Submission of

Pacific Gas and Electric Company

to the

National Transportation Safety Board

Pipeline Accident

San Bruno, California

September 9, 2010

Docket No. DCA-10-MP-008

June 17, 2011

INTRODUCTION

PG&E appreciates the opportunity to submit these comments. They are necessarily limited to the NTSB's factual investigation and root cause analysis. PG&E does not want the narrowness of this focus to suggest that it has not learned a broader lesson from this tragic accident. The events of September 9th have lead PG&E to recognize that its gas transmission business can and must be focused more sharply on public safety. The recently submitted report of the Independent Review Panel (IRP) of the California Public Utilities Commission has similarly identified areas in which our culture and operations can be made substantially better. We very much appreciate the work the IRP has done and the NTSB continues to do and pledge to put the learnings of this accident to good use in remaking our gas transmission business.

I. FACTUAL BACKGROUND

A. Summary of Line 132 Installation and Segment 180 Construction

Line 132 is one of three PG&E gas transmission lines that serve the San Francisco Peninsula. PG&E constructed Line 132 in two primary phases, in 1944 and 1948. The 1948 project installed approximately 18 miles of pipeline and included the section of Line 132 that runs through San Bruno.

1. 1948 Construction

In 1948, PG&E extended Line 132 north to expand gas transmission capacity to keep up with the rapidly increasing demand for gas service in and around the San Francisco Peninsula. The construction, which installed the portion of Line 132 that goes through San Bruno, began in August 1948.

PG&E does not manufacture pipe for any part of its gas transmission system. PG&E ordered the pipe for Line 132 from Consolidated Western Steel Company, which filled the order from its Maywood facility in Southern California. PG&E ordered approximately 100,000 feet of 30" electric fusion welded[1], X52 Grade, .375" wall thickness (wt) steel pipe. PG&E specifications called for 30' or 60' sticks of pipe. The specifications permitted up to 5% of the order to be comprised of "jointers" – two or more smaller sections of pipe joined together by welding - though the individual lengths of pipe making up the jointer could be no shorter than 5 feet long.

PG&E hired Moody Engineering Company to inspect the manufacturing and testing of the Line 132 pipe at Consolidated Western's Maywood, California plant but has not located the final report issued in connection with this inspection. See NTSB Data Response 018-002, Moody Engineering Invoice # 8265. However, PG&E has located a Moody Engineering Inspection Report for Line 153 pipe, whose specifications were dated 3 months later than the Line 132 pipe specifications and were identical to the Line 132 specification. See NTSB Data Response 035-008 (Specifications for Pipe, Purchase

---

[1] This pipe is also referred to as submerged arc welded pipe.

Order 7R-66585 [Line 153]) and NTSB Data Response 018-002, (Specifications for Pipe, Purchase Order 7R-61963 [Line 132]). The Moody Engineering Inspection Report explains Consolidated Western's manufacturing process and the quality assurance provided by Moody's inspection. Given that the two orders were relatively contemporaneous and that both orders were filled by the same manufacturer at the same mill, it is reasonable to conclude that the manufacturing process was identical for both orders.

The pipe was made from flat steel plate of specific composition, rolled in 30' sections to approximately 29 ½ inches outside diameter and welded using the "Union Melt" process. "Union Melt," also known as electric fusion welding, or submerged arc welding, was a relatively new pipe manufacturing technology and represented a significant improvement over the lap welding or flash welding methods commonly used at the time for making large diameter pipes. The Moody Report explained that the Union Melt process called for long seam welding first on the outside of the pipe and then on the inside of the pipe. Each 30' stick was then hydraulically expanded to its intended 30" outside diameter size, a process that also significantly strengthened the pipe. Each stick of pipe was then hydrostatically tested to 1170 psig, and while under pressure a 2 pound hammer was repeatedly dropped on the long seam weld for 10 seconds to ensure the integrity of the weld. After manufacturing, Consolidated Western delivered the pipe to a third party vendor, where it was double wrapped with hot asphalt coating to protect against external corrosion, and then trucked to the Line 132 job site

