BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

PREPARED DIRECT TESTIMONY OF ROYCE DON DEAVER ON BEHALF OF THE UNITED ASSOCIATION OF PLUMBERS, PIPE FITTERS AND STEAMFITTERS LOCAL UNION NOS. 246 AND 342, AND THEIR INDIVIDUAL MEMBERS

(from R. 11-02-019)

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I. Introduction

Pipelines do not last forever. They wear down, and eventually they can lose their suitability for service. This fundamental and immutable fact is why industry standards and the federal regulations developed throughout the 20th century require a multi-factored program of preventing and checking for leaks, corrosion, dents, mechanical and manufacturing defects, poor pipe installation, and the effects of stress in operating pipelines at various pressure levels. Each component of the maintenance and evaluation program in the federally mandated Integrity Management Program[1] is necessary for a comprehensive approach to preventing, identifying, and fixing leaks, cracks and corrosion that affect the life of pipelines and public safety.

California natural gas and liquid transmission pipelines face even greater physical challenges because of earthquake risks, rapid population increases and development of previously rural and remote areas. Temperature and water also play a role in the life of a pipeline.

Pipeline materials are never perfect. How close to perfection a pipeline can be is affected by the composition of the steel and the manufacturing process quality; the type and quality of the welds to connect pieces of pipe; how branch connections are made to the pipe; the handling of the pipe during construction; the composition and quality of the coating used to protect it from the elements; the skill of the welders joining segments of pipe; the method of installation into the ground; the inspection during construction; the pressure testing after construction; and documentation of these factors. The design, construction, operation, and maintenance of a pipeline involve hundreds of critical activities that must be performed to ensure a safe pipeline. Any activity not properly performed—or not performed *at all*—can cause failures that jeopardize the safety of the public and the supply of gas delivered to customers.

Industry standards and federal rules have attempted to control these design, materials, construction, operation, and maintenance issues as our knowledge of these factors increase over time. Today, we simply know more and can do more with pipeline materials and construction in the 21st century than we were able to accomplish with pipeline materials and construction technology in past decades.

[1] *See* 49 CFR 192.901 et seq.

The oil and gas industry began to develop standards for pipe fabrication, welding, placement, and testing in 1935. The first gas pipeline industry standard, ASA B31.1.8, was published in 1955. In 1961, California adopted standards into its regulations and laws, largely following the industry standards of the time. In 1970, the United States Department of Transportation (U.S. DOT) adopted the industry standards existing at the time into federal law and regulation. Pipeline integrity management rules were issued in December 2003. The industry standards and California and federal regulations focus on the technical requirements for design, pipe materials, construction, welding, corrosion coating, inspecting, testing, corrosion control, operations, maintenance, and emergency response.

The federal rules have always been written through an industry-dominated process. Thus, we cannot use the federal regulations as a model of best practices in the pipeline design, materials, construction, maintenance, and operation arenas. We can only view the federal rules as the agreed-upon minimum practices for pipeline construction, use and maintenance. After all, the title of 49 CFR Part 192 calls the rules "Minimum Federal Safety Standards." Industry standards are prepared and approved on a consensus basis, meaning every participant must agree on the contents. Therefore, industry standards sometimes represent the lowest common denominator of industry practices, not the best practices. These are often lagging, not leading, industry practices.

Although the federal rules are minimum practices to ensure pipeline integrity, the pipeline owner and operator is charged with the responsibility to ensure public safety in the operation of its gas pipelines.[2] The federal rules, adopted by the Commission as a minimum standard, create a multi-layered approach to ensuring that an old pipeline is still safe. That approach to finding preexisting problems in pipelines requires the following four inspection and testing methods:

1. Periodic surveying for leaks by using ground-sniffing instruments to detect gas leakage.
2. Direct assessment and physical inspection of the pipeline itself to detect and correct corrosion, mechanical damage, cracks, coating problems, and other pipeline integrity conditions.
3. Pressure testing, using water pushed through the pipes at specified pressure levels to detect

[2] *See, e.g.*, I.11-02-16 at p. 9, where the Commission states, "PG&E's obligations to public safety are informed by federal standards, but they do not depend on federal safety rules alone."

flaws, cracks, brittle pipe, corrosion, and mechanical damage that lower the strength of the pipeline. Pressure testing is required to be performed when the pipe is installed to make sure that it is fit for use. Pressure testing is also done to determine whether an existing pipeline is fit for continued service.

4. In-line inspection, using smart pigs that can travel inside the pipe to find corrosion, cracks, inferior welds, and mechanical damage.

All four inspection methods are necessary because they each give us different information on the physical condition of the pipeline and the safety of its continued operation. Taking away any of these four inspection methods from a pipeline integrity program can create a dangerous void in our knowledge about the soundness of the pipeline's future or continued operation. It is similar to the four blind men inspecting the elephant; unless each inspection tool is used periodically and appropriately, we will never get the complete picture of how the old pipeline is holding up. An incomplete picture leads to incorrect conclusions about what we know and what we are facing. In the case of pipelines that transport natural gas throughout California, inaccurate pictures lead to disasters like San Bruno.

Finally, there is human error during or after construction. Even a perfectly constructed, strong pipeline can develop problems through human error. The subject is barely addressed in the federal rules, but it is perhaps the most important element in pipeline safety. However, it has received little attention through the years under the assumption the pipeline industry has an interest in providing qualified people and compliance plans that are clear-cut and deployable. The Commission's directives to California gas pipeline owners and operators do not specifically address this issue, but the Commission should develop rules on worker qualifications.

The pipeline industry focuses on third-party error, which usually occurs when someone else digs to and dents or hits a pipeline. But digs and dents are only one small factor in the many factors that affect the life and ability of a natural gas transmission pipeline to safely transport gas.

My testimony will focus on the following key issues:

- **A focus on hoop stress alone will not ensure safety.** Hoop stress is the pressure exerted on the metal walls of a pipe by the gas traveling inside of the pipe. A survey of all accident data collected over several decades shows that hoop stress is not a good predictor of when a pipeline might experience a rupture. My survey demonstrates that hoop-stress-based exemptions from testing requirements should be eliminated from California's gas pipeline systems.

- **Old electric-weld pipe should be pressure tested to high levels and operated at extremely low levels, or completely eliminated.** A survey and technical analysis of data that was comprehensively collected by the DOT over two decades shows that old pipelines (pre-1975) that were manufactured and put together with EW pipe fail more quickly than the U.S. DOT had assumed they would when they allowed that kind of pipe to be used.
- Operating pressure limits and potential impact radius must be calculated properly to ensure the integrity of pipelines.
- Pressure testing must be conducted to sufficiently high levels and use proper methodology to establish an adequate level of assurance that the pipeline can be operated safely.
- All grandfathering of old pipes must be eliminated. This means that past pressure tests must meet today's standards. Merely reducing the MAOP or operating pressure of a pipeline is not a reliable method to ensure safety when a pipeline is found to be in unsatisfactory condition.
- Pipelines should be retrofitted to allow old pipelines to be inspected by in-line-inspection tools to monitor wear and tear going forward.
- Reliance on industry fatigue models for pipe may be misguided when those models are based on above-ground piping and are only based on analyzing hoop stress.
- Approving an Implementation Plan that fails to adequately ensure the safety of pipelines will be a waste of ratepayers' and shareholders money and will negatively affect California's economy.

