SAN BRUNO APPROVED Q&A

Updated: 10/19/2010 – 11:00 A.M.

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About the Pipeline in Question

1. Is 132 the pipeline that ruptured?
Yes.

2. Where exactly did the rupture occur?
Mile marker near mile post 39.28.
[NOTE: NTSB report says 39.33. The 39.28 mile post is correct.]

3. How long is the pipeline?
Line 132 is 51.5 miles long.

4. Where does (the line) go?
Line 132 begins in the City of Milpitas (near the intersection of Hwy 237 and I-880) and ends in San Francisco at 23rd St and Illinois St.

5. Is it buried underground, above ground or in a tunnel?
The pipeline is buried underground.

6. Is a 30" steel line typical for gas transmission?
Yes. PG&E gas transmission pipelines range in diameter from 4" to 42"

7. What is the age of the ruptured pipe?
The section of transmission Line 132 where the accident occurred was installed in 1956.

8. How old is the pipeline itself, was it all installed in 1956?
The original line was built in 1948. The section in San Bruno was built in 1956 to accommodate housing development.

9. Have we mapped Line 132 to identify low spots, etc.?
We map and monitor all of our gas pipelines.

10. When did the pipe last have maintenance performed?
A corrosion check was performed in November 2009. A routine inspection was also performed in March 2010. Helicopter patrols were performed in March and June 2010.

11. Is it typical to have such a large gas pipeline going through a residential neighborhood?
It is not unusual for homes to be built in an area subsequent to a pipeline installation. In this case the pipeline was installed in 1956.

12. What happened to the 30-inch-diameter pipeline segments on either side of the segment that failed? Have they been checked? What was found?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question

13. Is it possible for a SmartMeter to cause an explosion in a gas transmission pipeline, such as occurred in San Bruno?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question. However, it was reported on 9/16/2010 that the NTSB does not believe SmartMeters contributed to the San Bruno accident.

14. A PG&E officer said the maximum operating pressure of the pipe was 400 psig. You are saying the MOP is 375 psig. Why the difference?
The Maximum Allowable Operating Pressure (MAOP) of Line 132 is 400 psig. However, it is connected to other pipelines with lower MAOP than Line 132, so we have to rate the Maximum Operating Pressure (MOP) of the line at the lowest MAOP of any line connected to it, which is 375 psig.

15. Has the Maximum Allowable Operating Pressure (MAOP) of Line 132 always been 400 psig?
The MAOP of L132 has not been changed since it was established at 400 psig in the early 1970s.

16. Congresswoman Speier said that the pressure of Line 132 at the time of the accident was 386 psig. Our Q&A states that Line 132 had a Maximum Operating Pressure (MOP) of 375 psig prior to the accident. Which figure is correct?
The maximum allowable operating pressure (MAOP) of line 132 is 400 psig. PG&E often sets a lower maximum operating pressure (MOP), which establishes the normal pressure for the pipeline; in the case of line 132, PG&E's MOP for line 132 is 375 psig. The NTSB's Preliminary Report indicates that a power supply malfunctioned and the electronic signal to the regulating valve for Line 132 to be lost and resulted in the regulating valve moving from partially open to the full open position as designed, increasing the pressure somewhat, but still below the MAOP of 400 psig.

17. When we say "immediately after the accident" we reduced pressure, is that hours after the accident? Days? When did we initially reduce pressure on Line 132?
PG&E took action at 3:00 AM on September 10th to reduce the pressure in line 132 by 10%.

18. What is the current Maximum Operating Pressure (MOP) on line 132 that was involved in the San Bruno accident?
The operating pressure of any pipeline varies. Line 132 had a Maximum Operating Pressure (MOP) of 375 psig (pounds per square inch gauge) prior to the accident. Immediately after the accident, PG&E reduced the Operating Pressure by 10 percent to 337 psig. The Operating Pressure was reduced again on 9/16 by another 10 percent to 300 psig.

19. Congresswoman Speier said there was an electrical power outage on the day of the accident that may have compromised our ability to monitor the pressure on Line 132 from Milpitas. Can we confirm any electrical outages impacting the Milpitas terminal on September 9?
According to the NTSB Preliminary Report, PG&E was working on an uninterruptable power supply (UPS) system at Milpitas Terminal, The report states, “During the course of this work, the power supply from the UPS system to the supervisory control and data acquisition (SCADA) system malfunctioned so that instead of supplying a predetermined output of 24 volts of direct current (VDC), the UPS system supplied approximately 7 VDC or less to the SCADA system. Because of this anomaly, the electronic signal to the regulating valve for Line 132 was lost.”

20. What type of external corrosion coating was originally used on the transmission pipe in San Bruno?
According to the NTSB Preliminary Report, the pipeline was coated with hot applied asphalt and was cathodically protected.

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21. Who manufactured the pipe?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

22. Has PG&E observed any statistical relationship between the age of pipes in its system and the likelihood of a leak or failure?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

23. Did PG&E crews install the pipeline or did a contractor?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

24. Was this made of mild steel? If not, can you describe the pipe's metal alloy composition?
According to the NTSB's Preliminary Report, the pipe was constructed using 30 inch diameter steel pipe (API 5L Grade X42) with a 0.375 inch thick wall.

25. Did this pipe have a rated burst strength? What was it?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

26. Can you describe the safety margin between the maximum operating pressure and the burst pressure rating/or the yield strength? Please explain.
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

27. Was the pipe heat treated after the longitudinal weld was made when originally manufactured?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

28. Were the longitudinal welds facing up when it was installed? Were the longitudinal welds aligned or offset on successive segments?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

29. Was there a single longitudinal weld in the pipe sections that failed or more than one?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

30. The topography in this area has a dip and we understand that contour was accommodated with short sections welded together. Do you know how many girth welds were used within 100 feet of the point of failure of the line?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

31. What type of welding was used on the girth welds?

Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

32. How do you address the integrity of welds in older pipelines?
We are committed to providing safe and reliable gas service to our customers, including providing appropriate training and certification for all PG&E pipeline welders and performing aggressive testing of pipeline welds.

For longitudinal welds, all welds are inspected at the foundry. The pipe must meet the requirements of American Petroleum Institute (API) Standard 5-L. The longitudinal seams are inspected and subjected to a hydrostatic pressure test at 90% of the yield strength. For a typical 30-inch pipe, this would be 945 psi. The pipe is then subjected to non-destructive testing pursuant to Recommended Practice SNT-TC-1A of the American Society of Non-Destructive Testing. Each weld seam is subjected to ultra-sonic testing pursuant to the American Society for Testing and Materials (ASTM) Standard E 213 and the first eight inches of each pipe end is X-rayed pursuant of ASTM Standard E 94. In addition, we perform destructive testing on at least one pipe section from each steel ingot for yield and tensile strength pursuant to API Standard 5-L.

Girth welds are performed by PG&E certified welders on-site. All PG&E pipe welders are specially trained and certified on the necessary knowledge and skills to perform the work in a manner that ensures the safe operation of the pipeline. This training and certification meets the requirements of the American Petroleum Institute (API) Standard 1104 and the Welding and Brazing Qualifications of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. The pipeline welder certification requires that selected welds are subjected to visual inspection and destructive testing to ensure the welds meet the specifications of the work being performed. PG&E relies on a bending test and strength test to determine the integrity of a pipeline weld. If a test weld breaks or shows incomplete fusion, undercut, overlap, incomplete penetration, air contamination, included slag or the weld shows tears or cracking as a result of either the bending or strength tests, the employee is not certified to weld. After the welder is certified, he or she is required to recertify every six months.

The girth welds themselves are subject to three types of inspections. First, all girth are visually inspected to verify the weld is performed according to design and meets all API and PG&E standards. The weld must be free from inadequate stringer-bead penetration or burn-through, excessive undercutting, or the presence of any cracks or contamination. Second, a percentage of each day's welds must pass a radiographic examination of the entire weld circumference. For example, along highways and railroad rights of way, 100% of the girth welds are X-rayed. Finally, all girth welds on pipelines that will operate at 20% of the pipe's yield strength must be X-rayed.

33. I understand that PG&E has said the pressure in the pipe was 375 psi and the maximum operating pressure rating was 400 psi. I'm told by metallurgists that pipeline pressures are seldom constant, but can cycle by as much as 20 to 40 psi in normal use, because of compressor operation. Is that correct?

As a general statement, pipeline compressor operation is a factor that can contribute to variations in pressure in pipeline operation. However, not all pipelines are served from a compressor and not all pipelines are subject to such pressure fluctuations.

34. Can that cycling cause metal fatigue over a half century of use?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

35. Had PG&E observed any internal or external corrosion on the failed pipe segment?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

36. Engineering experts at UC Berkeley say the facture surfaces of the pipe show a lack of tensile necking, indicating embrittlement and weakening. Do you have any comment?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.
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37. Did PG&E ever see evidence before the accident that hydrogen sulfide gas or other contaminants, such as water, were in the pipe?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

38. What specification did PG&E have for hydrogen sulfide gas in the line and how did PG&E monitor or enforce that?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

39. The pipe ruptured at a low point in the street. What steps did PG&E take to insure that water or other contaminants did not accumulate internally in this dip?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

40. Did PG&E have a drip system to collect water or other contaminants upstream of the point where the accident occurred?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

41. Was that drip regularly cleaned out?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

42. Does the starting point of the pipe in Milpitas connect to a pipeline company other than PG&E? Who?
No, all pipelines that enter and exit Milpitas Terminal are owned by PG&E.

43. Does the termination point of the pipe in San Francisco feed a PG&E distribution network or some other network?
Yes, the termination point of the 3 transmission pipelines to San Francisco serves several distribution networks in the City and County of San Francisco.

44. Do you know what region of the country or continent does the gas transported in that pipe originate from?
The gas in the subject pipeline is transported from one of or a combination of four sources; Western Canada, the Southwestern US, the Rocky Mountains as well as within California.

45. Was there ever any evidence prior to the accident of hydrocarbon fed bacteria in the soil around the pipe?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

46. Did PG&E ever raise concerns with the city of San Bruno that sewage known to be leaking in the area of the gas line could contribute to corrosive conditions?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

47. Could we please obtain a copy of PG&E's Internal Corrosion Direct Assessment plan?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

48. Did PG&E excavate around the gas line to inspect after the 2007 and 2008 sewer bursting work done by the city? If not, what inspection method was used?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

49. What was the vertical separation between the sewage line and the gas line where they crossed?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

50. Is there a water pipe that crosses or parallels the gas line near the accident site? How close is that water pipe?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

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2011 Gas Transmission & Storage Rate Case Document

51. We have a document that says you deemed this 2.9 mile segment of the pipeline north of the accident to be at an unacceptably high risk. Why didn't you fix it immediately?
The document says that our long range planning tool deems the pipeline segment's relative risk to be too high if the pipeline is not replaced as scheduled, in 2013, and if the risk factors leading to the projection have not changed substantially. We do not delay or defer work that is necessary for public safety. Any issue identified as a threat to public safety is always addressed right away. The document you refer to is based on one of our planning tools, not a tool designed to address or be used for immediate safety concerns.

52. Is this the line that exploded?
Line 132 ruptured in San Bruno. However, the segment of the line identified in the filing is not the segment that ruptured.

53. Where is the segment located?
It is located 2.8 miles north of the San Bruno accident in South San Francisco.

54. Has it been checked again?
The segment was checked for leaks on September 10 and no leaks were found.

55. Your filing says "the risk of failure at this location is unacceptably high." If that's true, why are you waiting until 2012 to replace it?
PG&E is committed to performing the work necessary to assure the safety of its gas transmission system. Accordingly, PG&E is constantly prioritizing its projects using the most recent up to date information available.

In this particular case, PG&E identified this line section in 2006 as being a project for 2009 its workpapers for the 2008 gas transmission rate case, and sought five million dollars to fund the work. In early 2008, the pipeline engineer responsible for this area reanalyzed all available information on this segment. The information he reviewed included all of the data from the External Corrosion Direct Assessment (ECDA) conducted on segments of Line 132. In addition to reviewing the available data, the responsible engineer personally conducted a field investigation of the segment. This involved driving the entire section, observing that a portion of it was contained within a well-marked right of way and a portion under a public cul-de-sac. After this, in consultation with other pipeline integrity engineers, the responsible pipeline engineer determined that third party dig-in risk did not warrant immediate replacement of the segment (a third-party dig had caused a leak at MP 43 in November 2001) and the segment had not experienced any leaks due to corrosion. Based upon his review of information from the prior ECDA, his own observations, and his engineering judgment, and knowing that PG&E was going to be performing another ECDA later that year or the next year, he determined that the work did not need to be done as previously scheduled.

The 2006 work paper forecast $5 million for the replacement of this segment of Line 132. When pipeline projects were reprioritized, that forecast money was spent on other priority projects instead. In fact, in 2008 and 2009, PG&E spent a total of $380 million on gas transmission capital projects, $12 million more than forecast.

The "unacceptably high risk" referred to is if it is not replaced in 2013 in accordance with our projection, and if the risk factors leading to the projection have not changed substantially.

56. What method do we use to internally inspect and clear Line 132?

There are three federally approved methods to complete a transmission pipeline integrity management assessment, In-Line Inspection, Pressure Testing and Direct Assessment. To date, PG&E has used In-Line Inspection and Direct Assessment techniques as appropriate on L132. PG&E performed assessments on L132 in 2004, 2007 and in 2009. Please see PG&E's response to the question below regarding the methods used to internally inspect Line 132.

57. Was Line 132 hydro-tested?
No

58. When was Line 132 last internally inspected?

An Internal Corrosion Direct Assessment was performed in 2007 on L132. Work was performed at two locations; a location near San Bruno Mountain and a location by Coyote Creek near Milpitas. No internal corrosion was found.

59. What method was used?

At the location near San Bruno Mountain, we exposed a 40-foot section of pipe at a low point and performed ultrasonic testing to determine if there was any pipe metal loss that could indicate internal corrosion. We performed a second ultrasonic test at this same location near San Bruno Mountain using a focused beam multi-frequency device, no internal corrosion was found at this location. The other location by Coyote Creek near Milpitas was excavated, the pipe was cut and an in-line inspection was performed using a tethered instrument pig. No corrosion was found.

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Auto-Shut Off Valve

60. Do we have emergency equipment that allows automatic shutdown of pipes? For example, check valves, overpressure relief valves, etc.?
PG&E has hundreds of automatic over pressure protection control valves that protect pipelines from exceeding their maximum operating pressure. PG&E also has some lines with rupture control valves for specific needs and the 24 hour control center has the ability to shut down some pipeline systems via remote control.