2. The 1956 Relocation of Line 132 in San Bruno – Segment 180

In 1956, PG&E relocated a portion of Line 132 to accommodate a planned residential development in the Crestmoor neighborhood in San Bruno. The rerouted portion of Line 132 was identified as Segment 180. The project called for the use of approximately 1900 feet of the same type of 30" pipe that had been used on the 1948 construction of Line 132. PG&E did not purchase pipe for the relocation project but completed the job using pipe held in its existing inventory. See NTSB Exhibit 2AF.

B. Milpitas Terminal

Milpitas Terminal provides liquids removal, pressure and flow control, overpressure protection, and metering of natural gas being provided to San Jose and San Francisco Peninsula customers. Gas is provided to the station from four incoming gas transmission pipelines (Lines 300A, 300B, 131 and 107). The station supplies gas to four outgoing gas transmission pipelines and a distribution feeder main. Outgoing Line 100 serves the San Jose area, while Lines 101, 109 and 132 provide gas to the San Francisco Peninsula. Line 109 had a maximum allowable operating pressure (MAOP) of 375 psig, while the other three outgoing pipelines had an MAOP of 400 psig.[2]

[2] The MAOP is a pressure ceiling for normal operations that is designed to provide a substantial safety margin, well below the maximum pressure the pipeline is designed and manufactured to withstand. Notwithstanding the safety margin built into MAOP, pursuant to CPUC directives PG&E has reduced the pressure on each of these lines to 300 psig.

Final pressure control for gas going into the four outgoing transmission pipelines is provided by three parallel runs of regulation (V-17/17R, V-21/21R, V-27/27R), with a fourth run of regulation (V-29) acting as a backup. Pressure regulated gas can also be provided to the outgoing pipelines via a station bypass (V-62).

Milpitas Terminal is located approximately 39 miles south of the rupture site. It is classified as an unmanned facility, meaning local operators are not required to operate, monitor and control the station. Milpitas Terminal is controlled and monitored from PG&E's Gas Control Center in San Francisco via the gas Supervisory Control and Data Acquisition ("SCADA") system, which provides real-time telemetric pipeline information to gas system operators through electronic data points located throughout PG&E's transmission system, including Milpitas Terminal. Milpitas Terminal is also the site of a local gas transmission maintenance headquarters.

1. UPS Construction Work at Milpitas Terminal

On March 31, 2010, during equipment and electrical system testing, the station Uninterruptable Power Supply (UPS) failed. The function of the UPS system at Milpitas is to provide power in the event of a loss of outside utility electrical power to equipment and systems where a short loss of power could impact the station control. Redundant standby generators installed at the site are designed to begin generating electrical power about 30 seconds after a loss of utility power. Thus, the UPS system bridges the time for the control system between the loss of utility power and the standby generator system coming online.

A permanent replacement for the station UPS had a lead-time of 4-5 months when ordered. Therefore, PG&E decided to install several temporary UPS's to provide the same functionality as the primary UPS until the permanent UPS could be installed. On April 1 and 2, 2010, three temporary small commercial UPS units were installed to provide uninterruptible power for the electronic valve controllers. On April 23, 2010, a fourth temporary small UPS unit was installed to power the station Programmable Logic Controller (PLC) system.

On September 9, 2010, a PG&E construction team was tasked with disconnecting the remaining circuits connected to the electric distribution panel (UDP) to allow for replacement of the panel the following day. As part of this activity, any electrical circuits that could affect the ability to control or monitor the station were being switched over to three additional temporary small UPS systems to provide for the station to remain in operation while the UDP was replaced and the new UPS system installed.

