.40.) PG&E increased the pressure on Line 132 to a little over the "system MAOP" of that line so that they could increase pressure as needed for customer demand, and at the same time, PG&E believed it would eliminate the need to consider manufacturing and construction threats as unstable as a result of increasing the pressure above the 5 year MOP. (*Ibid.*) Identifying manufacturing and construction threats as unstable would mean that an assessment method capable of assessing seam, girth weld, and other manufacturing and construction anomalies would need to be used (hydrotesting or In Line Inspection). (*Ibid.*) This practice has never been approved by either PHMSA or the Commission, neither of whom were aware of it.[21]

Essentially, PG&E engaged in the practice of increasing the pressure on Line 132 every 5 years to set the MAOP for the purpose of avoiding the need to deem manufacturing and construction threats unstable, thereby avoiding hydrostatic testing or in-line inspections on Line 132. However, because of the pressure excursions a test capable of detecting seam problems was required, and in fact it is clear that Segment 180 would not have survived a proper hydrotest because it would have been subjected to pressures greater than the pups were capable of withstanding. (CPSD-9, p.49; CPSD-1, p.60.) This practice created an unreasonably unsafe system in violation of Public Utilities Code Section 451.

C. Recordkeeping Violations

The Commission had safety jurisdiction over PG&E's gas pipelines when Line 132 and Segment 180 were constructed. ASA B31.1.8-1955, Section 824 described recordkeeping requirements of welding procedures and welder qualifications. Additionally, Chapter IV, Design, Installation, and Testing, Sections 840 and 841

[21] NTSB Hearing Transcript, March 2, 2011, p.349.

required that as-built drawings and related design and construction documents and test records be maintained as long as the pipe remained in service. (CPSD-1, p.62.)

GO 112 requirements, which incorporated ASME B31.8 standards by reference, and mandated the natural gas utilities compliance with these standards, have been in effect in California since 1961. The federal pipeline safety standards in 49 CFR Part 192, became effective since 1970, and explicitly required gas operators to keep all as-built drawings and construction documents. (CPSD-1, p.62.)

CPSD's investigation found that, at the time of the incident, PG&E transmission pipeline records were not accurate, complete, or verifiable. PG&E's records showed inaccurate information for Segment 180 of Line 132 and PG&E could not identify the manufacturer of Segment 180 or locate its as-built drawings, alignment sheets, specifications and other design, material, construction, inspection, and testing records. The investigation also found that PG&E's quality control failed to correct inaccuracies in its Geographic Information System (GIS). (CPSD-1, p.62.)

PG&E failed to follow the recordkeeping standards in ASA B31.1.8-1955 which were applicable at the time Segment 180 was constructed and, in turn, violated the Public Utilities Code Section 451 by operating its system unsafely by lacking accurate and locatable records essential for safe pipeline operation. (CPSD-1, p.62.)

These recordkeeping issues are being dealt with much more extensively in CPSD's other San Bruno-related proceeding, I.11-02-016, the PG&E Recordkeeping OII. CPSD more completely explored the issues concerning PG&E's recordkeeping with regards to Line 132 and specifically Segment 180 in that proceeding. Therefore, a discussion here of PG&E's recordkeeping practices would be redundant. Although CPSD documented numerous violations with regards to recordkeeping relating to Segment 180 in this proceeding, CPSD will defer to I.11-02-016 as the proper venue to allege those violations, in order to avoid overlap.

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

1. Background

PG&E's gas facilities include 42,141 miles of natural gas distribution pipelines and 6,438 miles of transmission pipelines, 1,059 of which are located in High Consequence Areas (HCAs). Of these 1,059 HCA pipeline miles, 50 miles are in class 1 areas, 29 miles are in class 2 areas, 945 miles are in class 3 areas, and 4 miles are in class 4 areas. (CPSD-9, p.51.)

PG&E's Supervisory Control and Data Acquisition (SCADA) system provides remote control of for all of its 6,438 miles of gas transmission pipeline. Parts of PG&E's 42,141 miles of gas distribution pipeline are also monitored by SCADA. About 9,000 sensors and devices are installed along the length of the pipelines to enable the display of flow rates, equipment status, valve position status, pressure set points, and pressure control among other data. (CPSD-1, p.71.)

The Peninsula transmission pipelines 101, 109, and 132 all originate from PG&E's Milpitas Terminal. The Milpitas Terminal serves as a receiving point for natural gas coming from the northern portion and natural gas supplied from the southern portion of the state. (CPSD-1, p.74.)

The Milpitas Terminal has four incoming lines and five outgoing lines and is equipped with pressure regulation and overpressure protective devices to control incoming and outgoing pressure. The pressure regulating valves are electrically actuated with the SCADA system controls while the monitor valves are pneumatically controlled valves. (CPSD-1, p.73.)

The Milpitas Terminal utilized an Uninterruptible Power Supply (UPS) to power the SCADA and control equipment during power outages, to bridge the time before emergency generators start delivering backup power. (CPSD-1, p.80.)

The UPS at Milpitas Terminal had been in service since the 1980s with a three-phase system that was no longer needed and for which parts were no longer available. Therefore, PG&E decided to replace it. (CPSD-1, p.81.)

In February 2010, PG&E asked a Contract Engineer to offer a proposal to investigate and provide recommendations for the UPS/battery problems. In mid-March 2010, a Contract Work Authorization was approved for the Contract Engineer to perform the proposed work on the UPS at Milpitas Terminal. (CPSD-1, p.81.)

On March 31, 2010, the UPS at Milpitas Terminal failed, exposing the gas control system to a short interruption of power and potential loss of pressure control. (CPSD-1, p.81.)

PG&E installed at Milpitas Terminal three temporary mini-UPS units on April 1-2, 2010, to provide temporary backup power. (CPSD-1, p.81.)

2. System Clearance Form Deficient

49 CFR Part 192.605(a) requires operators to maintain a manual of written procedures for conducting operations and maintenance activities. Part 192.605(b) states that the manual must include procedures for "operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part."

If operating design limits have been exceeded (abnormal operations), Part 192.605(c) states that the procedures shall include responding to, investigating, and correcting the cause of all of the following:

- Unintended closure of valves or shutdowns;
- Increase or decrease in pressure or flow rate outside normal operating limits;
- Loss of communications;
- Operation of any safety device; and
- Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

49 CFR Part 192.13(c) requires gas operators to maintain, modify as appropriate, and *follow* the plans, procedures, and programs that it is required to establish under Part 192. (Emphasis added.) This section requires PG&E to both <u>create</u> the procedures and <u>follow</u> them.

In 2009, PG&E issued PG&E's "Work Procedures (WP) 4100-10 Gas Clearance Procedures for Facilities Operating Over 60 PSIG". These work procedures prescribe gas system operation procedures for Brentwood Gas Control, System Gas Control, and all manned stations. (CPSD-1, p.82.)

WP4100-10 requires system clearance for work that affects gas flow, gas quality, or the ability to monitor the flow of gas. All system clearances require authorization from PG&E's Gas System Operations (GSO). (CPSD-1, p.82.)

WP4100-10 requires the Clearance Supervisor to report key communication steps identified in the Sequence of Operations to Gas Control including operation of any piece of equipment that affects the flow and/or pressure of gas or ability of Gas Control personnel to monitor the flow and/or pressure of gas on SCADA. (CPSD-1, p.84.)

A clearance application to replace the temporary UPS that was installed in April with a permanent UPS was submitted on August 19, 2010 as Clearance Number MIL-10-09 and approved by PG&E Gas Control on August 27, 2010. (CPSD-1, p.83.)

However, there were a number of instances where WP4100-10 was not adhered to in Clearance MIL-10-09. Further, the clearance application went through a process of review and approval without the details required by PG&E's procedure. (CPSD-1, p.84; CPSD-9, p.90.) The clearance form did not adequately detail the work to be performed. (CPSD-9, p.90.)

First, PG&E's WP 4100-10 requires a designated Clearance Supervisor for all clearances at all times. MIL-10-09 marked the Clearance Supervisor as "TBD". (CPSD-1, p.83.)

Second, a checkbox on MIL-10-09 asks if normal function of the facility will be maintained was checked "No". The clearance application requires an explanation whenever this box is checked "No". However, there was no explanation provided on the clearance application as to how the work will affect normal function of Milpitas Terminal. (CPSD-1, p.83.) The importance of this explanation was illustrated when, after the rupture (at 7:05 p.m.), a SCADA operator incorrectly stated, "it was a regular scheduled clearance, it wasn't supposed to affect anything." (CPSD-9, p.90.)

Third, under the Sequence of Operations, the clearance application showed "Report On Daily and Report Off". It did not list any specific operations or key communication steps to be reported to Gas Control. (CPSD-1, p.83.)

Fourth, one of the steps taken during the UPS work at Milpitas Terminal was switching the controllers to manual which locks the valve to its current setting and disables Gas Control's ability to change the valve settings remotely. This should have been clearly stated on the clearance application as a key communication step within its Sequence of Operations. (CPSD-1, p.83.)

Finally, WP4100-10 requires the Clearance Supervisor to fill in any steps in a system clearance with the time, date, and initials of the person completing the step and file the clearance as completed. There is no record provided by PG&E showing the specific steps taken and the time, date, and initials of the person completing each step in the system clearance. (CPSD-1, p.83.)

Due to the lack of detail on the work clearance form for UPS replacement, the SCADA operators would not have been aware of the scope and magnitude of the work being performed at the Milpitas Terminal. (CPSD-9, p.90.)

By failing to follow its internal work procedures, PG&E violated 49 CFR Part 192.13(c). Failing to follow the work procedures resulted in an unreasonably dangerous condition on September 9, 2010, in violation of Public Utilities Code Section 451.

In addition, PG&E's WP4100-10 does not require pre-planning for handling any abnormal operations that may be encountered during the clearance work. (CPSD-1, p.85.) Thus, PG&E's workers did not anticipate the extent of any abnormal conditions that may be encountered during the UPS clearance work and did not prepare for how to address these abnormal conditions prior to performing the UPS work in Milpitas. (CPSD-1, p.85.) By failing to account for abnormal conditions in its work procedures manual, PG&E violated 49 CFR Part 192.605(c). PG&E was required by Part 192.605(c) to specifically prepare for "increase or decrease in pressure…outside normal operating limits", and "loss of communications"; it is apparent that on September 9, 2010, PG&E was not prepared for these abnormal conditions.

If the form had included the necessary information, the SCADA operators would have at least been aware that power interruptions were planned to specific instrumentation at the Milpitas Terminal and might have taken steps to mitigate the risk. (CPSD-9, p.90.) CPSD staff determined that PG&E personnel at Milpitas had little recognition that they were working with a very critical system that demands a high level of care in planning and execution of their work. (CPSD-1, p.98.) The lack of detail in the clearance form, and lack of procedures to account for abnormal operating conditions in its work procedures manual, contributed to the explosion.

3. Aging and Obsolete Equipment at Milpitas Terminal

The local control system at Milpitas Terminal was decades old in 2010. (CPSD-1, p.94.) It had been upgraded multiple times from the original manual system to a fully automated terminal that is managed from the Gas Control Center in San Francisco through the SCADA system. (CPSD-1, p.94.) The upgrade modifications were not always executed properly which resulted in poorly made electrical connections, improperly labeled circuits, missing wire identification labels, aging and obsolete equipment at the end of useful life and inaccurate documentation. (CPSD-1, p.94.)

Scheduled replacement before the end of expected lifetime is necessary to maintain integrity of safety related control systems. (CPSD-5, p.42.) PG&E's past practices have been to monitor and react rather than predict and be proactive. (CPSD-5, p.42.) Examples of PG&E's failure to timely replace aging equipment are as follows.

Uninterruptible Power Supply. The UPS for the Milpitas control system had failed at least once before February 2010. (CPSD-5, p.44.) It had been in service since the 1980s and parts were no longer available so it had to be replaced. (CPSD-5, p.44.) The Milpitas UPS remained in operation until it failed. (CPSD-5, p.44.) PG&E did not replace either the UPS or the 24 Volt DC (VDC) power supplies at Milpitas until after they aged into the "Wearout Failure Period"[22] for aging equipment.

[22] The IEEE is one of several organizations that publishes the well-known "Bathtub Curve." (IEEE

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The analysis performed by Gulf Interstate Engineering for PG&E of the PS-A and PS-B 24-volt power supplies states: "due to the age of the power supply it is possible that the Aluminum Electrolytic capacitors, that are a part of the Regulation / Current limiting circuit, may have started to degrade." (CPSD-5, p.44.) The power supplies were installed in about 1988 or 1989 at Milpitas, when the original local control system was installed. At the time of failure they were about 21 years old, well past the time they should have been replaced. (CPSD-5, p.44.) The capacitors in the power supplies have a 100,000 hours nominal lifetime. (CPSD-5, p.44.) This equates to 11.4 years under continuous use. (CPSD-5, p.44.) To be safe, these power supplies should have been replaced routinely at least every 10 years. (CPSD-5, p.44.) However, these had been in use for about 21 years, well past their expected wearout time. (CPSD-5, p.44.)

<u>Pressure Controllers</u>. There are 26 pressure controllers at Milpitas, which communicate with the SCADA computers in San Francisco to control the pressure on PG&E's pipelines. (CPSD-1, p.87.) Shortly after restoring power to the mimic panel, the Gas Technician noticed that three controllers had failed to return to normal operation and the Construction Lead observed that all the pressure displays on the mimic panel were showing zero. (CPSD-1, p.87.)

The three malfunctioning pressure controllers (CPSD-1, p.88) were manufactured in August 2002. Assistance from the factory was necessary to restore them to operational status on the day of the incident. (CPSD-5, p.43.) PG&E states that it has 162 Moore/Siemens pressure controllers and some are 15 years old. (CPSD-5, p.43.) It was not until 10:30 p.m. when the Senior Gas Engineer was able to restore the pressure controllers to operation. (CPSD-1, p.88.) The pressure controllers suffered a rare type of malfunction and the manufacturer had to be contacted to advise how to correct it. (CPSD-1, p.88.) PG&E did not determine if this malfunction was indicative of failing or defective units and they are still in service. (CPSD-1, p.88.)

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1413.1 2002: "Guide for Selecting Reliability Predictions".) (CPSD-5, p.43.) This provides a method for predicting the failure period for aging equipment.

Loose wires and poorly made electrical connections. Loose wire connections with sparks were found inside the control panel during the work on the day of the incident. (CPSD-5, p.46.) Additional loose wires and wiring situations were found inside the control panel during the clean-up which followed later at the time the UPS upgrade was completed in October. (CPSD-5, p.46.) Terminals were found with more wires forced on them than they were designed to hold. (CPSD-5, p.46.) The risk of forcing more wires under a terminal than it is designed to hold is that some the wires can come loose, spark or short. (CPSD-5, p.46.)

Improperly labeled circuits. Ambiguous labeling on the circuit breakers led to confusion about which circuit breaker fed the two components of the chromatograph. (CPSD-5, p.46.) This led to the technician working on the wrong one for a time. (CPSD-5, p.46.) Floorboards were raised to trace the wires to see what they were connected to. (CPSD-5, p.46.) Proper documentation should have included markers on the wires and well as identification of the circuits, breakers and terminals. (CPSD-5, p.46.) The fact that the crew had to raise the floor boards to trace out the wiring shows that they did not or could not rely on documentation. (CPSD-5, p.46.)

Missing and inaccurate identification labels. The wire identification labels were present on only some of the wiring in the control system. (CPSD-5, p.47.) The remaining identification labels were those dated from the original construction about 1989. (CPSD-5, p.47.) Apparently, upgrades and maintenance since the original installation was done without the required labels.

The two 24 VDC power supplies that supplied the shorted pressure feedback circuit, PS-A and PS-B, are identified on the PG&E drawings as PS-1 and PS-2, but as PS-A and PS-B on the equipment. (CPSD-5, p.47.)

Wires in the control system were not identified as required by the IEEE[23] and NPFA[24] standards among others. Industry practice is to identify the conductors inside a

[23] IEEE, "IEEE Standards Definition, Specification, and Analysis of Systems Used for Supervisory Control, Data Acquisition, and Automatic Control" Std. 37.1-1994, Section 8.1 Identification (first

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control panel with tags or colors that correspond with the engineering documentation. (CPSD-5, p.47.)

Inaccurate documentation and equipment identification. Wiring from circuit breaker panels to the items of equipment were not identified on the drawings and/or the technicians did not have enough confidence in it to refer to it. (CPSD-5, p.47.)

Pre-existing document errors were identified in the redlined as-built drawings for the UPS upgrade. (CPSD-5, p.47.) When the UPS upgrade was completed in October 2010, the drawings were redlined to show the corrections necessary to make them agree with the existing installation. Some examples of these document errors are:

- Dwg. 3800221 Rev 5 – Marked up for "as found" conditions. No sheet identification.
- Dwg. 388103 Rev 3 – Marked up for as found conditions.
- Dwg. 388121 Rev 2 – Obsolete but still active.
- Dwg. 388272 Rev 2 – Had not been updated for removal of PS-C and separators.
- Dwg. 3800230 Rev 3 identifies circuits for 24 VDC power supplies PS-1 and PS-2 instead of the PS-A and PS-B as the equipment was labeled. The drawing also shows UDP Ckt 14 as a "spare" but the redline Dwg. 388273 Rev5 identifies PS-A and PS-B as fed from this same UDP Ckt no.14. (CPSD-5, p.48.)

Errors in the Milpitas operations and maintenance document. An entry shows that it was updated for PLC replacement June 16, 2004. (CPSD-5, p.48.) But it still contains numerous references to the VAX computer which was removed from service in 2001. (CPSD-5, p.48.) It also has a reference to the ADACS SCADA system that had been removed from service before September 9, 2010. This referenced version of the maintenance manual for Milpitas was last updated December 31, 2009. This manual for

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edition published in 1979)

[24] National Fire Protection Association (NPFA) Standards 79, "Electrical Standard for Industrial Machinery," 2012 Edition, Chapter 13.2, "Identification of Conductors."

Milpitas maintenance had not been correctly updated for 9 years at that time of the incident. (CPSD-5, p.48.)

The Milpitas Terminal was kept in a dangerously unsafe condition. Over decades of updates and revisions to the controls and SCADA at Milpitas, the integrity of documentation, wiring connections, identification of electrical components, and the equipment itself had deteriorated and increased the chance of an incident. (CPSD-1, p.99.) By poorly maintaining a system at Milpitas that had defective electrical connections, improperly labeled circuits, missing wire identification labels, aging and obsolete equipment, and inaccurate documentation, PG&E created an unreasonably unsafe system in violation of Section 451.

4. Poorly Designed SCADA Alarms

The PG&E SCADA system is programmed to alarm when the pressure exceeds the Maximum Allowable Operating Pressure (High-High alarm) or if the value is less than a preset low level (Low-Low alarm). It does not provide automatic control or intelligent alarming functions such as high rate of change alarms. (CPSD-1, p.73.)

The SCADA center received multiple alarms of increasing pressures on lines leaving the Milpitas Terminal. (CPSD-1, p.89.) The SCADA center alarm console displayed over 60 alarms within a few seconds, including controller error alarms and high differential pressure and backflow alarms from the Milpitas Terminal. These alarms were followed by pressure alarms on several lines leaving the Milpitas Terminal, including Line 132. (CPSD-1, p.11.)

Post-incident, PG&E conducted tests in an attempt to replicate the alarms that were generated during the time when control was lost on September 9, 2010. (CPSD-1, p.91.) PG&E was able to recreate all of the types of alarms observed but not necessarily all of the conditions that could cause them. (CPSD-1, p.91.) The Supervising Engineer who performed the replication and analysis stated that he could not explain all of the alarms that occurred. (CPSD-1, p.91.) PG&E confirmed that they were unable to determine the cause of controller errors from 5:01 p.m. to 5:09 p.m., or why there were none from the time pressure control was lost at 5:23 p.m. until after 8:40 p.m. (CPSD-1, p.91.) Also they could not determine why the three malfunctioning controllers never generated an alarm. (CPSD-1, p.91.) The loss of 24 Volts supplied by power supplies PS-A and PS-B would create some of the controller alarms observed, but not all. (CPSD-1, p.91.)

CPSD staff made the following findings with regards to the SCADA system:

- The "glitches" and anomalies that the Gas Operators' encounter in their SCADA data have caused them to be extra cautious when observing unusual data in order to give themselves time to assess whether that data is "real."
- The Gas Operators are burdened with too many unnecessary alarm messages that increase the risk of an important alarm not being correctly handled.
- The design of the controls at Milpitas and of the SCADA system did not take advantage of redundant pressure data available in the system to increase reliability and safety.
- The SCADA system does not incorporate a leak or rupture recognition algorithms. Such a system would require more and closely spaced pressure sensors.

(CPSD-1, p.99.)

By maintaining a SCADA system that gave too many unnecessary alarm messages to its Operators, and was generally poorly designed, which increased the risk of an important alarm being mishandled, PG&E created an unreasonably unsafe system in violation of Section 451. The electrical, pressure control, and SCADA problems at Milpitas all contributed to the Line 132 rupture. (CPSD-1, p.99)

E. PG&E's Emergency Response

The NTSB found that PG&E took 95 minutes to stop the flow of gas and to isolate the rupture site—a response time that was excessively long and contributed to the extent and severity of property damage and increased the life-threatening risks to the residents and emergency responders. (CPSD-9, Exec. Sum., p.x) PG&E's confusion during that time is directly related to its failure to maintain and follow good emergency planning.

Federal regulations (49 CFR Parts 192.605(a) and (c), 192.615(a),(b) and (c), 192.616(d) and (e)) govern an operator's response in an emergency, and emergency preparedness.

Part 192.605(a) requires that operators prepare *and follow* a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations.

49 CFR Part 192.605(c) requires that for transmission lines, the emergency manual must include procedures to provide safety when operating design limits have been exceeded that *respond to* and *correct* the cause of: increase or decrease in pressure outside normal operating limits; loss of communications; operation of any safety device; and any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

49 CFR Part 192.615(a) requires operators to maintain emergency plans. These plans must be written and, at a minimum, must provide for:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

49 CFR Part 192.615(b) requires operators to furnish copies of its emergency plans to its supervisors responsible for emergency actions, ensure that the appropriate personnel are trained, and review employee activities to determine whether the plans are followed in an emergency.

49 CFR Part 192.616(d) requires operators to educate the public, appropriate government organizations, and persons engaged in excavation on various safety items such as the one-call notification system, possible hazards from unintended gas leaks, public safety steps if such an event occurs, procedures for reporting an incident, and signs to look for if such an event occurs.

49 CFR Part 192.616(e) requires operators to create a public awareness program that includes activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

PG&E's emergency plans were deficient and contributed to the severity of the San Bruno tragedy. PG&E failed to formulate and disseminate a sufficient emergency response plan. PG&E employees appeared confused and unprepared on the day of the incident, failing to follow the plan PG&E did have in place. PG&E employees did not communicate internally in a proper and timely way, which contributed to its inability to get a meaningful and timely situational awareness and adequately marshal its resource to respond to the emergency. PG&E failed to properly and timely communicate with external agencies, such as fire departments and police. PG&E's employees exhibited a lack of training and preparedness on the day of the incident. PG&E failed to properly ensure public awareness of its facilities and their inherent potential for harm. PG&E failed to properly use the tools of remote control valves and automatic shut-off valves. PG&E administered alcohol testing too late to be effective.