II. Qualifications and Documents Reviewed in Preparing Testimony.

From 1964 to 1997, I worked for Exxon Pipeline Company as an engineer. I was involved in most all aspects of pipeline design, construction, and operations. Since 1997, I have been President of DEATECH Consulting Company near Houston, Texas. My work involves expert witness activities involving design, construction, operations, maintenance, corrosion control, testing, and work place safety of pipelines and other industry facilities. I have been a member of over 25 technical committees including many for ASME, API, and TAPS. I am a licensed professional engineer. I have not previously testified before the California Public Utilities Commission.

In preparing this testimony, I reviewed Resolution L-410, and the notice of R.11-02-019, and associated documents, including D.11-06-017. I reviewed the Independent Review Panel Report, dated June 9, 2011, available at http://www.cpuc.ca.gov/PUC/ events/110609 _sbpanel.htm, and the National Transportation Safety Board (NTSB) Report on San Bruno dated August 30, 2011, available at http://www.ntsb.gov/doclib/reports/2011/ PAR1101.pdf. I reviewed federal regulations and G.O. 112-E. I reviewed numerous reports and publicly available data from the U.S. DOT on hoop stress, electric weld pipe, hydrotesting, and pipe failures. I have also reviewed numerous historical and current industry standards and recommended practices. My review and opinions are guided by the Commission's decisions and my principles of ordinary care for a gas pipeline utility.

A. The Commission Has Required PG&E to Replace or Pressure Test All Transmission Pipeline that Has Not Been Tested.

In Resolution L-410 and R.11-02-019, the Commission ordered PG&E to use "traceable, verifiable, and complete records" to determine the "valid MAOP, based on the weakest section of the pipeline or component to ensure safe operation, of PG&E natural gas transmission lines in Class 3 and Class 4 locations and Class 1 and Class 2 HCAs that have not had MAOP established through prior hydrostatic testing."

Then, in D.11.06.017, the Commission found that "MAOP determined by component calculation is useful for prioritizing segments for interim pressure reductions and replacement or pressure testing, but MAOP determined in this manner is not reliable enough for permanent pipeline operations." (P. 27.) It further noted that "Natural gas transmission pipelines (operating at a pressure producing a hoop stress of 20% or more of SMYS) placed in service in California after July 1, 1961 were required to be pressure tested per General Order 112; however, pipelines installed before this date were exempted from pressure test requirements." (P. 27.) The Commission found that "Natural gas transmission pipeline operators should be required to replace or pressure test all transmission pipeline that has not been so tested." (P. 28.)

The Decision specifically encourages other measures that enhance public safety, finding that Implementation Plans should include "prioritization of pressure testing for critical pipelines that must run at or near MAOP values which result in hoop stress levels at or above 30% of SMYS, and other such measures that will enhance public safety during the implementation period." The findings and conclusions discussed herein fit within the measures that will enhance public safety and should be addressed in PG&E's Implementation Plan.

B. PG&E Should Be Held to a Standard of Ordinary Care for Gas Pipeline Utilities.

In evaluating PG&E's Implementation Plan, I have employed the following definition of "ordinary care" for a pipeline company:

1. Full and complete compliance with federal, state and local regulations;
2. Full and complete compliance with industry standards, recommended practices, guides, and publications;
3. Use of research, testing, and comprehensive engineering analysis when standards, recommended practices, guides, and publications are not available on how to perform or analyze a specific activity;
4. Placing the public safety and environmental protection ahead of the commercial interest of the pipeline company;
5. Conservative and objective analysis of information and data to err, when unavoidable, on the side of public safety, public health, and environmental protection rather than the financial interests of the pipeline company;
6. Behave proactively in seeking out, preventing, and solving problems before accidents and releases occur; and
7. Not taking avoidable chances with public safety, public health, others' property, and the environment.

These are the core values and behaviors needed for a company that manufactures, transports, or otherwise handles hazardous materials. These values should be expected of all pipeline operators in California, and these are the standards to which the California Public Utilities Commission should hold all gas utilities. With these values in mind, I turn to the specific recommendations to improve PG&E's Implementation Plan.

II. Hoop-Stress-Based Exemptions from Hydrotesting Should Be Eliminated.

The maximum allowable operating pressure (MAOP) of a pipeline is based, in part, on the strength of the manufactured pipe before it goes into the ground. One type of stress that pipes experience in service is hoop stress. Hoop stress is the average circumferential stress in a perfectly round, uniform pipe. It is a measure of the average stress on the pipe metal caused by internal pressure. Hoop stress is different than the operating pressure of a pipeline, which is the pressure of the natural gas inside the pipe. Internal pressure is usually measured in pounds per square inch (psi) and values usually range from 100 psi to 1000 psi in gas transmission pipelines. Hoop stress is typically measured in ksi (thousands of pounds per square inch), and values typically range from 5 ksi to 50 ksi.

The amount of hoop stress that a pipe should be able to withstand is measured as Specified Minimum Yield Strength (SMYS).[3] SMYS is a value specified by the pipe manufacturer that takes into account the strength limits of steel pipe. It is the stress that a particular pipe should be able to withstand indefinitely with little or no permanent yielding or deformation.

Under federal regulations, pipelines are allowed to operate at up to 72% of SMYS, and sometimes at up to 80% of SMYS, depending on their location.[4] There are additional limits on operating pressure based on the location of the pipeline. Pipelines are assigned class locations (1, 2, 3, and 4) based on consideration of the number and types of buildings that would be affected by a pipeline rupture. Pipelines that are in Class 3 and 4 locations, and in high consequences areas (HCAs), cannot operate at as high of a pressure as those in less populated areas. The allowable operating pressure of a pipeline is determined by hydrotesting, or through previous operating pressure if the pipe was exempt from hydrotesting at the time of its installation.[5]

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[3] See 49 CFR § 192.3 (SMYS is defined as: "(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or (2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).").

[4] See 49 CFR §§ 192.611, 192.619-192.620

[5] See 49 CFR §§ 192.3; 192.503; 192.611; 192.619; 192.620.
49 CFR § 192.619 (a)(2)(ii) provides that for steel pipe operated at 100 p.s.i. or more, the test pressure is divided by a factor determined in accordance with the following table:

(footnote continued on next page)

Hydrotesting has been used by pipeline utilities for over seventy-five years to verify pipeline integrity before putting a pipe into service. Pipelines are hydrotested to make sure that they are structurally sound and do not leak. Pipes are cleaned out and filled with water. The pressure is slowly raised to the required test level, and then held for a period of time, generally between 4 and 8 hours under federal regulations.[6] The maximum allowable operating pressure (MAOP) of a pipeline after it is in service is based on the pressure to which it was tested when it was constructed, with certain exemptions for older lines.[7]

New pipelines in all class locations must be hydrotested to a factor of 1.1 to 1.5 times their maximum allowable operating pressure (MAOP).[8] But pipelines installed prior to 1970 were exempted from pressure tests under federal regulations. Pipelines may be tested at as low as 1.1 x MAOP in Class 1 locations. Current pressure testing requirements do not take into account old manufacturing, construction, and fabrication techniques that were frequently used in the past. Current pressure testing requirements do not take into account other stresses on the pipe during the life of the pipe from being in the ground. Both the root cause of San Bruno and data on numerous natural gas pipeline failures show that pipes may fail even when their operating pressure is well within the limits set by federal regulations.