61. What is the difference between manual valves, automatic valves and remote controlled valves?
Manual valves can only be operated by a trained, federally-qualified individual at the valve location. Automatic valves are fully automated valves that will operate without human intervention when specific operating conditions on the pipeline arise. Remote-controlled valves can be remotely operated from a control center. It is possible to have automated, remote-controlled valves.

62. How is a valve turned off? What is the process?
The process is different for each type of valve: remotely controlled, automatic, manual.
- Remotely controlled valves: these are valves operated by remote control from our 24-hour manned Gas Control Center
- Automatic valves: these are valves with control programs triggered to operate via a specified change in pipeline conditions and do not require remote control or personnel on site
- Manual valves: these are valves hand-operated by wheel and gear assembly or by wrench with an indicator to show whether it is open or closed

63. Was there an automatic shut off valve near the site of the accident?
There is no automatic shut off valve near the site of the recent San Bruno accident.

64. Was there an automatic shutoff on this segment?
No.

65. Should there have been an automatic shut off valve in a highly populated area?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

66. Do we have any plans of going to automatic detection on our lines? Is that even possible?
The PG&E gas system is monitored by our Gas Control Center on a 24 hour, 7 day a week basis to detect and respond to abnormal operating conditions. PG&E is examining the use of different kinds of technologies on its pipelines.

67. How far apart are they typically spaced?

The spacing of shut-off valves on transmission pipelines varies according to population density. In accordance with federal regulations, PG&E has shut-off valves no more than twenty miles apart in rural areas on transmission lines, and has shut-off valves no more than five miles apart in densely populated urban areas. In general PG&E has more shut off valves than required by federal regulations.

68. How many are manual and how many are automatic on line 132?
On Line 132 there are twenty manual valves. PG&E has remotely operated valves in the terminal stations that feed Line 132.

69. What determines whether a valve is manual or automatic?
It depends upon safety regulations and operational needs. Prior to installing or replacing a valve, we consider a variety of factors, such as the design of the pipeline system in which it is to be installed, pipeline safety code requirements and the type of control required or desired from the valve installation. A great majority of the valves on PG&E's gas transmission system are manual valves because automation is not required and not necessary for the operating characteristics of the pipeline system.

70. Is it expensive and or difficult to replace a manual valve with an automatic one?
The cost to replace a manual valve operator on a transmission system with an automatic valve operator (called a valve actuator) and the controls that are required to operate the actuator will vary depending on the specific conditions at the installation location, with an estimated average cost of $500,000 and a range of $150,000 to $1 million for a 24-inch valve on the San Francisco peninsula. It is possible to replace the valve controls and/or the valves, but the projects can be complicated and each one would take from six to twenty-four months depending upon the complexity of the project.

71. Is the company replacing manual valves with automatic ones?
PG&E does replace manual valves with automatic valves when appropriate for operational purposes, but it is not common and there is no program to replace manual valves with automatic valves. The change to an automatic valve would be driven by changing operating conditions or a change in the pipeline system in which the valve is installed. Our valve installations and control systems designs are consistent with industry practice and federal regulations.

72. If so, can you provide any information on the status of that process?
Not applicable.

73. Where are the valves located that were turned off on Thursday night?
The valves on the transmission pipeline were located at mile point numbers 40.05 and 38.49, approximately 3/4 mile upstream and downstream of the accident location. The shut off valves on this line are 1.5 miles apart and the rupture location was approximately in the middle of the two valves.

74. San Bruno Fire says workers also had to turn off distribution line valves. How many needed to be turned off? How long did that take?

The smaller, lower-pressure distribution lines that make up the neighborhood's local supply system were isolated by closing 3 valves and squeezing the pipe closed (an approved method of shutting plastic distribution pipe) in two other locations. According to the NTSB Preliminary Report, the distribution line valves were turned off at about 11:30 p.m. after PG&E workers were able to isolate the system.

75. Are we retrofitting older pipes for shut off valves for transmission lines?
PG&E is evaluating its existing system design and will report the results of that evaluation back to the CPUC as directed in their September 13, 2010 letter.

76. When will we make a recommendation to the CPUC on Automatic Shutoff Valves?
In the CPUC's Resolution L-403 issued on September 24, the CPUC asked PG&E to "conduct a review of all natural gas transmission line valve locations in order to determine locations where it would be prudent to replace manually operated valves with remotely operated or automated valves and shall report its results to the Commission within thirty (30) days of the issuance date of this Resolution." PG&E is currently working on this review, and will respond to the CPUC by no later than October 24.

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Pipeline Replacement Program

77. Describe the pipeline replacement program.
The GPRP (Gas Pipeline Replacement Project) is a multi-year project to upgrade our gas distribution facilities. This program also included gas transmission facilities in the early phases of the program. Since the inception of the GPRP through the end of 2009, PG&E has replaced over 2100 miles of pipeline system-wide, and has spent approximately $1.5 billion.

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Impact of Accident

78. How many gas customers lost service as a result of this accident?
Approximately 300.

79. Was there widespread outages in and around San Bruno? How many customers lost service?

The outage was confined to the affected neighborhood, and approximately 300 customers were taken out of service.

80. How did the transmission and distribution systems operate in the immediate aftermath?
The distribution system located within the affected neighborhood was disconnected from the rest of the distribution system the night of the incident. The disconnected system was returned to service by reconnecting it to the distribution system, performing a leak survey and then returning service to the customers. The rest of the distribution system continued normal operation.

The affected section of Line 132 was isolated by shutting off the mainline valves and removed from service. Flow in Line 132 north of the incident was maintained through an interconnection with Line 109 and continued operation. The transmission system (Lines 101/109/132) had the pressure reduced by 20% to a maximum operating pressure of 300 psi.

81. How are the systems operating now?
The distribution system is operating normally and providing gas service to all the remaining customers in the affected area

82. Do you continue to loop around the immediate site of the explosion?
Yes, the affected section remains isolated and the flow of gas is being looped around it.

83. How long will you continue to loop around the immediate site of the explosion?
Working with the CPUC, the decision of replacement of the affected segment of Line 132 has yet to be determined.

84. Are you still operating at the reduced pressure (300 psi) vs. your normal 375 psi?
The transmission pipeline system on the Peninsula including Line 132 is currently running at a reduced maximum operating pressure of 300 psig .

85. How long is this likely to go on?
PG&E will be working closely with the CPUC on how to best address the current situation and whether, or how much, to increase the current operating pressure

86. As a result, will you (or could you) operate the Backbone system with lower pressures in high consequence areas (HCA) than you run on segments in more low-risk areas?
Ensuring the delivery of reliable gas service to our customers is a priority for PG&E. We will be working closely with the CPUC on how to best address the current situation and whether, or how much, to increase the current operating pressure.

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General Safety

87. What factors go into PG&E's consideration to dispatch a crew? When are crews dispatched?
We take seriously all reports of gas odor or gas leaks and work to resolve these quickly – the most serious within one hour and all within the same day of receiving a call.

There are a number of factors that may involve dispatching a Maintenance & Construction (M&C) crew for response. Some of those factors may include:

- A report of a gas emergency from a customer calling our Contact Center.
- A public safety agency (e.g., police and fire) contacting PG&E dispatch directly through PG&E's dedicated emergency response line.

In either case, we immediately dispatch a gas service representative (GSR) as a first responder. Once the GSR is onsite, we will determine if a crew is needed. For example, if there is a leak detected outside, if there is a structure fire, or if there is a dig-in by a 3rd party. For a reported dig-in, crews are dispatched at the same time as a GSR.

88. Can this kind of accident happen again?
We will be working with local, state and federal agencies to determine the cause of the event and taking appropriate actions based on the findings of those investigations.

89. What are "suspect leak trends"?
"Suspect leak trends" is an internal phrase used to describe our methodology for assessing leak data. It is not related to actual leaks being suspected. We look at historical leak averages for each division and if there are changing trends, we focus our assessment there first. Ultimately, we look at the whole system.

90. Why aren't you providing more details about your gas system and safety practices?
PG&E has provided and continues to provide a substantial amount of detailed information about its gas system and safety practices. However, as a result of the NTSB investigation we are not permitted to discuss certain details related to this matter.

91. With whom did PG&E share our emergency response plan prior to the Sept. 9th tragedy?
PG&E does not widely distribute the plan as it includes confidential operating information. However, PG&E does routinely share important plan elements with public safety agencies during joint exercises.

92. Who has copies of PG&E's emergency response plan now?
PG&E does not widely distribute the plan as it includes confidential operating information. However, PG&E does routinely share important plan elements with public safety agencies during joint exercises.

93. Did PG&E share the plan with emergency responders prior to the San Bruno accident?
PG&E maintains an annual public safety agency training program designed for emergency responders to learn about both gas and electricity first response and safety issues. These exercises were last performed on the Peninsula (including San Bruno) in June 2006.

94. Did the CPUC have a copy of the emergency response plan prior to the accident?
The last time the PUC requested a copy of the plan was during the first quarter of 2010, during their annual audit process.

95. Will you send me a copy of the emergency response plan?
PG&E does not widely distribute the plan as it includes confidential operating information. However, PG&E does routinely share important plan elements with public safety agencies during joint exercises.

Examples of confidential information included in the plans are:

- Critical facility and redundant resources location information,
- Employee names,
- Internal emergency response phone numbers, and
- Home phone numbers.

96. Isn't that area one where there are typically landslides and other natural earth movement, and was that taken into account when the pipeline was first sited there?
PG&E's gas transmission and distribution system is generally engineered and designed considering soil conditions and potential earth movements.

97. Are there any seismic concerns or issues with this particular location? Any faults, slippage, landslide concerns? Has PG&E done geological studies and risk assessments of this area for pipelines?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question. PG&E's geosciences department continuously studies our service territory for seismic activity.

98. Does PG&E have a seismic GIS layer that is used as a basis for categorizing pipes as having the "potential for ground movement?"
PG&E does have ground movement information in GIS and that information is used to determine if there is a "potential for ground movement".

99. Is there a document available that explains our pipeline maintenance schedule?
There is no one document that explains all of the maintenance PG&E performs on our transmission and distribution pipelines, although federal and state regulations establish minimum maintenance tasks and schedules for pipeline operators. PG&E standards further specify maintenance tasks and schedules, establishing the framework for a comprehensive pipeline safety program.

These codes specify design, construction, maintenance and operation requirements for natural gas pipelines such as:

- PG&E provides immediate 24 hour response to gas odor calls
- All gas pipelines are leak surveyed at regular intervals
- PG&E conducts periodic patrols of our pipelines
- Pipeline assessments are conducted periodically on critical pipelines
- Pipelines are cathodically protected to prevent external corrosion
- PG&E strongly supports Underground Service Alert, #811, the one call system used to locate underground pipelines and facilities before excavation by others
- PG&E personnel stand by when known excavation is occurring in close proximity to pipelines
- PG&E's pipeline system is continuously monitored on a 24 hour basis
- Gas is odorized to allow easy leak detection by the public

100. Have you surveyed the transmission lines in San Bruno?
Two days after the accident in San Bruno, we began surveying the three transmission lines that feed the San Francisco Peninsula. As an added safety measure, we have also reduced the operating pressure by 20 percent on these three lines. The leak surveys were completed on September 10.

101. What designates a "high risk" pipeline? What does PG&E need to do to address these pipelines?
PG&E does not operate "high risk" pipelines. We operate our pipeline system with an appropriate margin of safety and a constant monitoring program. PG&E does operate pipelines which run through populated areas, and some are designated as "High Consequence Areas" (HCAs) by federal regulation.

HCAs are areas of higher population density with 20 or more dwellings, public gathering places or structures difficult to evacuate, such as nursing homes, hospitals, day cares, etc.). Being in a High Consequence Area does NOT mean that the transmission pipeline is less safe, or creates greater risk, or that there is a higher likelihood of failure. What it means is that more people are in close proximity to the line.

If this is a reference to PG&E's internal "Top 100" list, this is a list of gas transmission pipeline segments that have been identified for engineering analysis and future work as part of PG&E's ongoing preventive maintenance process. This dynamic list is regularly updated as work is completed and new items are added. As part of this analysis we take into account (among other things) population density and environmental impact. As with an HCA designation, being on the list for future work does not mean the pipeline is unsafe or that there is a high likelihood of failure.

102. What is the schedule of replacement for older pipes?
PG&E's transmission pipelines are now included in the transmission pipeline integrity management program, not the Gas Pipeline Replacement Program (GPRP). PG&E's transmission pipeline replacement decisions are based on a variety of pipeline factors beyond just age, including, among other things, pipe material and design, soil resistivity,

pipe coating, pressure, potential for third-party damage, seismicity or the potential for ground movement, water crossings and number of customers served.

103. If a new segment is added today, how do the standards differ from earlier methods used to install the transmission system through San Jose?
PG&E installs new pipe segments in accordance with Federal and State codes, and PG&E design standards. These codes and standards, along with national industry standards, are routinely reviewed and improved to assure the highest quality pipeline construction standards. PG&E revises its standards as new regulatory requirements are initiated.

Further, PG&E continually assesses the integrity of its transmission system and inspects the system in accordance with Federal code and PG&E procedures, which are designed to address pipe segments installed today as well as segments installed in earlier decades.

104. Can I see copies of safety inspection reports for the past 5 years on the following: PG&E's two parallel lines Nos. 34 running through the western edge of Bakersfield, the lines No. 10 and No. 6 running through the heart of Bakersfield?
PG&E makes copies of its extensive inspection, maintenance and operations records available to the California Public Utilities Commission and other governmental agencies but for security reasons does not publicly release copies of those records. However, PG&E provides an overview of its inspection, maintenance and operations practices in response to your question below.

105. Can I see reports on what portions of any of these lines have been replaced or upgraded from 1989 to present?
Since 2005, PG&E has completed eight transmission pipeline projects in the greater Bakersfield area to accommodate population growth in the area and is in the process of completing two additional projects. All pipelines within the PG&E system, including Kern County and the city of Bakersfield, are in compliance with Part 192 of the Code of Federal Regulations (CFR). Many currently exceed the minimum guidelines. PG&E's transmission pipelines are assessed as part of its transmission pipeline integrity management program and are leak surveyed on at least an annual basis.

106. If copies can't be obtained quickly, could you let me know verbally what safety inspections have been done and the results?
PG&E follows maintenance and operations practices required by Part 192 of the Code of Federal Regulations (CFR) and California Public Utilities Commission General Order 112-E. In addition to these regulatory requirements, PG&E has its own operating and maintenance standards to ensure compliance with the regulations. PG&E routinely conducts leak surveys of all our natural gas transmission and distribution lines. In 2008, we accelerated the distribution leak survey program to complete it in three years instead of the usual maximum five.