PG&E's failure to create and follow good emergency plans created an unreasonably unsafe system in violation of Public Utilities Code Section 451. PG&E has also violated 49 CFR Parts 192.605(a) and (c), 192.615(a),(b) and (c), 192.616(d) and (e). The discussion below addresses these violations.

1. Emergency Response Plans

PG&E's Emergency Plan consists of two main parts: the basic company-wide plan; and, the district/division plans that are included as an appendix to the basic plan. (CPSD-1, p.117.) These two parts are not always in concert with each other. There appears to be fragmentation in coordination between the corporate Emergency Plans and those at the Divisional level. The plans are structurally different in look and feel. This could be a source of confusion during emergencies. (CPSD-10, p.76.) When gas transmission lines transverse more than one district, there can be different approaches to emergency response. (*Ibid.*)

More importantly there are distinct inconsistencies between the two parts of what should be a consistent whole. The Peninsula District plan has four levels of emergency response escalation. Yet, the company-wide plan has only three levels of escalation. (CPSD-10, p.76.) Such incompatible guidance can lead to a disorganized and ineffective response to an emergency. The inconsistencies between corporate and divisional level Emergency Plans violate the legal requirement in 49 CFR Part 192.615(a)(3) for a "prompt and effective response" to an emergency notice.

In addition, PG&E's Peninsula Division Emergency Plan has a section for External Mutual Assistance Agreements. (CPSD-297, p.F-2.1.) The Plan states that operators should document those assistance agreements. With regards to external mutual assistance agreements, the Plan states it has "none in written form." (CPSD-297, p.F-2.1.)

PG&E's failure to have a mutual assistance agreement with local first responders violates the requirement for coordination between the pipeline operator and first responders to establish planned responses to emergencies. By failing to create an assistance agreement for notifying and coordinating with appropriate fire, police, and other public officials of gas pipeline emergencies, PG&E violated 49 CFR Part 192.615(a)(8).

PG&E's failure to have a mutual assistance agreement also violates the requirement to establish a liaison with first responders to learn their responsibilities and resources and to plan how they can "engage in mutual assistance." By failing to have mutual assistance agreements with local first responders, PG&E violated 49 CFR Part 192.615(c)(4), which requires operators to establish and maintain liaisons with appropriate fire, police, and other public officials to plan how the operator and the officials can *engage in mutual assistance* to minimize hazards to life of property.

PG&E's failure to create and maintain a mutual assistance agreement with local first responders created an unreasonably unsafe condition, in violation of Section 451.

2. PG&E Emergency Response Actions

PG&E must be able to effectively respond to emergencies, including being able doing the following:

- Receive, identify, and classify notices of emergency events. (Part 192.615(a)(1).)
- Promptly and effectively respond to each type of emergency notice. (Part 192.615(a)(3).)
- Provide for the proper personnel, equipment, tools and materials at the scene of an emergency. (Part 192.615(a)(4).)
- Perform an emergency shutdown of its pipeline as necessary to minimize hazards to life or property. (Part 192.615(a)(6).)
- Make safe any actual or potential hazards to life or property. (Part 192.615(a)(7).)
- Notify the appropriate first responders of an emergency and coordinate the response with them. (Part 192.615(a)(8).)

However, no outgoing calls were made by PG&E to fire or police officials upon discovery of the incident. (CPSD-1, p.118.) PG&E's SCADA system limitations caused delays in pinpointing the location of the break. (CPSD-9, Exec. Sum., p.x) PG&E lacked a detailed and comprehensive procedure for responding to large-scale emergencies such as a transmission pipeline break, including a defined command structure that clearly assigns a single point of leadership and allocates specific duties to supervisory control and data acquisition staff and other involved employees. (*Ibid.*)

But for PG&E employees who acted on their own initiative and outside the corporate chain of command, PG&E's response would have been even worse. PG&E itself admits the amount of time it took to turn off the gas "did not help the first responders." (Reporters Transcript (RT) 336:10-17.)

There are many aspects to PG&E's failed emergency response on September 9, 2010. PG&E's response to the explosion on that day needed to be a coordinated effort between Gas Control Operators, Dispatch Center, employees in the field, and management. The following discussion covers how each aspect of the response failed, beginning with the Gas Control Operators' inability to recognize and locate the rupture on Line 132.

a) Operational Awareness and Control

Based on a review of PG&E's Gas Control Operator Logs, there appears to have been a significant amount of confusion as to the location of the incident, its severity and the mitigation efforts required. (CPSD-10, p.75.)

At 5:22 p.m., the SCADA center alarm console displayed over 60 alarms within a few seconds, including controller error alarms and high differential pressure and backflow alarms from the Milpitas Terminal. (CPSD-1, p.11.) These alarms were followed by pressure alarms on several lines leaving the Milpitas Terminal, including Line 132. (CPSD-1, p.11.)

- At 6:11 p.m. on September 9, 2010, Line 132 ruptured. (CPSD-1, p.11.)
- Two minutes later SCADA showed that Line 132 pressure at Martin Station decreased from 361.4 psig to 289.9 psig. (PG&E-40, p.5.)
- Three minutes thereafter (6:15) SCADA alarms showed the pressure decreased to 186 psig then 144 psig. (*Id.* at 6.)
- No later than 6:18 p.m. SCADA Operator B stated he knew Line 132 had a break in it. (CPSD-9, p.101)

- Yet, at 6:27 when Dispatch calls Gas Controls and tells them they are getting reports of shooting flames and louds sounds, Gas Control said they had not gotten any calls about it. (PG&E-40, p.7)
- Around 6:30 (19 minutes after the explosion) Operator B stated he knew the rupture was within a 12-mile corridor in the vicinity of San Bruno. (CPSD-9, p.101)
- At 6:31 Gas Control told Dispatch that Line 132 may be involved in the unfolding San Bruno incident, and a minute later they call San Francisco Division Transmission and Regulation (T&R) Supervisor. (PG&E-40, p.8)
- At 6:51 (40 minutes after the rupture) Operator C told a PG&E pipeline engineer that he thought PG&E's transmission line did <u>not</u> break. (CPSD-9, p.101.)
- At 6:53 Operator D told the SCADA T&R supervisor they believe Line 132 had a break. (*Id.*)
- Yet, two minutes later Operator C, and the on-site superintendent, still believed it was not Line 132 but instead a distribution line. (*Id.*)
- At 7:22 Gas Control told a PG&E Sr. VP that it is likely that Line 132 has a break but nothing has been confirmed. (PG&E-40, p.11.)
- At 7:25 (1 hour and 14 minutes after the rupture) Gas Control confirmed that Line 132 was involved but still does not know the exact location. (*Id.* at 12.)
- At 7:29 Gas Operators remotely closed valves at the Martin Station downstream of the rupture. (CPSD-1, p.12.)
- At 7:46 manual valves are closed to isolate the rupture. (*Ibid.*)

This event time line shows that Gas Control was confused and not in control of the situation. While one operator believes Line 132 had a break in it within minutes, other operators continue believe Line 132 did not break. At 6:51 p.m. Gas Control informs a PG&E employee it is not a transmission line, two minutes later Gas Control says it is Line 132, and two minutes later after that Gas Control says it is not a transmission line.

Even after Gas Control was confident that Line 132 had a break, PG&E did not know the location of the rupture and made the choice to not decrease the pressure, which had the effect of feeding the fire. Gas Control states at 6:49 p.m., "We are going to feed the line break at this pressure but I would take the pressure down if I know more about what was feeding it…" (CPSD-9, p.101.)

At times PG&E employees thought it might have been a jet airplane crash (PG&E-40, p.10; CPSD-1, p.116), or a gas station explosion (PG&E-40, p.7.), or a break in their distribution lines (CPSD-9, p.101).

The NTSB concluded that limitations in PG&E's SCADA system contributed to its delay in recognizing there had been a transmission line break and where it was located. (CPSD-9, p.102.) PG&E's ability to respond 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. (CPSD-10, p.77.)

PG&E's inability to obtain situational awareness demonstrates that it did not promptly and effectively respond to the emergency, in violation of 49 CFR Part 192.615(a)(3). PG&E did not adequately receive, identify, and classify notices of the emergency, in violation of 49 CFR Part 192.615(a)(1). Its lack of situational awareness hampered its ability to provide for: resources at the scene of an emergency, in violation of 49 CFR Part 192.615(a)(4); emergency shutdown or pressure reduction in the necessary pipe section, in violation of 49 CFR Part 192.615(a)(6); making safe any actual or potential hazard to life or property, in violation of 49 CFR Part 192.615(a)(7): and, notification of the appropriate first responders, in violation of 49 CFR Part 192.615(a)(8). This created an unreasonably unsafe situation on September 9, 2010, in violation of Section 451.

b) Internal Communications

Emergency response requires a coordinated effort by PG&E's employees, including: Gas Control Operators who are responsible for using the SCADA system to monitor and operate the pipeline system; Dispatch which is responsible for sending personnel wherever needed; Gas Service Representatives (GSRs) who are the field responders to gas situations; and various levels of management, who assist as needed and hold authority to authorize acts by other PG&E personnel.

However, at about 6:15 p.m., as PG&E was confronted with the Milpitas Terminal anomalies and the low pressure alarms at the Martin Station coupled with the reports of a fire in San Bruno, it is clear that the communications between the SCADA center staff, the dispatch center, and various other PG&E employees were poor, and that the roles and responsibilities for dealing with such emergencies were poorly defined. (CPSD-9, p.98.)

After Line 132 burst at 6:11 p.m., Dispatch is contacted at 6:18 by an off-duty PG&E employee alerting them of a fire; in response Dispatch said it would notify a supervisor. (CPSD-1, p.108.) Off duty PG&E employees contacted Dispatch at 6:21 and 6:23, one of the employees informed Dispatch they are headed to the site. (*Ibid.*)

Dispatch responds and at 6:23 directed a GSR to the intersection of Sneath and Skyline in San Bruno to investigate a reported explosion. (*Ibid.*) At 6:25 p.m. Dispatch reports the explosion to the Peninsula On-Call Supervisor, who says "I'm probably on my way." (*Ibid.*)

At 6:27, sixteen minutes after the explosion, Dispatch calls Gas Control to see what pressure data they have. (*Id.* at 108-09.) At 6:30 Dispatch checks in with the GSR who is still in traffic but can see flames. (*Id.* and PG&E-40, p.7.) At 6:31 Gas Control calls Dispatch to discuss the possibility that PG&E facilities are involved in the fire. (CPSD-1, p.109.) On minute later Gas Control calls and leaves message for the San Francisco T&R Supervisor. (*Ibid.*)

At 6:35 a Measurement and Control (M&C) mechanic calls Dispatch and informs them he is headed to PG&E's Colma Yard. (*Id.*) At 6:36 the SF T&R Supervisor returns Gas Control's call and tells them to call the Peninsula Division T&R Supervisor. (*Id.* at 110.)

At 6:40, about 30 minutes after the explosion, the Peninsula On-Call Supervisors calls M&C mechanics, who have already self-reported to the Colma Yard to go to the valves. (*Ibid.*) At 6:41 the GSR and Senior Distribution Specialist who are at the explosion site informed Dispatch that they did not know the cause of the flames but that a PG&E line was in the vicinity. (*Ibid.*) The GSR also called two different supervisors to let them know he was on site. (*Ibid.*)

At 6:48, over 30 minutes after the explosion, the Senior Distribution Specialist told Dispatch to send "a couple of gas crews and electric crews." (*Ibid.*) At 6:50 at least one of the self-reporting Mechanics arrived at the Colma Yard. (*Ibid.*) At 6:53 the San Francisco T&R Supervisor told Gas Control that he had crews responding but that they might be heading to the Martin Station. (*Ibid.*)

Around 6:54, Dispatch calls PG&E's Troublemen Supervisor and asks for the gas and electric utilities in the area to be turned off. (*Id.*) At 6:57 PG&E's Operations Emergency Center is opened. (*Id.* at 111.)

At 7:02 a Mechanic at the Colma yard calls Dispatch and states they are going to shut off the valves and isolate the rupture. (*Id.*) At 7:06, the Mechanic's plan is approved by the Peninsula Division T&R Supervisor. (*Id.*) At 7:16 Dispatch begins to relay the Troublemen Supervisor's plan to require all Colma Yard employees to report in. (*Id.*)

At 7:20 the Mechanics arrive at the first valve. (*Id.* at 112.) At 7:22 and 7:23 calls to Dispatch requesting to know if GSRs or other employees are being send to the San Bruno, are responded to by Dispatch saying haven't heard anything yet. (PG&E-40, p.12)

At 7:22 Gas Control informs the Senior Vice President that accident was likely on their Line 132. (CPSD-1 at 112.) At 7:25 Dispatch informed Gas Control that the on-site M&C Superintendent confirmed that it was a reportable incident under GO 112-E. (*Ibid.*)

At 7:27 the SF Division T&R Supervisor requested the Gas Control lower the pressure as low as possible at the Martin Station to isolate Line 132 from the north. (*Ibid.*) Two minutes later Gas Control remotely closes the Line 132 valves at Martin Station. (*Ibid.*) One minute later, at 7:30, the Mechanics close valves closest to rupture on the south side. (*Ibid.*; see also CPSD-9, p.17.) By 7:46 the Mechanics close valves north of the rupture. (CPSD-1, p.112.) At 7:52 valves are closed at a District Regulation Station to prevent back-feed into line 132. (*Ibid.*) Later that night the local distribution system is isolated. (*Ibid.*)

The timeline demonstrates that internal communication was muddled and uncoordinated. Various actors acted at cross purposes with others; no clear line of command was established. The following points illustrate the lack of effective communication:

- It is unclear which if any supervisor was ultimately in charge.
- When the first supervisor (San Francisco T&R Supervisor) is contacted by Gas Control (21 minutes after the explosion) they have to leave a message.
- When that supervisor calls back (at 6:36) he tells them to call a different supervisor (Peninsula Division T&R Supervisor).
- It is the Peninsula On-Call Supervisor that calls the M&C mechanics to go to the Colma Yard (approx. 4.5 miles from the break). Fortunately, they were in the process of self-reporting to the Colma Yard when they got the call.
- When a GSR wanted to let PG&E know he was on site he called two different supervisors.
- When the SF T&R Supervisor told Gas Control he had crews responding he told them they "might" be headed to the Martin Station.
- It was the Peninsula Supervisor that approved the mechanics' plan to shut off the valves.
- It was the Troublemen Supervisor who required all Colma Yard employees to report in.
- It was the SF T&R Supervisor who requested that Gas Control remotely lower the pressure at the Martin Station.

While PG&E's procedures mentioned rules and responsibilities for the entity as a whole, there was no procedure that expressly outlined each individual's role, responsibilities and lines of communications in the event of an emergency. (CPSD-1, p. 117.) Multiple and redundant reports of the same emergency went through Dispatch potentially preventing critical information from being relayed. (*Ibid.*) Several Gas Control operators contacted the same supervisory without being aware that there their fellow operators had already made that contact. (*Id.* p. 117-118.)

Dispatch was inefficient: repeating and redundant calls to and from Dispatch impacted PG&E ability to receive other important calls. For example, describing his attempts to call PG&E Dispatch one first responder stated that "It was very difficult to place a call. Multiple attempts on the cell phone were system busy, call failed." (CPSD-1, p.118.) And while Dispatch did learn of the explosion at 6:18 p.m., they did not send anyone to check it out till 6:23 p.m. (CPSD-9, p.99.) The dispatch center initially dispatched only a single service representative (at 6:23) to assess the scene and did not immediately dispatch a qualified crew to shut off valves. (*Ibid.*)

PG&E Dispatch had (1) dispatched a GSR and called that GSR to check in at 6:30 (PG&E-40, p.7), (2) confirmed their on-site presence (PG&E-40, p.10) at 6:41, and (3) told San Bruno Police they were on-site (*ibid.*), and (4) had further confirmation of PG&E on-site at 7:22 (*Id.* at 11.). Yet at 7:22 Dispatch states when asked if GSR have been dispatched to San Bruno "we haven't heard anything yet." (*Id.* at 12.) A minute later, when Concord Dispatch is asked by a GSR if "guys" are being sent to San Bruno, Dispatch states "they haven't said anything yet." (*Ibid.*) Again at 7:31 Dispatch tells a caller when asked if GSRs are needed at San Bruno, that they haven't gotten any calls [requesting GSRs]. (*Ibid.*)

Despite numerous calls between Dispatch, Gas Control, and various PG&E employees, Dispatch never sent any employee out to expressly shut off the valves. (CPSD-9, p.99.)

Gas Control was similarly ineffective. The geographic monitoring responsibilities of the Gas Control staff were arbitrary. (CPSD-1, p.117.) Staff decided which regions they preferred to observe at any particular time, potentially leaving gaps in coverage while other areas received redundant coverage. (*Id.* at 118.) Moreover, as discussed above regarding operational awareness, Gas Control Operators were unequally aware of the situation and received and shared conflicting information as to what was occurring at the site. The lack of assigned roles and responsibilities resulted in SCADA staff not allocating their time and attention in the most effective manner. (CPSD-9, p.98.) They did not initially notice the dropping pressure at the Martin Station after the rupture, but rather were alerted by staff at the Brentwood SCADA facility. (*Ibid.*) Several SCADA operators contacted the same SCADA transmission and regulation supervisor (supervisor 6), but seemed unaware that the senior SCADA coordinator had already made contact with the supervisor. (*Ibid.*) Further, the low pressure alarms at Martin Station were initially acknowledged by two SCADA coordinators. (*Ibid.*)

Gas Control spent a significant portion of their time during the first 95 minutes after the rupture providing telephone briefings and updates to various PG&E employees and officials. (CPSD-9, p.98) They also received multiple calls about opening of various emergency response centers. (*Ibid.*) These calls were handled by whichever control was available and were done so without any command structure. (*Ibid.*) NTSB found it would have been beneficial to have a sole point of contact for the Milpitas Station so others would be free to monitor the rest of the system. (*Ibid.*)

Each SCADA staff member was left to form his or her own impression as to the nature and severity of the rupture based on the information they had, resulting in some conflicting and erroneous assessments. (CPSD-9, p.98) Operator B and Operator C continued to have conflicting view of what was happening. Operator B thought there was a break in Line 132 within minutes but operator C thought it was a distribution line. (CPSD-9, p.101.)

PG&E's supervising engineer, who is responsible for all SCADA and control systems, exhibited a lack of training and preparedness. (CPSD-9, p.99.) After going home for the day, he contacted Gas Control at 6:51 p.m. requesting information, and called again at 7:19 to say that Milpitas Terminal workers said they did not need his help, and when Gas Control suggested he go to Milpitas he declined. (*Ibid.*) He eventually showed up at Milpitas Terminal at 9:00. (*Ibid.*)

In addition, there was confusion as to who specifically had the authority and responsibility to order that specific valves be closed. The local operating supervisor has the authority to dispatch crews to shut off mainline valves in cases of emergencies. (CPSD-1, p.120.) Gas Control also has emergency authority to close valves. (*Ibid.*) Yet, in responding to the incident, the Peninsula On-Call Supervisor claimed that he did his duty by telling mechanics to head in the direction of the valves because someone else would tell the mechanics which valves to shut and if it was okay to shut the valves. (CPSD-1, p.121.) In fact, the mechanic stated that after the Peninsula On-Call Supervisor told him to go the Colma Yard to begin staging, the mechanic himself came up with a plan as to what valves to shut. (*Ibid.*) He formulated this plan with information from TV news, not with information provided by Gas Control or Dispatch. (*Ibid.*) He called not the Peninsula On-Call Supervisor but the Peninsula T&R Supervisor and got sign-off on his plan – almost an hour after the initial fire and explosion. (*Ibid.*) After shutting off the valves nearest to the south of the break, the mechanic took it upon himself to head to the valves north of the break and shut them off. (*Ibid.*)

The M&C Superintendent stated that when the battalion chief told him to shut off the gas because it was hampering rescue and firefighting efforts, he was told by the Senior Distribution Specialist that his transmission supervisor for San Francisco was on it. (CPSD-1, p.122.) That person was "very confident that they were going to have the transmission valves for that area secured shortly … I fully trusted [the SF Division T&R Supervisor] to do the right thing [and make the decision to ask someone to send personnel to close the valves]." (*Ibid.*) Yet the SF T&R Supervisor claims that no one directed the crew to shut off the valves, and they acted on their own. (*Ibid.*) The battalion chief's request was approximately 6:30-6:35 p.m. (*Ibid.*) At that time the mechanics were either at or driving to the Colma Yard, where they would wait until their plan to shut off the valves was approved by the Peninsula Division T&R Supervisor about thirty minutes after the battalion chief requested the valves be closed.

In summary, PG&E's response to the Line 132 break lacked a command structure with defined leadership and support responsibilities within the SCADA Gas Control center. Execution of the PG&E emergency plan resulted in delays that could have been avoided by better utilizing the SCADA center's capability. PG&E lacked detailed and comprehensive procedures for responding to a large-scale emergency such as a transmission line break, including a defined command structure that clearly assigns a single point of leadership and allocates specific duties to SCADA staff and other involved employees. (CPSD-9, p.99.)

The facts above demonstrate that PG&E did not promptly and effectively respond to the emergency, in violation of 49 CFR Part 192.615(a)(3). PG&E did not adequately receive, identify, and classify notices of the emergency, in violation of 49 CFR Part 192.615(a)(1). PG&E did not provide for the proper personnel, equipment, tools and materials at the scene of an emergency, in violation of 49 CFR Part 192.615(a)(4). PG&E's efforts to perform an emergency shutdown of its pipeline were inadequate to minimize hazards to life or property, in violation of 49 CFR Part 192.615(a)(6). Rather than make safe any actual or potential hazards to life or property, PG&E's response made the hazards worse, in violation of 49 CFR Part 192.615(a)(7). PG&E's failure to notify the appropriate first responders of an emergency and coordinate with them violated 49 CFR Part 192.615(a)(8). It is clear that PG&E's emergency plans were ineffective, and were not followed. This created an unreasonably unsafe situation on September 9, 2010, in violation of Section 451.

PG&E also violated 49 CFR Part 192.605(c)(1) and (3) by failing to have an emergency manual that properly directed its employees to respond to and correct the cause of Line 132's decrease in pressure, and its malfunction which resulted in hazards to persons and property, and notify the responsible personnel when notice of an abnormal operation is received.

c) External Communications

No outgoing calls were made by PG&E to fire or police officials upon discovery of the incident. (CPSD-1, p.118.) Instead, San Bruno Police called PG&E at 6:54, San Mateo County Sheriff called PG&E at 7:02, and San Mateo County Fire Department called PG&E at 7:59. (CPSD-1, p.118.)