A. Root Cause of San Bruno Explosion

One of the primary conclusions of the NTSB Report is that over pressuring—exceeding the allowable operating pressure—did not cause the rupture in San Bruno. The NTSB explains: "The internal line pressure preceding the rupture did not exceed the PG&E maximum allowable operating

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Footnote continued from page 9

Class location	**Factors, segment—**		
	Installed before (Nov. 12, 1970)	**Installed after (Nov. 11, 1970)**	**Converted under §192.14**
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[6] 49 CFR § 192.505 (c) & (e).
[7] See 49 CFR §§ 192.3; 192.503; 192.611; 192.619; 192.620.
[8] 49 CFR § 192.620; *see also id.* §§ 192.503; 192.619.

pressure for Line 132 and would not have posed a safety hazard for a properly constructed pipe." (NTSB Report, p. 132.)

Rather, the NTSB finds, exempting pre-1970 pipes from pressure testing led to the explosion. The NTSB Report explained: if "grandfathering of older pipelines had not been permitted since 1961 by the California Public Utilities Commission and since 1970 by the U.S. Department of Transportation, Line 132 would have undergone a hydrostatic pressure test that would likely have exposed the defective pipe that led to this accident." (NTSB Report, pp. 106-07 (emphasis added).)

These findings are consistent with my research on other natural gas pipeline incidents. Data on pipeline ruptures demonstrates the critical importance of hydrotesting all of California's transmission lines, and repairing and replacing all inadequate and poorly constructed pipelines. Recent studies that focus entirely on hoop stress as a measure of the adequacy of hydrotests rely on data about above-ground piping. But underground pipes are different – they are susceptible to seismic and other ground stresses, corrosion, and mechanical damage, but they are hidden from visual inspection and tests, and their physical condition is difficult to determine.

B. Hoop Stress-Based Distinctions in PG&E's Decision Tree.

PG&E's Implementation Plan decision tree contains numerous distinctions based on a percentage of the pipe's Specified Minimum Yield Strength (SMYS). PG&E proposes to follow the DOT regulations defining transmission pipelines as those pipelines that operate at 20% of SMYS or higher.[9] For pipelines operating at 20 to 30% SMYS, PG&E proposes delaying testing, or deferring replacement as compared to those pipelines operating at more than 30% of SMYS.

Pipeline regulations consider the hoop stress on a pipeline in creating exemptions from hydrotesting and other safety requirements. But my study of data reported to the U.S. DOT shows that

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[9] Transmission pipelines that operate at less than 20% SMYS are excluded from the pressure testing requirements for transmission lines; *see* 49 CFR § 192.3 ("*Transmission line* means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field."); 49 CFR 192.505(a) ("Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure."); PG&E Implementation Plan, Ex. 3A.

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there is not a strong correlation between natural gas pipeline incidents and operation above 30% of SMYS. ASME B31.8 includes requirements for designing and operating pipelines that gives consideration to stresses other than hoop stress, but these requirements have not been codified in federal law.

C. DOT Data Shows that Hoop Stress Is Not a Good Predictor of Gas Pipeline Incidents.

Attached as Exhibit C is my meta-study of five studies containing data related to natural gas pipeline incidents. My study shows that the pipelines that have experienced leaks and ruptures were often being operated at a low percentage of SMYS when the incident occurred, suggesting that 30% of SMYS is not a good predictor of when an incident might occur. ***About half of the incidents occurred at a hoop stress of less than 20% of SMYS.***

In 1970-73, there were 1,635 natural gas pipeline incidents reported to the DOT. [10] ***About 50% of the ruptures due to outside forces occurred at a hoop stress of 5,000 psi or less, which is less than 10% of SMYS for X-52 pipe.***[11] About 80% of the ruptures due to outside forces occurred at a hoop stress of 15,000 psi or less (which is less than 29% SMYS for X-52 pipe). About 50% of the ruptures due to construction or material defect occurred at a hoop stress of 15,000 psi or less (less than 29% SMYS of X-52 pipe). Over 50% of the ruptures occurred at a hoop stress of 12,000 psi or less (23% SMYS of X-52 pipe).

In 1970-1984, 60% of in-service incidents occurred at low to moderate hoop stress (under 12 ksi), or less than 23% of SMYS for X-52 pipe. 22% of incidents occurred at very low hoop stress (under 3 ksi, or less than 6% of SMYS for X-52 pipe).

For incidents with reported failure stress data in 1970-84, 61.4% of the incidents occurred at a hoop stress of 9 ksi or less, which would be 17.3% of SMYS (or less) for an X-52 pipe. ***This means that under PG&E's Implementation Plan, well over half of the pipeline incidents during the years that failure data was reported to the DOT involved pipe that would not even be looked into, much less***

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[10] *See* Deaver, P.E., *Exemptions for Low Hoop Stress and Low Pressure Gas Transmission Pipelines*, Jan. 25, 2011, filed herewith as Exhibit C, p. 2.

[11] X-52 pipe is approved by API 5L for use in natural gas transmission lines, and was and continues to be commonly used in such lines.

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hydrotested. Current federal rules allow an even greater percentage of potentially problematic pipe to be left untested.

By contrast, for ruptures and leaks occurring during *pressure tests* in 1970-84, only 9.2% of incidents occurred when the test pressure was 12 ksi or less. Notably, 47.5% of the incidents during pressure tests occurred when the hoop stress was over 39 ksi, which is 75% SMYS for an X-52 pipe.

According to my analysis of all publicly-available data reported to the DOT, in 1984-1990, nearly half (44%) of all on-shore natural gas pipeline incidents involved pipes that were operating at less than 20% of SMYS. Well over half (56.3%) occurred where the pipes were operating at less than 30% of SMYS. ***Under PG&E's Implementation Plan, most of these pipes would not even be checked for verifiable records, much less hydrotested. Even those that were checked would be de-prioritized in favor of pipe operating above 30% of SMYS.***

Table 1. Natural Gas Pipeline Incidents Compared to Percent of SMYS, 1984-1990

Percent of SMYS	Percent of Total Incidents
≤ 10%	34.7
> 10% to ≤ 20%	9.3
> 20% to ≤ 30%	12.3
> 30% to ≤ 40%	14.4
> 40% to ≤ 50%	8.6
> 50% to ≤ 60%	5.6
> 60% to ≤ 70%	6.9
> 70% to ≤ 80%	6.0
> 80% to ≤ 90%	0.9
> 90% to ≤ 100%	1.3

In 1985-1994, my review of publicly available data involving natural gas incidents similarly shows that pipelines with problems were often operating at a low percentage of SMYS. (See Exhibit C.) Unfortunately, more recent data is not available because no studies have analyzed the incidents reported to the U.S. DOT since the mid 1990s, and to collect and glean this information through individual records would be a massive undertaking. The U.S. DOT does not analyze or summarize the data based on cause. Thus, the data set used in my analysis comprises the most comprehensive failure data publicly available.

The NTSB Report recommended establishing metrics to evaluate performance-based regulations and compliance programs.[12] These data would have provided some of the metrics recommended by the NTSB for evaluating performance-based regulations and pipeline operators' compliance programs.