2. September 9, 2010 Events at Milpitas

On the afternoon of September 9, 2010, the construction team consisting of a Technical Crew Leader, a Construction Utility Worker, a Gas Control Technician, and an Engineering Contractor began work on the removal of the remaining electrical circuits from the UDP panel and transferring the circuits that could affect station monitoring and control over to small temporary UPS systems. A pre-construction meeting (tailboard) was held to discuss the work to be performed. The work was being done under a System Gas Clearance, which, among other things, informs gas system operators of the nature of the work.

The team tailboarded the work to transfer over three types of circuits to temporary UPS systems and the replacement of the UDP. Gas Control was to be notified prior to each of the three circuit transfers. The team started the work and upon its completion, confirmed all control and communication equipment was functioning properly. At this point, all work had been completed as planned and without incident.

However, at 5:22 p.m., power was lost to all devices being provided 24VDC power from power supplies, PS-A and PS-B. This included pressure transmitters providing pressure control signals to the valve controllers regulating gas pressure into the outgoing pipelines. This loss of control signal caused the regulating valves being controlled by these controllers to open, resulting in an increase in gas pressure for the four outgoing transmission pipelines. Prior to the control system malfunction, the pressure in the outgoing lines was approximately 362 psig. The monitor valves, which provide overpressure protection, began to close as designed when the pressure reached their set point of 386 psig.

In addition to the loss of power to the pressure transmitters, there was a loss of power to other station devices powered by PS-A and PS-B. This resulted in a large portion of the SCADA data points for Milpitas Terminal being inaccurate and unable to be monitored from Gas Control in San Francisco. Gas Control also lost the ability to control the position of various regulator and monitor valves that were powered from PS-A and PS-B. The monitor valve local control system, which is pneumatic, was unaffected by the power problem.

The Gas Control Technician at Milpitas Terminal worked with Gas Control in San Francisco to monitor pipeline pressures as well as manually position and monitor various valves. The remainder of the team, supported by the Gas Control Technician, worked on troubleshooting and fixing the power problem which caused the loss of control for the primary pressure regulation valves. While this troubleshooting was taking place, and after it was confirmed that the monitor valves were limiting gas pressure into the outgoing transmission lines, at 5:52 p.m., PG&E's Gas Control Center reduced the pressure set points of regulator valves at upstream stations to Milpitas Terminal (PLS 7A, PLS 7B and Sheridan Road) to 370 psig. This was done as a further precaution to limit the pressure in the transmission lines exiting Milpitas, and to allow the construction crew at Milpitas Terminal to focus their efforts on resolving the power problem.

At 6:11 p.m., as pressures began to decrease, Line 132 experienced a line rupture at mile point 39.28.

C. PG&E's Post Rupture Actions

1. Concord Dispatch Response

Concord Dispatch is one of PG&E's central dispatch centers, which territories include the Peninsula gas transmission system. Both routine and emergency calls involving PG&E's gas and electric systems come into Concord Dispatch, which in turn assigns the appropriate PG&E responder to the situation. Concord Dispatch first learned of a fire in San Bruno at 6:18 p.m. One minute later, Concord Dispatch contacted a PG&E Gas Service Representative (GSR) in nearby Daly City to ask whether he could see a fire in San Bruno. Over the next few minutes, Concord Dispatch received additional calls from off-duty PG&E personnel reporting the fire in San Bruno. At 6:23 p.m., Concord Dispatch contacted the on-duty GSR and directed him to respond to the site, consistent with PG&E's procedures. By 6:25 p.m., Concord Dispatch had notified the Peninsula Division on-call supervisor of the event. At 6:27 p.m., Concord Dispatch notified PG&E Gas Control of the reports of the explosion. Thereafter, Concord Dispatch continued to contact PG&E emergency response personnel and make appropriate notifications within PG&E's system.