PG&E's transmission pipeline replacement decisions are based on a variety of pipeline factors, including, among other things, pipe material and design, soil resistivity, pipe coating, pressure, potential for third-party damage, seismicity or the potential for ground movement, water crossings and number of customers served.

There are three federally approved methods to complete a transmission pipeline integrity management baseline assessment: In-Line Inspections, Pressure Testing and Direct Assessment. (External Corrosion Direct Assessment (ECDA) is the primary method used for Direct Assessment.)

In-line inspection involves a tool (commonly known as a "pig") inserted into the pipeline, which identifies areas of concern such as potential metal loss (corrosion) or geometric abnormalities in the pipeline. Excavations are performed in areas of concern as required by federal regulations.

External Corrosion Direct Assessment is a four step process:

- Preassessment: provides guidance for selection of the pipeline segment and which indirect methods to be used.
- Indirect Examination: indirect above-ground electrical surveys are performed to detect coating defects and the level of cathodic protection.
- Direct Examination: Based on the indirect examination, points of potential interest are excavated to expose the pipe surface for metal loss measurements, and estimated corrosion growth rates.
- Post Assessment and Continuing Evaluation: sets re-inspection intervals, provides a validation check, and provides performance measures

Pressure testing involves filling the pipeline with a test medium (i.e. water, gas, air) and testing to a certain pressure for specified duration.

107. Have any portions of those lines have been replaced in the last 20 years as the community has grown past those lines?
Since 2005, PG&E has completed eight transmission pipeline projects in the greater Bakersfield area to accommodate population growth in the area and is in the process of completing two additional projects. All pipelines within the PG&E system, including Kern County and the city of Bakersfield, are in compliance with Part 192 of the Code of Federal Regulations (CFR). Many currently exceed the minimum guidelines. PG&E's transmission pipelines are assessed as part of its transmission pipeline integrity management program and are leak surveyed on at least an annual basis.

108. What is the recommended easement for natural gas lines and how is that easement applied?
For its gas transmission pipelines, PG&E will typically seek a 50 foot wide right-of-way easement, but has historically placed transmission lines in rights-of-way as wide as 100 feet and as narrow as 30 feet. PG&E attempts to place the gas line in the centerline of the right-of-way, but may need to deviate from the centerline due to construction conditions and topographical features.

109. Can a house be built directly on top of a gas transmission line?

All of PG&E's transmission pipelines are located within right-of-way owned by PG&E or in right-of-way owned by governmental entities. PG&E's right-of-ways vary in width from 30 feet to 500 feet. PG&E has the legal right to prevent the construction of buildings within its right-of-ways. The governmental right-of-ways in which PG&E's transmission pipelines are located also preclude the construction of buildings. PG&E regularly patrols its transmission pipelines. If construction of a building is found to be taking place within PG&E's right-of-way or within the governmental right-of-way in which the transmission pipeline is located, steps are taken to stop the construction.

110. What's your response to the LA Times article that says your leak rate is higher than the national average?

- All natural gas pipeline operators (over 400 total) make semi-annual reports to the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding Integrity Management Program (IMP) activities within High Consequence Areas (HCAs)
- These reports -- posted on PHMSA's website -- include:
  - Number of miles of pipeline in HCAs for that utility/operator
  - Number of transmission pipeline leaks within those HCAs, broken down by cause (third-party damage, etc)
- PG&E has a very comprehensive and conservative approach to reporting gas system leaks to PHMSA. A robust integrity management system depends on identifying risks, and taking appropriate action before detectable leaks become larger problems
- Since 2004, PG&E has reported 36 leaks on transmission lines in HCAs. As stated, PG&E tends to over-report leaks that may not be included in the semi-annual IMP reports of other pipeline operators
  - For example, PHMSA guidelines provide that leak statistics need not include leaks that can be eliminated by lubrication, adjustment or tightening. However, PG&E's semi-annual reports include several transmission leaks that fall into this category
- Even with PG&E's very conservative reporting, the leak rates are comparable to the industry average:
  - From 2004 through mid-2010, PG&E reported an average of 0.0057 leaks per year for every mile of HCA pipeline
  - During that same period, the industry reported an average of 0.0049 leaks per year for every mile of HCA pipeline
  - If you adjust for PG&E's conservative reporting, PG&E's leak statistics would be better than the industry average
- HCA pipelines are defined by regulations and do not vary depending on the size of the operator. Comparing to the entire industry average is important because it gives a comprehensive and realistic analysis

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Spending

111. What did PG&E do with funds allocated for GPRP work but not fully spent from the early 1990s through 2007? Why did it not spend all of the money allocated for GPRP?
The GPRP (Gas Pipeline Replacement Project) is a multi-year project to upgrade our gas distribution facilities. Since the inception of the GPRP through the end of 2009, PG&E has replaced over 2100 miles of pipeline system-wide, and has spent approximately $1.5 billion. These costs are recovered in our General Rate Case (GRC).

Our GRC filings are prepared years in advance and are based on projected costs in future years and are not a line-item budget. The CPUC understands future costs cannot be calculated exactly and allows utilities to reallocate funds as necessary for higher priority projects.

PG&E constantly monitors its system and makes any necessary repairs or investments. Since 2007, the CPUC required PG&E to explain why allocated funds were not spent as specifically authorized on GPRP. As PG&E explained to the CPUC in its current GRC, during the last three years, PG&E identified higher priority gas distribution capital projects that it included within the scope of the GPRP. As a consequence, PG&E actually spent more on this program than it received funding for.

PG&E's transmission pipelines are in the transmission pipeline integrity management program, not the GPRP. Funding for gas transmission pipeline replacements is through the Gas Transmission rate cases, not the General Rate Case. PG&E's transmission pipeline replacement decisions are based on a variety of pipeline factors, including, among other things, pipe material and design, soil resistivity, pipe coating, pressure, potential for third-party damage, seismicity or the potential for ground movement, water crossings and number of customers served.

112. According to PG&E's regulator filings, the company had requested $235 million a year in capex in its 2011 Gas Transmission and Storage Rate Case that was settled in August, and PG&E received $174 million a year from the settlement. What was the capex requested in the 2007 Gas Transmission rate case (capex, I believe, represents a part of the rate request) and what was ultimately granted?
Note that PG&E interprets the "2007 Gas Transmission rate case" as the Gas Accord IV settlement, which covered the three-year period 2008-2010 and was filed with the Commission in March 2007.

Unlike other Gas Transmission and Storage rate cases, PG&E and Settlement Parties came to a Settlement Agreement for the period 2008-2010 (Gas Accord IV) prior to PG&E filing a proposed litigation case with the Commission. Gas Accord IV was a settlement of rates and did not have a stated "settlement" capital expenditure amount. PG&E provided to the Commission workpapers supporting an average of $196 million a year in capex to demonstrate that the settlement/adopted amounts were just and reasonable.

113. Regarding the filing PG&E made in its 2011 Gas Transmission rate case: The administrative law judge had asked parties in the settlement to reconsider the allowed amount in light of the San Bruno incident. PG&E said (I'm paraphrasing) that any costs related to the mandated inspection and repairs to its pipeline system should be taken up in a separate rate case. The company said that the current settlement doesn't provide sufficient funds for those expenses. Does the utility plan to ask the commission to recover these costs in rates? Let me know if it isn't clear what I'm asking. Here's a link to the filing:
https://www.pge.com/regulation/GTS-RateCase2011/Pleadings/PGE/2010/GTS-RateCase2011_Plea_PGE_20100920-01.pdf
As stated in our Sept. 20 comments, PG&E anticipates filing an Advice Letter seeking permission to begin tracking in a memorandum account any costs associated with additional requirements adopted by the Commission in response to the San Bruno incident. Whether we will seek rate recovery of those costs will be determined later, at an appropriate time.

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Top 100

114. What is the Top 100 list?
PG&E has a comprehensive inspection and monitoring program to ensure the safety of its natural gas transmission pipeline system. PG&E monitors system status on a 24-hour basis, and regularly conducts leak inspections, surveys, and patrols of all of our natural gas transmission pipelines. Any issues identified as a threat to public safety are immediately addressed.

PG&E also uses the data it collects to help plan and prioritize future work. One of the tools PG&E uses is a risk management program that inventories each of the 20,000 segments within PG&E's natural gas transmission pipeline system and evaluates them against criteria such as:

- The potential for third party damage like dig-ins from construction
- The potential for corrosion
- The potential for ground movement
- The physical design and characteristics of the pipe segment

PG&E also considers the proximity to high density populations, potential reliability impacts and environmentally sensitive areas.

Based on all of these factors, PG&E determines which segments warrant further evaluation, monitoring or other future action. PG&E also creates a list of the "Top 100" segments to help inform future work plans. As conditions change from year to year, PG&E reevaluates the segments included on the list.

There are a range of actions PG&E may take for the segments identified on the list. For example, if a segment is on the list due to a high level of construction activity in the area, PG&E might enhance the physical markings of the lines and conduct outreach to help avoid accidental dig-ins. In other cases, PG&E may increase its monitoring or propose to rebuild the line sometime in the future.

115. I heard from City Manager X that you are notifying government officials that they have a Top 100 pipeline in their area. Is that true?
We are making contact with city and county officials throughout the service area and letting them know if there is one of these pipeline sections in their area.

116. Can you tell me what you told City Manager X?
We will soon share more detailed information on PG&E's natural gas transmission system, and we look forward to providing you with additional information in the near future.

117. What is the status of all the projects listed in the Top 100? Why are only a few in the construction phase?
This is a long-term planning document, so it makes sense that most projects would be in various states of monitoring, planning and evaluation.

118. What is the significance of the relative ranking of the Top 100 list? Is something listed #1 on the list deemed a higher priority than something ranked 50th or 100th?
PG&E's "Top 100" list is not a list of projects PG&E has identified as "priority candidates for replacement or upgrade for reasons of public safety." Any issue identified as a threat to public safety is always addressed right away. We do not delay or defer work that is necessary for public safety.

The "Top 100" list is part of our ongoing risk management program, and is one of the tools used to prioritize our engineering analyses and future work on our transmission pipelines. Due to the serious consequences of a pipeline failure, we use very conservative assumptions as to the status of a pipeline when conditions are not yet fully known.

In the population of 20,000 segments, each segment is evaluated based on risk factors in a multi element algorithm. The product of this effort is a relative listing/ranking of all segments with the highest product being number one. The list of 100 is simply the top 100 highest products of that mathematical process. The Top 100 list is then provided to pipeline engineers to further evaluate each segment for subsequent action. There is no precise correlation between ranking number 1 and ranking "n" as to sequence of evaluation or action. Each segment in the top 100 is evaluated. The engineers' professional judgment will determine, for example, that number 21 may not need any action, but number 72 may.

119. Please provide a detailed description of the criteria PG&E uses in deciding which pipeline segments to characterize as high priority projects, including any mathematical formulas used to rank such segments in terms of priority.
The variables considered under each of the four principal factors are as follows:

Potential for third party damage
- Potential ground break frequency
- 3rd party damage prevention
- Ground cover protection
- Pipe diameter
- Wall thickness
- Line marking
- Maximum operating pressure (MOP) vs. pipe strength
- Third party leak rate
- Public education program efforts

Potential for corrosion (25 percent weighting):
- Soil resistivity
- Corrosion survey criteria
- Coating visual inspection
- Casing survey
- In-line inspection
- External corrosion leak rate
- Coating design
- DC/AC interference
- Coating age
- MOP vs. pipe strength
- Pipe visual inspection
- Test pressure
- External corrosion direct assessment (ECDA)

Potential for ground movement (20 percent weighting):
- Water/earthquake fault crossings/levee crossing
- Soil stability
- Seismic area
- Erosion area
- Ground movement mitigation efforts
- Girth weld consideration

Physical design and characteristics (10 percent weighting)
- Pipe seam design
- Girth weld condition
- Material flaws or unique joints
- Pipe age

- MOP vs. pipe strength
- Design/Materials Leak Rate
- Test Pressure vs. Pipe Strength

In assessing potential consequences, the following are principal factors:

- Population density in proximity to pipeline
- Pipeline proximity to a potential area of population concentrations
- Potential impact radius

Impact on environment:
- Presence of a water crossing
- Passing through or adjacent to an environmentally sensitive area

Impact on reliability
- Reliability impact on customers in the event of a pipe failure
- Number of customers to experience a gas service outage
- Proximity of critical facilities

120. For the pipe segments that are listed on the Top 100 due to the potential for ground movement, what is typically done to mitigate potential movement?
The mitigation depends on what the most significant attributes of the threat are. Here are some examples based upon actions PG&E has taken: (1) where the relative risk ranking for a segment is high because it crosses a fault, PG&E may redesign the fault crossing so the pipe can safely retain pressure in the event of ground surface faulting (although it may need to be replaced again if there is ground surface faulting); (2) where the pipe is in a known slide area, PG&E may reroute the pipe around the slide area; and (3) where the pipe is on the list because of potential high ground acceleration in the event of a large earthquake and the pipe was installed prior to 1947, PG&E may replace the pipe.

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Maps

121. We're hearing from a county supervisor that PG&E will be releasing maps with natural gas transmission shutoff valve locations to first responders. It seems to be a change in policy from last week, when PG&E said it wouldn't be releasing them to any cities or counties because of security concerns. Can you clarify PG&E policy? And also, why the change in policy?
PG&E continues to help provide the communities we serve with information about our gas system. As part of this effort, we are sharing the location of our gas lines and valve stations to first responders and other appropriate emergency response organizations. We are

working closely with those first responders to ensure the proper security of that information.

122. Are you leaving behind with first responders maps that detail gas transmission pipeline and shutoff valve locations?
We have been and will continue to provide this information to emergency responders who request this information.

123. Isn't this a change in policy?
PG&E continues to help provide the communities we serve with information about our gas system. This is part of that ongoing discussion.

124. You've been saying you will not release the list or locations of pipelines to customers due to security reasons. Now you've released a list and maps for customers on the PG&E website. Isn't that contradictory?
The safety and security of PG&E's gas system remains a high priority of our company. The maps we provided on Sept. 20 are a result of our efforts to strike an appropriate balance between protecting the energy delivery system and releasing enough information to address our customers' concerns. The public maps do not include as much detail as those our technical experts use to monitor and maintain our system.