These studies make clear that considering hoop stress alone is not a sufficient predictor of problems with natural gas pipelines. Corrosion, dents, and other geometric irregularities also cause higher stress in the pipeline, but these stresses are not normally considered in formulating regulatory compliance requirements. For underground pipe, stresses caused by external loads, seismic forces and ground movement are not fully addressed in formulating regulatory compliance requirements. But these factors are critically important in ensuring the safety of gas pipelines located in California.

Pipeline hoop stress should not be the only consideration in determining which pipe segments should be tested and replaced. Hoop stress is a primary consideration, but there are many other sources of loads acting on pipelines. Pipelines often contain flaws, corrosion, and geometric irregularities. Many pipelines are old and constructed of inferior and sometimes unknown materials. Blanket exclusions of low-hoop-stress pipelines in regulations and industry standards should be discontinued.

The safe operating pressure limits of a pipeline cannot be determined unless other sources of stress than internal pressure are analyzed and stress limits are set and satisfied from all sources. The DOT data leads to the conclusion that hoop stress by itself is not an adequate justification for exemptions from pressure testing. Operating limits are based on consideration of hoop stress. Operating limits are supposed to be lower than the point at which a pipe fails from internal pressure. When failures occur while the pipeline is operating below its MAOP, and at a low percentage of SMYS, the MAOP has failed to adequately account for stresses other than internal pressure that have weakened the pipe. The older a pipeline becomes, the higher the levels of stress from sources other than internal

[12] NTSB Report, p. 121.

pressure are likely to be.

PG&E's pressure testing proposals represent a significant enhancement in safety as compared to current lax federal standards. But the testing plan does not go far enough to ensure safety. The DOT definition of transmission pipe contains a blanket exclusion of all transmission pipe operated at less than 20% of SMYS, and the PG&E Implementation Plan incorporates that definition. Imprudently, this exclusion de-prioritizes transmission pipe operating at less than 30% of SMYS. The Implementation Plan fails to adequately assess and test pipe in ways that could have serious safety consequences.

PG&E should include ***all*** transmission pipe in its decision tree, even pipe operating at less than 20% of SMYS. It should prioritize work based on location in Class 3 and 4 locations and HCAs, and on manufacturing and construction specifications, rather than based on whether the pipe is operating at more than 30% of SMYS. Eliminating hoop-stress-based exemptions from testing requirements is necessary to ensure the safety of PG&E's system.

III. Electric Weld Pipe Needs to be Tested or Replaced.

In Exhibit D, I have reviewed and commented on a report by the U.S. DOT Office of Pipeline Safety (OPS), titled "Electric Resistance Weld Pipe Failures on Hazardous Liquid and Gas Transmission Pipelines."[13] This report found that 102 natural gas incidents were caused by electric weld (EW) failures during 1971-1986. The DOT OPS study covered both electric resistance welded (ERW) pipe and electric flash welded (EFW) pipe. (Collectively, both of these pipe types are referred to as electric welded (EW) pipe.) ERW and EFW pipe welds are similar in appearance, have many of the same metallurgical properties, and experience many of the same types of defects. They are sometimes misidentified on pipeline documents because they look similar.

A. EW Pipe and Measurement of the Strength of Pipe Seams.

Pipeline segments are manufactured using a variety of techniques to weld pipeline seams together. While some pipe segments are seamless, many contain machine-made welds. Federal pipeline regulations take into account the strength of these seam welds on pipes in calculating the strength of the

[13] U.S. Department of Transportation, Office of Pipeline Safety, *Electric Resistance Weld Pipe Failures on Hazardous Liquid and Gas Transmission Pipelines*, August 1989.

pipe.[14] The measurement of the strength of a seam weld is known as a joint factor. A joint factor of 1.0 indicates the pipe seam weld is as strong as the base metal or steel from which the pipe is welded. It means that the pipeline operator does not have to reduce MAOP to account for the seam weld. A joint factor of less than 1.0 would reduce the pressure at which the pipe would be allowed to be operated, indicating that the seam weld was weaker than the pipe itself.

Many of California's pipelines are 40 to 60 years old, and some pipelines have been in service for more than 100 years. To ensure the safety of these pipelines, the pipe seam joint factor must be appropriate for both short-term and long-term pipeline service. If a type of pipe is given a pipe seam factor of 1.0 for design purposes, but the pipe seam has a significant history of failing in service before its base metal fails, a pipe seam factor of 1.0 is not justified.

EW pipe was first manufactured in the 1920s, and low-frequency, inferior ERW pipe was made until 1980.[15] The EW manufacturing process often resulted in "cold welds," where loss of heat during the welding process resulted in areas where the pipe did not bond together properly.[16] EW pipes frequently contained defects that were undetectable by visual inspection. A pressure test to 90% of SMYS would have identified those pipes that had cold weld problems, but pipes were often only tested to 75% of SMYS.[17]

Despite a long history of problems associated with EW pipe, federal regulations apply a longitudinal joint factor of 1.0 for EW pipe. This means that without justification, EW pipe enjoys the same pipe joint factor as seamless pipe and double submerged arc welded (DSAW) pipe. By contrast,

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[14] See 49 C.F.R. §§ 192.105, 192.113. Section 192.105(a) provides that the design pressure for steel is determined by the formula $P=(2\ St/D)\times F\times E\times T$, where P=Design pressure in pounds per square inch (kPa) gauge; S=Yield strength in pounds per square inch (kPa) determined in accordance with §192.107; D=Nominal outside diameter of the pipe in inches (millimeters); t=Nominal wall thickness of the pipe in inches (millimeters); F=Design factor determined in accordance with §192.111; E=Longitudinal joint factor determined in accordance with §192.113; and T=Temperature de-rating factor determined in accordance with §192.115.

[15] Kiefner, *Dealing with Low-Frequency-Welded ERW Pipe and Flashwelded Pipe with Respect to HCA-Related Integrity Assessments*, Paper No. ETCE2002/PIPE-29029, February 4-6, 2002, available at http://www.kiefner.com/downloads/ERW.pdf, p. 2. EW pipe made since 1980 has used a different manufacturing technique and does not pose the same problems as pre-1980 pipe.

[16] *See id.*

[17] *Id.*

furnace butt-welded pipe has a joint factor of 0.6, and "other" types of pipe have a joint factor of 0.6 or 0.8 depending on the size of the pipe.[18] A joint factor of 0.6 indicates the seam is only 60% as strong as the steel from which the pipe is made, and ensures a commensurate reduction in pressure. As the DOT data show, this joint factor of 1.0 is not justified for early EW pipe.

B. Pressure of Early EW Pipe at Failure Was Low Compared to Previous Hydrotesting.

Using data from the DOT study for early EW pipe, I compared the hydrotest pressure at the time of installation to a pipe's failure pressure. This is known as a test pressure ratio at failure. A pipe which was tested to 800 psi, but failed while in service at 500 psi, would have a test pressure ratio at failure of 1.6. A test pressure ratio at failure of 2.0 means that the pipe failed when it was operating at only 50% of the test pressure.

For the available data, I found that the average ratio of test pressure to failure pressure was 1.742. On average, early EW pipe that experienced failures were failing at 57.4% (100% ÷ 1.742) of the test pressure. This means a pipe that was tested to approximately 1,000 psi at installation would have failed, on average, while being operated at only 574 psi. This data suggests that EW pipe does not ensure public safety.