2. Field Personnel Response

By 6:25 p.m., Concord Dispatch had contacted the Peninsula Division on-call supervisor, who thereafter called the Peninsula Division Transmission & Regulation (T&R) Supervisor and the Measurement & Control (M&C) mechanic assigned to the area. During this same time period, PG&E employees who became aware of the accident, including the area M&C mechanic, self dispatched to the scene even before officially being called by PG&E. The responding M&C mechanics isolated the rupture by closing the mainline valve south of the rupture at 7:30 pm and the mainline valve to the north at 7:45 pm.

II. ANALYSIS

A. Metallurgical and Historical Analysis of the Ruptured Portion of Segment 180

The NTSB Metallurgical group examination of the ruptured pipe pieces revealed that the ruptured section contained six "pups" of varying lengths, tensile strengths and weld quality.[3] The common denominator among these six "pups" is that all of the outside long seam weld caps were ground down. This fact leads to the conclusion that the failed section was likely prepared as a jointer intended to go through a pipe expander.

[3] A "pup" is a field slang term for sections of pipe that are less than a standard shipping length of pipe. Sometimes the terms "spools" or "cans" are used synonymously.

As referenced above, the Moody Engineering report explains the process by which jointers could be made by first joining together shorter lengths of pipe to make full sticks and sending the sticks through a pipe expander. The expansion process (cold working operation) increased the yield strength of the pipe by 12,000 to 20,000 psi and resulted in a finished diameter of 30." For a full length piece of pipe, the long seam weld cap would be placed in an alignment groove in the expander. For jointers, however, in order to accommodate the offset alignment of the long seams, the outside weld caps had to be ground down or the expander would likely deform the pipe. The presence of the ground caps on the pups in Segment 180, therefore, suggests that the pups were likely prepared by the manufacturer for use as jointers that would go into the expander.

There is no evidence that PG&E ever rolled flat steel plate into pipe and welded the longitudinal seam in the field or at a local fabrication shop. Nor is there evidence that PG&E had the capability or the equipment to do so. The NTSB interview of a former PG&E employee who worked on the Segment 180 project confirmed that long seam welds were done at the manufacturer. <u>See</u> NTSB Exhibit 2F. These facts lead to the conclusion that the defect in the long seam was a manufacturing, not a construction defect.

B. <u>PG&E's September 9, 2010 Pre-Rupture and Post Rupture Conduct:</u>

1. Milpitas System Pre-Rupture Response to Increasing Pressure

While the pressure increase at Milpitas Terminal on September 9, 2010 was unintended, PG&E's redundant regulation controls operated as designed. After the power failure at Milpitas Terminal, the pneumatically controlled monitors began to close and throttle down, thereby limiting the downstream pressure to approximately 392 psig and restoring pressure to the set point of 386 psig - both pressures below the established MAOP of Line 132. The pressure at the rupture location did not exceed 386 psig. Accordingly, the pressure increase at Milpitas Terminal would not have caused an adequately welded pipe to rupture.

2. Gas Control's Pre-Rupture Response to Increasing Pressure

Gas Control and the on-site Gas Technician worked together to troubleshoot the problems occurring at the terminal after confirming that the monitor valves were controlling pressure around their set points as designed. At 5:52 p.m., when the cause of the increased pressure was not yet identified and resolved, Gas Control utilized its remote control capabilities and lowered 3 regulation set points at stations upstream from Milpitas Terminal, thereby controlling pressure before gas reached Milpitas Terminal. Gas Control's response to the increasing pressures from Milpitas Terminal were timely, appropriate and did not contribute to the rupture.