125. Is there a phone number customers can call about gas line locations and pipelines on PG&E's priority list?
1-888-743-7431

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Gas Transmission Surveys/Inspections

126. Have we conducted a baseline assessment of this pipeline as required by the 2002 Pipeline Safety Improvement Act? - Within 10 years of Act or five years for "risky" lines?
Yes. The first pipeline integrity assessment of Line 132 was conduced in March 2005. Another assessment was done in October 2009.

127. Has the pipeline been inspected under the IMP Program?
Yes. See answer above.

128. When was the pipe last leak-surveyed?
The section of transmission Line 132 was surveyed for leaks in March 2010. The distribution network in the area was surveyed for leaks in June 2008.

129. How often is that pipe leak-surveyed?

The section of the transmission line where the accident occurred is surveyed for leaks at least once a calendar year and/or not less than every 15 months. The distribution network where the accident occurred is surveyed for leaks every five years.

130. How much of the PG&E high-pressure, HCA transmission and distribution pipelines are surveyed every six months? All? Most? Half? Less than half?
PG&E performs a number of different maintenance activities to ensure the safe operation of our transmission pipelines. Any issue identified as a threat to public safety is always addressed immediately. We do not delay or defer work that is necessary for public safety.

PG&E performs the following maintenance activities for gas transmission pipelines, utilizing a combination of preventative, corrective and/or condition based maintenance.

Leak survey: Transmission pipelines are all surveyed for leaks at least once per calendar year. Distribution pipelines are surveyed for leaks at least once every five years.

Pipeline Patrols: Transmission pipelines are patrolled either aerially or on the ground on a quarterly basis.

Cathodic Protection: Two different types of maintenance checks are performed to assure that pipelines are protected from corrosion; these checks assure that protection systems are performing properly. They are performed at 2 month and annual intervals.

Odorization of Natural Gas: Proper levels of odorization are verified by conducting periodic tests of the odorized gas.

Pipeline Integrity Assessment: In High Consequence Areas, assessments are performed at least every 7 years per federal regulations.

131. Does PG&E usually conduct leak surveys of its natural gas transmission system?
PG&E routinely conducts leak surveys of all our natural gas transmission and distribution lines. In 2008, we accelerated the distribution program to complete it in three years instead of the usual maximum five.

132. What are the surveys designed to do?
Leak surveys are designed to confirm the integrity of our transmission and distribution lines by trained and federally qualified operators, using approved instruments and techniques.

133. How many people do we have doing leak surveys?
PG&E has between 55-65 full time employees on any given day that perform leak survey across our system. This is work completed in our normal maintenance cycle which is ongoing. The Gas Transmission accelerated leak survey process will utilize 118 or so outside resources that consist of Mutual Aid and contractors. We do have some work

completed by local gas transmission employees that are assigned to their districts as it makes sense in our plan.

134. Have you resurveyed the transmission lines in San Bruno?
The day after the accident in San Bruno, we began surveying the three major transmission lines that feed the San Francisco Peninsula. As an added safety measure, we have also reduced operating pressure by 20 percent on these three lines. The surveys except for some inaccessible areas such as San Bruno Mountain were completed on September 11. The inaccessible areas were completed on September 20.

135. PG&E has talked about accelerating gas line inspections, getting it done in 3 years instead of 5, for distribution. How does transmission fit in here?
We perform surveys for leaks on our transmission lines annually or semi-annually.

136. Do we have additional background on how we conduct our external corrosion pipeline inspection program, such as explaining the "poking ground" method?
External Corrosion Direct Assessment (ECDA) is a four step process:
1. Preassessment: provides guidance for selection of the pipeline segment and which indirect methods to be used.
2. Indirect Examination: indirect aboveground electrical surveys are performed to detect coating defects and the level of cathodic protection.
3. Direct Examination: Based on the indirect examination, points of potential interest are excavated to expose the pipe surface for metal loss measurements, and estimated corrosion growth rates.
4. Post Assessment and Continuing Evaluation: sets re-inspection intervals, provides a validation check, and provides performance measures.

One of the tools used for indirect examination that provides an indication of the condition of the protective coating on a pipeline is called direct current voltage gradient (DCVG). This is the method described as "poking the ground."

137. Did we do Internal (not External) Corrosion Direct Assessment or any kind of in-line cleaning on Line 132 (i.e. scraper pig)?
Yes; where ECDA access was not available and at the most probable locations for internal corrosion to occur.

138. How do we check gas pipelines for signs of internal (not external) corrosion?
A variety of methods including In Line Inspection (ILI), Ultrasonic testing, x-ray and Guided Wave assessment are used.

139. What is Guided Wave and Ultrasonic Testing?
Both of these testing technologies use waves similar to sound waves to detect defects in pipeline walls. Ultrasonic testing techniques use waves traveling from the outer surface of the pipe wall to the inner surface of the pipe wall to detect wall thickness loss at a point. Guided wave testing technologies use lower frequency waves directed through the pipeline wall longitudinally to detect defects in larger areas the pipe wall.

140. What company do we use to conduct corrosion assessments?
A variety of inspection companies; for example, Mears, G.E., Tuboscope.

141. How much money goes to Internal Corrosion Direct Assessment (Jackson could only find funding for ECDA in our rate filing)?
In 2009 alone approximately $22Million was invested to modify pipelines that allows them to be internally inspected. An additional $5 million was spent on in line inspections.

142. Can we provide Line 132 mapping that shows any "low spots" or "dead zones"?
PG&E is unable to respond to this question as the layout of line 132 is connected to the NTSB's ongoing investigation.

143. Upon finding evidence of liquid in the filters at the Milpitas regulator station, what steps did PG&E conduct to keep any potential corrosion in check?
PG&E installed a liquid separator at Milpitas as a means of preventing liquids from travelling downstream into the L132 system. PG&E has used guided wave and ultrasonic testing on L132. No internal corrosion has been found.

If Asked As Follow-up: By "has used" and "has found," do we mean that we specifically conducted these tests after and in response to finding evidence of liquid in the filters at the Milpitas regulator station to confirm that no internal corrosion was found, or that we "have used" this testing in general?
The Internal Corrosion Direct Assessment (ICDA) testing for L-132 in 2007 found no evidence of internal corrosion.

144. When did we conduct Guided Wave and Ultrasonic Testing?
2007

145. Guided Wave uses long-wave ultrasound technology, so when we say we conduct Guided Wave and Ultrasonic Testing, do we mean manual or direct ultrasonic testing?
The ultrasonic testing conducted as part of the Internal Corrosion Direct Assessment conducted in 2007 was performed manually.

146. How much microbially influenced corrosion (MIC) has been found in our system and what do we do when we find it, if not a scraper pig?
PG&E has repaired 7 leaks on transmission pipelines due to internal corrosion since January 2005. We found that MIC might have been a factor in only one of the leaks.

When discovered, PG&E repairs the leak, removes any liquids and adds microbial inhibitors to the pipeline when appropriate.

Further Background:
Since 2005, PG&E has encountered 7 internal corrosion leaks on its gas system. Of the 7 internal corrosion leaks, 4 were on gas gathering lines that carry gas from producing wells

in California to PG&E's gas transmission pipeline system. PG&E's gas gathering pipeline system is located in specific areas where producing natural gas wells are located in northern California. We have no information as to the cause of the gas gathering line leaks.

Of the three gas transmission pipeline leaks, we found that MIC might have been a factor in only one of the leaks. This possible conclusion is based on post-repair testing at 8 locations on this pipeline. That testing found that conditions favorable to MIC might be present at one of the 8 locations. On the basis of this analysis, we concluded that MIC might have been a factor in one of the reported leaks.

147. Who did internal corrosion direct assessment on Line 132 before the San Bruno accident (if it was done before)?
The Internal Corrosion Direct Assessment (IDCA) of L-132 was conducted in 2007. Several different contractors contributed to the ICDA such as performing flow analysis and conducting guided wave testing. The ICDA was performed by PG&E employees.

148. What pressure was Line 132 operating at when it ruptured?
According to the NTSB's Preliminary Report, the pressure was 386 psig.

149. Referring to the 2011 GRC PowerPoint titled, PG&E's Gas Leak Survey Program – what is the relevance to San Bruno?
The Accelerated Leak Survey effort referred to in the PowerPoint was a comprehensive re-survey of all PG&E's gas distribution facilities previously surveyed in 2006 and 2007. The Accelerated Leak Survey did not include transmission facilities (such as this pipeline), since transmission pipelines such as the one in San Bruno is leak surveyed at least once a year.

Among the benefits of the leak survey program was that PG&E improved its survey process and enhanced its training for leak surveyors. On page 6, it states that on the Peninsula, four of four sampled lots did not meet the criteria in the leak survey.

PG&E sampled its territory to see if there was a significant difference between the historical results and the results using the new survey process. Four of the four Peninsula lots did not meet the criteria, which is one of the reasons PG&E decided to resurvey the entire system. PG&E has already completed the Accelerated Leak Surveys in the Peninsula Division, and, as noted above, the transmission pipelines are surveyed at least once a year.

150. Had the Peninsula portion of the gas distribution system been fixed before the pipeline rupture?
The Peninsula portion of the gas distribution system was not and is not in need of a "fix." Any Grade 1 leaks found during the Accelerated Leak Survey were promptly repaired.

151. What is the difference between a direct assessment versus in-line inspection?
There are three federally approved methods to complete a transmission pipeline integrity management baseline assessment: In-Line Inspections, Pressure Testing and Direct

Assessment. External Corrosion Direct Assessment (ECDA) is the primary method used for Direct Assessment.)

- In-line inspection involves a tool (commonly known as a "pig") inserted into the pipeline, which identifies areas of concern such as potential metal loss (corrosion) or geometric abnormalities (dents) in the pipeline. Excavations are performed in areas of concern as required by federal regulations.
- External Corrosion Direct Assessment is a four step process:
  - *Preassessment*: provides guidance for selection of the pipeline segment and which indirect methods to be used.
  - *Indirect Examination*: indirect aboveground electrical surveys are performed to detect coating defects and the level of cathodic protection.
  - *Direct Examination*: Based on the indirect examination, points of potential interest are excavated to expose the pipe surface for metal loss measurements, and estimated corrosion growth rates.
  - *Post Assessment and Continuing Evaluation*: sets re-inspection intervals, provides a validation check, and provides performance measures
- Pressure testing involves filling the pipeline with a test medium (i.e. water, gas, air) and testing to a certain pressure for specified duration.

152. What is the age of the transmission lines in Fresno, Kings County and Madera County?
PG&E's transmission pipelines in the three county area have been installed from 1931 to 2009, with the majority installed in the 1950s and 1960s.

153. When were (the lines) last inspected? What was found?
PG&E inspects its transmission pipelines semi-annually or annually for leaks, quarterly for general inspection patrols and every seven years for an integrity inspection if warranted per Integrity Management program rules. No unusual or adverse conditions have been found on the transmission pipelines in those counties.

154. Were (the lines) slated for replacement or OK?
The pipelines are not scheduled for replacement.

155. How much maintenance work has PG&E done on the lines in the three counties in recent years?
PG&E has performed all required pipeline maintenance on the pipelines, as outlined above.

156. Are any transmission pipelines currently scheduled for replacement in 2010 or 2011?
PG&E's transmission pipelines in the three counties are not scheduled for replacement in 2010 or 2011 at this time.

157. Have there been any CPUC reportable incidents on these transmission pipelines since 2005?
There have been no reportable incidents on PG&E's transmission pipelines in the three county area since 2005.

158. Are there any transmission pipelines in Tulare County?
No, there are no PG&E transmission pipelines in Tulare County.

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Pigging

159. PG&E did not use an internal pigging device on the San Bruno line. When a PG&E officer indicated that PG&E did not use an internal pigging device did she mean the San Bruno section only, or the entire line?
The entire pipeline, except for a single instance in 2007 on a small portion of the line near Coyote Creek.

NOTE: Approved answer from question above addresses the premise of the question about whether Line 132 was internally inspected

When was Line 132 last internally inspected? **[click on question to jump to its current location above in document]**

An Internal Corrosion Direct Assessment was performed in 2007 on L132. Work was performed at two locations; a location near San Bruno Mountain and a location by Coyote Creek near Milpitas. No internal corrosion was found.

160. What percentage of PG&E's 1,021 miles of HCA pipeline cannot be pigged?
Approximately 216 miles of the 1021 miles of HCA pipeline is currently pigable (21%). [Note: approximately 805 of 1021 miles is not pigable = 79%.] There are approximately 117 miles of HCA pipeline for which planning is in progress to make various pipeline segments pigable in advance of planned future pigging. Most older pipelines are not "pigable". This means that the pipeline has certain characteristics that would prevent a pig from successfully traveling down the pipeline. Pipeline characteristics that would prevent a pig from traveling down a pipeline include the use of plug valves as mainline valves, large changes in pipe diameter, bends that are too sharp and obstructions protruding into the pipeline.

161. How important is pigging as a means of detecting potential problems?
Pigging or In-Line Inspections are one of the three federally approved methods within 49 CFR Part 192, Subpart O to complete an Integrity Management assessment. The other two federally approved methods are Direct Assessment and pressure testing.

162. Is the pigging of the HCA lines in Bay Area a huge job and will cost a lot of money and take a lot of time?
As we have noted many times, pigging is just one of three different, effective, federally approved methods of assessment. There are three different federally approved methods of assessment, each of which serves its own unique purpose in the larger picture of ensuring the safety of our system. PG&E uses all three methods.

- Internal Line Inspection (ILI), often called "pigging": Effective in identifying areas of direct metal loss through third-party damage or corrosion as well as deformations in the pipe caused by third-party damage. It is an excellent tool to get both current and past information on the pipe. It is also limited to piping configurations that will allow the passage of an inline inspection tool and piping systems that have enough pressure to propel the device.
- Direct Assessment (DA): Effective tool to identify potential coating damage, which is the first level of protection against external corrosion. Effective in assessing the current level of cathodic protection, which helps show the current and future health of the pipe. It can be performed on nearly any pipeline, regardless of diameter or configuration.
- Pressure (hydro) test: Effective method to test current pipe integrity. Predominant method used for new construction and can be used on any pipeline segment that can be isolated and taken out of service while the testing is performed

PG&E has a plan to retrofit Lines 101, 109 and 132 to make them, and other Lines, capable of being assessed through ILI. That does not mean PG&E will automatically use ILI. As noted above all three forms of assessment are utilized by PG&E to ensure the safety of our system.