Any pressure testing that may have previously been done on EW pipe under federal regulations would have been based solely on MAOP, which does not consider the particular weakness of EW pipe. Based on the data in the study, ***a test pressure ratio of 1.25 x MAOP would have eliminated only 20% of pre-1970 EW seam failures***. The pressure testing requirements in the federal regulations are inadequate to protect against EW pipe that fails even when it is operated at as low as 57% of its test pressure.[19]

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[18] 49 CFR § 192.113.

[19] Since 1970, 49 CFR Part 192 has only required a minimum pressure test factor of 1.1 times the allowable maximum steady state operating pressure (MAOP) for the gas pipeline in a Class 1 location. 49 CFR §§ 192.619 & 192.610. Additionally, a 10% "overpressure" margin has been allowed since 1971, meaning that a pipe is allowed to operate at 10% over MAOP for pressure limiting purposes. *Id.* §§ 192.195; 192.199; 192.201(a)(2)(i); 192.619. Thus, the pressure test factor provides *no* margin above the allowable maximum operating pressure in the pipeline in a Class 1 location. In effect, the federal government allows Class 1 pipes to operate at their

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C. Conclusions from Analysis of Early Natural Gas EW Pipe Seam Failures.

In my study of EW pipe, I analyzed all of the 81 natural gas pipelines incidents over a fifteen year period (1971-1986) where complete data was publicly available from the DOT. (See Exhibit D.) The EW pipe included in the study had been installed during a forty-year period. The average time to failure in this data set was 15.65 years. I calculated a linear regression equation based on the 81 data points, which shows that the failure of early EW pipe was not dependent on the length of time that it was in service.

For a pressure test conducted at 90% of SMYS in a Class 1 location, the MAOP would have to be 35% of SMYS for the pressure test to reliably prevent future incidents. (See Exhibit D, p. 7.) This limit is considerably lower than the 72% of SMYS allowed in 49 CFR Part 192 for the MAOP of Class 1 gas transmission pipe. That means that Class 1 pipe would have to be tested to 2.6 x MAOP.

Similarly, for Class 2 locations, to achieve a 90% confidence level based on the data in this study, the allowable maximum operating pressure would have to be 31.3% of SMYS. The required test factor to achieve this goal would be 2.9 x MAOP.

D. EW Pipe Should Be Replaced.

These data I reviewed very strongly support the need for a pressure test ratio of at least 2.0 x MAOP for all parts of pipelines comprised of early EW pipe. This study is based on data of ruptures during the 1970s and 1980s. Since the time of these incidents, utilities have continued to operate EW pipe. This pipe has likely continued to deteriorate. The data included in the DOT study supports an even higher test pressure ratio for populated and environmentally sensitive areas.

An average ratio of hydrostatic test pressure to in-service failure pressure of 1.742 shows that early EW pipe was failing at 57.4% of the test pressure (100% ÷ 1.742). But in Class 1 locations, pipes are permitted to operate at 90.9% of the test pressure (100% ÷ 1.1), meaning that current operating

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hydrotest pressure, creating no margin of safety. For a Class 2 location, the minimum pressure test factor is 1.25 x MAOP. *Id.* § 192.619(a)(2)(ii). With the 10% overpressure allowance, a pressure test provides a 1.136 margin above MAOP [1.25/ 1.1]. For a Class 3 and Class 4 location, the minimum pressure test factor is 1.5 x MAOP [1.5/1.1]. *Id.* With a 10% overpressure allowance, the pressure test provides a 1.364 margin above allowable maximum operating pressure.

requirements do not sufficiently account for the high failure rate of early EW pipe. This indicates the pipe seam factor of early EW pipe should be less than 0.63 (57.4% ÷ 90.9%), and not 1.0 as allowed in 49 CFR Part 192. In other words, the MAOP must be multiplied by 0.63 to account for the extra vulnerability of early EW pipe. The ratio of failure pressure of electric weld pipe to hydrostatic test pressures show that the longitudinal joint factor should be lowered from 1.0 to 0.63 for early EW pipe.

1. Applying an Appropriate Longitudinal Joint Factor to EW Pipe.

If the longitudinal joint factor of early EW pipe is lowered to 0.63 for all class locations, we can calculate the appropriate ratio of test pressure to MAOP as follows:

For a Class 1 location, with a 10% margin for overpressure protection, and a 10% margin for pressure reversal and other premature failures, the ratio should be increased from 1.1 x MAOP to 1.6 x MAOP. The data demonstrate that to ensure the safety of EW pipe in Class 1 locations, PG&E should repeat a pressure test every 15.7 years to match the average failure period experienced by EW pipe in my analysis.

For Class 2 locations with a longitudinal joint factor of 0.63 for early EW pipe, a 10% margin for premature failure, and a 10% margin for overpressure protection, the 90% confidence level pressure test ratio is 1.78 or 1.8 x MAOP. This compares to a test pressure factor of 1.25 x MAOP, an EW longitudinal joint factor of 1.0, and no margin for overpressure protection or premature failure contained in current federal pipeline safety regulations. This combination of lower joint factor and higher test pressure will ensure that early EW pipe will not fail at less than a 90% confidence level based on the 81 gas pipeline failures described in the U.S. DOT report. The pressure test would have to be repeated every four years to ensure a 90% confidence level based on the failure period after the test. Such a testing interval is cost-prohibitive.

For a Class 3 location, with a longitudinal joint factor of 0.63 for early EW pipe, a 10% margin for premature failure, and a 10% margin for overpressure protection, the 95% confidence level pressure test ratio is 2.13 or 2.1 x MAOP. This compares to a test pressure factor of 1.5 x MAOP, an EW longitudinal joint factor of 1.0, and no margin for overpressure protection or premature failure contained in current federal pipeline safety regulations. This combination of lower joint factor and higher test pressure than presently required will ensure that early EW pipe will not fail at less than a 95%

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confidence level based on the 81 gas pipeline failures described in the U.S. DOT reports. ***To achieve a 95% confidence level, the pressure test would have to be repeated annually, which is not feasible or cost-effective.*** This demonstrates that ***replacement of all early EW pipe*** in Class 3 locations should be completed with highest priority, as the safety of such pipelines cannot be ensured for any reliable time period after hydrotesting.

For a Class 4 location with a longitudinal joint factor of 0.63 for early EW pipe, a 10% margin for premature failure, and a 10% margin for overpressure protection, the 99% confidence level pressure test ratio is 3.0 x MAOP. This compares to a test pressure factor of 1.5 x MAOP, an EW longitudinal joint factor of 1.0, and no margin for overpressure protection or premature failure contained in current federal pipeline safety regulations. This combination of lower joint factor and higher test pressure than presently required will ensure that early EW pipe will not fail at less than a 99% confidence level based on the 81 gas pipeline failures described in the U.S. DOT reports. ***To achieve a 99% confidence level, the pressure test would have to be repeated in one month, a practice that, of course, is not feasible.*** This demonstrates that ***replacement of all early EW pipe in Class 4 locations*** should be completed with highest priority, as the safety of such pipelines cannot be ensured for any reliable time period after hydrotesting.