3. Post Rupture Responses

a. Concord Dispatch Response

PG&E personnel at the Concord Dispatch center took timely and appropriate actions in response to conflicting information they were receiving in regard to the Line 132 rupture. Directing the on-duty GSR to respond to the scene was consistent with PG&E procedure and an appropriate response to an event the nature of which was still unknown. GSRs are designated personnel trained to be the initial responders to gas incidents. Their role is to identify and assess the situation, and take or direct appropriate next steps, including calling for specially-equipped or trained crews to address particular incidents. As noted in the IRP Report, improvements in communication and emergency response procedures are issues that warrant continual evaluation and action.

b. Gas Control Center Response

Gas system operators analyzed incoming SCADA data efficiently and appropriately under difficult circumstances. The accurate SCADA pressure readings related to the rupture were integrated with numerous unusual and erroneous SCADA points resulting from the power failure that were simultaneously coming into Gas Control. The gas system operators evaluated these inconsistent SCADA points in order to avoid making a hasty or uninformed operational decision. Without appropriate analysis, there could have been substantial and unpredictable collateral consequences, e.g., an uncontrolled shutdown of the entire Peninsula system, including critical facilities such as hospitals, which itself would have created a severe public safety risk. Notwithstanding the above, as noted in the IRP Report, improving emergency response and making the right technology and tools available to assist are important issues that warrant continual evaluation and action.

c. Field Personnel Response

The field personnel who closed the valves to isolate the rupture were experienced and well trained. Remotely shutting off the gas supply from the stations that had remote control valves would not have stopped the gas flow more quickly than manually shutting-in the valves nearest the rupture, as occurred on September 9. The NTSB Heat Transfer Study indicates that the loss of life and property damage resulting from the accident occurred in the first minutes after the explosion. As the Fire Captain for the City of San Bruno Fire Department explained at the NTSB hearing in March 2011, his personnel arrived on the scene in approximately 20 minutes and at no time after arriving did the flame from the pipeline impede rescue efforts concerning any of the survivors.

III. <u>PROBABLE CAUSE</u>

Based on the NTSB metallurgical group findings, PG&E has concluded that the root cause of the rupture at mile point 39.28 of Line 132 was a defective longitudinal seam weld wherein the weld metal on the longitudinal seam of the ruptured section only penetrated approximately 55% of the wall thickness of the pipe. There was no tearing of the base metal used to form the pipe. The lack of weld penetration was a manufacturing defect that was present when the pipe was put into service and effectively diminished the overall strength of the long seam weld, which weakened over time until it failed on September 9, 2010.

IV. CONTRIBUTORY CAUSES

PG&E believes that some of the facts and/or events addressed during the NTSB's investigation both require and merit further study in order to determine whether these facts or events may have been contributory causes.

A. 2008 Sewer Replacement Project

The Interstate Natural Gas Association of America (INGAA) and the Blue Ribbon Independent Review Panel (IRP) commissioned by the California Public Utilities Commission note that the City of San Bruno's 2008 Sewer Replacement Project, which used a pneumatic pipe bursting tool in the immediate vicinity of Line 132, may have destabilized the defective long seam weld. PG&E believes that further investigation, including additional metallurgical testing, simulations and geoscience data collection and analysis, is necessary before this theory can be conclusively validated or disproven. For example, investigation may be conducted to evaluate the ground support of the pipeline and to what extent, if any, ground support changed due to the above-referenced work performed in the vicinity of the pipeline. Excavation and analysis of soil undisturbed by the post rupture work performed within the crater would allow for field testing of the soil density and collection of soil samples for laboratory testing of the soil consistency, compaction, and settlement behavior.

B. Ductile Tear in Pup 1

NTSB metallurgy reports reveal the existence of a ductile tear in the longitudinal seam on Pup 1. PG&E believes that determining how and when the ductile tear came into existence, and quantifying the force required to grow the tear to rupture, is critical to the investigation. Early in this process, PG&E requested that NTSB conduct fracture toughness testing on the long-seam weld metal on the pups to determine resistance to tearing. Now that more is known about the material that is available for testing, PG&E believes that J-Integral toughness testing is appropriate and should be conducted on Pup 1 and Pup 4 weld metal. This testing may provide key information regarding the initiation and growth of the ductile tear in Pup 1, which ultimately resulted in the Line 132 rupture.