163. Are we under any requirement to increase the amount of "pigable" miles of pipeline, or do we have a specific goal?

There is no specific requirement to make pipelines pigable. Rather, the federal code (49 CFR 192.921) requires that pipeline operators conduct regular pipeline assessments (once every seven years) using one or more of three approved methods depending on the threat to which the covered segment is susceptible: (1) internal inspection (pigging or other means), (2) pressure testing (hydrostatic or inert gas), or direct assessment (ultrasonic, guided wave or other means).

164. How many miles of the 1,107 miles of transmission line in the Bay Area have already been pigged and when did that take place?

First, a clarification -- 1,107 is not the miles of transmission line in the Bay Area. It is the total number of pipeline miles (HCA and non-HCA) that PG&E, at the time of the rate case filing, planned to inspect across its entire service territory with in-line inspection (ILI) from 2008-2014. Since 2002, PG&E has ILI inspected 156 miles of HCA pipelines system wide and a total mileage (HCA and non-HCA) of 713 miles.

As of August 31, 2010 PG&E has performed integrity management assessments system wide on approximately 737 miles of its 1021 miles of High Consequence Area (HCA) pipeline since inception of the integrity management program in 2002. Approximately 567 miles of HCA pipeline have been assessed using Direct Assessment methods; 156 miles using in-line inspection methods and 14 miles using pressure testing methods. PG&E does not track its baseline assessments of HCA pipeline by county or region.

165. PG&E says it has performed IMP assessments on 737 of 1,021 miles of HCA pipeline, and the figures in the last IMP report (from 6/30/10) cite 65 of 1,021 miles of HCA pipeline assessed as part of the IMP.

Since the inception of the integrity management program in 2002 through August 31, 2010, PG&E has performed integrity management assessments on approximately 737 miles of its 1,021 miles of High Consequence Area (HCA) pipeline throughout the service area.

During the reporting period of January 1, 2010 through to June 30, 2010, we performed integrity management assessments on approximately 65 miles of the 1021 miles of High Consequence Area (HCA) pipeline throughout the service area.

166. How many miles have not yet been pigged in the Bay Area and when do we plan to pig those lines?
As noted above, PG&E does not track its baseline assessments of HCA pipeline by county or region. We have approximately 20,000 pipeline segments, and the pipeline data base simply does not have a "county" field. Although we would like to be more responsive on this point, it would take valuable resources away from other more pressing work to provide a Bay Area figure.

On a system wide basis, in 2010 PG&E's integrity management program will continue to conduct baseline and periodic assessments (at least every 7 years) of the 1021 miles of High Consequence Area (HCA) pipelines. As discussed above in our introductory comments, pigging is just one of three different, effective, federally approved methods of assessment.

Each federally approved method serves its own unique purpose in the larger picture of ensuring the safety of our system. Approximately 200 miles is expected to continue to be assessed using in-line inspection (ILI) methods and approximately 800 miles is expected to continue to be assessed by Direct Assessment (DA) methods. PG&E's integrity management program is dynamic and adjustments to mileages, locations and test methods are made as the results of assessments are evaluated and incorporated into the program.

PG&E has a plan to retrofit Lines 101, 109 and 132 to make them, and other lines, capable of being assessed through ILI. That does not mean PG&E will automatically use ILI. As noted above all three forms of assessment are federally approved, effective and utilized by PG&E to ensure the safety of our system.

167. Where are the unpiggable lines in the Bay Area (he plans to use this for a map graphic), why are they unpiggable and what the schedule is for retrofitting them to make them piggable?
There are a number of pipelines in PG&E's system that are not piggable in their current state. Under federal regulations, direct assessment or pressure testing are also approved methods to assess the integrity of a line. In some cases, PG&E elects to retrofit a pipeline to make it piggable. Among the many things that make a pipeline unpiggable, these are the most prevalent reasons:

- Pigging is often difficult when a pipeline has multiple diameters or bends that follow road or geographic contours. Instrumented pigs (termed smart pigs) are large cylindrical devices that fit snugly inside the pipeline to be inspected and the devices therefore have great difficulty moving through pipelines of varying size and with many bends.

- Most pipelines were built with plug valves which, when in the full open position, do not have an internal opening that is the same diameter as the pipeline.
- The pig cannot pass through facilities such as compressor or regulator stations.
- Finally, as each pipeline segment is retrofitted to eliminate sharp bends or protruding valves, the segment must be equipped with pig launching and receiving facilities at locations where the installation of these facilities is feasible and appropriate given their size and the pigging operation for which they are designed.

PG&E has plans to retrofit some pipelines to accommodate pigs in the next five years. For example, lines 101, 109, and 132 are on the current retrofit list. However, PG&E does not currently plan to make all transmission lines piggable, but the Company will complete integrity management assessments as required by current regulations.

168. Is the ultimate goal to have everything inspected by in-line inspections? If so, what is the schedule to make this happen?
There is no current plan or goal to have all pipelines assessed by in-line inspections. The regulatory requirement is to perform baseline integrity assessments of all 1021 miles of HCA pipeline by December 17, 2012. There are three approved methods of assessment; in-line inspection, pressure testing and direct assessment. PG&E has completed assessment of over 700 miles of HCA pipeline since 2002 and is on track to complete the initial assessment of all 1021 miles of HCA pipelines before the December 2012 date.

169. Does table 5-4 on pages 5-12 of PGE's GTS 2011 Rate case mean that 68.9 miles will have been ILI'd ("pigged") by the end of this year, and 235.6 miles by the end of 2014, for a total of 304.5 miles?
Yes, that is correct. These were PG&E's plans at the time of the rate case filing. (Sept. 18, 2009).

170. What does "Overall ILI mileage" mean?
"Overall ILI mileage" means the total number of miles that PG&E intended to pig at the time of the rate case filing. This includes the number of miles in High Consequence Areas that we pig and the number of miles not in HCAs that we pig. PG&E pigs more miles than HCA miles because it is more efficient, and in some cases necessary, to do so than to exclude those non-HCA miles.

171. Does the table 5-4 on pages 5-12 of PGE's GTS 2011 Rate case signify that 802.5 miles of HCA line *can't* be ILI'd?
No. It doesn't necessarily mean that the miles we assess through Direct Assessment cannot be assessed through ILI. It means that, due to the characteristics of the pipe, some segments are better assessed through Direct Assessment, and some segments are better assessed through ILI. When our gas engineers make informed recommendations to inspect a pipe through Direct Assessment, it is because it is the most appropriate method for that segment.

172. Explain the footnote (a) to Overall ILI Mileage in table 5-4 on pages 5-12 of PGE's GTS 2011 Rate case.
The footnote is intended to explain why the "Overall ILI Mileage" that we pig is greater than the miles we pig that are in High Consequence Areas. Due to the non-contiguous nature of HCAs and the technical challenges of ILI, the overall miles of pipe assessed with ILI is approximately four times the miles of HCA assessed using ILI. We pig lines that are not located in HCAs because it is more efficient, and in some cases necessary, to include those miles (for example, if there are non-HCA segments adjacent to HCA segments).

173. Also, 471.9+633.6=1,105.5 (not 1,107). Why is that?
For the reasons explained above, those numbers (471.9 and 633.6) are not supposed to add up to 1,107. The first two columns are only HCA miles, and the "Overall ILI mileage" signifies all the miles that we pig, whether they are in an HCA or not.

174. Will the pigging of these lines in Bay Area HCAs cost a lot and take a long time?
As noted above, pigging is just one of three different, effective, federally approved methods of assessment. There are three different federally approved methods of assessment, each of which serves its own unique purpose in the larger picture of ensuring the safety of our system. PG&E uses all three methods.

- **Internal Line Inspection (ILI), often called "pigging":** Effective in identifying areas of direct metal loss through third-party damage or corrosion as well as deformations in the pipe caused by third-party damage. It is an excellent tool to get both current and past information on the pipe. It is also limited in its application to single diameter piping that has enough pressure to propel the device.
- **Direct Assessment (DA):** Effective tool to identify potential coating damage, which is the first level of protection against external corrosion. Effective in assessing the current level of cathodic protection, which helps show the current and future health of the pipe. It can be performed on nearly any pipeline, regardless of diameter or configuration.
- **Pressure (hydro) test:** Effective method to test current pipe integrity. Predominant method used for new construction and can be used on any pipeline segment that can be isolated and taken out of service while the testing is performed
- PG&E has a plan to retrofit Lines 101, 109 and 132 to make them, and other Lines, capable of being assessed through ILI. That does not mean PG&E will automatically use ILI. As noted above all three forms of assessment are utilized by PG&E to ensure the safety of our system.

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Reports/Claims/Accusations

175. Customers in the area have reported that they smelled gas and called PG&E to report it. Are there any records of customers reporting gas in the area?
We take seriously all reports of gas odor or gas leaks and work to resolve these quickly – the most serious within one hour and all within the same day of receiving a call.

We have found no record of anyone reporting smelling gas in the affected San Bruno neighborhood from September 1 and September 9. We reached that conclusion after a thorough review of all calls received by our four contact centers.

We have reviewed all calls in the affected area from July 1 – Sept 9. We found two gas leak calls: July 23 and July 27; they were adjoining properties; a small leak was found at the meter (distribution system) of one home, which was repaired. Statistically, we've reviewed 3.1 million calls.

176. A customer whose house was destroyed claims he saw PG&E checking for gas leaks in the area days before the accident. Is this true?
In examining our records from September 1 to September 9, we have thus far found no record of PG&E performing gas leak surveys in the affected area. However, people may have seen meter readers or electric crews in the area.

177. In the days following the explosion, residents in the area reported PG&E doing work all night, again at the intersection of Sneath and Claremont. What were they doing there?
In order to make the area safe it was necessary to shut off the gas supply to the natural gas distribution piping serving these homes. Accomplishing the shut down of the natural gas distribution system quickly meant it was necessary for PG&E crews to dig up buried distribution piping in several locations to allow the use of large clamps to squeeze shut the natural gas pipes. One of the locations where the natural gas distribution system piping was dug up and squeezed shut was near the intersection of Sneath and Claremont in San Bruno. In order to restore the distribution piping system to service it was necessary for the PG&E crews to later repair the piping that had been squeezed shut which meant that work was performed periodically in the excavation at Sneath and Claremont.

178. TURN claims that PG&E ignored customer complaints about gas leaks in San Bruno. What's your response?
It does everyone a disservice to speculate before the investigation is complete. The National Transportation Safety Board (NTSB) has jurisdiction over the investigation. We are cooperating fully with NTSB and other agencies to identify the cause of this accident. Until then, we will not engage in speculation.

179. Regarding a statement made in the Sacramento Bee: According to PG&E's filings with the CPUC, an internal audit in 2007 of its residential distribution lines in Sonoma County found major problems in how it reported gas leaks.
In 2007, PG&E identified an incident in which one leak surveyor in one division had falsified records. PG&E took swift disciplinary action that included termination of that employee as well as management-level employees who shared accountability.

Upon discovery, PG&E immediately developed a plan for corrective action including a complete resurvey of the entire division. Further, to ensure that falsification of records was not a systemic issue; PG&E evaluated its gas leak survey activities across the system.

PG&E did not find any additional evidence of falsification.

At the same time, while performing this evaluation, PG&E found opportunities to improve consistency, tools, processes and training in survey techniques. As part of the quality improvement process, PG&E introduced an enhanced, uniform, leak-grading criteria. These enhancements led us to significantly improve the consistency of our leak detection methods. PG&E also compressed five years of routine activity into less than three; this was an unprecedented effort. We brought in additional resources, identified leaks, and repaired leaks.

PG&E also wants to emphasize that there were no accidents or safety issues related to the surveys that were falsified.

180. There are reports that you have segments of pipe that are sewn together rather than solid pieces. Is that a common practice?
PG&E, and the industry, does not "sew together" pipes; pipes are welded, not sewn. The “sewing together” of pipes is not a term used at PG&E. This term may refer to the longitudinal seam which is a common characteristic of the manufacturing process for many pipes, since many pipes originate from plate steel which is rolled and then welded to form cylindrical pipe.

181. What is PG&E's response to the Class Action Lawsuit that has been filed (seeking immediate release of the $100 million dollar fund)?
PG&E hasn't had a chance to review the lawsuit in detail but we're disappointed to hear about legal action this close to the terrible tragedy. Right now, our focus is helping the families of San Bruno rebuild and recover from this event. Our efforts don't preclude legal action but it's regrettable that this has happened before an NTSB investigation has been completed. We'll continue to focus on recovery efforts and turn to this in due time.

If asked again about the lawsuit as a follow-up:

We are committed to our customers in San Bruno and will continue to be there to help rebuild the city, and we are currently reviewing those documents.

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Falsified Gas Leak Survey

182. We have documents from TURN that say your employees falsified gas leak survey records.

In the last several years, PG&E has spent well over $100 million to improve its gas system. In 2007, PG&E identified an incident in which one leak surveyor in one of PG&E's 18 divisions had falsified records. PG&E took swift disciplinary action that included termination of that employee as well as well as management-level employees who shared accountability. Upon discovery, PG&E immediately developed a plan for corrective action including a complete resurvey of the involved division. Further, to ensure that falsification of records was not a systemic issue; PG&E evaluated its gas leak survey activities across the system. PG&E did not find any evidence of falsification. At the same time, while performing this evaluation, PG&E found opportunities to improve consistency, tools, processes and training in survey techniques. As part of the quality improvement process, PG&E introduced an enhanced, uniform, leak-grading criteria. These enhancements led us to significantly improve the consistency of our leak detection methods.

183. How many employees were involved?
This was an isolated event involving one of several hundred employees who do this type of work. It was in no way reflective of the integrity of the vast majority of our people.

184. Were there any accidents or safety issues related to the surveys that were falsified?
No.

185. Why didn't PG&E provide this information to the public?
There was no safety threat to the public. We provided our regulator, the CPUC, this information as we discovered the deficiencies and designed and implemented the improvements.

186. Where did this occur?
It was an isolated incident in one division.

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CPUC

187. What is your response to the CPUC's Sept 13 letter directing PG&E to take action on multiple items relating to its gas system?
We are working to comply with all aspects of the letter.

188. Last September, PG&E filed a document with the CPUC for the natural gas rate case, requesting money to install separators to get water out of gas lines. A significant amount of water was getting into pipelines that connect to Milpitas, including 100, 101, 109, and 132, causing corrosion and safety problems. What kind of problems were created by this situation?
PG&E was finding liquids in filters at distribution regulator stations served from Lines 101, 109 and 132 from Milpitas Terminal. The liquids issues were localized in De Anza Division (Cupertino, Los Gatos, Mountain View, Sunnyvale etc.). The liquids were mostly

compressor oil rather than water. The presence of liquids can cause corrosion and potentially damage equipment. [Note: We had collapsed filters and had an over pressure situation with a distribution system in De Anza due to liquids fouling pilot regulators.]