Moreover, PG&E was not on site until 30 minutes after the explosion. (RT 406:15-19.) First responders were on site one minute after the explosion. (PG&E-40, p.5.) For 29 minutes important conversations between PG&E and first responders did not happen. PG&E acknowledged that PG&E personnel were not present on site to give emergency responders the benefit of PG&E's insight into the potential gas transmission ruptures. (RT 405:28 – 406:5.) PG&E acknowledged that knowledge that the possibility a fire is being fed by a high pressure line is relevant and necessary to first responders. (RT 355:12-16.) Twenty minutes after the explosion PG&E had reason to believe their line may be involved but they did not call 911 and on-site personnel did not arrive until 30 minutes after the explosion. (RT 353:21 to 354:1.)

PG&E's Dispatch, not just on-site personnel, are directed to contact police, fire and other emergency responders, under section 3.3.2 of the Company Plan. (PG&E-39, p.1-28.) While PG&E Dispatch did send PG&E's employees to the site, they did not simultaneously call the local fire department as required under various sections of their own emergency plan. (RT 359:26 – 360:5, RT 360:15 – 27, and PG&E-39, pp.1-40, sec.4.4.1. and 1-47, sec.5.8.2.) Nor did PG&E call the California Highway Patrol as is required under its emergency response plan. (RT 421:23 – 422:8.)

At the time of the San Bruno rupture PG&E's Gas Control did not have a policy to call 911. (RT 121:8-19.) Yet, PG&E's Transmission and Distribution (T&D) Emergency Plan did have 911 listed as emergency contact information for incidents involving the Milpitas Station. (PG&E-42, p.85-86; see also RT 19:1 – 420:11.)

PG&E's own emergency response plans and manuals require calling 911. (PG&E-1, p.10-6:6-8 and p.11-18:28.) Yet, Gas Control operators said that, "no outside agencies are called unless the supervisor out in the field requests it." (CPSD-1, p.119.)

PG&E agrees that their emergency plan was deficient in not more closely tying 911 notifications to SCADA alarms. (PG&E-1, p.10-6:8-10; see also RT 319:13-17.)

In summary, PG&E failed to establish and maintain adequate means of communication with the appropriate fire, police and other public officials, in violation of 49 CFR Part 192.615(a)(2). PG&E failed to protect "people first and then property", in violation of 49 CRF Part 192.615(a)(5). PG&E failed to notify appropriate fire, police, and other public officials of a gas emergency and coordinate with them, in violation of 49 CFR Part 192.615(a)(8). PG&E failed to establish and maintain a liaison with fire, police, and others to plan how to engage in mutual assistance to minimize hazards to life and property, in violation of 49 CFR Part 192.615(c)(4).

d) Training and Public Awareness

PG&E's GSRs have no specific training as to how to recognize the difference between fires of low-pressure natural gas lines, high-pressure natural gas lines, gasoline or jet fuel lines, or how to tailor the response to each of these types of fires. (CPSD-1, p.123.) This lack of training is evident by the events on September 9, 2010.

When an off-duty GSR, who was not onsite, called Dispatch at 6:21 they stated they thought it was a gas fed fire because it sounded like a jet engine. (PG&E-40, p.6.) Yet when a GSR who was on site called Dispatch at 6:41 (30 minutes after the break), they informed Dispatch that they did not know the cause of the flames. (*Id.* at 10.) When told faulty information by the Dispatch that it was a plane crash into a gas station, the GSR did not have the information or knowledge to correct Dispatch. (*Ibid.*) None of the first three PG&E first responders were qualified to operate mainline valves. (CPSD-9, p.15; RT 314:12-14.) PG&E's employees would benefit from additional training on how to recognize and respond to different types of fires, as would first responders. (CPSD-1, p.123.)

PG&E's management does not appear to take past company experiences seriously. When PG&E's Director of Incident Command was asked if he was aware of NTSB's finding that the first responders for the Rancho Cordova explosion were not properly trained, he said he was "not aware of this." (RT 312:27-313:3.) He did admit that there were lessons to be learned from Rancho Cordova but stated, "I don't have the detailed understanding of what those lesson were." (RT 315:23-316:1.)

Further, the law requires operators to make the public aware of dangers. However, in San Bruno first responders were not aware of the location or specifications of PG&E's pipelines. (CPSD-01, p.124; see also RT Vol.5 345:16-21.) The NTSB has recommended that PHMSA require pipeline operators to share system-specific information, including pipe diameter, operating pressure, product transported, and potential impact radius with first responders.

PG&E's inadequate training resulted in a slow and ineffective recognition of the incident, in violation of 49 CFR Part 192.615(a)(3). PG&E further failed to train the appropriate operating personnel to assure they are knowledgeable about procedures and verify that the training is effective, in violation of 49 CFR Part 192.615(b)(2). PG&E failed to train its employees and determine whether procedures were effectively followed in emergencies, in violation of 49 CFR Part 192.615(b)(3). PG&E failed to periodically review its emergency response by its personnel to determine the effectiveness of the procedures, in violation of 49 CFR Part 192.605 (c)(4). PG&E did not educate the public and governmental organizations as to hazards associated with unintended releases on a gas pipeline and steps that should be taken for public safety in the event of a gas pipeline release, in violation of 49 CFR Part 192.616(d).

e) Remote Control Valves, Automatic Shutoff Valves, and Pressure and Flow Transmitters

49 CFR Part 192.935(c) requires that if an operator determines, based on a risk analysis, that an automatic shutoff valve (ASV) or a remote control valve (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.

The use of remote control valves and/or automatic shut-off valves in proximity to the rupture would have likely reduced the time to isolate the rupture. (CPSD-1, p.19.) The valves that were closed to isolate the rupture had to be operated by hand. To do that the mechanics left the Colma Yard approximately at 7:06. (PG&E-40, p.11.) They arrived at the first valve (v-38.49) at 7:30 and at the next valve (v-40.05) at 7:46. (*Id.* at 13.) It took 40 minutes from the time PG&E decided to isolate the rupture to the time it actual did isolate the rupture. NTSB found that "the use of either automatic shutoff valves or remote control valves would have reduced the amount of time to stop the flow gas." (CPSD-9, Exec. Sum., p.x.)

This time delay had a direct relationship to the intensity of the fire. (CPSD-9, p.102.) If the gas had been shut off earlier the fire would likely had been smaller and resulted in less damage. (*Ibid.*) PG&E acknowledges that use of RCVs could have reduced the time it took to isolate the rupture by about 1 hour. (CPSD-9, p.103.)

CPSD recognizes that valve closures can, by themselves, create unsafe conditions regarding gas pressure at the end-use customers' domicile. But such harm can be mitigated by the judicious use of remote valves. Moreover, newer valve models are less likely to falsely trip, and can be overridden by Gas Control. (CPSD-9, p.104.)

In addition to remote and automatic valves, more and closer spaced pressure transmitters would have likely allowed PG&E to determine the location of the rupture earlier, thus reducing the time to isolate the rupture. (CPSD-1, p. 120.)

The NTSB has recommended the development of standards for rapid shutdown of failed natural gas pipelines as early as 1971, and again in 1995. (CPSD-9, p.103.) While federal regulations (49 CFR Part 192.179) require the spacing of valves on transmission lines based on class location, the regulations do not require a specific response time or the specific use of ASVs or RCVs. (CPSD-9, p.103.) The NTSB concluded that the pressure differentials after the break would have likely trigger the closing of ASVs downstream and upstream, and even if only the downstream valve had closed it would have been a significant benefit in locating the location of the break. (CPSD-9, p.104.) Also, that use of such valves along the length of Line 132 would have significantly reduced the time taken to isolate the rupture and reduce the flow of gas. (*Ibid.*)

The IRP report found that, "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." (CPSD-10, p.15.)

PG&E also admits that if the valves isolating Segment 180 "could have been turned [off] sooner some damage could have been mitigated. (RT 280:13-15.) As will be discussed in the upcoming briefs on fines and remedies, CPSD recommends that PG&E perform a study to provide Gas Control with a means of determining and isolating the location of a rupture remotely by installing RCVs, ASVs and appropriately spaced pressure and flow transmitters on critical transmission line infrastructure and implement the results.

f) Drug and Alcohol Testing

49 CFR Part 199.225(a) states that as soon as practicable following an accident, the operator shall test each employee for alcohol if that employee's performance either contributed to the accident or cannot be completely discounted as a contributing factor to

the accident. Part 199.225(a)(2)(i) further requires that if the alcohol test is not administered within 2 hours following the accident, the operator shall prepare and maintain on file a record stating the reasons why the test was not promptly administered; and if the test is not administered within 8 hours following the incident, the operator shall cease attempts to do so.

PG&E failed to meet the 2 hour window for administering an alcohol test to the employees involved in the incident, and failed to file a record stating the reasons why the test was not promptly administered. Both inactions are a violation of 49 CFR Part 199.225(a). Alcohol testing of four Milpitas Terminal employees commenced at 3:10 a.m. and concluded at 5:02 a.m. on September 10, 2010. (CPSD-9, p.104.) The accident occurred at about 6:11 p.m. on the previous evening. Therefore, alcohol testing should have been completed by 2:11 a.m. on September 10, at the latest. (*Ibid.*)

Thus, the use of alcohol as a factor in the San Bruno accident cannot be excluded. (*Ibid.*) In addition, PG&E failed to test any of the PG&E Gas Control staff. (CPSD-9, p.105.) PG&E's failure to drug and alcohol test all personnel whose performance cannot be completely discounted as a contributing factor is a violation of 49 CFR Part 199.225(a) and 49 CFR Part 199.105(b).

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

In 2012, PG&E launched an advertising campaign, admitting that it had "lost its way." PG&E did indeed lose its way, but this euphemism is not apt insofar as it implies an accidental or careless departure. PG&E deliberately charted its own path off course from its long-range plan for pipeline safety improvement approved by the Commission in 1985.

In 1985, the Commission approved PG&E's 20-year plan for pipeline safety improvements, the Gas Pipeline Replacement Program (GPRP). (D.86-12-095 (1986) 23 CPUC 2d 149, 198-99; D. 12-12-030, slip op., p. 45.) In PG&E's GPRP, PG&E had planned to replace 2,467 miles of aging distribution and transmission pipeline. (*Ibid.*) Contrary to PG&E's claims in the hearing, PG&E was well aware of the fact that portions of Line 132 included the original, pre-1950 pipeline and it had questionable welding, because Charles J. Tateosian, PG&E's head of Gas Design and Vice President of Gas Operations, presented material to PG&E, and made a presentation to PG&E's Board which included this information when PG&E was preparing its GPRP. (CPSD-5 (Stepanian), pp. 63-64, CPSD-162 (Tateosian Deposition), Vol. I, p.82-85, 92, 152, 161-162, 168-189.)

In 1992, heavily influenced by the 1989 Loma Prieta earthquake, the Commission again considered and approved PG&E's GPRP, and explicitly found that "natural gas pipeline replacement was an essential safety improvement." (D.92-12-057 (1992) 47 CPUC 2d 143, 234.) Notwithstanding DRA's protest that PG&E had not spent all of the funds, which PG&E had forecast it needed for its GPRP and the Commission had previously approved (*Ibid.* at 233), the Commission authorized all of the dollars PG&E had requested for its GPRP, and expressed its "fervent hope that PG&E spends all of the money on the program." (*Ibid.* at 234.) In 2007, in approving the settlement of PG&E's general rate case for 2008-2010, the Commission again emphasized:

> The GPRP is a high-priority program that affects public safety and the reliability of PG&E's Gas Distribution system. We conclude that it is reasonable for the Settlement to provide substantially increased funding for this program, provided that PG&E actually spends these funds on the GPRP. Therefore, we will approve the Settlement outcome for Gas Distribution capital expenditures with the condition that PG&E uses all the funds provided by the Settlement for the GPRP for this purpose. If PG&E fails to do, it should provide a detailed explanation in its next GRC. Absent a compelling explanation, we may impose a disallowance similar to the deferred-maintenance disallowance addressed elsewhere in today's Opinion.

(D.07-03-044, slip op. p. 83, 2007 Cal. PUC LEXIS 173, *119 (2007).) In sum, the CPUC "routinely approved" PG&E's ratemaking requests for the GPRP. (D.12-12-030, slip op., p. 34.)

However, as the Commission recently acknowledged:

> The decision-making and priorities driving PG&E's pipeline safety actions in 1985 and 1992 show a different PG&E than

> the PG&E of the early 2000's. The 1985 plan showed PG&E thinking ahead, coordinating with local authorities planning similar trenching work, updating meters and associated system components as part of a comprehensively planned, orderly approach to making economically sound upgrades as part of an overall system improvement plan. PG&E included "manpower and training" among its considerations, showing that it was planning to use its own employees and not outside consultants. In this way, PG&E staff would study its system and actually perform pipeline tests and replacements, thus retaining the knowledge within the organization for long-term operations and planning.
>
> In contrast, as the Independent Review Panel pointed out, more recently PG&E's field operations and integrity management efforts were not coordinated.

(*Id.* at 46-47.)

CPSD expert witness Gary Harpster conducted a focused audit of PG&E's GT&S's[25] services and rates from 1996 through 2010.[26] Consistent with the Commission's and the Independent Review Panel's prior findings, Mr. Harpster's prepared testimony (CPSD-168), Chapters 6-9, documents in detail how PG&E significantly decreased funding and the corresponding priority for the safety of PG&E's gas pipeline system, particularly in the three years leading up to the San Bruno explosion. Mr. Harpster further demonstrates how, during this same period, PG&E underspent CPUC-authorized amounts for safety, while making over $400 million in surplus revenues in excess of PG&E's authorized return on equity (ROE) of 11.2%. Among

[25] PG&E's GT&S operates and maintains PG&E's backbone, transmission and storage facilities. The backbone system receives gas at the California/Oregon Border and at the border between Arizona and Southern California and transports the gas to PG&E's service territory. The backbone system also includes the Bay Area loop. The local transmission lines connect the backbone system to PG&E's distribution system. (CPSD-168 (Harpster), p. 2-1, referencing Chapter 2 of PG&E's testimony in the Gas Accord V (2011) rate case.)

[26] The beginning period of Mr. Harpster's audit was 1996 to provide Mr. Harpster with background to the unbundling of the transmission services and rates from PG&E's general rate cases as a result of PG&E's Gas Accord settlement, which the Commission adopted on August 1, 1997 in D.97-08-055 (the Gas Accord Decision). The ending period of the audit is 2010 because the focus is the events leading to the San Bruno explosion, which occurred on September 9, 2010. (CPSD-168 (Harpster), pp. 1-3, 2-7.

other findings, Mr. Harpster's conclusion that PG&E's budgeting practices were "well outside of industry practice" was not disputed or rebutted by PG&E.

From 1997 through September 9, 2010, the date of the San Bruno explosion, PG&E created an unreasonably unsafe system in violation of California Public Utilities Code Section 451, by continuously cutting its safety-related budgets for its GT&S and, therefore, causing the following: 1) a reduction in the replacement of PG&E's aging transmission pipeline through its GPRP, and in essence, the suspension of the transmission replacement part of its GPRP prematurely well before its original goal; 2) not seeking sufficient funds for its O&M, and then spending less than the amount it sought from the Commission, including using less effective and lower cost integrity management methods, such as ECDA over ILI, and 3) reducing its safety-related workforce. During the same time period, PG&E announced that any cost savings would accrue to the shareholders, provided bonuses or "incentives" to management and employees, paid quarterly cash dividends to shareholders from retained earnings, repurchased stock from PG&E Corporation or from a PG&E subsidiary, expended funds to enhance public perception of PG&E, and expended money to affect ballot initiatives. (CPSD-1, pp.135 -143.)

1. Mr. Harpster's Findings Establish That PG&E Heavily Constrained Its Natural Gas Safety Spending, Intentionally Subjugating Safety To Profit

In Chapters 6 through 9, Mr. Harpster detailed his findings, which are based on internal PG&E documents and data responses. Mr. Harpster's undisputed findings paint a stark and disturbing portrait of how PG&E ignored the professional recommendations of its own engineers and systematically reduced integrity management and maintenance resources and significantly reduced necessary capital spending under the GPRP for its GT&S. PG&E pressured its GT&S Line of Business to reduce transmission expenses, selected cheaper integrity management methods, deferred or abandoned maintenance projects, and reduced staffing. Chapters 6-9 of Mr. Harpster's testimony is not repeated in its entirety here, but numerous findings and evidence are referenced below.

a) PG&E's reduction of maintenance staffing, lack of operational metrics, and deferral of projects and maintenance

PG&E reduced maintenance staffing, lacked operational metrics, and deferred projects and maintenance. Mr. Harpster found the following:

- Maintenance work generally increases as a gas system ages and throughput increases.[27] But from 1998 to 2010, PG&E reduced the GT&S union headcount for maintenance workers from a peak of 302 to 220.[28] Reduction of the union workforce by nearly 25% directly conflicts with PG&E's stated goal in 1985 to retain knowledge within the organization for long-term operations and planning.[29]

- PG&E's workforce for gas distribution decreased by 28% between 1996 and 2010.[30] PG&E discovered serious safety-related deficiencies in its gas distribution operations during 2007-2009.[31] This reduction in workforce had negative implications for local transmission gas pipeline safety.[32]

- PG&E did not monitor the miles of pipeline it leak-surveyed on a centralized basis, and maps and logs were stored at each local headquarters. PG&E cannot provide actual leak survey mileage statistics for its entire backbone or local transmission systems.[33]

- Under the GPRP, PG&E committed to replacing 15 miles of transmission pipeline a year. However, in 2000, PG&E replaced the transmission portion of the GPRP with its Pipeline Risk Management Program (PRMP). If the GPRP had remained in place, PG&E would have been required to replace 165 miles of transmission pipeline during 2000-2010. Instead, PG&E replaced only 25 miles of transmission pipeline under the PRMP.[34]

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[27] CPSD-168 (Harpster), p. 6-2.

[28] CPSD-168 (Harpster), p. 6-1, Table 6-1, CPSD-176 (OC-35).

[29] D.12-12-030, slip op., pp. 46-47.

[30] CPSD-168 (Harpster), pp.6-5, 6-6, Table 6-5, CPSD-250 (OC-329).

[31] CPSD-168 (Harpster), p. 6-6.

[32] *Ibid.*

[33] CPSD-168 (Harpster), p. 6-16, CPSD-214 and CPSD-215 (OC-235 and OC-236).

[34] CPSD-168 (Harpster), p. 6-13, CPSD-186 (OC-68, Att. 12, p. 60), Table 6-14, CPSD-209 (OC-214). *also* D.12-12-030. slip op., pp. 33-34: "[I]n 1985, PG&E started a 25-year program to replace 2,467 miles

(continued on next page)

- From 2001-2006, PG&E repaired most, if not all, of the leaks reported for its backbone transmission system. From 2007-2010, with the exception of 2008 when approximately 60% were repaired, PG&E only repaired 50% or less of the leaks reported.[35]
- After 2004, PG&E's PRMP existed in name only. PG&E ceased preparing annual reports for its PRMP in 2008.[36] PG&E did not prepare separate risk management plans or track risk management projects.[37]
- PG&E did not track the corrective work request[38] backlog prior to November 2003. The days in backlog increased by 54 days between 2004 and 2010, reflecting a 33% increase in the backlog – despite a 46% decrease in corrective work orders issued.[39]
- In October 2009, PG&E suspended the performance of corrosion maintenance work for the remainder of the year, deferring it to 2010 so that crews could repair the large number of leaks discovered in leak re-surveys.[40]
- In 2009-2010, there was a large increase of leaks reported as the result of special leak surveys implemented by PG&E in response to the discovery of serious systematic deficiencies in its leak survey program and the San Bruno explosion.[41]

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of natural gas distribution and transmission pipeline, with about 500 miles of transmission pipeline. The Commission routinely approved the ratemaking requests for this program from 1985 to 2000, and PG&E replaced an average of 24.1 miles of transmission pipeline each year. In 2000, however, the remaining 212.3 miles of transmission pipeline were transferred out of the Gas Pipeline Replacement Program into the Risk Management Program, where about 4.4 miles per year were replaced through 2010, leaving a pipeline replacement deficit of about 160 miles, including lines 109 and 132."

[35] CPSD-168 (Harpster), p. 6-16, Table 6-18, CPSD-216 (OC-237).

[36] CPSD-168 (Harpster), p. 6-15, CPSD-197 (OC-100).

[37] CPSD-168 (Harpster), p. 6-15, CPSD-196 (OC-99) and CPSD-225 (OC-258).

[38] Corrective work requests are non-routine jobs necessary for system repair and improvement, including jobs to correct unsafe conditions, restore customer service and maintain compliance with safety rules. Corrective work requests do not include preventative maintenance. (CPSD-168 (Harpster), p. 6-19, CPSD-299 (OC-262) and CPSD-221(OC-251).)

[39] CPSD-168 (Harpster), p. 6-19, Table 6-22, CPSD-218 (OC-239), CPSD-234 (OC-278) and CPSD-257 (OC-342).

[40] CPSD-168 (Harpster), p. 8-9 and CPSD-224 (OC-257, Att.9).

[41] CPSD-168 (Harpster), pp. 6-17, Table 6-19, CPSD-216 (OC-237)

- In 2010, PG&E adopted what it called the "Reduce Pipeline Project Work" initiative, the stated purpose of which was to defer all project work that was not required by code or contractual obligation to "2011 or beyond."[42]
- Preparing for the May 2010 CPUC audit of PG&E's Integrity Management program consumed about two-thirds of Integrity Management's time for six months. The amount of effort required to prepare for the audit is an indication of the large backlog of incomplete work, presumably attributable to staffing shortages.[43]

b) PG&E's emphasis on cheaper, but less thorough, integrity management assessment methods and reduction of such assessments

PG&E emphasized cheaper, but less thorough IM assessment methods, and reduced the number of such assessments. Mr. Harpster found:

- According to PG&E's Fall 2000 California Gas Transmission (CGT) Capital Program Review, PG&E's PRMP was designed specifically to attempt to justify less expensive alternative methods to "verify" pipe integrity in lieu of In-Line Inspection (ILI), such as smart pigging,[44] or hydro-testing in order to save "millions of dollars."[45]
- The PG&E corporate focus on cheaper integrity assessment methods again was manifest in PG&E's spring 2001 CGT Capital Program Review, which acknowledged then pending federal legislation language as potentially requiring smart pigging or hydro-testing, which could cost "in excess of $200 million over a 10-year period." PG&E expected to save approximately $150 million over the 10-year period by using cheaper assessment methods and using the Risk

[42] CPSD-168 (Harpster), p. 9-16, Table 9-17, CPSD-226 (OC-259, Att. 4, p. 21).

[43] CPSD-168 (Harpster), pp.9-14, 9-15, CPSD-194 (OC-92, Att. 4, pp. 4, 9).