C. 1988 Leak on Line 132

Records indicate that in 1988, during a regularly-scheduled leak survey, PG&E identified a leak on Line 132, about 9 miles south of the rupture sight at approximately mile point 30.5. Consistent with its 1988 standards, PG&E replaced a 12' section of the pipeline, rather than repairing the leak. The project documents describe the leak as a "longitudinal weld defect." PG&E employees and former employees who recall the replacement project have described the leak as a small pinhole leak.[4] The welder on the replacement project described the leak as a pinhole leak on the girth weld near its intersection with the longitudinal seam. PG&E believes further investigation of the nature of the leak is necessary to determine its relevancy, if any, to the San Bruno accident.

IV. PG&E CONTINUOUS IMPROVEMENT INITIATIVES

Recognizing that the San Bruno accident has called into question fundamental precepts related to gas system operations, PG&E has undertaken a number of improvement initiatives to enhance and underscore PG&E's commitment to safety.

A. Automated Valves

PG&E is expanding the use of automated shut-off valves throughout its system. In the first weeks after the San Bruno accident, PG&E conducted and then provided to the CPUC an initial study that identified potential locations where the installation or upgrade of automated valves may be feasible. That work continues. PG&E has installed automated valves and SCADA capability on multiple regulator and monitor valves that control Line 132 and Line 109 cross-ties on the Peninsula system. PG&E also is installing, replacing or upgrading numerous automated valves in locations throughout PG&E's transmission system. In 2011, PG&E expects to install, replace or upgrade 29 automated valves, and will submit a proposal to the CPUC for determining the number and locations of additional automated valves to be installed. On June 9, 2011, the CPUC adopted a decision requiring all California natural gas transmission pipeline operators to submit an implementation plan for the testing and replacement of pipelines without pressure test records and the retrofitting of pipelines for ILI and use of automated valves. PG&E will submit its plan, including valve automation, by August 26, 2011.

B. Gas Control Initiatives

Following the San Bruno accident, PG&E initiated an in-depth review and evaluation of its gas control operations, work processes and procedures. PG&E took these actions to assure that its gas control operations and operators were guided by clear and defined roles and responsibilities, simplified alarm and information controls, including alarm fatigue management, and clear communication channels and decision-making structures. PG&E retained outside consultants and experts in operational assessments, human factors analysis, alarm management, and operator training. PG&E gas control personnel, along with personnel from maintenance and construction, engineering, transmission planning and telecom, participated in a 5-day alarm management workshop. Together with its consultant, PG&E has developed and is in the process of implementing changes to its alarm management plan, alarm philosophy and standard alarm management protocol. PG&E has also obtained and put to use training

---

4 PG&E contacted employees and former employees involved in the project to compile a list of persons who could assist the NTSB in further investigation.

software for enhanced operator training in abnormal operating conditions and alarm prioritization. PG&E's review of its gas control procedures and practices continues, concurrent with the development of updated gas control policies and procedures in connection with the Control Room Management regulations that become effective in August 2011.

C. Pipeline Integrity and Validation Field Work

PG&E has conducted and continues to undertake substantial field work to confirm and validate pipeline integrity and records. To guide this field work, PG&E developed specific evaluation criteria, testing protocols and public awareness materials.

In the weeks immediately after the San Bruno tragedy, PG&E did numerous excavations and inspections on Lines 101, 109 and 132 in the Peninsula transmission system to verify pipe specifications and confirm the integrity of the pipelines. Digs included radiography of long seam welds, other non-destructive testing, pipe strength verification, and detailed visual inspections.

Based on the NTSB's preliminary findings, PG&E has started hydrotesting or replacing in 2011 approximately 152 miles of pipe whose records are similar to those for the section of Line 132 that failed in San Bruno. PG&E plans to either strength test, verify the existence of prior strength tests, reduce pressure on, or replace all 152 miles of this pipe.