189. The work was scheduled to be done by November 2009. Was it ever completed?
Yes, two large filter-separators were installed at Milpitas Terminal in November 2009 and post installation testing shows that liquids are not showing up in regulator station filters in De Anza Division.

190. Since that document said PG&E was concerned about corrosion from the liquids, do you know if those lines were checked for corrosion after the separators were installed, and if so, did you find corrosion?
PG&E installed the separators on those lines to mitigate operational issues being caused by liquids clogging certain filters, not corrosion issues. PG&E has continued to perform all routine surveys on those lines.

191. How long had liquid been getting in?
As stated previously, PG&E found the presence of some liquids in filters at distribution regulator stations served from Lines 101, 109 and 132 from Milpitas Terminal localized in De Anza Division (Cupertino, Los Gatos, Mountain View, Sunnyvale etc.). Small amounts of liquids have been found in those lines for approximately 10 years, but only recently did the levels of those liquids cause the operational issues that led to PG&E's decision to install separators.

192. What were the "at least four over-pressure incidents at regulator stations feeding DFMS," as cited in our 2011 GAS TRANSMISSION AND STORAGE RATE CASE? Where did they take place (which of the 4 lines)?
The DFMs mentioned are within PG&E's De Anza and San Jose Divisions, and feed gas at transmission pressure to the cities of Milpitas, San Jose, Santa Clara, Los Gatos, Campbell, Saratoga, and Cupertino.

193. What is the significance of "over-pressure incidents" (what problems do they/could they cause)?
An over-pressure incident is when the pressure in a pipeline inadvertently rises above the Maximum Operating Pressure (MOP) of the pipeline system. The consequence of such an incident depends on how much the pipeline pressure exceeds the MOP. The great majority of the incidents do not cause any upset in the routine operation of the systems as the systems are capable of handling pressures well above the MOP (due to a design safety factor required by Federal safety regulations).

194. **Is this something we deal with all the time, or is this unusual?**
An over-pressure incident is an unusual event. PG&E takes over-pressuring of pipelines very seriously by following-up on the event to determine root cause and taking remedial action as warranted by the particular incident.

195. What is PG&E doing to comply with the CPUC's order to survey the entire gas transmission system?
To comply with the CPUC's order to survey our entire gas transmission system, PG&E is utilizing PG&E employees, mutual aid from other utilities and outside contractors that will all work under PG&E supervision. The techniques used to leak survey the system will be a combination of leak survey by foot patrol and leak survey by aerial patrol.

Regarding the foot patrol, on Tuesday, September 21, 89 leak surveyors, supervisors and support staff will arrive at PG&E's training facility in Livermore to complete training and operator qualification. San Diego Gas and Electric and So Cal Gas together will send 34 employees and the other 56 surveyors are outside contractors.

For aerial patrol, PG&E has already begun helicopter flights with PG&E employees and the technology needed to identify leaks from the air.

196. Is PG&E increasing staff for its pipeline safety and maintenance efforts, especially in light of the CPUC's recent direction to investigate all lines?
To comply with the CPUC's order to survey our entire gas transmission system, PG&E is utilizing PG&E employees, mutual aid from other utilities and outside contractors that will all work under PG&E supervision. The techniques used to leak survey the system will be a combination of leak survey by foot patrol and leak survey by aerial patrol.

Regarding the foot patrol, beginning Wednesday, September 22, training will begin at PG&E's training facility in Livermore to complete training and operator qualification of approximately 106 people. These people will come from mutual aid agreements with San Diego Gas and Electric Company and So Cal Gas together with outside contractors.

For aerial patrol, PG&E has already begun helicopter flights with PG&E employees and the technology needed to identify leaks from the air.

PG&E is currently evaluating its long-term staffing needs related to its pipeline safety and maintenance work.

197. Does PG&E still expect to meet the CPUC’s deadline for completing pipeline inspections?
PG&E is making significant progress to complete the system-wide inspections, but has requested an additional ten days to complete the aerial and ground inspections of our gas transmission lines. Both helicopter availability and weather conditions have slowed down our progress to date. In addition, fog conditions in certain locations along the coast have made aerial surveys impractical. PG&E proposes to complete ground surveys in those areas in place of aerial surveys in order to complete the leak survey work. We expect to be completed with the inspections and in a position to report the results by October 22. With respect to the instrument surveys on the gas transmission lines in San Bruno, we are also making progress, but request the extension to ensure adequate time to obtain permits necessary to complete the surveys.

198. Has PG&E detected any leaks so far and what have steps have been taken?
PG&E has found some leaks during its inspections and is repairing them on a timeline consistent with our standards.

199. Is PG&E providing to the CPUC today (October 12) any <u>data on pipeline valves</u> (automatic, remote controlled) the CPUC had requested? Also, when did PG&E ask the CPUC for a 10-day extension on the gas transmission survey to be completed and reported? Is there any other pipeline data the CPUC requested that PG&E is providing?

In the CPUC's Resolution L-403 issued on September 24, the CPUC asked PG&E to "conduct a review of all natural gas transmission line valve locations in order to determine locations where it would be prudent to replace manually operated valves with remotely operated or automated valves and shall report its results to the Commission within thirty (30) days of the issuance date of this Resolution."

PG&E is currently working on this review of natural gas transmission line valve locations, and will respond to the CPUC by the Resolution due date of Monday, October 25. PG&E asked for an extension of the line inspection on October 5th. The primary drivers for the extension include weather conditions such as high winds and fog.

200. Can you provide a description of the gas leaks PG&E found when <u>resurveying</u> the gas transmission lines as the CPUC has ordered. How many, how significant were the leaks we found and repaired?
The CPUC has ordered PG&E to conduct an <u>accelerated leak survey of all natural gas transmission pipelines</u>, giving priority to segments in class 3 and class 4 locations. PG&E is in the midst of performing that survey, and is scheduled to report the results to the CPUC's Executive Director on or before October 22. We will not be providing interim results prior to providing our official report to the CPUC's Executive Director.

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San Bruno Community Outreach

201. I heard PG&E is donating money to San Bruno residents – how much?
We are committed to our customers in San Bruno and will be there to help rebuild the city. One step in that direction is the "Rebuild San Bruno Fund," in which PG&E pledged up to $100 million for the residents and city of San Bruno to help recover from last Thursday's tragic accident.

202. $100 million is a lot of money – it sounds like you are admitting fault?
We know that no amount of money can ever make up for what's been lost and we are fully complying with the NTSB's investigation because we want to get the community the answers it deserves. This program is just one piece of our promise that PG&E will live up

to its commitment to help rebuild this community and help the people of San Bruno rebuild their lives.

203. How are San Bruno residents getting the funds?
On Monday (9/13) PG&E provided San Bruno officials with an initial check for $3 million to help compensate the city for its estimated expenses incurred to date. The company is also taking immediate steps to provide assistance to affected residents. For residents in the affected area, PG&E will provide disbursements of $15,000, $25,000, or $50,000 per household depending on the extent of damage incurred.

204. If people accept PG&E's money – will they be ineligible for a full insurance claim or be forced to waive other compensatory benefits?
No. Residents are not being asked to waive any potential claims in order to receive these funds. Also, these funds are being provided in addition to the company's ongoing provision of funds to ensure affected residents continue to have access to temporary housing and other basic necessities.

205. What is the Rebuild or Purchase Program?
For property owners in the Glenview Subdivision whose home was either destroyed or significantly damaged, we are offering the Rebuild or Purchase Program to help you rebuild your home in its current location or to sell your property.

206. Who is eligible for the Rebuild or Purchase Program?
The Rebuild or Purchase Program is for those property owners in the Glenview Subdivision whose homes were either destroyed or significantly damaged in the September 9, 2010 accident. The geographic boundaries of the program area are Sneath Lane to the north, San Bruno Avenue to the south, Skyline Boulevard to the west, and the Crestmoor Canyon Open Space to the east.

207. What is the Neighborhood Restoration Plan (NRP) and the Value Assurance Program (VAP)?
For property owners in the Glenview Subdivision, we are offering two complementary programs: the Neighborhood Restoration Plan and the Value Assurance Program.

The Neighborhood Restoration Plan will offer up to $10,000 for exterior home improvements not covered by insurance and not related to any damage caused by the September 9, 2010 accident. This could include new landscaping/hardscaping, painting, new fences or other exterior work.

The purpose of the program is to help restore and improve the neighborhood. This is being offered in addition to the relief fund checks that were already distributed to affected residents.

The Value Assurance Program will allow eligible property owners to sell their property with the assurance that PG&E will pay the difference (if any) between actual gross sales price of the home and Fair Market Value The purpose of the VAP is to protect local property values in the Glenview Subdivision.

208. How will I receive these NRP funds?
These funds may be jointly paid to you and licensed contractors who conduct the work, subject to the terms and conditions of this agreement. This will ensure that you do not have to pay for the work out of your own pocket.

209. How do I participate in the Value Assurance Program?
The VAP is available to all property owners in the Glenview Subdivision who choose to sell their home within five years of the commencement of the VAP. The VAP will commence on January 10, 2011. If you plan to sell your home during that time, contact your Claims Manager ***before*** you list the property for sale and they will provide you with all the information you need to participate.

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Customer Claims

210. What is our claims process for San Bruno residents in the affected area?
[NOTE: THIS ANSWER IS BEING UPDATED DUE TO THE CLOSING OF THE 900 CHERRY AVENUE CENTER ON FRIDAY. Our current claims process is mostly for immediate needs. Our claims representatives are at 900 Cherry Avenue every day from 9 a.m. to 6 p.m., and our claims representatives are also going door to door to assist customers. We are also streamlining our process for larger claims and longer term needs, so that it will be easier for our customers when those requests begin to come in.]

211. Can customers file multiple claims, or are we encouraging them to wait and file one claim?
Whichever best meets the needs of our customers. We know that our customers may need to be reimbursed for some items now, and then file an additional claim later.

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PHMSA

212. In 2004, the PHMSA ordered utilities to do risk assessments that take into account the special dangers posed by high-pressure lines that carry gas under heavily populated areas. Have we done this?
PG&E has fully implemented 49 CFR Part 192 Subpart O which mandates integrity assessments in High Consequence Areas. These regulations require all pipeline operators to identify transmission lines in high consequence areas by December 17, 2004, and to risk rank those pipelines for the purpose of prioritizing pipeline assessments. PG&E completed this activity prior to the deadline. The regulations also require fifty percent of the

transmission pipelines in "High Consequence Area" to have their baseline assessments completed by December 17, 2007, and PG&E completed that activity by the deadline. The regulations require all transmission pipelines in HCAs to have their baseline assessments completed by December 17, 2012, and PG&E is on track to meet that deadline.

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San Bruno Wildfire Insurance Application Q&A

213. Is the San Bruno accident covered by wildfire insurance?
No. The San Bruno accident does not fall within the definition of "wildfire", and will not be covered by the wildfire insurance application.

214. Why does PG&E need wildfire insurance?
The increasing number of fires in California over the last several years has made the liability insurance market for wildfire incidents uncertain and unstable, leading to higher costs for less coverage statewide.

[Only if asked]
In general, why do customers have to pay for damage caused by your equipment?
This is essentially the way it is now – we recover the costs of insurance premiums in rates, as does any other business. These are costs of doing business and the CPUC has allowed recovery of those costs.
[Only if asked]

215. What is the rate impact?
Because this would only go into effect in the event of a wildfire that involved our equipment, there is not a rate impact at this time.

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About PG&E Gas System

216. What is the basic outline of your gas system?
PG&E has an extensive natural gas system, stretching from the Oregon border down to Bakersfield. This system includes 42,141 miles of natural gas distribution pipelines and 6,438 miles of transportation pipelines, serving 4.3 million natural gas customer accounts. High-pressure transmission lines transport the natural gas to the distribution system via a network of mostly underground lines. The gas in these lines provides sufficient supply to meet short-term peak demands. The distribution system distributes gas to the customer.

217. How many gas transmission lines do we have in San Mateo County?

Excluding connectors or distribution feeder mains, PG&E has three transmission pipelines in San Mateo County

218. What is the oldest pipeline we have?
PG&E has pipeline that was installed prior to the 1940s. This pipe is regularly inspected and maintained to ensure integrity.

219. In 2007, PG&E sold about 571 million standard cubic feet of gas daily to your residential and business customers (according to this link: http://search.pge.com/cs.html?url=http%3A//www.pge.com/pipeline/library/regulatory/downloads/cgr07.pdf&charset=iso-8859-1&qt=MMCF&col=pge&n=6&la=en). Do you have an updated figure (i.e. more recent than 2007)?
The referenced report provides data from 2002 through 2006, and does not address 2007. For more current information, please refer to the California Gas Report Index http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml, which provides data through 2009.

Additionally, please note that the 571 million SCF per day of gas referenced in the question is only out-of-state gas received from Canadian sources (line 8, page 21) for 2006 and does not reflect the total volume of gas PG&E sent out to customers in that year. The total volume of gas PG&E sent out to all customers for 2006 is reflected on line 33 -- annual daily average of 2,298 million SCF per day.

220. What pressure do our gas transmission lines typically operate under?
Gas transmission lines in PG&E's system typically operate between 100 and 1040 psig. PG&E has short pipelines which interconnect to the McDonald Island Storage Facility which operate at 2160 psig.

221. What is the percentage of older to newer pipes in our system?
The bulk of PG&E's system has been installed since 1950.

222. Can you give us an overview of you gas control systems?
- PG&E has an extensive natural gas system, stretching from the Oregon border down to Bakersfield.
- This system includes approximately 42,000 miles of natural gas distribution pipelines and approximately 6,500 miles of transmission pipelines, serving 4.3 million natural gas customer accounts.
- High-pressure transmission lines transport the natural gas to the distribution system via a network of mostly underground lines. The distribution system distributes gas to the customer.
- The Milpitas Gas receives gas from Arizona and redirects the gas to our customers in the East Bay, Peninsula and San Francisco.
- In San Francisco, our Gas Control Center is a 24/7 facility that monitors PG&E's natural gas system.