[44] As the Commission explained in D.12-12-030, slip op., pp. 74-75, for ILI, a cylindrical-shaped inspection tool (a "pig") is inserted into and passed through the interior of a pipeline segment, and then retrieved at the end of the inspection run. The ILI tool has hundreds of sensors that obtain data on pipeline conditions including indentations, wall loss, pipe strain, metallurgical variations, and various types and shapes of cracks. ILI is useful to identify, locate, and remove excessive pups, miter bends, and wrinkle bends. The Commission also recognized that ILI has an important role in the overall operation of a natural gas transmission system, and that increased ILI is particularly useful when (as with PG&E) the validity of system records is in question.

[45] CPSD-168 (Harpster), p. 7-2, CPSD-186 (OC-68, Att. 11, pp. 67-68.

Management program as a means to reduce PG&E's costs, instead of PG&E's safety risks.[46]

- During 2005-2008, ILI accounted for 54% of the total miles of pipeline assessed by PG&E.[47] But in 2009 and 2010, ILI only accounted for 13% of the total miles assessed.[48]
- Total ILI miles assessed by PG&E averaged 125 miles a year between 2005 and 2008. In 2009 and 2010, the annual average fell nearly 100 miles, to 26 miles per year.[49]
- As of 2004, PG&E primarily used External Corrosion Direct Assessment (ECDA)[50] as its integrity assessment method.[51] However, in contrast, PG&E knew in February 2004 that Southern California Gas Company "made a business decision to primarily utilize ILI as their integrity assessment method" and was "proposing to pig approximately six times the mileage under the Pipeline Safety Rule than PG&E."[52]
- From 2001-2010, PG&E used the ECDA method to assess 437 miles of the HCA (High Consequence Area) pipelines and only used ILI inspections for 181 HCA pipeline miles.[53]
- In 2008, PG&E reduced Integrity Management expense by changing assessment methods for some projects from ILI to ECDA and deferring some projects to 2009. The 2008 Gas Transmission Expense Program Review documents that PG&E ignored the advice of its own engineers: "*Gas Engineering would strongly prefer to smart pig PG&E's higher stress pipelines to obtain a much better*

[46] CPSD-168 (Harpster), p. 7-2, CPSD-186 (OC-68, Att. 10, p. 55).

[47] CPSD-168 (Harpster), p. 6-8, Table 6-7, CPSD-258 (OC-343).

[48] *Ibid.*

[49] CPSD-168 (Harpster), p. 6-9, Table 6-8, CPSD-207 (OC-211).

[50] ECDA "is a method of surveying a pipeline by first selecting likely areas of potential corrosion for assessment, and then excavating and physically examining those areas." (CPSD-9, NTSB Accident Report, p. 61, n.99. ECDA is a less expensive assessment method than pressure testing and ILI. *See e.g.,* D.12-12-030, slip op., p. 72.)

[51] CPSD-168 (Harpster), p. 6-12, Table 6-11, CPSD-259 (OC-344).

[52] CPSD-168 (Harpster), p. 6-12, CPSD-232 (OC-268, Att. 5).

[53] CPSD-168 (Harpster), p. 6-9, Table 6-8, CPSD-2207 (OC-211).

initial evaluation of the line, but that is not financially viable at current funding rates."[54]

- Like 2008, PG&E reduced Integrity Management spending in 2009 by changing assessment methods for projects from ILI to ECDA to reduce costs by $6 million and by deferring 41 miles of assessments until 2010.[55] The 2009 budget was considered to be the minimum funding, combined with increases in 2010-2012, to maintain the feasibility to comply with the United States Department of Transportation 2012 inspection deadline.[56]
- In 2010, PG&E adopted a cost-saving initiative to change integrity management assessment methods from ILI to ECDA to create, in its own words, "headroom" in 2011 and 2012 in order to allow PG&E to "push more work" to those years.[57]
- PG&E hydrotested only 14 miles of its existing pipeline during 2003 to 2010.[58]

c) PG&E's sustained underfunding for pipeline safety

Mr. Harpster found that PG&E continuously underfunded pipeline safety.

Mr. Harpster found that:

- The PRMP was viewed internally by PG&E as a cost-reduction measure. Over the life of the originally planned GPRP program (to 2009), PG&E expected the PRMP would yield a total of $60 million dollars in savings.[59]
- GT&S was under significant pressure to reduce expenses in 2008. The combined Maintenance and Integrity Management budgets were $23.2 million below the GT&S's budget request.[60]

[54] CPSD-168 (Harpster), p.7-8, CPSD-186 (OC-68, Att. 3, p. 2) (emphasis added); CPSD-230, (OC-264 and OC-264, Supplemental, Att. 6, p. 9).

[55] CPSD-168 (Harpster), pp. 8-3, 8-5, CPSD-186 (OC-68, Att.2, pp. 11, 14, 28), CPSD-229 (OC-262).

[56] CPSD-168 (Harpster), p. 8-5, CPSD-224 (OC-257, Att. 5a).

[57]CPSD-168 (Harpster), p. 9-10, CPSD-230 (OC-264, Att.1) and CPSD-226 (OC-259, Att. 4, p. 8).

[58]CPSD-168 (Harpster), p. 6-14, Table 6-15, CPSD-208 (OC -213) and CPSD-260 (OC-345).

[59]CPSD-168 (Harpster), p. 7-1, CPSD-186 (OC-68, Att. 12, p. 132).

[60]CPSD-168 (Harpster), p.7-6, Table 7-1, CPSD-244 (OC-314) and CPSD-184 (OC-66, Att. 23).

- Actual 2008 Integrity Management spending was 30% below the initial GT&S request.[61]
- The 2008 approved budget only funded 76% of the GT&S Maintenance budget request.[62]
- The 2008 budget request for maintenance projects was $25.2 million. The approved maintenance project budget was 47% below the initial GT&S request.[63] PG&E bluntly acknowledged in its Fall 2007 Program Review that its "long-term reliable operation is jeopardized at the current level of funding," that reduced spending "will perpetuate significant underfunding of the gas transmission maintenance program," and the backlog of correction maintenance would grow.[64]
- PG&E's 2008 Gas Transmission Program Review documents PG&E's recognition that since 2007 "many high priority reliability projects were underfunded/postponed." PG&E also tragically predicted: "While the effects of deferred maintenance can immediately impact operations and reliability, effects are most impactive when maintenance is deferred over a multiple year period as will likely be the case in 2008 to 2010."[65]
- According to a PG&E internal email, in 2009 – the year before the San Bruno explosion – GT&S was "saddled" by its management with an Integrity Management expense budget set 32% below GT&S's initial budget request.[66] And PG&E actually spent even less – $1.9 million less than the final approved budget amount.[67]
- PG&E's approved budget in 2009 for pipeline maintenance was $7.1 million less than the amount requested.[68]

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[61] CPSD-168 (Harpster), pp.7-6, 7-7, Table 7-1, CPSD-244 (OC-314), CPSD-184 (OC-66, Att. 23), and Table 7-3, CPSD-244 (OC-314) and CPSD-175 (OC-23).

[62] CPSD-168 (Harpster), p.7-10, p. 7-6, Table 7-1, CPSD-244 (OC-314) and CPSD-184 (OC-66, Att. 23).

[63] CPSD-168 (Harpster), p.7-10, CPSD-231 (OC-267).

[64] CPSD-168 (Harpster), p.7-11, CPSD-186 (OC-68, Att. 4, p. 18).

[65] CPSD-168 (Harpster), p.7-11, CPSD-186 (OC-68, Att. 3, p.2).

[66] CPSD-168 (Harpster), p. 8-3, CPSD-229 (OC-262, Att. 5); p. 8-2, CPSD-184 (OC-66, Att. 23), Table 8-3, CPSD-244 (OC-314) and CPSD-175 (OC-23).

[67] CPSD-168 (Harpster), Table 8-3, CPSD-176 (OC-314) and CPSD-244 (OC-23).

[68] CPSD-168 (Harpster), p. 8-1 Table 8-1, CPSD-244 (OC-314) and CPSD-184 (OC-66, Att. 24).

- PG&E's 2009 budget cuts for maintenance were, in GT&S's own words, "very deep," leaving GT&S unable to fund all Priority I work.[69]
- PG&E's Spring 2009 Expense Program Review notes that $6.4 million of Priority I and II maintenance projects remained unfunded. PG&E acknowledged the risks of not funding these projects: deferral of critical maintenance, reliability impacts and reduced efficiency.[70]
- In 2009, PG&E actually spent $60.3 million on pipeline maintenance – $6.3 million over budget – but only because of significant unplanned emergent repair work.[71] PG&E then implemented cost reduction measures to close the "budget gap" caused by the unplanned expenditures, including strict hiring controls.[72]
- GT&S was under significant pressure to reduce expenses for a third straight year in 2010. In October 2009, PG&E Vice Presidents requested an analysis of how to further reduce the GT&S 2010 budget to $89.8 million (the original projected need was $111.1 million).[73]
- The 2010 budget was set $6.7 million below the already constrained 2009 actual expense level.[74]
- The 2010 Integrity Management budget was 11% below the initial request, and the maintenance budget was 24% below the initial request.[75]
- In 2010, PG&E again cut its Integrity Management budget by deferring projects, and developed 21 formal cost reduction initiatives

[69] CPSD-168 (Harpster), p. 8-6, CPSD-230 (OC-264, Att. 9). PG&E defines Priority I corrective work as "*high risk* work due to safety, reliability, customer or stakeholder issues." (CPSD-168 (Harpster), p. 9-4 and CPSD-186 (OC-67, p. 28) (emphasis added).)

[70] CPSD-168 (Harpster), p. 8-7, CPSD-186 (OC-68, Att.2, p.18).

[71] CPSD-168 (Harpster), pp. 8-1, 8-2 & n.1, Table 8-2, CPSD-224 (OC-257, Att. 2).

[72] CPSD-168 (Harpster), p. 8-2, CPSD-185 (OC-67, p. 16).

[73] CPSD-168 (Harpster), pp. 9-1 Table 9-1, 9-5, CPSD-226 (OC-259, Att. 5, October 7, 2009 email), p. 9-3, Table 9-5, CPSD-186 (OC-68, Supplemental, Att. 3, p. 15).

[74] CPSD-168 (Harpster), p. 9-1 CPSD-230 (OC-264, Att. 3b).

[75] CPSD-168 (Harpster), p. 9-1 and Table 9-1, CPSD-244 (OC-314) and CPSD-186 (OC-68, Att. 2, p. 4).

to bridge the gap between the expense funding requested by GT&S and management's budget target.[76]

2. PG&E Presented No Meaningful Rebuttal To Chapters 6-9 of Gary Harpster's Testimony

PG&E failed to rebut Chapters 6-9 of Mr. Harpster's prepared direct testimony. PG&E's expert witness, Matthew O'Loughlin, who responded to Mr. Harpster's testimony,[77] admitted that Mr. O'Loughlin's testimony did not respond to Chapters 6 through 9 of Mr. Harpster's testimony.[78] The fact that Mr. O'Loughlin did not refute Mr. Harpster's testimony in Chapters 6- 9, because Mr. O'Loughlin "was not asked to do that,"[79] does not negate Mr. Harpster's analysis or the substantial evidence of PG&E's budget cuts, inadequate testing and deferral of maintenance.

Nor did PG&E conduct any meaningful or substantive cross-examination of Mr. Harpster regarding this testimony. Instead, PG&E's cross-examination danced around the edges of Mr. Harpster's rebuttal testimony, such as asking Mr. Harpster questions requiring him to conduct exercises in arithmetic.[80] Chapters 6 through 9 of Mr. Harpster's prepared direct testimony were, in effect, never refuted by PG&E.

3. PG&E Underspent For Safety By $156 Million During 1997-2010

During 1997-2010, the Commission approved a series of settlements (known as the Gas Accord I through Gas Accord IV). With one exception, 2004, in approving these settlements, the Commission did not explicitly specify how much was approved annually for capital expenditures (capex) and Operations and Maintenance (O&M) expenses for GT&S. Consequently, the parties' expert witnesses imputed amounts authorized by the Commission for these expenses (imputed adopted amounts) for 13 of the years covered

[76] CPSD-168 (Harpster), p. 9-5, CPSD-226 (OC-259, Atts. 5 and 9), p. 9-7, Table 9-7, CPSD-247 (OC-323, Att.1).

[77] PG&E-10, p. 2; RT 539:13-22.

[78] RT 617:3-618:14.

[79] RT 618: 8-16.

[80] *See, e.g.,* RT 225:918.

by the settlements for comparison to the actual amounts PG&E spent. (*See* RT 547:19-548:15.) This comparison will show whether PG&E underspent or overspent for capex and O&M for GT&S compared to what the Commission had authorized them to spend. If PG&E was underspending, this means that the funds could be used by PG&E for profits and were not available for the safety expenses which PG&E had forecasted.

Regarding the amounts actually spent by PG&E for GT&S during this 13-year time period, with one exception, there is no disagreement between the experts because these amounts are documented in the FERC Form 2.[81] Therefore, the dispute between the experts focuses on the "imputed adopted amounts" where each expert used a different methodology to determine how much the Commission had authorized the utility to spend for capex and O&M where Commission decisions did not specify what was approved for recovery in rates by PG&E. The methodology for determining the "imputed adopted amounts" is critical in determining whether or not PG&E is spending more than what the Commission authorized or is spending less than what the Commission authorized.

Over 1997-2010, based on contemporaneous PG&E documents and forecasts, Mr. Harpster determined that PG&E's GT&S underspent for capex and O&M, spending $156.5 million *less* than the imputed adopted amounts.[82] In sharp contrast, PG&E witness O'Loughlin claims that during 1997-2010, PG&E's GT&S *overspent* for capex and O&M by $304 million *more* than the imputed adopted amounts. (PG&E-11 (MPO-1), p.4, Figure 2; p.3, Figure 1.) As fully explained below, Mr. O'Loughlin creates an illusion of PG&E's overspending on capex and O&M for GT&S by artificially understating what the Commission approved in rates. That PG&E was overspending on safety is nothing but a mirage.

[81] As explained *infra*,the one exception is the actual expenditures related to the San Bruno explosion, $21.8 million, that Mr. O'Loughlin has taken into account as to why PG&E overspent. In contrast, Mr. Harpster's position is that those costs should never be collected from ratepayers and thus should not be included in any analysis of whether PG&E overspent its budget.

[82] CPSD-170 (Harpster), pp. 7-8 ($39.9 million under spending for O&M and $116.6 million for capex for the 14-year period).

4. At PG&E's Direction, Mr. O'Loughlin Did Not Address Undisputed Facts Regarding PG&E's Budget Process And Conducted An Analysis Contrary To Commission Precedent

Mr. O'Loughlin's conclusion that PG&E overspent for capex and O&M by over $300 million during 1997-2010 is completely at odds with reality. As demonstrated above in Section F.1, *supra,* PG&E's own internal, contemporaneous documents, forecasts and data responses are compelling evidence of the tremendous constraints enforced on GT&S's budgets by PG&E executive management. This evidence supports Mr. Harpster's position that PG&E underspent for GT&S capex and O&M. But PG&E did not allow Mr. O'Loughlin to address the impact of the PG&E internal documents or budget forecasts referenced in Chapters 6-9 of Mr. Harpster's prepared direct testimony. (PG&E-11 (MPO-1), p. 2; RT 539:13-22; 618:8-19.)

Not only does Mr. O'Loughlin's opinion have no basis in fact, but it is contrary to Commission precedent because it uses settlement revenue requirements from the Gas Accord settlements as the imputed adopted amounts for capex and O&M spending. In approving PG&E's settlement of its general rate case and other cases, in D.04-05-055, under the heading "9.3 In the Public Interest," the Commission made clear that Commission approval of a settlement is based on the fundamental premise that PG&E will spend sufficient revenues to meet its safety obligations:

> The Settling Parties further state that "the Settlement provides sufficient capital to allow PG&E to adequately maintain the facilities and ensure their long term availability to serve customers."
>
> Absent this type of commitment, we would be unable to find that the Settlements are in the public interest. We emphasize that claims by PG&E that a particular project or activity was not funded in this GRC will not be entertained simply because the total amount granted in this case is less than the total amount initially requested. This policy is consistent with our prior holding that "[I]t would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonable deferred maintenance, or to make ratepayers pay a second time for

> activities explicitly authorized by the Commission in the past. (D.00-02-046, Conclusion of Law 15, p. 536.[emphasis in original omitted].)
>
> *In adopting the Settlements, we make it abundantly clear that PG&E is expected to continue to meet all of its service obligations and maintain and upgrade its system in a manner consistent with its TY 2003 forecast. By providing PG&E with the discretion to spend the authorized revenue requirement as it sees fit, we are not authorizing PG&E to defer maintenance, cancel proposed upgrades or service improvements, or reduce staffing in a manner inconsistent with the objectives identified in its request. In future GRCs, we will not entertain claims that the adopted revenue requirement somehow forced PG&E to do otherwise.*[83]

Accordingly, Mr. O'Loughlin's use of settlement revenue requirements as the basis for the imputed adopted amounts for GT&S's capex and O&M is improper, particularly in light of the existing internal budget documents and PG&E forecasts.

Mr. O'Loughlin admits that this approach was the result of his direction from PG&E. PG&E restricted Mr. O'Loughlin's task to a limited comparison of actual expenditures to settlement revenue requirements, contrary to PG&E's own budget process, and Commission precedent. As Mr. O'Loughlin stated:

> Somebody could have done an analysis of PG&E's budgets to what it actually spent. That would be one interesting analysis. Somebody could do an analysis of PG&E's litigation forecast to what it actually spent. That would be another interesting analysis. . . It certainty [sic] wasn't what I was retained to do, which is to compare what was actual expenditures to what was provided for in revenue requirements and rates. And that's the comparison I'm doing. Using budgets or using litigation forecasts are not particularly helpful for answering the question that I have answered.[84]

The Commission should adopt Mr. Harpster's analysis and reject Mr. O'Loughlin's. Mr. Harpster's conclusions are based on amounts forecasted by PG&E,

[83] D.04-05-055, 2004 Cal. PUC LEXIS 254 at *116-118. (Emphasis added).

[84] RT 622:17-623:5.

are supported by substantial evidence (including contemporaneous internal PG&E documents), and are consistent with Commission precedent. Mr. O'Loughlin's overspending theory ignores PG&E documents, is based on erroneous factual assumptions, and imputes amounts based on settlement revenue requirements, contrary to Commission precedent.

5. Comparison Of The Experts' Approaches Demonstrates Why Mr. Harpster's Approach Should Be Followed And How Mr. O'Loughlin Was Able To Erroneously Conclude That PG&E Somehow Overspent For Capex And O&M

Mr. O'Loughlin did not use PG&E's own imputed adopted amounts, which PG&E provided in its data responses to Mr. Harpster. Instead, Mr. O'Loughlin criticized Mr. Harpster's methodology and, for many of the years in question, used settlement revenue requirements as PG&E's imputed adopted amounts, contrary to Commission precedent.[85] Below the experts' differing approaches and conclusions are compared.

1997-2002: For 1997-2002, there is no significant difference between Mr. Harpster's and Mr. O'Loughlin's imputed adopted amounts, except, as discussed below, for Mr. O'Loughlin's assumption regarding partial roll-in of PG&E Line 401 rates.[86] (*See* Section F. 6*, infra.*) Although the Gas Accord I Settlement did not have a breakdown, significantly, both experts based their imputed adopted amounts for capex and O&M on the 1996 forecast underlying the 1996 general rate case, which resulted in the Gas Accord I Settlement. (*Compare* CPSD-168 (Harpster), pp. 2-7 & 2-8 with PG&E-11 (MPO-11), p.26.)

2003: In 2003, the Gas Accord Settlement was a "black box," and included no cost data at all, including any breakdown for capex and O&M. However, on January 13, 2003, PG&E had filed a 2003 forecast with its 2004 rate application. The 2003 forecast

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[85] RT 545:3-547:18; *see also* CPSD-298 and CPSD-299.

[86] PG&E's Line 401 was the expansion of its existing intrastate pipeline (Line 400) by 755 MMcf/d that corresponded with PG&E's interstate pipeline's expansion to Canada.

included detailed forecasts for capex and O&M. Accordingly, Mr. Harpster relied upon PG&E's 2003 forecasted amounts. (CPSD-168 (Harpster) p.2-9.) In contrast, Mr. O'Loughlin used an outdated 1996 forecast underlying the Gas Accord I Settlement to forecast 2003 rates. Mr. O'Loughlin assumed that 2003 was simply an extension of the Gas Accord I. However, this assumption was invalid because the Gas Accord I Settlement expired on December 31, 2002. In addition, PG&E had expanded its transmission system by 218 Million cubic feet per day (MMcf/d) in 2002, a significant material change from 1996.[87] Accordingly, PG&E's 2003 forecast, used by Mr. Harpster, clearly provides the more reasonable basis to impute the rate components (*e.g.,* O&M and capex) than the obsolete 1996 forecast used by Mr. O'Loughlin.[88]

According to Mr. Harpster, PG&E's actual capex spending in 2003 was $10.8 million less than the imputed adopted amount based on the PG&E 2003 forecast. In contrast, in Mr. O'Loughlin's view, in 2003 PG&E spent $32.8 million more than the imputed adopted amount based on the 1996 forecast.[89] For O&M, Mr. Harpster found that PG&E's actual O&M in 2003 was $10.7 million less than his imputed adopted amount, while Mr. O'Loughlin determined that PG&E overspent by $4.1million beyond the imputed adopted amount (again using the 1996 forecast).[90] The Commission should reject PG&E's attempt to use an outdated forecast to impute capex and O&M, and adopt Mr. Harpster's approach, based on PG&E's 2003 forecast.

2004: For 2004, there was no reason to impute what the Commission had approved because the Commission's decision explicitly stated what it had adopted for capex and O&M.[91] For 2004, Mr. Harpster and Mr. O'Loughlin agree that PG&E's

[87] CPSD-170 (Harpster), pp. 42-52.

[88] CPSD-170 (Harpster), pp. 42-43.

[89] *Compare* CPSD-170 (Harpster), p. 8, Table 3-3 (year 2003) with PG&E-10 (O'Loughlin) (MPO-1), p. 48, Figure 12 (year 2003).

[90] *Compare* CPSD-170 (Harpster), p. 8, Table 3-3 (year 2003) with PG&E-10 (O'Loughlin) (MPO-1), p.24, Figure 5 (year 2003).

[91] D.03-12-051, 2001 Cal. PUC LEXIS 1279 at *297-303, 314-322; *see also* PG&E-10 (O'Loughlin) (MPO-1), p. 51.

GT&S significantly underspent for safety by approximately $70 million compared to what the Commission had specifically approved.[92] The fact that one year, 2004, is a large component (*i.e.,* more than 40%) of the $156 million total Mr. Harpster determined that PG&E had underspent for capex and O&M during the 14 years in question, lends even more credence to the validity Mr. Harpster's approach.