2. Adequate Pressure Testing Levels.

A pressure test ratio of 3.0 x MAOP would have eliminated 95% of the pre-1970 EW test failures and made early EW failures in service a less significant safety concern. Such a pressure test would be appropriate for pre-1970 EW pipe in populated areas and highly sensitive environmental areas, seismic areas, and areas near aqueducts, gas storage fields and water aquifers. If pre-1970 EW pipe had been tested to 100% of its specified minimum yield strength (SMYS), its allowable maximum operating pressure should be only 33.3% of SMYS based on testing to 3.0 x MAOP [100/3]. This would have significantly reduced the allowable maximum operating pressures in pipelines, but would have been necessary for public safety.

For older EW pipe, a pressure test above a hoop stress of 90% of SMYS is unlikely to be achievable without numerous test failures, testing costs, pipeline repairs, and re-testing. A pressure test to 75% of SMYS or less is more likely to be consistently achievable. ***It may be more efficient to simply***

replace existing EW pipe than to test it to sufficiently high levels, experience failure, and then replace the failed pipe. Alternatively, testing EW pipe to lower levels may result in lower rates of failure for testing purposes, but will not ensure the future operational safety of PG&E's gas transmission pipeline going forward.

I have created the following minimum test pressure recommendations to address the 10% overpressure allowance for pressure limiting devices in 49 CFR Part 192, and a 10% margin for pressure reversals and other premature failure considerations with electric resistance welded and electric flash welded pipe. The test pressures for pre-1980 electric resistance welded and electric flash welded pipe are based on the data in the 1989 U.S. DOT report on electric resistance welded pipe failures. Pressure test levels should be as follows:

1. Pre-1980 electric resistance welded and electric flash welded pipe where a pipe longitudinal joint factor of 1.0 is applied:
   a. For Class 1 locations, a minimum test pressure of 2.5 x MAOP;
   b. For Class 2 locations, a minimum test pressure of 2.9 x MAOP;
   c. For Class 3 locations, a minimum test pressure of 3.3 x MAOP; and
   d. For Class 4 locations, a minimum test pressure of 4.8 x MAOP.
2. Pre-1980 electric resistance welded and electric flash welded pipe where a pipe longitudinal joint factor of 0.63 or lower is applied:
   a. For Class 1 locations, a minimum test pressure of 1.6 x MAOP;
   b. For Class 2 locations, a minimum test pressure of 1.8 x MAOP;
   c. For Class 3 locations, a minimum test pressure of 2.1 x MAOP; and
   d. For Class 4 locations, a minimum test pressure of 3.0 x MAOP.
3. For electric resistance welded pipe manufactured after 1980 with a seam factor of 1.0,
   a. For Class 1 locations, a minimum test pressure of 1.33 x MAOP (1.1 x 1.1 x 1.1 MAOP);
   b. For Class 2 locations, a minimum test pressure of 1.50 x MAOP (1.1 x 1.1 x 1.25 MAOP);

c. For Class 3 locations, a minimum test pressure of 1.8 x MAOP (1.1 x 1.1 x 1.5 MAOP); and

d. For Class 4 locations, a minimum test pressure of 2.0 x MAOP.

4. For seamless and double submerged arc welded pipe manufactured to a standard that does not match API 5L quality level 2,

a. For Class 1 locations, a minimum test pressure of 1.25 x MAOP (1.1 x 1.1 MAOP);

b. For Class 2 locations, a minimum test pressure of 1.4 x MAOP (1.1 x 1.25 MAOP);

c. For Class 3 locations, a minimum test pressure of 1.65 x MAOP (1.1 x 1.5 MAOP); and

d. For Class 4 locations, a minimum test pressure of 1.8 x MAOP.

5. For seamless and double submerged arc welded pipe manufactured to a standard that matches API 5L quality level 2,

a. For Class 1 locations, a minimum test pressure of 1.25 x MAOP;

b. For Class 2 locations, a minimum test pressure of 1.25 x MAOP;

c. For Class 3 locations, a minimum test pressure of 1.5 x MAOP; and

d. For Class 4 locations, a minimum test pressure of 1.5 x MAOP.

IV. PG&E's Calculation of Potential Impact Radius Is Under-Inclusive of High Consequence Areas (HCAs).

A. Calculation of Potential Impact Radius.

Under current federal regulations, high consequence areas (HCAs) may be calculated using two different methods.[20] The first method calculates HCAs by including pipes in Class 3 and 4 locations, and pipe segments in Class 1 and 2 locations where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy.[21] The second method identifies HCAs by calculating whether the potential impact

[20] See 49 C.F.R. §§ 192.903 & 192.905.
[21] *See id.*

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radius (PIR) of an incident contains 20 or more buildings intended for human occupancy. PG&E uses the second method to calculate HCAs.

PIR is the radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property. HCAs are those pipe segments that are located in dense geographical location such that a rupture or failure would affect 20 or more buildings within 660 feet of the potential failure site.

Under federal regulations, PIR is calculated using the following equation:

$PIR = 0.69 \text{ x } d \, x \, (p)^{0.5}$

PIR is the radius of a circular area in feet surrounding the potential point of failure, p is the MAOP in the pipeline segment, and d is the nominal diameter of the pipe in inches.

For the San Bruno incident, the PIR of the affected segment was about 400 feet. However, the radius of the blast was approximately 600 feet, with a house approximately 900 feet from the rupture damaged by the fire.[22] The extent of damage experienced in the San Bruno pipeline rupture tragically illustrates the inadequacy of the current federal PIR calculation.

1. Basis of PIR Equation

The PIR equation in 49 CFR Part 192 is based on the recommendations of the gas pipeline industry. The recommended PIR equation appeared in Gas Research Institute Report No. 00/0189, *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*.[23] The emergency escape conditions assumed for the PIR equation are:

1. Pipeline ruptures and soon ignites;
2. A person at the PIR distance remains still for five seconds “to evaluate the situation” and identify a nearby shelter;
3. The person then runs 2.5 meters per second (25% of an Olympic sprinter) in the direction of a wooden building within 200 feet to provide shelter from the fire;

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[22] See NTSB Report, p. 19, fig. 11. Although the fire damage primarily extended to a radius of about 600 feet from the pipeline blast center, it damaged a house as far as 900 feet away.

[23] See Mark J. Stephens, *A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, Prepared For the Gas Research Institute, Contract No. 8174 (October 2000), available at http://www.cycla.com/opsiswc/docs/s8/p0054/IMPGas_00-0189HCAsize.pdf

4. After running for about 25 seconds, the person reaches a suitable shelter and has immediate access to the building;
5. The total response time to reach a sheltered building is 30 seconds;
6. For 30 seconds of fire exposure, the allowable heat exposure for 1% chance of mortality is 5,000 BTU/hr.-ft.^{2};
7. If the fire-exposure time becomes 60 seconds, the mortality rate goes to 50% for a 5,000 BTU/hr.-ft.^{2} exposure; and
8. If the fire-exposure time becomes 90 seconds, the mortality rate goes to 100% with at 5,000 BTU/hr.-ft.^{2} fire exposure.

These fire exposure versus mortality studies are based on industrial settings involving trained people in fire protective clothing, hard hats, and long sleeves. Fire exposure for older people, people with disabilities, and for people with less protective clothing, results in higher mortality rates.