- Operators in our San Francisco Gas Control Center utilize our SCADA system to monitor operating information on our gas system. SCADA stands for Supervisory Control and Data Acquisition.
- Using SCADA information and other available tools, our operators monitor compressor stations and pipelines along our natural-gas system and are able to adjust pressure and flow rate within the system, as needed.
- Sensors along our natural-gas system feed information about pressure, flow rate and other operating information to SCADA where it is used by our operators.

Only if asked:

- Our Milpitas Gas Terminal is unmanned, although crews frequently work at the site.

223. How many people normally staff the Gas Control Center?
During the weekdays the San Francisco Gas Control Center has 5 or 6 operators on shift and on weekends there are 4 operators on shift.

224. How many were working when the accident occurred on Sept. 9?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

225. How are pipe pressures monitored in the system?
PG&E uses Supervisory Control And Data Acquisition (SCADA) systems to monitor pressure in the transmission and distribution gas system. Pressure readings are taken throughout the system and monitored 24 hours a day, seven days a week by PG&E personnel in the Gas System Control office in San Francisco.

226. Did our systems detect any gas pressure, flow changes or other conditions prior to the explosion?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

227. In general, how do alarms appear to operators?
Sensors along our natural-gas system feed information about pressure, flow rate and other operating information to our San Francisco Gas Control Center where it is view and used by our operators. When a sensor reports a reading that passes a pre-determined alarm point, the SCADA system displays an alert message .The alarm must be acknowledged, analyzed and followed-up on by the operator.

228. Now that we have confirmed that there were no plans to replace the SCADA system in Milpitas, and that it had not been recently replaced, why are the Brentwood and San Francisco SCADA systems scheduled for replacement in 2011?
PG&E has no plans to replace its current SCADA system. Enhancements and modifications to the SCADA system occur periodically as pipeline facilities are added, replaced, or reconfigured.

229. Can the employees working at Milpitas station hear the alarms if, for instance, an alarm goes off? Or do they only hear them in the SF Control Center?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

230. Can these workers at the Milpitas separately control valves, etc. or do they have to send a message to someone else who has to do that (i.e. from the SF Control Center)?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

231. Did we have workers at the Milpitas terminal shortly before the blast or during that time period?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

232. Are we aware of any problems with any of the employees were having with SCADA systems (either in SF or Milpitas) before the blast?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

233. Where specifically is the gas terminal in Milpitas?
Near the intersection of Hwy 237 and I-880.

234. Is the only SCADA system that is relevant to line 132 Milpitas, where it originated, or is the SF SCADA system also relevant because it lies on the opposite end of line 132?
PG&E has only one, comprehensive SCADA system to monitor the operation of its pipeline system. Both ends of the Line 132 pipeline are contained in the single SCADA system.

235. Could you provide any additional information about the SCADA system in general – what additional information can PG&E provide about the SCADA system and how it works?
PG&E utilizes a single SCADA system to monitor the operation of the transmission and distribution pipeline system 24 hours a day, 7 days a week. PG&E's SCADA system utilizes standard industry software similar to all gas utilities.

236. Could you provide SCADA details during the time of the event?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

237. What is a UPS (uninterruptible power supply system), and how does it affect gas transmission?
A dedicated source of back-up electrical power to ensure continuous energy in that period between when the standard electric circuit fails and the emergency backup electrical power

begins operation. It allows any facility protected by such a system to continue operation by receiving electricity either from battery backup or on-site emergency generation without interruption.

238. How does it work? Can we provide any diagrams, explanations?
The UPS at Milpitas is a standby UPS. The equipment is powered by a standard electric utility circuit. When there is a power interruption, a power converter is activated in milliseconds and begins to provide equipment electrical power from the UPS batteries until power is restored or on-site emergency generation is activated. The ongoing NTSB investigation prevents PG&E from providing any diagrams specific to the UPS at Milpitas Terminal.

239. Why did this UPS fail?
Since the NTSB has gone on record that the operations work done at the Milpitas terminal is specifically an area of its inquiry, we cannot comment further on this subject.

240. When did PG&E replace the UPS? Was it replaced on September 9th?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

241. Why were you replacing the UPS? Was there something wrong with the old one?
The existing UPS has been in service for more than 20 years. It was installed at a time when the Milpitas terminal had a number of large computers that needed three-phase electric power for energy and cooling for the computers. That kind of power is no longer necessary. Moreover, the company that made the existing UPS system is no longer in business and we could not find a reliable source of replacement parts.

242. How long was power out? When did it go out?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

243. Did the UPS failure cause pressure in Line 132 to exceed the MOP of 375?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

244. What is the protocol for dealing with gas transmission line pressure when a UPS fails?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

245. Is there/was there a backup power source?
There is and was both a battery back-up and stand-by generation at Milpitas if the normal electric service is interrupted.

246. Did PG&E workers at the Milpitas Terminal notify those at the Gas Control Center in San Francisco that the UPS has failed?

Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

247. Is this a CPUC reportable failure?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

248. Has PG&E filed any kind of paperwork with the PUC or PHMSA regarding the work on the Uninterruptable Power Supply at Milpitas?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

249. Is there any public discussion of it?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

250. On the night of the incident there was 34 minutes between the time PG&E noticed pressure dropped (6:11 p.m.) and when PG&E dispatched a crew to isolate the ruptured pipe section (6:45 p.m.). Why did we not dispatch someone sooner?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

251. Why was PG&E not able to stop flows on the local distribution system of the burn area sooner? (report notes the gas distribution system feeding burned homes was shut off at 11:30 p.m.)
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

252. Why was the valve that moved from the partially open to fully open position designed to do so when the electric signal to regulate the valve for Line 132 was lost? Why was it designed to do that?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

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TURN Response

253. NOTE—Similar to question 17 and new questions added at end. State regulators in 2007 gave PG&E the go-ahead to spend $5 million of ratepayer money to replace a section of the same pipeline that exploded last week in San Bruno. But the work never got done as scheduled in 2009, and this year you asked for another $5 million to do the same job by 2013, according to documents you submitted to the California Public Utility Commission as part of a general rate-increase request. Can you respond?

At the outset, we want to be clear that this is a different section of pipe, approximately 2.8 miles away and installed at a different time than the pipe that ruptured.

PG&E is committed to performing the work necessary to assure the safety of its gas transmission system. Accordingly, PG&E is constantly prioritizing its projects using the most recent up to date information available.

In this particular case, PG&E identified this line section in 2006 as being a project for 2009 its workpapers for the 2008 gas transmission rate case, and sought five million dollars to fund the work. In early 2008, the pipeline engineer responsible for this area reanalyzed all available information on this segment. The information he reviewed included all of the data from the External Corrosion Direct Assessment (ECDA) conducted on segments of Line 132. In addition to reviewing the available data, the responsible engineer personally conducted a field investigation of the segment. This involved driving the entire section, observing that a portion of it was contained within a well-marked right of way and a portion under a public cul-de-sac. After this, in consultation with other pipeline integrity engineers, the responsible pipeline engineer determined that third party dig-in risk did not warrant immediate replacement of the segment (a third-party dig had caused a leak at MP 43 in November 2001) and the segment had not experienced any leaks due to corrosion. Based upon his review of information from the prior ECDA, his own observations, and his engineering judgment, and knowing that PG&E was going to be performing another ECDA later that year or the next year, he determined that the work did not need to be done as previously scheduled.

The 2006 work paper forecast $5 million for the replacement of this segment of Line 132. When the pipeline projects were reprioritized, that forecast money was spent on other priority projects instead. In fact, in 2008 and 2009, PG&E spent a total of $380 million on gas transmission capital projects, $12 million more than forecast.

254. What is the status of the project and how have we spent the funds, if at all?
No significant work has begun on this job as it is scheduled for 2013.

255. When will the project be completed?
The project is scheduled to be completed in November, 2013.

256. According to The Utility Reform Network, PG&E's expense request for 2011 as part of the gas rate case is $5.2 million. Is that accurate?
This is partially correct. PG&E has requested approximately $5.2 million in 2011 for O&M costs associated with meter protection and $630,000 in capital expenditures related to meter protection work. These expenditures cover items such as relocating meters, installing barrier posts to prevent vehicular contact with meters, and/or relocating service shut-off valves.

In 2009, PG&E completed a comprehensive review and enhancement of its meter protection program (MPP) policies and work procedures. As part of this review and enhancement, PG&E validated the criteria for when a meter requires protection, established a prioritization system for determining the order of protection installations, trained all leak survey employees to identify locations that require protection and implemented the use of a portable electronic data collection tool to gather information on locations requiring protection.

This program improvement allows PG&E to direct its resources on the highest priority work, more clearly define the necessary correction activities for each location and provide our customers, employees and general public a safe and reliable gas system.

257. TURN says that the 2011 request is $4.2 million higher than 2008 recorded amounts due to lower than forecasted spending on the Meter Protection Program (MPP) in 2008.
This is approximately correct for the comparison of the $5.2 million O&M expenditures requested in 2011 for meter protection. PG&E's recorded 2008 expenditures for this category of work was $967K for the Meter Protection Program.

258. TURN claims PG&E deferred MPP work to do higher priority work: "Preventive maintenance activities that required additional funding in 2007 included, leak survey and cathodic protection." In the line item for 2008-09, less money is projected for "miscellaneous" under cathodic protection in 2009 than in 2008. Miscellaneous includes include valve replacements and service cut offs, according to TURN's analysis of the rate case filings.
TURN's characterization of "deferred maintenance" when addressing the decisions that PG&E must make regarding managing day-to-day operations of a vast gas distribution system is simplistic at best and does not reflect the realities.

PG&E is faced with the relatively complex choice of determining appropriate levels of spending across multiple areas that have requirements in terms of safety, reliability and customer satisfaction. In making such decisions among possible expenditures, PG&E has the duty to prioritize as circumstances change, to ensure that relative impacts on safety reliability and customer needs are appropriately evaluated and addresses responsibility.

PG&E provides safe and reliable service to its customers with the funds available to it by prudently prioritizing its activities based on the actual conditions at the time.

With regard to the question addressing a miscellaneous category of work, PG&E cannot respond to this as there is no "miscellaneous" category under cathodic protection in PG&E's 2011 GRC application. Also, the cathodic protection work category does not encompass valve replacements or service cut-offs. Those types of work are captured in other work categories.

259. I want to make sure I understand PG&E's reading of these filings, and get a sense as to how such deferred work on valve replacements might impact safety issues such as the type that surfaced in the San Bruno explosion.
PG&E's 2011 GRC application has extensive testimony and supporting documentation that supports the need for and processes to prioritize all work. This is both an expectation of

the CPUC as well as a business process performed by every utility in order to ensure the highest priority work is performed in order to provide safe, reliable service to its customers, employees and the public while spending within overall levels set through the rate-making process.

When considering the question of "deferred maintenance," it is important to note that in 2007, 2008 and 2009, PG&E spent substantially more in the gas and electric distribution lines of business than was approved by the Commission in the 2007 GRC. In that three year period, PG&E spent above the authorized amount by $325.4 million in O&M and $567.3 million more in capital related to it gas and electric distribution system.

Finally any "valve replacements" related to PG&E's general rate case (2011 GRC) would not have been relevant to the gas transmission line involved in the San Bruno Incident. The 2011 GRC covers the gas distribution system, but does not cover the gas transmission system which was involved in the San Bruno incident. Any discussions in the 2011 GRC related to valve replacements are focused on the lower pressure gas distribution system.

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Meeting Winter Gas Needs

260. Have there been any decisions yet whether to rebuild or relocate the section of line?
PG&E is currently evaluating the impacts of all options, and will work closely with stakeholders to determine the best alternative.

261. How much would it cost to relocate the line?
At this point, it would be premature to speculate as we're currently evaluating all the options.

262. Is not having the segment of pipe a hindrance to our operations, i.e. are we able to continue providing gas to the area in the future?
Ensuring the delivery of reliable gas service to our customers is a priority for PG&E. This is a factor that we are evaluating as we continue to assess the impacts of all options, with weather playing a significant role.

263. What kind of work we are doing around the site?
In the last few days, PG&E has been doing an in-line camera inspection of the pipeline with the full knowledge and consent of the NTSB.

264. Can you provide the emergency response plan that was in place at the time of the San Bruno incident?
Since this is part of the NTSB's ongoing investigation into the cause of this accident, we need to refer you to the NTSB's public affairs department for a response to this question.

Generally speaking, PG&E maintains an annual public safety agency training program designed for emergency responders to learn about both gas and electricity first response and safety issues. PG&E does not widely distribute the plan as it includes both confidential operating information and personal information. However, PG&E does routinely share important plan elements with public safety agencies during joint exercises.

Examples of confidential information included in the plans are:

- Critical facility and redundant resources location information,
- Employee names,
- Internal emergency response phone numbers, and
- Home phone numbers.

265. If PG&E can't raise the pressure of Line 132, what impact will that have on customers going into holidays/colder weather? What are the implications? How would customers be affected?
Safety is PG&E's highest priority. Ensuring the delivery of reliable gas service to our customers is also a priority for PG&E, and we are analyzing our ability to supply all customers on the Peninsula at the current lower operating pressure as the colder weather approaches, but safety is always our highest priority. We will be working closely with the CPUC on how to best address the current situation and whether, or how much, to increase the current operating pressure

266. What are the alternatives you would consider? What might we be able to do? What would be the plan?
System planning engineers are currently performing analysis to develop contingency plans. PG&E is currently making various modifications to our gas system to increase system capacity. As stated above, we will be working closely with the CPUC on how to best address the current situation, what the best options are, and whether, or how much, to increase the current operating pressure

267. What areas would be impacted?
Noncore customers along the Peninsula could be impacted with larger impacts on the northern portion of the Peninsula.

IF ASKED:
What are non-core and core customers?
Noncore customers pay a reduced gas transportation rate due to their obligation to curtail their usage to insure reliable service to core (residential and small commercial) customers.

268. Is there any other way of getting needed gas to customers?
The only reliable supply of natural gas to the Peninsula is through the Line 101/109/132 transmission system.

269. Will we ask for voluntary curtailment of gas usage? How would that work?

We will be working closely with the CPUC on how to best address the current situation, what the best options are, and whether, or how much, to increase the current operating pressure.

270. What are the alternatives and implications for customers?
See response to # 240 and #241 above.

271. Has this happened before (when we haven't been able to raise the pressure of a pipeline or been able to meet demand)?
We have on occasion had to curtail non-core customers on our distribution system, consistent with PG&E gas tariffs and approved by CPUC regulators. Noncore customers pay a reduced gas transportation rate due to their obligation to curtail their usage to ensure reliable service to core (residential and small commercial) customers. Noncore customer curtailments have occurred on our distribution system during colder weather, pipeline maintenance activities, or if pipelines are hit causing PG&E to take portions of the system out of service.