2005-2006: Again, there is disagreement, but the differences are not substantial. (PG&E-11 (MPO-1), p. 39, Figure 8.) The experts agree that PG&E overspent for capex (PG&E-11 (MPO-1), p. 48, Figure 12) and underspent for O&M (PG&E-11 (MPO-1), p. 24, Figure 5) by similar amounts with a difference of $2-3 million per year. The Gas Accord III settlement was based upon PG&E's general rate case application for GT&S, which provided detailed costs for only 2005, but was silent as to 2006 or 2007. (CPSD-170 (Harpster), p. 55.) Consequently, the experts had an explicit basis for deciding the imputed adopted amounts for 2005 as a result of the Commission's approval of the Gas Accord III Settlement, but neither of them had a direct basis for imputing adopted amounts for 2006.

2007: In 2007, the experts had substantial disagreement. In March 2007, PG&E filed a detailed litigation forecast for each year from 2007 through 2010, with a breakdown showing capex and O&M, as support for its Gas Accord IV settlement. PG&E itself relied upon this forecast for its calculation of the imputed adopted amount of $156 million for capex in 2007. (PG&E-11 (MPO-6), p. 3.) PG&E's forecast for 2007 included an imputed adopted capex of $152.6 million, which would result in $5.7 million of overspending. (*See, e.g.,* PG&E-11 (MPO-1), p. 5, (MPO-6), Figure 6-2 (2007).)

Like PG&E, Mr. Harpster used PG&E's forecasted amount submitted in the Gas Accord IV proceeding, and similarly found that PG&E overspent its capex by $5.3 million (a difference of $400,000). (CPSD-170 (Harpster), p. 53, Table 8-1(year 2007), p. 57.) However, rather than use PG&E's 2007 forecast, Mr. O'Loughlin used a different methodology to impute amounts for capex. He applied a growth rate from the Gas

[92] CPSD-170 (Harpster), p. 8, 14-15 Table 3-9 (year 2004) and Table 3-19 (year 2004).

Accord III settlement revenue requirements (which do not have a breakdown of cost components). (PG&E-11 (MPO-1), p. 52.) According to Mr. O'Loughlin, for 2007, the imputed adopted amount for capex is $106.9 million, with PG&E overspending by $51.4 million – nearly ten times the amounts computed by PG&E and Mr. Harpster. (PG&E-11 (MPO-6), p. 3, Figure 6-2 (year 2007).)

But cross-examination of Mr. O'Loughlin revealed that there was no basis in the Gas Accord III Settlement or Gas Accord IV Settlement for Mr. O'Loughlin's imputations:

> Q. Well, sir, can you tell me where in Gas Accord 3 or 4 there's specific amounts budgeted in the settlement itself for O&M and Capex, capital expenditures?
>
> A. 2005 certainly had O&M amounts, and I believe it may have also had capital expenditure information. The years subsequent to that have to be developed by examining the settlement revenue requirements and then inferring or imputing from that the settlement capex that's implied by that revenue requirement level. But I would agree with you that there's no explicit capital expenditure amounts specified for, for example, 2008 to 2010.

(RT 621:24-622:10.)

2008-2010: A review of 2008-2010 emphatically demonstrates why Mr. O'Loughlin's overspending theory is wrong. Mr. O'Loughlin inferred amounts for capex that he thought were implied by the settlement revenue requirements of the Gas Accord IV settlement, even though his imputed approved amounts of capex were much smaller than what PG&E had budgeted or forecasted. Moreover, as noted above, Mr. O'Loughlin admitted there is no basis in the Gas Accord IV Settlement for this imputation.[93] Based on his imputed adopted amounts, Mr. O'Loughlin concluded that, in 2008, PG&E spent $127 million more for capex than his imputed adopted amount of $89.7 million. For 2008-2010, Mr. O'Loughlin's total imputed adopted amount for capex was $335.3 million. Because the actual total amount PG&E spent on capex was $610.1 million, Mr.

[93] RT 621:24-623:22

O'Loughlin's position is that PG&E's capex spending was 82% more than his imputed adopted amounts based on settlement revenue requirements.[94]

Not only is there no basis for his imputed adopted amount in the Gas Accord IV Settlement, but Mr. O'Loughlin could not show any internal PG&E documentation showing that PG&E had overspent for capex by $275 million.[95] Considering that Mr. O'Loughlin submitted 63 exhibits accompanying his testimony (PG&E-10 and PG&E-11), the lack of any supporting internal documents from PG&E discredits his theory that PG&E overspent for capex by nearly $300 million. Indeed, Mr. Harpster requested that PG&E provide any documents demonstrating that PG&E had spent significantly more on capex in 2008-2010 as indicated by Mr. O'Loughlin's imputed adopted amounts implied from the Gas Accord IV Settlement. PG&E stated that it was not aware that any such internal documents existed. (CPSD-170 (Harpster), pp. 83-84.) According to Mr. O'Loughlin: "It's more likely that they [PG&E] had documents that compared their actual spending to their budgets or something of that sort." (RT 635: 2-5.) Mr. O'Loughlin also agreed that for the Gas Accord IV period, PG&E had used its budgeted method for imputing what the Commission had adopted. (PG&E-10 (MPO-6), p.5.)

Mr. O'Loughlin's approach conflicts with PG&E's approach. Mr. O'Loughlin testified that PG&E's imputed adopted amounts for capex was higher than Mr. O'Loughin's imputed adopted amount for 2008-2010 by $278 million, and this difference arises from PG&E's use of its budgeted amounts as an estimate for the imputed adopted capex.[96] PG&E's budgeted method results in imputed adopted amounts for capex for 2008 through 2010 of $ 616 million., *See* PG&E-10 (MPO-6), p.3, Figure 6-2 (adding amounts for PG&E's imputed amounts for 2008-2010). Moreover, according to PG&E, PG&E actually spent $3.5 million *less* than its imputed adopted amounts for 2008-2010. This is shown by simply adding the differences for 2008-2010 under PG&E in Figure 6-2

[94] CPSD-170 (Harpster), p. 82; PG&E 10 (MPO-1), p. 48, Figure 12 (Years 2008-2010).

[95] RT 631:2-635:11.

[96] PG&E 10 (MPO-6), p. 5.

(-$2.8 million + $10.8 million - $11.5million = -$3.5 million.) But adding the corresponding amounts for Mr. O'Loughlin for 2008-2010 in Figure 6-2 deceptively shows that PG&E overspent for capex by approximately $275 million. The difference between PG&E and its own expert witness for 2008-2010 is over $278 million.

Unlike Mr. O'Loughlin, Mr. Harpster used PG&E's March 2007 litigation forecast for 2008 and 2009 capex, which had detailed capex expenses and was submitted by PG&E with the Gas Accord IV Settlement. However, because PG&E's 2007 litigation forecast for 2010 was unusually low (*i.e.,* $100 million, which was a $150 million decrease from the 2009 forecast and a $121 million decrease from the 2008 forecast), for 2010, Mr. Harpster utilized PG&E's March 2010 forecast from its 2011 GT&S rate case filing. On this basis, Mr. Harpster's imputed adopted amount for capex for 2008-2010 is $662 million, $326.8 million *more* than Mr. O'Loughlin's. (CPSD-170 (Harpster), pp. 70-72.) Under either PG&E's budgeted approach ($616 million) or Mr. Harpster's analysis ($662 million), PG&E's actual capex for 2008-2010 of $610 million was *less* than what the Commission approved. Only under Mr. O'Loughlin's analysis does PG&E appear to spend $275million *more* than the imputed adopted amounts.

In terms of O&M, under Mr. O'Loughlin's approach, PG&E spent $5.9 million more in 2008 and 2009 than Mr. O'Loughlin's imputed adopted amounts based on settlement revenues. In contrast, Mr. Harpster determined that, utilizing PG&E's 2007 forecast, PG&E had spent $3.7 million less for O&M during this period than what Mr. Harpster had imputed.[97]

For 2010, Mr. O'Loughlin concluded that PG&E spent $111million on O&M, which was $19.9 million more than his imputed adopted amount.[98] Of course, that was the year the San Bruno explosion occurred. Mr. Harpster quantified $21.8 million of O&M expenses related to the explosion which he excluded from actual costs because

[97] *Compare* PG&E-10 (O'Loughlin) (MPO-1), p.24, Figure 5 (years 2008 and 2009) with CPSD-170 (Harpster), pp. 7, Table 3-2 (years 2008 and 2009) and 60-61.

[98] PG&E-10 (O'Loughlin) (MPO-1), p.24, Figure 5 (year 2010).

these costs should not be recoverable from ratepayers.[99] On cross-examination, Mr. O'Loughlin testified that he did not agree that the entire $21.8 million of expenditures should be excluded because some of the O&M spending would have been incurred in any event. However, after reviewing the actual amounts for O&M for 2010 *(i.e.,* $111 million), Mr. O'Loughlin had to concede that 2010 actual spending was not only higher than 2009 or 2008, but was higher *by far* than any of the other years in his chart from 1997 to 2009 *(i.e.,* more than $15 million than the next closest amount in 2009).[100]

In sum, Mr. O'Loughlin's approach is unsupportable based upon any theory, internal PG&E documents or Commission precedent, as epitomized by the $275 million he claims PG&E overspent in 2008-2010. All of the internal documents show, in reality, PG&E was cutting GT&S budgets as evidenced in the exhibits referred to in Chapters 6-9 of Mr. Harpster's direct testimony, which PG&E did not dispute. In contrast, Mr. Harpster's methodology – using imputed adopted amounts based upon PG&E forecasts – is supported by contemporaneous internal PG&E documents and Commission precedent.

6. Mr. O'Loughlin's Approach Is Based Upon His Incorrect Assumption That PG&E's Transmission Rates Were At Risk

Mr. O'Loughlin's analysis GT&S is further flawed because he made faulty factual assumptions regarding the Gas Accord I decision and the Gas Accord Settlements. In his analysis, Mr. O'Loughlin initially assumed that the Gas Accord I decision[101] did not approve rates for full cost recovery of Line 401 (*i.e.,* PG&E's expansion of its transmission system in the early 1990s), because the parties provided for a "partial roll-in" of Lines 401 into the rates of existing non-core customers.[102] Mr. O'Loughlin

[99] CPSD-170 (Harpster), pp. 107-109.

[100] RT 568:15-569:4; *see also* PG&E-10 (O'Loughlin) (MPO-1), p.24, Figure 5.

[101] D.97-08-054 reproduced in its entirety in CPSD-300.

[102] PG&E-10 (MPO-7), pp.23-26.

quantifies the impact of this partial roll-in from 1997-2003 as $232.6 million that he did not include in his imputed adopted revenue amounts.[103]

However, Mr. O'Loughlin's assumption was wrong. As Mr. Harpster pointed out in his rebuttal testimony,[104] in the Gas Accord I decision, the Commission approved retail rates to recover PG&E's $736 million of Line 401 costs.[105] Accordingly, on cross-examination, when he was confronted with the Commission's Gas Accord I decision, Mr. O'Loughlin had to concede that the Commission had approved incremental rates (charged solely to expansion shippers) and partial roll-in rates (charged to existing noncore shippers and expansion shippers) to recover the $736 million of PG&E's Line 401 costs.[106] Mr. O'Loughlin then resorted to an alternative premise: PG&E's transmission system would not be fully utilized and PG&E thus was at risk for cost recovery. Again, the Gas Accord I decision demonstrates that this assumption, too, is erroneous, because the CPUC had instituted a crossover ban that prohibited PGT's expansion shippers from utilizing PG&E's existing Line 400.[107] Therefore, these shippers had to use PG&E's Line 401.[108]

Mr. O'Loughlin's erroneous assumption that PG&E was at risk for recovery of transmission rates also is contradicted by his prior testimony in 2001 before the FERC in *California Public Utilities Commission v. El Paso Natural Gas Company, et al.*, FERC Docket No. RP00-241. In that proceeding, Mr. O'Loughlin testified that Lines 400 and 401 were already operating at full capacity.[109] Finally, Mr. O'Loughlin's conclusion is at odds with the Commission's prior finding that: "As a result of the price advantages for

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[103] PG&E-10 (MPO-7), p. 24.

[104] CPSD- 170(Harpster), pp. 19-20, 22, 25.

[105] CPSD-300, pp.770, 792.

[106] RT 586:1 -590:10.

[107] CPSD-300, p. 765.

[108] CPSD- 300, p. 771.

[109] CPSD-301, pp. II-1 through II-2; RT 597:15- 609:6.

Canadian gas, the Redwood path, including Line 401, was highly utilized throughout the Gas Accord Period."[110] In short, there was no risk facing PG&E.

On re-direct, Mr. O'Loughlin attempted to downplay his partial roll-in theory by claiming that it directly affected only his O&M imputation amounts by $8 million. However, on re-cross-examination, he conceded that his partial roll-in theory had made it possible for him to claim that PG&E's actual revenues were $230 million more than his imputed adopted amounts because his partial roll-in theory had lowered his "imputed adopted" revenue requirement.[111]

7. CPSD and PG&E Agree That During 1997-2010, PG&E's GT&S Earned More Than $400 Million In Excess Of PG&E's ROE

PG&E's budget cuts and deferred maintenance for its GT&S, documented in Chapters 6-9 of Mr. Harpster's direct testimony, occurred at the very same time PG&E was making enormous profits from its GT&S. While most utilities could not financially survive by continuously spending more than what their regulator had authorized as Mr. O'Loughlin surmises, not only did PG&E's GT&S survive, but it thrived – earning an ROE of 14.6%.[112] Mr. Harpster and Mr. O'Loughlin agree that during 1997 through 2010, PG&E's GT&S's actual revenues exceeded its actual revenue requirements (needed to earn PG&E's authorized ROE of 11.2%) by more than $400 million.[113] The

[110] D.03-12-061, 2001 Cal. PUC LEXIS 1279 at *401.

[111] RT 679:3-24; RT 681:9-682:19.

[112] PG&E-10 (MPO-1), p.82.

[113] RT 540:17 - 541:17. In Mr. Harpster's rebuttal testimony (CPSD-170, p. 5), Mr. Harpster stated that GT&S had earned an ROE of 14.3%, which was $435 million in revenues beyond PG&E's Commission-authorized ROE of 11.2% over this 14-year period. Mr. O'Loughlin maintained that PG&E earned an ROE of 14.6%, which was $479.5 million more than the Commission's authorized revenue requirements based upon a 11.2% ROE during this 14-year period. (PG&E-10 (MPO-1), p.82.) These surplus revenues should be considered during the fines and remedy phase of this proceeding. In the Commission's D.12-12-030, slip op., p.4, the Commission made clear: "Our upcoming decisions in Investigations (I.) 11-02-016, I.11-11-009, and I.12-01-007 will address potential penalties for PG&E's actions under investigation. We do not foreclose the possibility that further ratemaking adjustments may be adopted in those investigations; thus, all ratemaking recovery authorized in today's decision is subject to refund." *See also id* at p. 126, Ordering Paragraph 3: "All increases in revenue requirement authorized

(continued on next page)

methodology by how each expert derived these surplus revenues and the total amount of the surplus revenues are different, but there is no disagreement that GT&S was enormously profitable during the 14 years leading up to the San Bruno explosion.

8. PG&E Diverted Revenues From Safety Budgets To Cover A Reserve For PG&E's Electric Business And To Fulfill Shareholders' Earnings Expectations

Mr. O'Loughlin attempted to justify PG&E's failure to use the GT&S profits for safety-related natural gas transmission by referring to PG&E's priorities for its other operations. Mr. O'Loughlin's position is that PG&E executive management, rather than the Commission, should decide PG&E's priorities for spending.[114] Further, even if PG&E's GT&S earned much more than its authorized ROE, other parts of PG&E did not do as well, and the overall authorized ROE of the entire company should be considered.[115] According to Mr. O'Loughlin:

> PG&E allocates its financial resources through an enterprise-wide planning and budgeting process. By this I mean that funding for each line of business is not limited to the specific revenues generated by that line of business. While regulatory funding levels are available as a data point in the decision-making process, budgets are ultimately set for each line of business according to the operating priorities set by PG&E rather than the revenue source. [Footnote omitted]. … [I]n my opinion, … one should not draw any conclusions about PG&E's overall safety culture or whether it prioritized profits over safety based upon the return history of GT&S in isolation.[116]

(continued from previous page)
in Ordering Paragraph 2 are subject to refund pending further Commission decisions in Investigation (I.) 11-02-016, I.11-11-009, and I.12-01-007."

[114] PG&E-10 (O'Loughlin), p.79.

[115] PG&E-10 (O'Loughlin), p.79.

[116] PG&E-11 (O'Loughlin), p.79. The footnote omitted from the quotation above referred to the accompanying Exhibit No. (MPO-37), which is one page of a chapter of PG&E testimony identified as (PG&E-8). CPSD found and provided the entire chapter of this testimony. *see* CPSD-304.

Mr. O'Loughlin, however, admitted that he could not trace where the surplus GT&S revenues went and did not know if the GT&S surplus revenues went to profits.[117] Moreover, a review of the entire chapter of PG&E's management priority planning testimony in its 2011 general rate case does not once mention natural gas transmission safety as a high priority.[118] In contrast, PG&E's priority planning chapter does explicitly mention "meeting the expectations of shareholders."[119] PG&E's Table 14-1 includes a heading for "Improve Safety and Human Performance," but lists only one bullet which addresses safety:

- Establish a culture where every employee works safely and without error.

The next heading in Table 14-1 is more telling: "On Budget, on Plan and On Purpose" which is followed by three bullets:

- Prioritize work and resources to achieve our business plans within the established cost and schedule.
- Enhance operational efficiency and investing in infrastructure.
- Deliver the planned financial and operational benefit for our customers and our shareholders.[120]

Similarly, PG&E Table 14-2, "Key Metric Scoring" has 0 to 3 ratings (with 3 being the best) for numerous subjects, starting with "Earnings from Operations," and the only safety-related metric is "OSHA Recordable Injury Rate."[121] Read together, rather than reflecting the obligation to safeguard the public from the inherent dangers associated with natural gas or electricity, PG&E's "safety culture" appeared primarily concerned with employee safety. In addition, the targets of achieving plans within the established cost and schedule, enhancing efficiency and delivering planned financial benefits for

[117] RT 649:20-650:12.

[118] CPSD-304.

[119] CPSD-304, p.14-1.

[120] CPSD-304, Table 14-1, p.14-5.

[121] CPSD-304, Table 14-2, p.14-6.

shareholders qualify any notion that safety of the public was a high priority concern for PG&E.

These conclusions are consistent with one of the findings in the "Report of the Independent Review Panel, San Bruno Explosion," June 24, 2011, p.7, which stated under the heading "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. [122]

In addition, PG&E allocated funds from each Line of Business (LOB) to build a reserve fund. For 2010, the year of the San Bruno explosion, PG&E had taken funds from each of its LOB, including GT&S, for a reserve fund allocated to Distribution and Nuclear Generation LOB.[123] Nowhere does PG&E ever indicate that, prior to the San Bruno explosion, funds were transferred to GT&S to help improve the safety of PG&E's gas transmission system. The upshot of PG&E's priority planning system is that PG&E management did not consider the dangers posed to the general public of aging, high-pressure natural gas pipelines in densely populated areas to be a high priority.

9. PG&E's Deferral Of Maintenance And Underfunding For Safety Made Catastrophic Failure Inevitable

The Commission has succinctly described the extraordinary dangers of natural gas pipelines:

> Among all public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. Unlike more common public utility facilities, gas pipelines carry flammable gas under pressure - in transmission lines, often at high pressure - and these pipelines

[122] CPSD-310, p. 7.

[123] CPSD-304, p. 14-3.

> are typically located in public right-of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems, including the pace at which death and life-altering injuries can occur, are far more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.
>
> In the context of an unending obligation to ensure safety, we must also realize that in practical terms safety is exacting, detailed, and repetitive. It is also expensive, so ensuring that high value safety improvements are prioritized and obtaining efficiencies wherever possible is also essential. And, in the end, if the goal of safe operations is met, the reward is that absolutely nothing bad happens. In short, safety is difficult, expensive and seemingly without reward.[124]

In light of the obvious grave danger to public safety posed by a natural gas high pressure transmission pipelines, it is both inexplicable and inexcusable for PG&E to have been cutting and deferring maintenance, preferring cheaper but less thorough integrity assessment methods, nickel and diming the GT&S over its safety budgets (even though the CPUC fully approved the budgets for the GPRP each time PG&E submitted its GPRP in its GRCs),[125] and not completing the GPRP, as originally planned.

Significantly, PG&E was well aware of maintenance and integrity management issues on Line 132. Chapter 4 of Gary Harpster's direct testimony documents PG&E's knowledge of manufacturing and workmanship defects on Line 132.[126] In 2008, PG&E suspected that sections of Line 132 had "manufacturing threats" at maximum operating

[124] D.12-12-030, slip op., p. 43.

[125] *Id.* at 34 (Commission "routinely approved ratemaking requests").

[126] CPSD-168 (Harpster), pp. 4-5, 4-6, CPSD-240 (OC-303, Atts. 10, 26, 27, 42).

pressure.[127] In 2008 and 2010, PG&E also considered upgrading Line 132 for ILI from MP 0.00 to MP 32.93, but the project was delayed due to lack of resources to perform engineering work and PG&E's changing criteria for choosing ILI/ECDA.[128] On February 2, 2010 – seven months before the explosion – PG&E repaired a circumferential weld leak on Line 132 caused by a "workmanship problem" with the original construction.[129] The NTSB also has confirmed several other girth weld defects in very close proximity to Segment 180 at MP 39.28, the pipeline segment that exploded.[130]

PG&E's "response" to Chapter 4 of Mr. Harpster's focused audit is not testimony from its own management or engineers substantiated with internal documents. Instead, PG&E submitted limited, conclusory and unsupported statements of an outside consultant, Joseph W. Martinelli. Mr. Martinelli's prepared direct testimony (exclusive of his background and a description of the materials considered) consists of one page. In these few lines, Mr. Martinelli comes to two very narrow and ultimately meaningless conclusions: (1) the PG&E expense budget constraints in 2008 to 2010 identified by Mr. Harpster "did not affect planned integrity management assessments for Segment 180 [of Line 132]"; and (2) PG&E's budget cuts did not affect the timing of the project to replace Line 132 from Milepost 42.13 to 43.55, which was driven by unidentified "engineering and risk management considerations."[131]

Mr. Martinelli's testimony should be given no weight whatsoever in this proceeding. In sharp contrast to Mr. Harpster's focused audit, which specifically identifies and attaches as exhibits the PG&E documents that provide the basis for his conclusions, Mr. Martinelli does not specifically identify any PG&E document or attach any exhibits. Instead, Mr. Martinelli states generally that he reviewed unspecified data

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[127] CPSD-168 (Harpster), p. 4-5, CPSD-240 (OC-303, Att. 37).

[128] CPSD-168 (Harpster), p. 4-5, CPSD-240 (OC-303, Att. 26).

[129] CPSD-168 (Harpster), p. 4-6, CPSD-240 (OC-303, Att. 4).

[130] CPSD-168 (Harpster), p. 4-6, CPSD-9, NTSB Accident Report, p. 43.