Thus, the PIR equation is based on unrealistic considerations of public safety. It should be rejected.

2. Technical Problems with the PIR Calculation

The PIR equation has the following technical problems:

1. The flow rate equation from a ruptured pipeline contains an incorrectly applied orifice coefficient of 0.62.[24] Since there is no flow obstruction in a ruptured pipeline, the orifice coefficient should not be applied.
2. The allowable heat intensity is the same as the allowable heat intensity for metal process equipment. ANSI API 521, which addresses flare designs and heat exposure analysis, indicates that a much lower heat intensity needs to be used for people exposed to a fire, even for a short time, for emergency escape purposes.
3. The emergency escape exposure time is based on an unrealistic set of conditions for application to public safety as discussed in 1 above.
4. The PIR equation is based on an assumption of instantaneous ignition and does not include the

[24] An orifice co-efficient measures the volumetric flow rate. The co-efficient indicates how restrictive the flow is.

effects of a delayed ignition resulting in a large initial fire. Where ignition is delayed, a large amount of gas may build up, resulting in a larger fire. For a one-minute delay in ignition, the 1% mortality distance is increased by 3.15 when compared to an instant ignition. The fireball would reach out to about 90% of the current PIR distance, to burn everything within that area. For a two minute delay in ignition, the 1% mortality distance is increased by four when compared to an instant ignition. The fireball from a two minute delayed ignition would reach 106% of the current PIR distance. [25]

3. Needed Changes to the PIR Equation

ANSI/API Standard 521, *Pressure-Relieving and Depressuring Systems*[26] covers the design of flares used for disposal of hazardous substances at refineries, chemical plants, natural gas processing plants, and gas transmission facilities. API 521 limits fire exposure to 1,500 BTU/hr.-ft.^{2} to locations where emergency actions lasting two minutes to three minutes can be required by personnel without fire exposure shielding, but with appropriate fire resistant clothing.[27] Under the federal regulations, there is an assumption of a 5,000 BTU/hr-ft.^{2} exposure for 30 seconds. If exposure goes to 90 seconds at this level, there is an estimated 100% mortality rate. Assuming two to three minutes is a more realistic escape time, changes to the calculation are needed to prevent deaths.

These requirements suggest that changes are needed to the PIR equation. A fire exposure limit of 1,500 BTU/hr.-ft.^{2} will increase the PIR equation by 1.83. Elimination of the orifice factor will increase the PIR equation by 1.27. The combined effect will be to increase the PIR by 2.37 to become:

$$PIR = 1.6 * d * (p)^{0.5}$$

where

d = pipe diameter in inches, and

p = internal pressure in psig.

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[25] FRANK P. LEES, LOSS PREVENTION IN THE PROCESS INDUSTRIES: HAZARD IDENTIFICATION, ASSESSMENT AND CONTROL, vol. 2, Chapter 16: Fire (2d ed. 1996).

[26] ANSI/API Std 521, Guide for Pressure-relieving and Depressuring Systems: Petroleum, Petrochemical and Natural Gas industries, American Petroleum Institute, Fifth Edition, Jan. 1, 2007 (available for purchase at http://www.techstreet.com/cgi-bin/detail?doc_no=api|std_521;product_id=1319585).

[27] *See id.*

Under this calculation, the San Bruno PIR would have been 930 feet, not 400 feet, as presently calculated under 49 CFR Part 192. The actual burn radius in San Bruno reveals the inadequacy of the PIR equation in calculating high consequence areas. Additionally, Gas Research Institute Report No. 00/0189 acknowledges that "anecdotal information on natural gas pipeline failures suggest that the time to ignition may typically be in the range of one to two minutes (as in the Edison, New Jersey incident of 1994)."[28] If a delayed ignition is considered, the PIR would increase. For a two-minute-delayed ignition, the PIR equation would be:

$$PIR = 3.5 * d * (p)^{0.5}$$

This would result in a larger PIR value, more closely approximating the potential impact radius of a failure.

PG&E's Implementation Plan relies on the federal regulations' flawed calculation of HCAs, and is under-inclusive of pipeline segments for pressure-testing, which could have a significant impact on public safety. Additional pipeline segments should be included as HCAs, and should be prioritized in phase 1 for pressure testing, repair and replacement.

V. Hydrotesting Requirements

A. All Pipelines Should Be Hydrotested to Today's Standards.

As the Commission recognizes, all pipes must be hydrotested to ensure the safety of the system. However, the one hour of pressure testing to 1.1 x MAOP permitted under the Commission's Decision will not be adequate to ensure the safety of the system.

The NTSB Report recognizes that lower pressure testing levels allowed under federal regulations are inadequate. It recommends a test pressure of 1.25x MAOP.[29] The NTSB report concludes that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure.[30] The NTSB's conclusion demonstrates that PGE should not be allowed to rely on

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[28] Mark J. Stephens, *Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, Gas Research Institute Technical Report No GRI-00/0189, October 2000, p. 7, available at http://www.cycla.com/opsiswc/docs/s8/p0054/IMPGas_00-0189HCAsize.pdf.

[29] See NTSB Report, p. 125.

[30] *Id.* p. 129; P-11-15.

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records of tests to less than 1.25 x MAOP as a substitute for testing.

Under PG&E's proposed Implementation Plan, records as low as 1.1 x MAOP can be relied on as a substitute for pressure testing or replacement. That proposal should be rejected.

Moreover, PG&E has admitted that its class location determinations contain significant inaccuracies. The Commission recognizes a serial problem exists concerning PG&E's class location data because it instituted an investigation into the problem.[31] The distinction between test levels for various class locations is based entirely on the estimated death and damage that a rupture would cause to a more highly populated area. There is no inherent difference in the type of pipe used in a class 2 location versus a class 3 location. Other experts have indicated a hydrostatic test to 1.5 x MAOP is required to reduce the chances of pressure reversals in older ERW pipe in populated areas.[32] As a result, to ensure safety, and in anticipation of future population growth, the Commission should require PG&E to test all pipelines at least to class 3 requirements, although such testing may be assigned a lower priority for pipelines in classes 1 to 2.

B. Test specifications

It is of utmost importance that all hydrotesting be properly conducted. Further specifications are needed in PG&E's Implementation Plan to demonstrate compliance with today's standards. I recommend that the Commission require the following minimum test methodologies:

1. Air and Gas Removal

First, all hydrotests must eliminate the air and gas in the pipeline through pigging and the use of high point venting. Air in the pipeline is compressible. Its compression absorbs pressure, alters pressure readings, and thereby decreases the reliability of the test. For pipelines that are not currently piggable, PG&E must detail how they plan to achieve a reliable result without pigging the pipe first.

2. Hold for At Least Eight Hours

Under Subpart J, strength tests are generally required to be held for at least 8 hours. There is an exception for fabricated units and short sections of pipe for which a post installation test is impractical;

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[31] See I.11-11-009.

[32] J.F. Kiefner, *Evaluating Pipeline Integrity-Flaw Behavior During and Following High Pressure Testing, AGA Seventh Symposium on Line Pipe Research*, October 1986.

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such segments may be tested for only four hours.[33] In my experience, a pressure test should be held for at least 8 hours. This helps to account for changes in temperature during the course of a test, and provides a more reliable result. Additionally, the hold time must not include any time during which the test segment was being filled with water; it should start when the test pressure is reached. Where PG&E proposes that it rely on prior pressure tests, such tests should not be relied on unless they were held to 8 hours, and the test period did not begin until the water temperature was stabilized.