PG&E also has identified approximately 35 miles of pre-1962, 30" DSAW pipe for in-line inspection, including the inspection of 19 miles by video camera. These inspections will occur prior to but in conjunction with the 2011 hydrotesting. PG&E has video inspected approximately five miles of pipe along Lines 132 and 101. The inspections confirmed the presence of DSAW long seams and did not identify any defects similar to those identified in the ruptured pipe by the NTSB, i.e., long seam welds lacking penetration.

D. Comprehensive Records Review and Pipeline Validation

Immediately following the Line 132 rupture, PG&E reviewed its records for the five transmission pipelines that comprise the Peninsula transmission system (Lines 101, 109, 132, 147 and 132A). The work involved a detailed examination of job files and included the review of every type of available and relevant information to confirm pipeline data. For each Peninsula pipeline, the specifications for each pipeline segment and pipeline feature, where possible, were verified and documented.

PG&E also expanded its records review and analysis to transmission pipelines system-wide. In connection with the NTSB's January 3, 2011 safety recommendations as directed by the CPUC, PG&E continues to gather, review, and analyze all relevant pipeline records in order to verify pipe specifications and validate the MAOP of all transmission lines in Class 3 and 4, and Class 1 and 2 HCA locations (a total of 1,805 miles). PG&E has reviewed and analyzed well over a million pages of pipeline records, and this work continues. PG&E is compiling this information into a comprehensive, centralized database.

E. Restoration of Milpitas Station

PG&E identified and completed a number of improvements to the electrical system at Milpitas Terminal prior to returning the station to full operation. These actions included: (1) installation of a maintenance bypass switch to provide improved safety when performing maintenance work on the UPS; (2) replacement of power supplies PS-A, PS-B and PS-C and the separation of power supplies to different UDP circuits to create greater redundancy; (3) verification of electrical power distribution connection diagrams with field conditions and updating where necessary; (4) replacement and rewiring of 24VDC distribution terminal blocks; (5) rewiring of 120VAC distribution terminal blocks; and (6) the installation of new circuits in the UDP panel to allow for greater separation of circuits during the performance of electrical and control work.

F. Interactive Web Pages

PG&E established on its website pages that provide detailed gas system and safety information. In particular, the web pages include an interactive feature through which interested persons can see the location of gas transmission lines in relation to an inputted address. Whether a PG&E customer or not, anyone can find where a transmission line is located relative to any address within the geographic area covered by PG&E's transmission system. In addition, the dedicated web pages provide safety information related to gas transmission and distribution systems, as well as updates regarding the resources PG&E is continuing to make available to help rebuild San Bruno and support its residents.

V. CONCLUSION

PG&E respectfully submits that the results of the investigation of this accident support the following conclusions:

1. The probable cause of the pipeline rupture was a defective long seam weld. which weakened over time until it ruptured on September 9, 2010.

2. The long seam weld was not completed in the field but rather was completed at a mill by a manufacturer.

3. While the events at Milpitas Terminal preceded the line rupture, the increased pressure would not have damaged an otherwise properly welded pipe.

4. The Milpitas Terminal's redundant (or dual) pressure control systems operated as designed to prevent the unintended pressure increase from exceeding the established MAOP of Line 132.

5. The pre-rupture actions of PG&E personnel at Milpitas Terminal and the Gas Control Center were timely and reasonable and were not contributory causes to the accident.

6. PG&E recognizes that the response in any emergency situation might be improved, the post-rupture actions of PG&E personnel at Concord Dispatch, Gas Control and in the field were timely and reasonable and did not exacerbate the damage caused by the rupture or impede emergency response to the accident.

7. PG&E believes that a determination of whether there were other contributory causes to the accident, including the important issues addressed in the June 8, 2011 IRP Report, cannot be made at this time without further investigation.

Respectfully Submitted,

[redacted]

William D. Hayes

PACIFIC GAS and ELECTRIC COMPANY