[131] PG&E-1 (Martinelli), p. 12-3:10 through p. 12-4:2.

responses of PG&E regarding PG&E's budget records and processes, unspecified information concerning replacements and improvements on Line 132, deposition testimony of an unnamed PG&E employee relating to PG&E's planned project to replace mile post 42.13 to mile post 43.55 on Line 132, other unspecified depositions, unspecified materials that identify the pipelines for which PG&E made plans to switch the method of assessment to ECDA, and unspecified documents related to the ECDA conducted on Line 132 in 2008-2010.[132] CPSD and the Commission can only guess what specific information Mr. Martinelli reviewed and believes supports his conclusions.

Mr. Martinelli's testimony also lacks any meaningful analysis. Mr. Martinelli's first conclusion purportedly responds to Mr. Harpster's finding at p.1-1 of his audit report that "PG&E reduced Integrity Management expenses by deferring projects and changing the assessment methods from ILI to ECDA" because of "resource constraints."[133] Mr. Martinelli concludes that expense constraints did not affect "PG&E's planned integrity assessments for of Segment 180" and that PG&E did not defer or delay any assessment of Line 132 planned by PG&E for 2008-2010.[134] In other words, PG&E budget constraints in 2008- 2010 did not cause PG&E to "switch" from its "planned" ECDA assessment method or defer planned maintenance on Line 132. But this testimony completely misses the point. PG&E's compliance with its pipeline safety and integrity management obligations is not confined to whether PG&E adhered to its inadequate plans.

Mr. Martinelli's narrow and uncorroborated conclusion wholly sidesteps the questions of whether PG&E's planned use of ECDA for Line 132 in the first place was appropriate or improperly driven by budget constraints and whether Line 132 should have been planned to have been tested, replaced or repaired sooner. Mr. Martinelli also fails to comment on PG&E's own internal documents, identified by Mr. Harpster, which explicitly state that, in 2008 and 2010, PG&E considered upgrading Line 132 from MP

[132] PG&E-1 (Martinelli), pp. 12-2:22-33, p. 12-3:10-20.

[133] PG&E-1 (Martinelli), pp. 12-3:4-23.

[134] PG&E-1 (Martinelli), pp. 12-3:15-20.

0.00 to MP 32.93 for ILI, but the project was delayed due to lack of resources to perform engineering work.[135] Simply because the particular project PG&E planned but twice shelved for Line 132 did not reach as far as Segment 180, MP 39.28, where the explosion occurred, does not mean that PG&E's budget cuts did not affect the safety and integrity of Segment 180 or Line 132. And Mr. Martinelli's testimony simply does not address it.

Mr. Martinelli's second conclusion, regarding the alleged reasons for delay in the replacement of a segment of Line 132 between mileposts 42.13 and 43.55 of Line 132, is equally meaningless. Mr. Martinelli concludes that this replacement project was not delayed due to budget cuts but, instead, was delayed due to unexplained and unspecified "engineering and risk management considerations."[136] Although the need to provide explicit reasons for deferral of this critical work is obvious, none are given. What Mr. Martinelli means is unclear, and his unexplained and unspecified statement is uncorroborated by any PG&E document or testimony. Mr. Martinelli fails to explain why or what the supposed engineering or risk management considerations were (if in fact they existed), fails to in any way rebut Mr. Harpster's testimony regarding PG&E's knowledge in 2008 and 2010 of manufacturing and construction defects on segments of Line 132, fails to explain its decision not to upgrade segments of Line 132 to ILI, and fails to explain the delay of a maintenance project on a segment proximate to the explosion.

Significantly, Mr. Martinelli does not even attempt to address the other "Key Findings" on pp.1-1 and 1-2 of Mr. Harpster's audit (CPSD-168):

- Gas safety funding was heavily constrained in the 2008, 2009 and 2010 budget process. Integrity management and maintenance project budgets were viewed as discretionary funding that could be reduced to meet the overall budget targets set by executive management.

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[135] *See* n. 70, *supra,* CPSD-168 (Harpster), p. 4-5, CPSD-240 (OC-303, Att. 26).

[136] PG&E-1 (Martinelli), p. 12-3:31 through p.12-4:2.

- PG&E placed excessive emphasis on meeting financial goals set by executive management in its budgeting process.
- PG&E's focus in 2008 through 2010 was on minimum compliance with integrity management rules rather than on gas safety excellence. PG&E reduced its IM expenses to the minimum needed to maintain compliance feasibility.
- The low priority that PG&E gave to safety and reliability requirements in the 2008 through 2010 budget process was "well outside of standard industry practice" – even during times of corporate austerity programs. Managing a gas system to the brink of regulatory non-compliance and accepting an elevated risk of system failures, is not industry practice.[137]

Mr. Martinelli's silence on these issues speaks volumes. Despite Mr. Martinelli's extensive experience of over 50 years in the gas and oil industry, and his stated qualifications regarding pipeline risk, budgets, integrity management and "best operational" and "best business" practices (PG&E-1 (Martinelli), p. 12-1:6 through p.12-2:20), Mr. Martinelli simply does not address whether PG&E's budgets and PG&E's pipeline safety and integrity management efforts complied with industry practice.

Putting aside the total lack of substance of Mr. Martinelli's testimony, and Mr. Harpster's findings, Mr. Martinelli's conclusions have no credibility. PG&E has no records concerning whether Segment 180 had ever been pressure-tested and PG&E incorrectly input into its GIS that it was a 30" seamless transmission pipeline.[138] The NTSB also found that "the PG&E GIS still has a large percentage of assumed, unknown, or erroneous information for Line 132" and the "lack of complete and accurate pipeline information in the GIS prevented PG&E's integrity management program from being effective."[139] Moreover, in 1983, PG&E's Mr. Tateosian presented to PG&E's officers

[137] CPSD-168, pp. 1-1, 1-2.

[138] CPSD-9, pp. 60-61.

[139] *Id.* at 110. The NTSB further concluded that PG&E used improper assumptions and non-conservative values for its GIS, and did not consider missing girth weld records or construction damage. PG&E also failed to note in its GIS that Segment 180 "contained six short pups welded together" and inaccurately identified the cause of a longitudinal seam leak on Line 132 discovered in 1988 (*Id.* at 107-09.)

and Board the need to replace PG&E's aging gas pipelines and proposed instituting the GPRP to facilitate the replacement. (CPSD-5, pp. 63-64 and CPSD-162 (Tateosian Deposition), Vol I, p. 168.) The presentation specifically identified Line 132, as well as two other gas transmission lines that serve the San Francisco Bay Area region, as needing to be replaced to be capable of operating at high pressures. (*Id.*, Vol I, pp. 82-85, 152 161-162, 168-174.)

In sum, PG&E's safety and financial priorities were grossly misplaced. PG&E offers no testimony to rebut Mr. Harpster's "key" findings that PG&E's safety and integrity management efforts in 2008-2010 were "well outside of industry practice."[140] The San Bruno explosion cannot be cast as an anomalous event totally outside the control of PG&E. If PG&E had appropriately prioritized and spent the funds the Commission had authorized for safety, either through its GPRP or its integrity management program, it is likely that PG&E would have replaced Segment 180 before the San Bruno explosion. And, as the Commission has noted, these kinds of incidents are preventable.[141]

VI. CONCLUSION

The consequences of this tragedy were especially severe, and entirely preventable. Over many years, PG&E's self-imposed budgetary restraints caused a drastic reduction in the replacement of PG&E's aging transmission pipeline. PG&E switched to less effective and lower cost assessment methods to be used such as ECDA over ILI. PG&E reduced its safety-related workforce. At the same time, PG&E paid bonuses, paid quarterly cash dividends to shareholders, repurchased stock, expended funds to enhance public perception of PG&E, and expended money to affect ballot initiatives. The safety-

[140] CPSD-168, pp. 1-1 though p.1-2.

[141] D.12-12-030, slip op., p. 43. *See also* D.92-12-057, 47 PUC 2d 143, 234: "On this [GPRP] program we must agree with PG&E as to both the importance and necessity of moving forward with the gas pipeline replacement program as quickly as possible. The 1989 Loma Prieta earthquake certainly showed us the importance of PG&E replacing its old pipes throughout the City of San Francisco. In fact, perhaps if the Marina District had its pipelines replaced, some of the problems that erupted in that neighborhood as a result of the earthquake may not have occurred. In any event, we want PG&E to move forward with this program with due diligence."

related cutbacks were a direct result of PG&E continuously emphasizing profits at the expense of safety.

Mistakes that had happened many years ago lay dormant in the ground, undiscovered. At so many points along the way, PG&E could have discovered its mistakes and yet did not. For example, had PG&E employees followed safe utility practices when Segment 180 was constructed by performing a visual inspection of the pipe sections, it would have seen the missing interior welds. Had PG&E properly conducted post-installation pressure testing, the defective sections would have burst and the flaws discovered. Had PG&E properly considered Segment 180 to be subject to manufacturing flaws and prioritized it for assessment using a method that could detect seam issues, the flaws would have been discovered. Had PG&E kept accurate, complete, and verifiable records it would have discovered the existence of the missing records, which would have caused PG&E to assess what was in the ground at Segment 180. Had PG&E responded to the leak reports from pipelines of similar ages and characteristics, it would have prioritized Segment 180 as high risk and tested or replaced the segment.

In 1985, the Commission fully funded PG&E's Gas Pipeline Replacement Program, which had been proposed by PG&E's Vice President of Gas Operations as early as 1983. The GPRP was designed to replace portions of older pipelines, including Line 132. If PG&E had fully utilized the funds the Commission had authorized and followed the advice of its then Vice President of Gas Operations, it could have prevented the catastrophe in San Bruno. Indeed, as late as 2008, if PG&E had merely followed its engineers' advice to use ILI on the higher stressed pipelines, PG&E could have discovered the flawed sections of Segment 180.

Yet, PG&E claims that it did not know about the existence of any flaws in Segment 180 and never discovered them, and this is unacceptable. Furnishing and maintaining safe natural gas transmission equipment and facilities requires that a natural gas transmission system operator <u>know the location and essential features of all such installed equipment and facilities</u>. (D.12-12-030, p.91.) The Commission should hold PG&E accountable and responsible for the multiple ongoing violations of federal and state pipeline safety laws that caused this tragedy. CPSD will address the level of PG&E's culpability, and additional steps that PG&E should take to remedy these violations, in the separate brief on fines and remedies.

Respectfully submitted,

/s/ TRAVIS T. FOSS

Travis T. Foss

Attorney for the Consumer Protection and Safety Division

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102
Phone: (415) 703-1998
Email: ttf@cpuc.ca.gov

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Appendix A: Proposed Findings of Fact

1. On September 9, 2010, at approximately 6:11 p.m., a 30-inch diameter natural gas transmission pipeline owned and operated by PG&E ruptured in San Bruno, California. (CPSD-1, p.7.) Gas escaping from the ruptured pipeline ignited, resulting in the loss of eight lives, injuries to 58 people, destruction of 38 homes, moderate to severe damage to 17 homes, and minor damage to 53 homes. (CPSD-1, p.7.)
2. Energy released by the explosion created a crater about 72 feet long by 26 feet wide. A 28-foot long section of pipe weighing approximately 3,000 pounds was ejected from the crater and landed approximately 100 feet from the crater in the middle of Glenview Drive. (CPSD-1, p.8.)

<u>PG&E's SCADA system</u>

3. PG&E's gas SCADA system provides remote control of 6,438 miles of transmission pipeline. Parts of PG&E's 42,141 miles of gas distribution pipeline are also monitored by SCADA. (CPSD-1, p.71.)
4. Supervisory Control and Data Acquisition (SCADA) is the use of computers and communications networks to gather field data from numerous remote locations, perform numerical analysis, and generate trends and summary reports. These reports are displayed in a structured format to enhance Gas Control Operators ability to monitor, forecast and send commands to field equipment. Some pipelines span long distances and are usually operated from a central location using a SCADA system. SCADA is employed for many different processes, such as management of electric power lines, operation of oil refineries, and operation of automobile assembly plants. SCADA systems make it possible to control a process that is distributed over a large area with a small group of people located in a single room. (CPSD-1, p.70.)
5. About 9,000 sensors and devices are installed along the length of the pipelines to enable the display of flow rates, equipment status, valve position status, pressure set points, and pressure control among other data. The current generation of SCADA used by PG&E is based on Citect software from Schneider Electric. (CPSD-1, p.71.)

6. PG&E's pipelines are controlled and managed from the Primary Gas Control Center (Gas Control) located in San Francisco. An alternate control center is located in Brentwood. Several compressor stations and local control stations, such as the Milpitas Terminal are situated along the pipelines, each with a separate local control system. (CPSD-1, p.72.)
7. The SCADA system is separate from PG&E's Geographical Information System (GIS). The GIS data is displayed on separate computer screens at each of the operator consoles at both the primary and alternate gas control centers. (CPSD-1, p.72.)
8. The SCADA system is programmed to register alarms when the pressure exceeds the MAOP or if the value is less than a preset low level. It does not provide automatic control or intelligent alarming functions such as high rate of change alarms. The operational decisions are made by PG&E Gas Operators in charge of the five consoles at the Gas Control Center. (CPSD-1, p.73.)
9. Monitor valves act as limiting devices to protect against accidental overpressure for the outgoing gas pipelines. Regulator valve set points for outgoing lines can either be manually set at the Milpitas Terminal or remotely set through SCADA by PG&E Gas Control. (CPSD-1, p.74.)

Milpitas Terminal

10. The Milpitas Terminal has four incoming natural gas transmission lines and five outgoing natural gas transmission lines and is equipped with pressure regulation and overpressure protective devices to control incoming and outgoing pressure. The pressure regulating valves are electrically actuated with the SCADA system controls while the monitor valves are pneumatically controlled valves. (CPSD-1, p.73.)
11. Each of the incoming pipelines to the Milpitas Terminal has a regulating valve and a monitor valve to limit the pressure within the terminal. Pressure is further reduced with a second regulating valve and a monitor valve for overpressure protection before it is sent through the outgoing lines. The monitor valves are normally left fully open.

When the downstream pressure starts to increase and exceed a pressure set point, the monitor valve moves to control the downstream pressure. (CPSD-1, p.75.)

12. PG&E's gas control system consists of Programmable Logic Controllers (PLCs), pressure controllers and related instrumentation which communicate with the SCADA computers in San Francisco. Redundant PLCs are provided with a fail-over switch so, if one fails, the other will pick up. The PLCs communicate with the 26 pressure controllers over a local Ethernet network. The PLCs execute a large program that calculates the flows and processes the inputs from many valve position sensors. The PLCs manage communication with the 26 pressure controllers and generate controller error alarms should a controller fail or lose communication. The PLCs also communicate commands issued by the Gas Operators located at Gas Control Center in San Francisco to control valves and to change pressure set points. Communication between the PLC software and the equipment is transmitted over individual wires connected to the PLC Input/Output (I/O) devices (also referred to as Genius Blocks). (CPSD-1, p.78.)
13. At the Milpitas Terminal, all of the pressure instruments have a full scale range of 0 to 800 psig. The pipeline at the Milpitas Terminal is rated up to 720 psig, therefore no pressure greater than 800 psig should ever occur. (CPSD-1, p.79.)
14. PG&E installed an Uninterruptible Power Supply (UPS) at Milpitas Terminal to power the SCADA and control equipment during a power outage and before the emergency generators start delivering backup power. (CPSD-1, p.80.)
15. In 2010, PG&E decided to replace the entire UPS system with a new one. The UPS at the Milpitas Terminal had been in service since the 1980s, with a three-phase system that was no longer needed and for which parts were no longer available. (CPSD-1, p.81.)
16. In February 2010, PG&E asked a Contract Engineer to offer a proposal to investigate and provide recommendations for UPS/battery problems at the Milpitas Terminal. In mid-March 2010, a Contract Work Authorization was approved for the Contract

Engineer to perform the proposed work on the UPS at Milpitas Terminal. (CPSD-1, p.81.)

17. On March 31, 2010, the UPS at the Milpitas Terminal failed, exposing the gas control system to a short interruption of power and potential loss of pressure control. (CPSD-1, p.81.)
18. On April 1-2, 2010, PG&E installed three temporary mini-UPS units at Milpitas Terminal to provide temporary backup power. (CPSD-1, p.81.)
19. A clearance application to install the permanent UPS at the Milpitas Terminal was submitted on August 19, 2010 as Clearance Number MIL-10-09 and approved by PG&E Gas Control on August 27, 2010. (CPSD-1, p.83.)
20. System clearance is required for work that affects gas flow, gas quality, or the ability to monitor the flow of gas. All system clearances require authorization from PG&E's Gas System Operations (GSO). PG&E Work Procedure (WP) 4100-10 issued August 2009 describes the two types of clearances required, depending on the work to be performed: (1) System Clearance and (2) Non-system Clearance. (CPSD-1, p.82.)
21. PG&E's WP 4100-10 requires a designated Clearance Supervisor for all clearances at all times. Clearance application MIL-10-09 marked the Clearance Supervisor as "TBD". Under the Description box is "GC M&C remove old UPS system and install new UPS at Milpitas Terminal", with the Special Instructions box marked "Yes". On the list of Special Instructions, it states: (1) "Technician to contact SF Gas Control prior to work and at the completion of work - Technicians will be on site with GC M&C during work"; and (2) the names and contact numbers of the technicians working on the project. The checkbox on the form which asks if normal function of the facility will be maintained was checked "No". The clearance application requires an explanation whenever this box is checked "No". However, there was no explanation provided on the clearance application as to how the work will affect normal function of the Milpitas Terminal. (CPSD-1, p.83.)
22. Under the Sequence of Operations, the clearance application states "Report On Daily and Report Off". It did not list any specific operations or key communication steps to

be reported to Gas Control. PG&E's Work Procedure requires the Clearance Supervisor to report key communication steps identified in the Sequence of Operations to Gas Control, including operation of any piece of equipment that affects the flow and/or pressure of gas or ability of Gas Control personnel to monitor the flow and/or pressure of gas on SCADA. (CPSD-1, p.83.) One of the steps taken during the UPS work at the Milpitas Terminal was switching the controllers to manual, which locks the valve to its current setting and disables Gas Control's ability to change the valve settings remotely. (Ibid.) This should have been clearly stated on the clearance application as a key communication step within its Sequence of Operations. (Ibid.) Further, PG&E WP 4100-10 requires the Clearance Supervisor to fill in any steps in a system clearance with the time, date, and initials of the person completing the step and file the clearance as completed. (Ibid.) No record was provided by PG&E showing the specific steps taken and the time, date, and initials of the person completing each step in the system clearance. (Ibid.)

23. At 2:46 p.m. on September 9, 2010, the work to replace the temporary UPS was begun at PG&E's Milpitas Terminal. (CPSD-1, p.7.)
24. Between 2:00 p.m. and 4:40 p.m., the team installed mini-UPS units 5, 6, 7 and 8. The three Ethernet Switches that connect the pressure controllers to the PLCs were also placed on mini-UPS at this time. (CPSD-1, p.86.)
25. At 4:46 p.m., the PG&E Gas Technician at the Milpitas Terminal called Gas Operator 2 to let him know SCADA communication with the Milpitas Terminal would be interrupted for a few minutes while they installed Mini-UPS unit 7, the last one of the day. (CPSD-1, p.86.)
26. The workers then discovered that an unidentified active circuit breaker remained in the Uninterruptible Distribution Panel (UDP). The Contract Engineer switched it off and the mimic panel went dead. After some research, he was able to identify power supply PS-C as the one which was connected to the unidentified breaker, and powered the indicators on the mimic panel. The Contract Engineer then installed mini-UPS unit 9 to power PS-C and the mimic panel. (CPSD-1, p.86.)

27. At that time, the system appeared to be operating normally. Alarm records show no activity from 5:09 p.m. to 5:21 p.m. The crew working in Milpitas was getting ready to wrap up, believing they had successfully completed the planned activities for the day. (CPSD-1, p.86.)

28. At 5:22 p.m., the SCADA center alarm console displayed over 60 alarms within a few seconds, including controller error alarms and high differential pressure and backflow alarms from the Milpitas Terminal. These alarms were followed by pressure alarms on several lines leaving the Milpitas Terminal, including Line 132. (CPSD-1, p.11.)

29. At 5:23 p.m., records of SCADA alarms and pressure readings indicate valves opening and pressure increasing. The pressure readings measured at flow meters M31, M32 and M38 on Lines 132, 101 and 109, respectively, increased from 370 psig to 380 psig in about 90 seconds. (CPSD-1, p.87.)

30. The alarms were likely caused by an intermittent short circuit on a piece of wire in the pressure feedback circuit in the Control System equipment enclosure which contains hundreds of wires. The short circuit started a cascade of failures in the gas pressure sensors and pressure controls which lasted for over three hours. The Contract Engineer and Construction Lead began disconnecting and reconnecting circuits to find where the shorted wires loaded on the 24 volt current loops. At about 8:40 p.m., they eliminated the short and all the instruments and controls then resumed normal operation. The shorted connection was at a terminal block near the PS-A and PS-B where wires were possibly jostled during connection of the mini-UPS. (CPSD-1, p.87.)

31. Because of the malfunctions, PG&E's Gas Operators in San Francisco lost the ability to monitor and control the valves at the Milpitas Terminal with the SCADA system displaying inaccurate information. (CPSD-1, p.95.)

32. Loss of information and control over the pipelines caused various regulating valves to fully open. This caused gas pressure in lines leaving the Milpitas Terminal, including Lines 101, 109 and 132, to increase. According to telemetry data obtained during the

investigation, the pressure on Line 132 leaving the Milpitas Terminal reached a high of 396 psig as measured manually. (CPSD-1, p.8.)

33. The Gas Technician at Milpitas began to manually apply valve pressure gauges to verify and report pressure readings and positions of regulating and monitoring valves to Gas Operators at the Gas Control Center. The Gas Technician was instructed to manually close certain valves and lower monitor valve set points. About 40 minutes after pressures began rising in the gas discharge header at the Milpitas Terminal, Line 132 ruptured. (CPSD-1, p.95.)
34. At 6:11 p.m., SCADA data indicated that a rupture had occurred when pressures on Line 132 upstream of the Martin station rapidly decreased from a high of 386 psig. (CPSD-1, p.11.)
35. It was after 10:30 p.m. when the Senior Gas Engineer was able to restore operation to the three PLCs which had malfunctioned. Those units suffered a rare type of malfunction and the manufacturer had to be contacted to advise how to correct it. PG&E did not determine if this malfunction was indicative of failing or defective units and they are still in service. (CPSD-1, p.87.)
36. The highest pressure recorded at an upstream location closest to Segment 180 just prior to the failure was determined to be 386 psig. Based on a review of historical pressure data, this was the highest pressure Segment 180 had experienced within the seven years preceding the rupture. (CPSD-1, p.8.)