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Pipeline 2020

272. Why do you call this Pipeline 2020?
Pipeline 2020 is a new PG&E program to guide the utility's efforts to strengthen its natural gas transmission system and advance industry best practices over the coming decade—thus the name. In consultation with state regulators and industry experts, our initiative will involve the accelerated modernization of gas transmission pipelines and valves, as well as support for research and development, development of industry best practices, and tighter coordination with public agencies and first responders.

273. Where do you plan to install automatic and remote shut-off valves?
We will start by closely examining our approximately 1,000 miles of gas transmission pipeline in densely populated and other critical areas. Our initial estimate is that our program could include upgrades to several hundred valves. We'll be filing an update with the CPUC in a couple of weeks. We'll work with industry experts and the CPUC to develop the right scope and timing.

274. What's your timeline?
Upgrading major infrastructure is a major undertaking. We will be working with regulators and third-party experts to help determine scope and timing. However, we've already begun enhancing our inspections of gas transmission infrastructure. If we identify any threat to public safety, whether through a customer report or our own ongoing assessments, we address the situation immediately.

275. How much will all this cost?
While we would like to be able to provide a ballpark estimate, the scope, timing and funding for this modernization program must be determined through a collaborative process with regulators and third-party experts. As this joint planning develops we will share cost estimates with regulators and the public.

276. Who is going to pay for all this?
The $10 million to spur the development of next-generation inspection technologies will be funded by PG&E, rather than its customers. We will work with the CPUC to recover costs for approved investments in pipeline upgrades, improved valves and other significant enhancements to our system wide transmission pipeline integrity program.

277. Why should ratepayers pay for this, when you were responsible for the explosion? Will PG&E move ahead with its 2020 upgrades without waiting for CPUC approval?
The cause of the explosion has not yet been determined by the NTSB. In advance of a determination of the cause of the event, PG&E has made a proposal to make upgrades in order to strengthen our gas transmission system and advance industry best practices. The scope and details of the 2020 pipeline upgrades require prior approval by the CPUC, because we are a public utility. The CPUC will determine the appropriate level of enhancement to our system and the cost recovery for the upgrades as part of their review.

278. Why didn't you do all this before?
The Pipeline 2020 program is a natural but major evolution of our existing programs, made an urgent priority by the San Bruno tragedy. PG&E already has a comprehensive inspection and monitoring program to ensure the safety of its natural gas transmission pipeline system and has upgraded that program over the years, proactively and in response to new state and federal regulations. We have instituted a number of additional measures following the San Bruno incident, including a comprehensive leak survey of the transmission lines to supplement our regularly scheduled leak surveys, a review of appropriate valve technology, and a significant improvement in our information sharing with local governments and first responders.
With Pipeline 2020, we are taking our programs to the next level, and going well beyond current regulatory requirements, to fulfill our commitment to customers and the public to ensure the safety and integrity of our gas transmission system.

279. Are we safe in the meantime?
Yes. Whenever we identify a threat to public safety, through a customer report or our own ongoing assessments, we take action to address it immediately. While we do not yet know the cause of the San Bruno tragedy, we have resurveyed all 200 miles of gas transmission lines serving the San Francisco Peninsula for leaks. The goal of Pipeline 2020 is to go beyond existing regulatory requirements to strengthen the integrity of our gas transmission system.

280. Can you do all this unilaterally? Do you need approval?
Some of the elements of the program, like enhancing our partnerships with local communities and first responders, can be done immediately and unilaterally. For other aspects, like pipeline modernization and installation of automatic or remotely operated shut-off valves, PG&E will work with regulators, independent experts and other stakeholders to determine the right criteria and timing.

281. How far behind the curve are you on industry best practices re policies and procedures?
PG&E operates its system pursuant to state and federal pipeline safety standards. In addition, we work with AGA and other industry participants to understand how they operate their gas

transmission systems. We are committed to working with others in the industry to develop and implement best-in-class practices. Part of the intent of Pipeline 2020 is to investigate further the practices others use in the industry from which we can all learn.

282. What kind of 3rd party are you thinking of? How will they be independent if you pay for them?
We will be seeking consultants with notable experience and expertise. We will look to for fresh, independent thinking as we develop and implement our program.

283. What is the "state of the art" in pipeline inspections? Why don't you follow it already?
There are currently three federally-approved pipeline inspection methods, each with its own advantages. As part of Pipeline 2020, PG&E will provide $10 million in funding to research and develop the next generation of pipeline inspection and diagnostic tools. Pipeline 2020 is really about taking the entire industry to the next level.

284. What kind of leading institutions and researchers do you have in mind for your R&D think-tank?
We will be looking for top-class engineering experience and talent, and for people who demonstrate a passion for advancing the state of the art in the interest of public safety and service reliability.

285. There already exist many organizations that do gas pipeline research and development. (for example: AGA, GTL, INGA, GOIA). Why does PG&E need to create another organization? Did PG&E consider funding an existing organization's research?
PG&E is creating a non-profit entity that will decide which competing research proposals should be pursued. We will work with industry groups and independent experts to identify specific research initiatives for funding. It may well be that some existing organizations get grants from the $10 million to fund these research initiatives.

286. What targets does PG&E hope to achieve with the first $10 million? Where will funding come from beyond the $10 million?
We expect that the non-profit entity will receive multiple proposals to study various aspects of pipeline maintenance and safety. We will be able to identify specific targets once these proposals are considered. We hope that other stakeholders with a strong interest in pipeline safety will contribute additional funding to the entity.

287. What is new about Pipeline 2020?
Pipeline 2020 is a natural but major evolution of our existing programs to strengthen our natural gas transmission system, made an urgent priority by the San Bruno tragedy. With Pipeline 2020, we are taking our programs to the next level, and going well beyond current regulatory requirements, to fulfill our commitment to customers and the public to ensure the safety and integrity of our gas transmission system. Pipeline 2020 also focuses on raising the bar for industry performance. PG&E - and for that matter to entire industry - will take a hard look at current best practices and work on taking them to the next level.

288. Several years ago PG&E testified before PHMSA and stated that automatic valves were too expensive and there is potential for inadvertent shut down. What happened to change PG&E's mind and cause it to look at installing automatic valves?
[Sent to Walnut Creek for review]

289. Over the years, the federal government has made calls to investigate the feasibility of automatic valves, but not requiring them. Hasn't the issue of whether auto valves are feasible been studied enough by research groups and the government, so why are we also calling for more research?
We are calling for more research on the next generation of diagnostic tools for pipeline maintenance and operations, not on the feasibility of automatic valves. Indeed, we expect to announce a program of upgrading manual valves in critical areas to automatic or remote shut-off valves, in consultation with regulators and independent experts.

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Misc.

290. Does PG&E want to increase the pressure on Line 132 in order to meet winter demand for gas in SF and the Peninsula? PG&E lowered the pressure by 20 percent after the accident.
PG&E will be working closely with the CPUC on how to best address the current situation and whether, or how much, to increase the current operating pressure.

291. PG&E has reported that it has lowered the pressure on line 132 to 300 psi. Has PG&E lowered the pressure on any other transmission lines since the accident?
Yes. Since Milpitas Terminal supplies all three Peninsula transmission lines (Lines 101, 109 and 132) from the same source, lowering the operating pressure of L132 to 300 psig also resulted in lowering the current operating pressures of Lines 101 and 109.

292. Was there a natural gas accident with a fatality in Madera August 22, 2003? What happened?
Yes, a farmer dug into PG&E transmission pipeline 118 while plowing his field. The line was marked for the farmer but the damage resulted in a leak that ignited causing equipment damage and the operator died 3 weeks later as a result of his injuries.

293. How much has PG&E spent on its gas system?
In recent years, PG&E has spent well over $100 million to improve its gas system, which is in addition to money regularly invested in the system.

294. Is there a difference between a gas leak in a transmission line as compared to a distribution line? i.e. would a transmission leak be harder to detect?
There is no significant difference in gas leaks or in detecting gas leaks just because they are on the distribution system vs. being on the transmission system.

295. Have we confirmed pipeline 131, in Fremont, is one of two pipelines in the Bay Area posing the highest risk? Is in or near the Hayward Fault?
FOR FREMONT CITY OR ELECTED OFFICIALS. Line 131 runs from the Brentwood Terminal to the Milpitas Terminal. Line 131 crosses the Hayward fault in the Fremont area. PG&E seismically retrofitted this crossing in 2002.
IF NOT FREMONT CITY OR ELECTED OFFICIALS: Line 131 runs from the Brentwood Terminal to the Milpitas Terminal. In 2002 PG&E seismically retrofitted Line 131 where it crosses the Hayward Fault.

296. What information do we have on the McDonald Island Pipeline project from 2005?
The McDonald Island Pipeline project was a 6.5 mile pipeline from the McDonald Island underground storage facility to the Brentwood Terminal that added both capacity and reliability to PG&E's system. The new line was bored under both the river and levees so that it would not be vulnerable to possible delta flooding. The pipeline was successfully put into operation in 2007.

297. Why did you cancel your contract with ServPro?
We originally had a contract with that company to do restoration work for our customers. As such, we hold Serve Pro, just like all our contractors, to the highest standards and immediately act when we hear concerns from our customers. Serve Pro is no longer on our list of approved contractors. We cannot get into the specifics of why that company is no longer on our list.

298. When was the last time the line at Ewing School in Fresno was inspected?
An external corrosion direct assessment was performed in June 2010 and a leak survey was performed in March and September 2010.

299. What type of cleaning work are you doing on transformers in San Bruno?
Last week's fire has caused residue and dirt to accumulate on electric insulators and other equipment on power poles. When the first moisture of the season comes, this wet residue can cause electrical arcing or flashovers, resulting in power outages and even pole fires.

There is light rain in the forecast over the next few days, so it's important for our crews to power-wash residue off of insulators as soon as possible.

Starting as early as 8:30am on September 17, PG&E crews and trucks will be in the neighborhood power-washing insulators on power poles, mainly located in backyards. Once again, this work is being done to enhance safety and electric service reliability in the area. Crews will be doing the work safely and as quickly as possible, however the work is expected to take most of the day.

300. Has any of PG&E's $992 million in general liability insurance been paid out, or are we waiting until the conclusion of the investigation? Is it more difficult for PG&E to get insurance for pipelines that are categorized as high risk?

PG&E does not intend to discuss specifics about insurance coverage this early in the process. We are committed to doing the right thing for our customers. We have established a fund up to $100 million to help residents and the city of San Bruno recover as soon as possible.

301. Did PG&E receive a request to mark its lines from D'arcy and Harty Construction which did sewer line work on and around Earl Avenue in San Bruno in April and May 2008? Can we check our records to confirm?
Yes - PG&E does have a record for a mark and locate request from D'arcy and Harty Construction around Earl Avenue in San Bruno. The request was made in May of 2008 for work to begin in June of 2008.

302. Did Chris Johns testify on Sept. 28 before a Senate subcommittee?
Mr. Johns appeared before the U.S. Senate Committee on Commerce, Science, and Transportation: Surface Transportation and Merchant Marine Infrastructure, Safety, and Security Subcommittee's hearing on pipeline safety on 09/28/10. Representatives from the NTSB, CPUC, the Pipeline Safety Trust and San Bruno Mayor Jim Ruane also testified at the hearing.

303. Congresswoman Speier has asked that PG&E move the transmission line. What is PG&E's response?
PG&E is currently evaluating the impacts of all options, and will work closely with stakeholders to determine the best alternative.

304. What are the pros and the cons of increasing pressure on Line 132?
Increasing the operating pressure of a pipeline increases the amount of gas that can flow through that pipeline to supply customers; maintaining a lower pressure reduces the stress on the pipeline.

305. How do we balance the needs of our customers with the safety of the pipeline?
Safety is PG&E's highest priority. Ensuring the delivery of reliable gas service to our customers is also a priority for PG&E, and we are analyzing our ability to supply all customers on the Peninsula at the current lower operating pressure as the colder weather approaches, but safety is always our highest priority.

306. What is the current pressure of the pipeline? (Our current information is still 300 psig. Is that still the case?)
The transmission pipeline system on the Peninsula including Line 132 is currently running at a reduced maximum operating pressure of 300 psig.

307. What pressure would we increase it to? The same operating pressure as prior to the accident?
The maximum allowable operating pressure of the Peninsula gas transmission system is 400 psig, and prior to September PG&E was operating with a maximum operating pressure of 375 psig. PG&E will be working closely with the CPUC on how to best address the current situation and whether, or how much, to increase the current operating pressure.

308. How much pressure do we need to adequately serve the area in colder conditions with the holidays approaching?
As noted above, ensuring the delivery of reliable gas service to our customers is a priority for PG&E. We will be working closely with the CPUC on how to best address the current situation and whether, or how much, to increase the current operating pressure.

309. How many customers are served off of L-132? (Is that possible to provide?)
The Peninsula gas transmission system (primarily Lines 101, 109 and 132) supplies gas to over a million people in San Francisco, San Mateo Counties and northern parts of Santa Clara. The pipeline system is interconnected and customers are not supplied simply from one pipeline.

310. What does an increase in pressure do?
An increase in pressure increases the volume of gas that can flow in the pipeline.

311. Where does the gas for L-132 come from?
The gas in Line 132 is transported from one of or a combination of four sources: Western Canada, the Southwestern US, the Rocky Mountains and within California.

312. What happens if there's not enough pressure?
Inadequate pressure can result in having to curtail large interruptible customers and, in extreme situations, significant reductions in the necessary amount of pressure would reduce the volume of gas flows such that it could interrupt supply to customers in general.

313. How have you responded to the October 15, 2010 letter from State Senator Dean Florez regarding the San Bruno Accident?
PG&E remains focused on responding promptly to requests for information on the September 9 San Bruno accident. To date, we have provided more than 50,000 documents to the NTSB, and have received more than 1,200 requests for information from the CPUC and other parties who all share a desire to learn the root cause of this tragic accident.

The NTSB is the lead investigator in this effort, and all of our responses are guided by the NSTB's rules for disclosing information about the accident.

> *If asked why we didn't provide all the information requested by Senator Florez in his letter of September 24:*
> NTSB guidelines prevent us from sharing information relating to the accident. Now that the NTSB has authorized the sharing of this information, we will be providing additional information to Senator Florez.
>
> We will provide this information as expeditiously as possible, and thank the Senator and his staff for recognizing the volume of material to be provided and the need for PG&E to prioritize this request against those of the NTSB and the CPUC.

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