<u>Response to the Explosion</u>

37. At 6:12 p.m., SCADA showed the upstream pressure at the Martin Station on Line 132 had decreased from 361.4 psig to 289.9 psig. At 6:15 p.m., SCADA showed a low-low alarm at the Martin Station that indicated a pressure of 144 psig on Line 132. Pursuant to PG&E's procedure, members of Gas Control attempted to troubleshoot the alarms by examining the pressures and conditions at different stations. (CPSD-1, p.108.)
38. At 6:12 p.m. the first police unit arrived at the scene. At 6:13 p.m., the first San Bruno Fire Department unit arrived at the scene. (CPSD-1, p.11.)

39. No outgoing calls were made by PG&E to fire or police officials upon discovery of the incident. (CPSD-1, p.118.)

40. At 6:18 p.m., an off-duty PG&E employee notified the PG&E Dispatch center in Concord, California, of an explosion in the San Bruno area. Over the next few minutes, the dispatch center received additional similar reports. (CPSD-1, p.11.)

41. At 6:18 p.m., PG&E Dispatch was notified of a fire in San Bruno by an off-duty PG&E employee who speculated a jet crash. The dispatcher responded that a supervisor would be notified. (CPSD-1, p.108.)

42. At 6:21 p.m., an off-duty a Gas Service Representative (GSR) called into Dispatch alerting them that there was a fire in San Bruno that appeared to be gas fed. The dispatcher responded that he would send a GSR out to investigate. (CPSD-1, p.108.)

43. At 6:23 p.m., PG&E Dispatch sent a GSR working in Daly City (about 8 miles from San Bruno) to confirm the report. About the same time, PG&E's Senior Distribution Specialist, who saw the fire while driving home from work, reported the fire to the PG&E Dispatch center and proceeded to the scene. (CPSD-1, p.11.)

44. At 6:25 p.m., PG&E's Dispatch called the Peninsula On-Call Supervisor to advise him of the incident. He responded, "I'm probably on my way." (CPSD-1, p.108.)

45. At 6:27 p.m., while Gas Operators 1 and 2 were still in the process of determining the cause of the alarm, PG&E Dispatch called Gas Operator 3 to inquire if they noticed a loss of pressure in San Bruno. PG&E Dispatch advised about large flames and that a GSR and a Supervisor were heading to the scene. Gas Operator 3 responded that they had not received any calls yet. (CPSD-1, p.108.)

46. At 6:28 p.m., the PG&E Gas Controllers discussed the low-low pressure alarms amongst themselves and associated the reports of the fire at San Bruno with the pressure drop at Martin Station. At 6:29 p.m., a PG&E Gas Controller mentioned to a caller that pressure on Line132 had dropped from 396 psig to 56 psig and that "we have a line break in San Bruno… while we have Milpitas going down." (CPSD-1, p.109.)

47. At 6:30 p.m., PG&E Dispatch called the GSR to check on his status. The GSR was still in traffic at the time. The Measurement and Control (M&C) Superintendent of the Bay Area, on-call 24/7 to respond to any gas event within his area, arrived at the scene just after 6:30 p.m., as the result of seeing news of the explosion and fire on television. (CPSD-1, p.109.)

48. At 6:31 p.m., Gas Operator 1 called PG&E Dispatch regarding the previous inquiry about the loss of pressure and speculated that PG&E's gas facilities may be involved in the incident. PG&E Dispatch responded to Gas Control that a radio news report claimed the fire was due to a gasoline station explosion. (CPSD-1, p.109.)

49. At 6:32 p.m., Gas Control left a message for San Francisco Transmission and Regulation Supervisor about the low-low alarm at Martin Station, and the possibility of a leak. (CPSD-1, p.109.)

50. At 6:35 p.m., the M&C Superintendent of the Bay Area called Gas Control to inquire about the fire and told them to call the superintendent of the region. He then proceeded to the scene. At about the same time, Mechanic 1 called Dispatch, saying that PG&E's transmission line ran through the scene of the fire and that the flame was consistent with ignited gas from a transmission line. As Mechanic 1 headed to the Colma yard (Yard), he was called by Mechanic 2, who was then told to head to the Yard. (CPSD-1, p.109.)

51. At 6:36 p.m., the San Francisco T&R Supervisor returned the Gas Control's call and told them to contact the Peninsula Division T&R Supervisor. The gas controllers had been coordinating with the Sr. Gas Coordinator to make the appropriate contacts. (CPSD-1, p.110.)

52. At 6:40 p.m., after confirming the involvement of PG&E's facilities with Dispatch and Gas Control, the Peninsula On-Call Supervisor called M&C Mechanics 1 and 2 and told them to "get to the yard, get their vehicles and head in that direction (of the valves)." (CPSD-1, p.110.)

53. PG&E first responders at the scene of the incident could not identify the cause of the fire. (CPSD-1, p.102.) PG&E had not offered specific training for its first responders

on how to recognize the differences between fires of low-pressure natural gas, high-pressure natural gas, gasoline fuel, or jet fuel. (CPSD-1, p.102.)

54. At 6:41 p.m., the GSR and the Senior Distribution Specialist were at the scene and reported to PG&E Dispatch that the fire department did not yet know the cause of the flames. The GSR made PG&E Dispatch aware that there were gas transmission lines in the area. PG&E Dispatch conveyed to the GSR that a jet might have struck a gasoline station, which in turn caused the gas line to blow with it. The GSR called the Gas Service On-Call Supervisor, and the Gas Service Night Supervisor, to let them know he was on site. The Gas Service Night Supervisor arrived on site later. (CPSD-1, p.110.)
55. At 6:48 p.m., the Senior Distribution Specialist told PG&E Dispatch, "We've got a plane crash" and "we need a couple of gas crews and electric crews." Dispatch acknowledged the request. (CPSD-1, p.110.)
56. Mechanic 1 arrived at the Yard at 6:50 p.m. Mechanic 2 arrived soon after. More internal contacts ensued. At 6:51 p.m., a Gas Control Operator claimed, "it looks like it might [be transmission], if anything, distribution." (CPSD-1, p.110.)
57. At 6:53 p.m., the San Francisco Division T&R Supervisor communicated to Gas Control that he had crews responding, but they might be heading to Martin Station. At 6:54 p.m., San Bruno Police called PG&E Dispatch requesting gas support. PG&E Dispatch replied, "We know, they're out there already." PG&E Dispatch then told the Troublemen Supervisor about a plane that had crashed into a gas station, and asked for gas and electric utilities in the area to be turned off. The Troublemen Supervisor replied that he was notifying the troublemen. (CPSD-1, p.110.)
58. At 6:57 p.m., PG&E's Operations Emergency Center (OEC) was opened. While watching the news on a television at the Yard, Mechanic 1 identified the location of the incident and the nearest valves to be shut to cut off fuel to the fire. (CPSD-1, p.110.)
59. At 7:02 p.m., the San Mateo County Sheriff asked PG&E Dispatch if they were aware of the plane crash; PG&E Dispatch responded, "I'll go ahead and relay that message."

At around the same time, Mechanic 1 called Dispatch and notified them of his plan to shut valves to isolate the rupture. (CPSD-1, p.110.)

60. At 7:06 p.m., Mechanic 1 called the Peninsula Division T&R Supervisor for authorization to shut the valves. The Peninsula Division T&R Supervisor approved. Mechanics 1 and 2 proceeded to the first valve location (containing valve V-39.49). Gas Control was continuously making and receiving calls to gather and relay information. (CPSD-1, p.111.)
61. At around 7:07 p.m., a Gas Control Operator mentioned that the M&C Superintendent of the Bay Area was on site but could not get close enough to the actual location itself because of the extent of the fire and that "until the crew arrives, secures it and comes up with a plan, we're just going to continue to feed it." (CPSD-1, p.111.)
62. At 7:12 p.m., the Troublemen Supervisor told PG&E Dispatch about his plan to order a mandatory call out requiring all Colma Yard employees to report in. (CPSD-1, p.111.)
63. At 7:15 p.m., a Gas Control operator commented, "The fire is so big I guess they can't determine anything right now." At approximately 7:15 p.m., an FAA representative informed PG&E's M&C Superintendent of the Bay Area that there was no plane involved in the incident. (CPSD-1, p.111.)
64. At 7:16 p.m, PG&E Dispatch began to relay the Troublemen Supervisor's plan. Minutes later, the M&C Superintendent of the Bay Area instructed the Senior Distribution Specialist, who was with him at the time, to call Gas Control and tell them the fire was gas related and to declare it a reportable incident. (CPSD-1, p.111.)Mechanics 1 and 2 arrived at the first valve location at 7:20 p.m. At 7:22 p.m., the Senior Distribution Specialist contacted PG&E Dispatch and said that while unconfirmed, it looked like gas was involved. At 7:22 p.m., Gas Control told the Senior Vice President that the incident was likely to be a Line 132 break, although nothing had been confirmed. At 7:25 p.m., PG&E Dispatch informed Gas Control that the M&C Superintendent of the Bay Area was on scene and confirmed that the incident was a reportable gas fire. Gas Control confirmed that Line 132 was the

involved line. At 7:27 p.m., the SF Division T&R Supervisor requested that Gas Control lower the pressure set points as low as possible at the Martin Station to isolate Line 132 from the north. (CPSD-1, p.112.)

65. At 7:29 p.m., Gas Control remotely closed the involved Line132 valves at Martin Station to cut off the feed of gas north of the rupture. By 7:46 p.m., Mechanics 1 and 2 had traveled north of the rupture and closed valves V-40.05 and V-40.05-2 at Healy Station to isolate the rupture. (CPSD-1, p.112.)

66. PG&E took 95 minutes to isolate the location of the rupture. The time for isolation could have been reduced had PG&E installed remote control valves (RCVs), automatic shut-off valves (ASVs), and/or appropriately spaced pressure and flow transmitters throughout its system to allow them to quickly identify and isolate line breaks. (CPSD-1, p.102.)

67. By early morning on September 10, firefighters declared 75% of all active fires to be contained. By the end of the day on September 11, 2010, fire operations continued to extinguish fires and monitor the incident area for hot spots and then transferred incident command to the San Bruno Police Department. (CPSD-1, p.13.)

68. During the 50 hours following the incident, about 600 firefighting (including emergency medical service) personnel and 325 law enforcement personnel responded. Fire crews and police officers conducted evacuations and door-to-door searches of houses throughout the response. In total, about 300 homes were evacuated. Firefighting efforts included air and forestry operations. Firefighters, police officers, and members of mutual aid organizations also formed logistics, planning, communications, finance, and damage assessment groups to orchestrate response efforts and assess residential damage in the area. (CPSD-1, p.13.)

69. PG&E performed post-incident drug testing of three PG&E employees and a PG&E contractor working on the UPS Clearance at the Milpitas Terminal. The drug testing was administered by a third party independent laboratory on September 10, 2011 between 3:36 a.m. and 5:21 a.m., and all four individuals tested negative. The post-

incident alcohol test of the same four individuals was performed on September 10, 2011 between 3:10 a.m. and 5:02 a.m. (CPSD-1, p.99.)

70. PG&E did not perform any drug or alcohol testing of its SCADA staff. (CPSD-9, p.105.)

<u>History of Segment 180</u>

71. The section of pipeline involved in the incident was Segment 180, at Mile Post (MP) 39.28 of PG&E's Line 132, located at the intersection of Earl Avenue and Glenview Drive in San Bruno, California. (CPSD-1, p.7.)

72. The City of San Bruno is in a Class 3 location, and Segment 180 was intended to meet the design and construction requirements in effect at that time for a Class 3 location. Class 3 refers to any location unit that has 46 or more buildings intended for human occupancy. (CPSD-5, p.6; CPSD-9, p.133.)

73. PG&E provided a pressure log from the Milpitas Terminal dated October 16, 1968, showing a recorded pressure of 400 psig for Line 132. This pressure log was used by PG&E as the basis for establishing a Maximum Allowable Operating Pressure (MAOP) of 400 psig for Line 132. (CPSD-1, p.23.)

74. Segment 180 was installed in 1956 as part of a relocation project of approximately 1,851 feet of Line 132 that originally had been constructed in 1948. The relocation of Segment 180 started north of Claremont Drive and extended south of San Bruno Avenue and moved the pipeline from the east side to the west side of Glenview Drive. (CPSD-1, p.15.) This relocation was necessary because of grading associated with land development in the vicinity of the existing pipeline. The construction was performed by PG&E personnel. (CPSD-1, p.15.)

75. Segment 180 originally was documented in PG&E records as being 30-inch diameter seamless steel pipe with a 0.375 inch wall thickness and having a Specified Minimum Yield Strength (SMYS) of 52,000 psi, installed in 1956. PG&E obtained this material specification information for Segment 180 from accounting records rather than engineering records. (CPSD-1, p.16.)

76. PG&E's identification of the entire length of Segment 180 as a seamless pipe was incorrect. (CPSD-1, p.7, p.47.) There was no American Petroleum Institute (API)-qualified domestic manufacturer of 30-inch diameter seamless steel pipe when the line was constructed. (CPSD-1, p.32; CPSD-9, p.61.) Segment 180 was in fact a 30-inch diameter Double Submerged Arc Welded (DSAW) pipe. (CPSD-1, p.7.)
77. PG&E believes the pipe was most likely produced by Consolidated Western in 1948, 1949 or 1953. (CPSD-5, p.21; CPSD-9, p.28.) According to PG&E, between 1947 and 1957, it purchased a total of 320,065 feet of 30-inch pipe from three suppliers. The pipe used for the 1956 project was assembled from multiple material procurement orders. (CPSD-5, p.21.)
78. The rupture of Segment 180 began on a fracture that originated in the partially welded longitudinal seam of one of six short pipe sections, which are known in the industry as "pups." (CPSD-9, p.x of the Exec. Summary.)
79. PG&E records for Segment 180 did not disclose the existence of the pups. The manufacturer of the pups is unknown. (CPSD-1, p.16.)
80. An NTSB metallurgical examination determined that the yield strength values of all six pups were lower than 52,000 psi, which is the designated yield strength for Segment 180. (CPSD-1, p.20; CPSD-9, p.28.)
81. Pup 1, the failed pup on which the facture initiated, was found to have yield strength of only 36,600 psi, and Pup 2 had the lowest yield strength of 32,000 psi. (CPSD-1, p.20.)
82. Longitudinally, Pups 1, 2 and 3 were partially welded on the seam from the outside and the weld did not penetrate through the inside of the pipe. No inside weld, required for a DSAW welded pipe, was found on the inside of the pipe. According to the NTSB metallurgical examination, the fusion welding process left an unwelded region along the entire length of each seam, resulting in a reduced wall thickness. (CPSD-1, p.20; CPSD-16, p.63.)

83. A visual examination of the pipe would have detected the anomalous and defective welds. The unwelded seam defects and manual arc welds ran the entire length of each pup and were detectable by the unaided eye and/or by touch. (CPSD-9, p.96.)

84. The girth welds and longitudinal seams associated with the pups had welding deficiencies related to incomplete fusion, burnthrough, slag inclusion, crack, undercut, excess reinforcement, porosity defects and lack of penetration. (CPSD-1, p.20; CPSD-16, p.6.)

85. The initial crack-like defect extended longitudinally along the entire length inside of the weld (the root) on Pup 1, resulting in a net intact seam thickness of 0.162 inches. With a nominal 0.375 inch wall thickness, the intact wall thickness was approximately 43% at the weld. There was also an angular misalignment on the inside of Pup 1. Given this initial defect, an additional 2.4 inch defect grew to failure. The initial crack-like defect first grew by ductile fracture (Stage 1). Then the crack grew by fatigue (Stage 2). The final stage was the rupture of the pipe, identified as a quasi-cleavage fracture (Stage 3). (CPSD-1, p.50; CPSD-9, p.41.)

86. All of the pups used for Segment 180 were less than 5 feet in length. (CPSD-1, p.22.)

87. PG&E was unable to produce records demonstrating that a strength test was performed on Segment 180 at the conclusion of its construction or at any time during its operation. (CPSD-1, p.22.)

88. The NTSB report found that the calculated burst pressure estimates were 594 and 515 psig for Pup 1; 668 and 574 psig for Pup 2; and 558 and 430 psig for Pup 3, respectively. The analysis was done assuming no crack growth in the weld defect in Pup 1 and no angular misalignment of the Pup 1 longitudinal seam. Based on the pipeline characteristics associated with the pups and the Class 3 location, if a strength test had been performed to 1.4 times MAOP (400 x 1.4 = 560 psig), it is highly probable that the pups in Segment 180 would have failed. (CPSD-1, pp.60-61; CPSD-9, p.49.)

<u>Integrity Management of Segment 180</u>

89. In 2004, PHMSA established the Gas Transmission Integrity Management Rule (49 CFR Part 192, Subpart O), commonly referred to as the "Gas IM Rule." The Gas IM Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect high-consequence areas within the United States. (CPSD-1, p.133.)

90. The integrity management (IM) requirements (49 CFR Part 192) for all pipelines in high consequence areas (HCAs) were effective with the signing into law of the 2002 Pipeline Safety and Improvement Act on December 17, 2002. This law required PHMSA to promulgate regulations concerning transmission pipelines in areas that could affect human safety no later than one year after enactment. PHMSA noticed the new regulations on December 15, 2003, and these regulations required that by December 17, 2004, operators were to have IM plans developed and to have identified all HCAs. (CPSD-1, p.25.)

91. The IM regulations include requirements for threat analysis, risk ranking, assessment methods and re-assessment timetables. (CPSD-1, p.25.)

92. PG&E did not always use conservative default values for pipeline segments in Line 132, when the actual value was missing or unknown. (CPSD-1, p.26; CPSD-9, p.108.)

93. PG&E did not always check the material specifications of pipeline segments in Line 132 for accuracy. (CPSD-1, p.26.)

94. PG&E did not always gather all relevant leak data on Line 132 and integrate it into its Geographic Information System (GIS). (CPSD-1, p.26.)

95. The investigation discovered a number of examples where data from PG&E's GIS were in error, but not discovered by PG&E, including (CPSD-1, p.32; CPSD-9, p.61):

    a. the pipe wall thickness was an assumed value for 21.5 miles (41.75 percent) of Line 132;
    b. the manufacturer of the pipe was unknown ("NA") for 40.6 miles (78.81 percent) of Line 132;
    c. the pipeline depth of ground cover was also unknown for 42.7 miles (82.79 percent) of Line 132;

d. three values were used for the SMYS of grade B pipe: 35,000 psi, 40,000 psi, and 45,000 psi;
e. two segments with unknown SMYS were assigned values of 33,000 psi and 52,000 psi, not 24,000 psi;
f. six consecutive segments, totaling 3,649 feet, specified an erroneous minimum depth of cover of 40 feet;
g. several segments, including Segment 180, specified 30-inch-diameter seamless pipe, although there was no API-qualified domestic manufacturer of such pipe when the line was constructed; and
h. the GIS did not reflect the presence of the six pups in Segment 180.

96. PG&E did not consider known longitudinal seam cracks dating to the 1948 construction and at least one other leak, which occurred in 1988, on a long seam of the 1948 portion of pipe. Closed leak information, such as the October 27, 1988, leak, which had been repaired, was not transferred to the GIS. (CPSD-1, p.26; CPSD-9, p.109.)

97. PG&E did not incorporate and analyze all of the known history of seam leaks or test failures. A number of defects were not incorporated into PG&E's analysis of the condition of the pipe for its 2004 Baseline Assessment Plan (BAP) (CPSD-1, pp.33-35; CPSD-9, p.39):

a. 1948, Line 132: Multiple longitudinal seam cracks found during radiography of girth welds during construction.
b. 1958, Line 300B: Seam leak in DSAW pipe.
c. 1964, Line 132: A leak was found on a "wedding band" weld; the leak was the result of construction defect. The defect was found on segment 200.
d. 1974, Line 300B: Hydrostatic test failure of seam weld with lack of penetration (similar to accident pipe).
e. 1988, Line 132: Longitudinal seam defect in DSAW pipe.
f. 1992, Line 132: Longitudinal seam defect in DSAW weld when a tie-in girth weld was radiographed.
g. 1996, Line 109: Cracking of the seam weld in DSAW pipe.
h. 1996, Line 109: Seam weld with lack of penetration (similar to accident pipe) found during camera inspection.
i. 1996, DFM-3: Defect in forge-welded seam weld.
j. 1999, Line 402: Leak in ERW seam weld.
k. 2002, Line 132: During a 2002 ECDA assessment, miter joints with construction defects were found on Segment 143.4.

l. 2009, Line 132: A leak was found on Segment 189 that was caused by a field girth weld defect. Segment 189 was originally fabricated by Consolidated Western using DSAW and installed in 1948.
m. 2009, Line 132: During the ECDA process, a defective SAW repair weld was found on Segment 186. As indicated in PG&E's pipeline survey sheet, the segment was originally fabricated by Consolidated Western using DSAW and installed in 1948.
n. 2011, Line 300A: Longitudinal seam crack in 2-foot pup of DSAW pipe (found during camera inspection).
o. 2011, Line 153: Longitudinal seam defect in DSAW pipe during radiographic inspection for validation of seam type.

98. PG&E's 2004 Baseline Assessment Plan (BAP) did not identify a construction threat based on "wedding band" joints in its threat algorithms. (CPSD-1, p.34.) PG&E's Likelihood of Failure (LOF) algorithm did not include threats from internal corrosion, stress corrosion cracking, equipment failure, incorrect operations (including human error), and cyclic fatigue. (CPSD-1, p.38.)
99. PG&E dismissed cyclic fatigue as a threat based on a report prepared for PHMSA on the stability of manufacturing and construction defects. PG&E did not incorporate cyclic fatigue or other loading conditions into the segment specific threat assessments and risk ranking algorithm. (CPSD-1, p.38, p.50.)
100. PG&E increased the pressure on many lines, including Line 132, to a little over the line MAOP (referred to as "pressure spiking") so that it could eliminate the need to consider manufacturing and construction threats as unstable as a result of increasing the pressure above the 5 year maximum operating pressure (MOP). (CPSD-1, p.40.)
101. Identifying manufacturing and construction threats as unstable would mean that an assessment method capable of assessing seam, girth weld, and other manufacturing and construction anomalies would need to be used (hydro-testing or In-Line-Inspection). (CPSD-1, p.40.)

102. PG&E's risk-ranking algorithm in Risk Management Protocol (RMP)-06 does not consider DSAW pipeline as having manufacturing defects, including seam and pipe body defects. (CPSD-1, p.41.)

103. A report entitled "Integrity Characteristics of Vintage Pipelines", referenced by PG&E in its first revision of RMP-06, identifies DSAW as having manufacturing defects, including seam and pipe body defects. Table E-6 in the "Vintage Characteristics of Pipelines" report identifies Consolidated Western as a manufacturer of DSAW pipe that has had incidents for both pipe body (1950 and 1954-56) and seam welds during certain years (1947, 1950, 1954-56). (CPSD-1, p.41.)

104. PG&E's implementation of the ECDA process along Line 132 shows that some HCAs were identified and designated as such by PG&E before December 2003. (CPSD-1, p.43.)

105. PG&E operated Line 132 to approximately 400 psig in order to establish a maximum baseline value on two occasions. PG&E operated the line at 402.37 psig on December 11, 2003; PG&E also operated Line 132 at 400.73 psig on December 8, 2008. (CPSD-1, p.44.)

106. In the 2004 BAP, PG&E identified Segment 180 as not having any DSAW manufacturing threat. (CPSD-1, p.46.)

Safety Culture

107. Over the period 1997 to 2010, PG&E spent approximately $40 million less than the Commission authorized, for pipeline transmission operations and maintenance (O&M). (CPSD-1, p.131.) Over the 13 years prior to the San Bruno explosion, PG&E had focused on decreasing O&M expenses. (CPSD-1, p.132; CPSD -168 (Harpster), p. 1-2.)

108. PG&E's GT&S capital expenditures were approximately $116 million lower than the Commission authorized amounts between 1997 and 2000. (CPSD-170 (Harpster), p.8.)

109. PG&E cannot identify any PG&E requests for the recovery of costs for safety improvements to the natural gas transmission pipeline system that were denied by the Commission. (CPSD-1, p.131.)

110. Between 1999 and 2010, PG&E's gas transmission and storage (GT&S) revenues were at least $435 million higher than the amounts needed to earn the authorized return on equity (ROE). (CPSD-1, p.133; CPSD-170 (Harpster), pp. 5, 9). Stated another way, between 1999 and 2010, PG&E's actual revenues for its GT&S exceeded actual revenue requirements by at least $435 million. (CPSD-170 (Harpster), pp.5, 10).

111. In 2009 and 2010, only 13% of the total miles assessed by PG&E had been inspected using ILI tools. (CPSD-168 (Harpster), p. 6-8.) At the same time, approximately 80% of Southern California Gas Company's transmission pipeline located in high-consequence areas has been inspected using ILI tools. (CPSD-1, p.134.)

112. PG&E changed assessment methods for some projects from in-line inspections to ECDA to reduce costs. (CPSD-1, p.134.)

113. PG&E deferred some integrity management expense projects to future years. (CPSD-1, p.134.)

114. PG&E changed the definition of the pipelines covered by integrity management rules in 2010 to reduce the scope of the integrity management program. (CPSD-1, p.135.)

115. PG&E's 2009 Investor Conference presentation included a slide on "Expenditures," which showed decreasing investments in gas transmission infrastructure; from $250 million in 2009 to $200 million in 2010. (CPSD-1, p.135.)

116. On February 16, 2005, the Chairman of the Board, Chief Executive Officer and President presented the idea of "Transformation" to the boards of directors, a company-wide business and cultural transformation campaign to reduce operating costs and instill a change in its corporate culture. As stated in the 2006 Annual Report, the reason for the investment in Transformation was, "If the actual cost

savings are greater than anticipated, such benefits would accrue to shareholders." (CPSD-1, p.135.)

117. PG&E Company's 2009 Annual Report discloses that the utility accrued $38 million, after-tax, of severance costs related to the elimination of approximately 2% of its workforce. (CPSD-1, p.139.) PG&E stated the 2% workforce reduction equated to about 409 employees. (CPSD-1, p.139.)

118. PG&E's actual return on equity for gas transmission and storage operations averaged 14.3% during 1999 to 2010. PG&E's authorized return on equity averaged 11.2% over that period. (CPSD-1, p.140; CPSD-170 (Harpster), p.10.)

119. PG&E Company authorized a cash dividend in 2005 of $476 million; in 2006, $494 million; in 2007, $547 million; in 2008, $589 million; and, in 2009, $624 million. (CPSD-1, p.140.)

120. PG&E's 2010 Annual Report stated that during each of 2008, 2009, and 2010, the utility paid $14 million of dividends on preferred stock. On December 15, 2010, the board declared a cash dividend on its outstanding series of preferred stock totaling $4 million that was paid on February 15, 2011. (CPSD-1, p.141.)

121. On December 15, 2004, PG&E's board authorized a purchase of shares of the company's issued and outstanding common stock with an aggregate purchase price not to exceed $1.8 billion, not later than December 31, 2006. By June 15, 2005, the Company projected that it may be able to repurchase additional shares of common stock through the end of 2006 in an aggregate amount of $500 million and, as such, increased the amount of the common stock repurchase authorization for a total authorization of $2.3 billion. (CPSD-1, p.141.)

122. The 2010 Annual Report notes that $57 million was provided in each year of 2008 and 2009, and $56 million was provided in 2010 as bonus compensation to PG&E Corporation employees and non-employee directors. (CPSD-1, p.142.) PG&E provides a Short-term Incentive Plan, a "Pay-for-Performance" bonus, and a Reward and Recognition Program. (CPSD-1, p.142.)

Appendix B: Proposed Conclusions of Law

1. PG&E failed to follow industry safety standards during the construction of Segment 180 in 1956, creating an unreasonably unsafe system in violation of Public Utilities Code Section 451.
2. By installing pipe sections (pups) in Segment 180 that did not meet any known industry specifications for fabrication of gas transmission pipe, PG&E created an unreasonably unsafe system in violation of Public Utilities Code Section 451.
3. By installing pipeline sections that were not suitable and safe for the conditions under which they were used, PG&E violated the safe industry practices described in Section 810.1 of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.
4. PG&E violated Section 841.412(c) by not conducting a hydrostatic test on Segment 180 post-installation, creating an unsafe system in violation of Section 451.
5. By failing to visually inspect for and discover the defects in Segment 180, PG&E violated Section 811.27(A) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.
6. By installing pipe sections in Segment 180 that were less than 5 feet in length, PG&E violated API 5LX Section VI, creating an unsafe system in violation of Section 451.
7. By installing pipe sections which did not meet the minimum yield strength prescribed by the specification under which the pipe was purchased, PG&E violated Section 805.54 of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

8. By assigning a yield strength value for Segment 180 above 24,000 psi when the yield strength was actually unknown, PG&E violated Section 811.27(G) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

9. By welding the pups in a deficient manner PG&E violated Section 811.27(E) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

10. By welding the pups in a deficient manner such that the girth welds contained incomplete fusion, burnthrough, slag inclusions, cracks, undercuts, excess reinforcement, porosity defects, and lack of penetration, PG&E violated Section 1.7 of API standard 1104 (4^{th} edition, 1956).

11. By not completely welding the inside of the longitudinal seams on pups 1, 2, and 3 of Segment 180 and failing to measure the wall thickness to ensure compliance with the procurement orders which required 0.375-inch wall thickness, PG&E violated Section 811.27(C) of ASME B31.1.8-1955, creating an unsafe system in violation of Section 451.

12. PG&E did not incorporate the pups, which were the weakest element of Segment 180, when it calculated the design pressure at 400 psi. This resulted in an unreasonably high MAOP for Segment 180, creating an unsafe system condition in violation of Section 451.

13. By not having complete and accurate knowledge of the specifications or characteristics of the pup that failed, PG&E could not have accurately determined the weakest element of the pipeline, and consequently did not know the design pressure of the pups. PG&E therefore did not meet the MAOP determination requirements in Section 845.22 of ASME B31.1.8-1955, creating an unsafe system condition in violation of Section 451.

Integrity Management

14. PG&E violated 49 CFR Part 192.107(b)(2), by not assigning a yield strength of 24,000 psi when the yield strength was unknown and untested.

15. PG&E violated 49 CFR Part 192.917(b), by not adequately gathering and integrating required pipeline data, thereby not having an adequate understanding of the threats on Line 132.

16. By failing to check for and verify the accuracy of its pipeline data, PG&E violated Section 5.7 of ASME B31.8S, which is incorporated by reference into 49 CFR Part 192.

17. PG&E's failure to analyze the data on pipeline weld defects resulted in an incomplete understanding of the manufacturing threats to Line 132, in violation of 49 CFR Part 192.917(a) and ASME-B31.8S Section 2.2.

18. As a result of ignoring the category of DSAW as one of the weld types potentially subject to manufacturing defects, PG&E failed to determine the risk of failure from this defect in violation of 49 CFR Part 192.917(e)(3).

19. PG&E violated 49 CFR Part 192.917(e) and (e)(3)(i), by not determining the risk of failure from manufacturing and construction defects of Line 132 after operating pressure increased above the maximum operating pressure experienced during the preceding five years.

20. PG&E violated 49 CFR Part 192.917(e)(3)(i), by not considering manufacturing and construction defects on Line 132 unstable and prioritizing the covered segments as high risk for the baseline assessment or a subsequent reassessment, after operating pressure increased above the maximum operating pressure experienced during the preceding five years.

21. PG&E violated 49 CFR Part 192.917(e)(2), by failing to consider and test for the threat of cyclic fatigue on Segment 180.

22. By not performing pipeline inspections using a method capable of detecting seam issues, PG&E violated Part 192.921(a).

23. PG&E violated 49 CFR Part 192.917(e)(4), by not conducting appropriate testing such as hydrostatic testing or in-line inspections on Line 132, after exceeding

MOP on segments of Line 132 that contained electric resistance welded (ERW) pipe.

24. PG&E did not know the variability or accuracy of assessment results as a consequence of failing to identify where and how unsubstantiated data was being used, in violation of ASME-B31.8S Section 4.4, which is incorporated by reference into 49 CFR Part 192.

25. PG&E violated 49 CFR Part 192.917(c) and ASME-B31.8S Section 5.7, by: 1) failing to conduct risk assessment that considers the identified threats for Line 132; 2) failing to consider the consequences of past events on Line 132; and 3) failing to account for missing or questionable data.

26. PG&E violated 49 CFR Part 192.917(c) and ASME-B31.8S Section 5, by using risk ranking algorithms that did not: 1) properly weigh the threats to Line 132, because PG&E did not include its actual operating experience; 2) properly identify the Potential Impact Radius of a rupture, by using a value of 300 feet where the PIR is less than that; 3) identify the proper Consequence of Failure formula, by not accounting for higher population densities; 4) use conservative values for electrical interference on Line 132, which created an external corrosion threat; 5) include any consideration of one –call tickets, which indicates third party damage threats; 6) include any consideration of historic problems with the type of pipe used on Segment 180.

27. PG&E violated ASME-B31.8S Appendix A, Section 4.2, by failing to use conservative assumptions where PG&E was missing important pipeline data such as pipe material, manufacturing process, and seam type.

28. PG&E violated Public Utilities Code section 451, by engaging in the practice of increasing the pressure on Line 132 every 5 years to set the MAOP for the purpose of eliminating the need to deem manufacturing and construction threats unstable,

thereby avoiding the need to conduct hydrostatic testing or in-line inspections on Line 132.

Milpitas Terminal/SCADA

29. PG&E violated 49 CFR Part 192.13(c), by failing to follow its internal work procedures that are required to be established under Part 192.

30. By failing to follow its work procedures on September 9, 2010, PG&E created an unreasonably dangerous condition in violation of Section 451.

31. PG&E violated 49 CFR Part 192.605(c), by failing to establish adequate written procedures for maintenance and operations activities under abnormal conditions.

32. PG&E created an unreasonably unsafe system in violation of Public Utilities Code Section 451, by poorly maintaining a system at Milpitas that had defective electrical connections, improperly labeled circuits, missing wire identification labels, aging and obsolete equipment, and inaccurate documentation.

33. PG&E created an unreasonably unsafe system in violation of Section 451, by poorly designing a SCADA system that gave too many unnecessary alarm messages to its Operators, thereby increasing the risk of an important alarm being mishandled.

Emergency Response

34. PG&E's failure to create and follow good emergency plans created an unreasonably unsafe system in violation of Public Utilities Code Section 451.

35. The inconsistencies between corporate and divisional level Emergency Plans violate the legal requirement in 49 CFR Part 192.615(a)(3) for a "prompt and effective response" to an emergency notice.

36. By failing to create an assistance agreement for notifying and coordinating with appropriate fire, police, and other public officials of gas pipeline emergencies, PG&E violated 49 CFR Part 192.615(a)(8).

37. By failing to have mutual assistance agreements with local first responders, PG&E violated 49 CFR Part 192.615(c)(4), which requires operators to establish and maintain liaisons with appropriate fire, police, and other public officials to plan how the operator and the officials can engage in mutual assistance to minimize hazards to life of property.

38. PG&E's slow and uncoordinated response to the explosion violates the requirement of 49 CFR Part 192.615(a)(3) for an operator to respond promptly and effectively to an emergency.

39. PG&E did not adequately receive, identify, and classify notices of the emergency, in violation of 49 CFR Part 192.615(a)(1).

40. PG&E did not provide for the proper personnel, equipment, tools and materials at the scene of an emergency, in violation of 49 CFR Part 192.615(a)(4).

41. PG&E's efforts to perform an emergency shutdown of its pipeline were inadequate to minimize hazards to life or property, in violation of 49 CFR Part 192.615(a)(6).

42. Rather than make safe any actual or potential hazards to life or property, PG&E's response made the hazards worse, in violation of 49 CFR Part 192.615(a)(7).

43. PG&E's failure to notify the appropriate first responders of an emergency and coordinate with them violated 49 CFR Part 192.615(a)(8). It is clear that PG&E's emergency plans were ineffective, and were not followed.

44. PG&E violated 49 CFR Part 192.605(c)(1) and (3) by failing to have an emergency manual that properly directed its employees to respond to and correct the cause of Line 132's decrease in pressure, and its malfunction which resulted in hazards to persons and property, and notify the responsible personnel when notice of an abnormal operation is received.

45. PG&E failed to establish and maintain adequate means of communication with the appropriate fire, police and other public officials, in violation of 49 CFR Part 192.615(a)(2).

46. PG&E failed to protect "people first and then property", in violation of 49 CRF Part 192.615(a)(5).

47. PG&E failed to establish and maintain a liaison with fire, police, and others to plan how to engage in mutual assistance to minimize hazards to life and property, in violation of 49 CFR Part 192.615(c)(4).

48. PG&E's inadequate training resulted in a slow and ineffective recognition of the incident, in violation of 49 CFR Part 192.615(a)(3).

49. PG&E failed to train the appropriate operating personnel to assure they are knowledgeable about procedures and verify that the training is effective, in violation of 49 CFR Part 192.615(b)(2).

50. PG&E failed to train its employees and determine whether procedures were effectively followed in emergencies, in violation of 49 CFR Part 192.615(b)(3).

51. PG&E failed to periodically review its emergency response by its personnel to determine the effectiveness of the procedures, in violation of 49 CFR Part 192.605(c)(4).

52. PG&E did not educate the public and governmental organizations as to hazards associated with unintended releases on a gas pipeline and steps that should be taken for public safety in the event of a gas pipeline release, in violation of 49 CFR Part 192.616(d).

53. PG&E violated 49 CFR Part 199.225(a), by failing to perform alcohol tests on the employees involved within 2 hours of the incident, and failing to record the reasons for not administering the test in a timely fashion

54. By failing to test any of the PG&E Gas Control staff, PG&E violated 49 CFR Part 199.225(a) and 49 CFR Part 199.105(b), which requires drug and alcohol testing of all personnel whose performance cannot be completely discounted as a contributing factor.

Safety Culture

55. PG&E created an unreasonably unsafe system in violation of Public Utilities Code Section 451, by continuously cutting its safety-related budgets for its GT&S and, therefore, causing the following: 1) a reduction in the replacement of PG&E's aging transmission pipeline by spending significantly less than the Commission had authorized through its approved funding of its GPRP and ending the transmission replacement part of its GPRP prematurely well before its original goal; 2) not seeking sufficient funds for its O&M, and then spending less than the amount it sought from the Commission, including using less effective and lower cost integrity management methods, such as ECDA over ILI; and 3) reducing its safety-related workforce. During the same time period, PG&E provided bonuses or "incentives" to management and employees, claimed that cost savings would accrue to the shareholders, paid quarterly cash dividends to shareholders from retained earnings, repurchased stock from PG&E Corporation or from a PG&E subsidiary, expended funds to enhance public perception of PG&E, and expended money to affect ballot initiatives.

Appendix C: Table of Violations

Violations relating to PG&E's fabrication and construction of Segment 180 on Line 132.

Violations	Duration
PU Code 451 – failure to safely construct segment 180	1956-09/09/2010
PU Code 451 – installing pipe that did not meet industry standards	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§810.1) by installing sections unsafe for operational conditions	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§81.412(c)) by not conducting a hydrostatic test	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§811.27(A) by failing to visually inspect segments	1956-09/09/2010
PU Code 451 – violation of API 5LX (§VI) by installing pups less than five feet	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§805.54) by installing segments that did not meet the appropriate minimum yield strength	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§811.27(G)) by assigning a yield strength above 24,000psi on a segment of unknown yield strength	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§811.7(E)) by using deficient welds	1956-09/09/2010
PU Code 451 – violation of Section 1.7 of API Standard 1104 (4th Ed 1956) by using deficient welds	1956-09/09/2010

PU Code 451 – violation of ASME B31.1.8-1955 (§81.27(C)) by using incomplete welds and failing to measure wall thickness	1956-09/09/2010
PU Code 451 – failure to incorporate pups in calculating the design pressure and MAOP	1956-09/09/2010
PU Code 451 – violation of ASME B31.1.8-1955 (§845.22) failure to meet MAOP determination requirements due to incomplete knowledge	1956-09/09/2010

Violations relating to PG&E's Integrity Management Program.

Violations	Duration
49 CFR 192.107(b)(2) – failure to assign a yield strength of 24,000 psi when strength was unknown	08/19/1970 – 09/09/2010
49 CFR 192.917(b) – failure to gather and integrate required pipeline data	12/15/2003 – 09/09/2010
49 CFR 192 (incorporating ASME B31.1.8S (§5.7)) – failure to check for & verify accuracy of data	08/19/1970 – 09/09/2010
49 CFR 192.917(a) (incorporating ASME B31.8S (§2.2)) – failure to analysis manufacture threat of weld defect	12/15/2003 – 09/09/2010
49 CFR 192.917(e)(3) – failure to consider DSAW as potentially subject to manufacturing defects	12/15/2003 – 09/09/2010
49 CFR 192.917(e), and 192.917(e)(3)(i) – failure to consider risks after operating above MOP of last five years	12/11/2003 – 09/09/2010
49 CFR 192.917(e)(3)(i) – failure to consider risk unstable and prioritize assessment of risks after operating above MOP of last five years	12/11/2003 – 09/09/2010

49 CFR 192.917(e)(2) – failure to consider and test for cyclic fatigue	12/15/2003 – 09/09/2010
49 CFR 192.921(a) – failure to use and inspection method capable of finding seam issues	12/15/2003 – 09/09/2010
49 CFR 192.917(e)(4) – failure to properly inspect or test after exceeding MOP on ERW pipe	12/11/2003 – 09/09/2010
49 CFR 192 (incorporating ASME B31.8S (§4.4)) – failure to identify where and how unsubstantiated data was used in threat identification	12/15/2003 – 09/09/2010
49 CFR 192.917(c) (incorporating ASME B31.8S (§5.7)) – failure to (1) consider identified threats in risk assessment; (2) consider past events on Line 132; and (3) account for missing/questionable data	12/15/2003 – 09/09/2010
49 CFR 192.917(c) (incorporating ASME B31.8S (§5)) – failure to use risk algorithms that: (1) properly weighed threats know via operating experience; (2) identified the proper potential impact radius; (3) identified the proper Consequences of Failure formula; (4) used conservative values for electrical interference; (5) considered one-call tickets; and (6) considered historic problems with pipe type	12/15/2003 – 09/09/2010
PU Code 451 – violation of ASME B31.8S, Appendix A (§4.2) by failure to use conservative data where data was missing	12/15/2003 – 09/09/2010
PU Code 451 – failure to safely operate its system by its practice of pressure spiking every 5 years to avoid testing or inspecting	12/15/2003 – 09/09/2010

Violations relating to PG&E's SCADA system and the Milpitas Terminal.

Violations	Duration
49 CFR 192.13(c) – failure to follow internal work procedures	09/09/2010
PU Code 451 – failure to follow internal work procedures to the extent it created an unsafe condition	09/09/2010
49 CFR 192.605(c) – failure to establish procedures for abnormal conditions	09/09/2010
PU Code 451 – failure to properly maintain the Milpitas Station	02/2010 – 09/09/2010
PU Code 451 – failure to design a SCADA system without too many unnecessary alarms	2005 – 09/09/2010

Violations relating to PG&E's Emergency Response.

Violations	Duration
PU Code 451 – failure to create and follow adequate emergency plans	08/31/2009 – 09/09/2010
49 CFR 192.615(a)(3) – failure to have a prompt and effective response due to inconsistent emergency plans	08/31/2009 – 09/09/2010
49 CFR 192.615(a)(8) – failure to create a mutual assistance agreement with local first responders	08/31/2009 – 09/09/2010
49 CFR 192.615(c)(4) – failure to plan how to engage in mutual assistance	08/31/2009 – 09/09/2010
49 CFR 192.615(a)(3) – failure to have a prompt and effective response due to a slow and uncoordinated response	09/09/2010
49 CFR 192.615(a)(1) – failure to adequately	09/09/2010

receive, identify and classify emergency notices	
49 CFR 192.615(a)(4) – failure to provide for proper personnel and resources at the emergency scene	09/09/2010
49 CFR 192.615(a)(6) – failure to adequately minimize hazards to life and property	09/09/2010
49 CFR 192.615(a)(7) – failure to make safe any actual or potential hazards to life and property	09/09/2010
49 CFR 192.615(a)(8) – failure to notify local first responders	09/09/2010
49 CFR 192.605(c)(1) and (3) – failure to have emergency manual that required the appropriate actions	08/31/2009 – 09/09/2010
49 CFR 192.615(a)(2) – failure to establish and maintain communications with local first responders	09/09/2010
49 CFR 192.615(a)(5) – failure to protect people first then property	09/09/2010
49 CFR 192.615(c)(4) – failure to establish and maintain a liaison with local first responders	08/31/2009 – 09/09/2010
49 CFR 192.615(a)(3) – failure to properly train personnel to recognize incidents	09/09/2010
49 CFR 192.615(b)(2) – failure to properly train personnel and ensure they are knowledgeable about procedures	09/09/2010
49 CFR 192.615(b)(3) – failure to determine if training is effective	09/09/2010
49 CFR 192.605(c)(4) – failure to periodically review its emergency response	09/09/2010

49 CFR 192.616(d) – failure to properly education the public and local officials	09/09/2010
49 CFR 199.225(a) – failure to perform alcohol tests in a timely manner and failure to record the reasons for lack of compliance	09/09/2010
49 CFR 199.225(a) and 49 CFR 199.105(b) – failure to perform drug and alcohol tests Gas Control staff	09/09/2010

Violations relating to PG&E's Safety Culture.

Violations	Duration
PU Code 451 – failure to place safety over profits by: reducing safety-related budgets; spending less than authorized on safety; prematurely ending its transmission pipeline replacement plan; not seeking sufficient O&M funds; using less effective and cheaper IM tools; reducing safety-related personnel; while at the same time using retained earnings to pay dividends, repurchasing stock, providing bonuses, expending funds on public relations and ballot initiatives.	01/01/1998 – 09/09/2010