3. Higher Pressure Testing Required.

Hydrotesting must be performed at sufficiently high pressure to ensure the safe-operation of the pipeline. There is no guidance in the federal regulations about the percentage of SMYS to which a pipe must be tested. Instead, hydrotesting requirements are based on MAOP, allowing PG&E to test a pipe at a low pressure compared to the SMYS of the pipe, and then to put the pipe back into service at a low operating pressure based on MAOP. But such a course of action defeats the entire purpose of hydrotesting in the first place. If pipes are tested at low pressures, PG&E will not be able to detect problems in the pipe that could fail soon after the test. When PG&E spends money on hydrotesting, it should be done at a high pressure that ensures safety without wasting resources.

PG&E should be less concerned about pipe ruptures during hydrotesting than pipe ruptures during service. If a pipe cannot be safely operated at the pressure it was designed to operate at, it should be replaced.

VI. In-Line Inspections

As the NTSB Report explained, "In-line inspection technologies can be effective at finding flaws and providing data for comparison over time. Another advantage is that in-line inspection is a nondestructive test method. However, there are some limitations to the technology. There is generally at best a 90 percent probability in-line tools will detect a certain type of known defect."[34] This

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[33] 49 CFR 192.505 (c) & (e).

[34] NTSB Report, pp. 83-84. Because a single smart pig can only detect flaws in a single direction, the Commission should require utilities to conduct surveys for both axial and longitudinal defects when using smart pigs. Axial magnetic flux leakage ("MFL") tools and circumferential MFL tools should be used together to maximize the likelihood of identifying both longitudinal seam defects, defects in girth welds, and metal-loss and corrosion issues. Separate mechanical damage tools should be used to detect areas of mechanical damage.

probability applies to each defect in the pipeline. Statistical methods used with in-line surveys indicate that if a pipeline contains numerous defects, the probably that at least one will not be detected increases above 10%.

The use of in-line inspection tools will allow PG&E to monitor pipelines on an ongoing basis. Currently, 80% of PG&E's transmission lines are not piggable.[35] While in-line inspections will be helpful for monitoring and promoting safety in the future, they are of less critical importance to install immediately. A PG&E engineer explained that retrofitting a pipe for pigging could take 3 to 4 years.[36] Given this time frame, hydrotesting will be of more assistance in assessing the safety of the highest priority pipelines immediately. PG&E should replace all pipe stubs and other impediments to testing, but this does not necessarily need to be prioritized in phase 1 of this proceeding, because hydrotesting should be given priority. When PG&E uncovers pipes with stubs and other limitations during hydrotesting, those stubs and other impediments should be replaced before the hydrotest is conducted to maximize cost efficiency. PG&E should plan to make its pipe 100% piggable over the next ten to twenty years.

VII. Automated Shut-Off Valves/Remote Shut-off Valves.

An automated or remotely operated shutoff valve is of little use unless the occurrence of a large leak or rupture is known to the pipeline company. Knowledge of the leak or rupture location is also necessary to know which valves to close. Therefore, the pipeline SCADA control center must know when and where a large leak or rupture occurs. This requires continuous monitoring of pressure and flow rate on a real time basis to detect an abrupt change in flow rate and pressure.

SCADA systems do not normally perform continuous measurement, monitoring, and analysis of pressure and flow rate. They use a polling or scanning technique to gather operating information at some pre-determined interval. With this method of data collection, a sudden change or spike in flow

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[35] *See* NTSB Report, p. 85, noting that as of August 2011, 987.98 miles of PG&E gas transmission lines could accommodate in-line inspection tools, and 742.42 of those miles have been inspected using those tools. PG&E has 6,438 total miles of gas transmission lines. *Id.* p. 51.

[36] NTSB Report, p. 66.

and pressure conditions can be missed between data scan times. These data scan durations are very short; therefore, any specific pipeline location may be monitored less than 1% of the time.

Where pressure and flow are continually monitored at two adjacent points, the difference in time for a pressure spike to reach each point can be used to estimate the location of the rupture or large leak, what valves to close and which emergency responders to call.

To ensure a rapid detection and closure of isolation valves, the valves should be closed automatically. The problem with inadvertent valve closures can be addressed with a manual override from the SCADA system to stop or slow down the closure. The automatic action relieves the control room operator from the burden of justifying valve closures.

The use of rapidly closing valves will likely have little effect on people trapped in the fire unable to find shelter. However, for those able to find shelter from the fire, rapidly closing valves should have a significant effect in reducing the likelihood of them losing their shelter to protect them from the fire. In populated areas, rapidly closing valves should have a positive impact on public safety.

VIII. Quality Control

I have reviewed the testimony of pipeline inspector Marshall Worland and U.A. Local 342 Business Representative Mike Mikich. Mr. Worland and Mr. Mikich describe welds in PG&E's existing pipelines that are completely unacceptable and extraordinarily dangerous. The defective welds and extensive corrosion they describe magnify the risks of a future incident like the San Bruno tragedy.

The condition of the existing pipelines suggests that in many locations, hydro-testing and inline inspection may be a waste of time and money, and allow continued public exposure to unacceptable risk of catastrophe. The Commission should direct PG&E to proceed ***now*** with identifying and replacing pipelines like those Mr. Worland and Mr. Mikich describe. Replacing those pipelines should be included in Phase I of PG&E's Plan.

A. Independence of testers and inspectors is necessary to quality control.

My 48 years of work with gas pipelines have shown me that in order to ensure quality control, it is crucial that all participants be competent, knowledgeable, independent, committed to public safety, and free of conflicts of interest and favoritism. Key personnel such as inspectors and testers must be required to independently perform their work without pressure from the pipeline operator or other sources.

Inspectors and testers must be held to a high standard of conduct, and they must be allowed to meet this level of conduct. Their duties require them to enforce requirements rigorously, including high standards of workmanship. That requires independence and objectivity unimpaired by close ties to the pipeline operator.

The necessary independence and objectivity appear to be lacking in the relationship between PG&E and its pipeline inspection service, CANUS Corporation. Mr. Worland and Mr. Mikich report that many of CANUS' inspectors, supervisors and executives are former PG&E employees. More troubling are their reports that CANUS refrains from inspecting welding done by PG&E-employed welders on pipelines for which it is engaged, and that CANUS does not hold PG&E-employed welders to PG&E's own welding specifications.

Public safety and pipeline integrity require pipeline inspectors and testers to enforce pipeline standards firmly and forcefully. The Commission should adopt rules that ensure independence and strong enforcement of standards. The Commission should make clear that these independence requirements apply to new construction and pipeline integrity issues such as pressure testing.

B. Worker qualifications

Inspector Worland also reports poor skill levels and welding practices among the PG&E-employed welders. As he explains (at ¶¶ 12-13), PG&E's welding procedures require the "root passes" for girth welds to be made in 6 to 8 minutes.

Pipe to be welded must be preheated before it is welded, and must maintain heat in the pipe while welding is completed. The purpose of the rule is to ensure that the temperature is maintained throughout all of the welding passes. If pipe cools down, it must be preheated before the weld is completed. Welding too slowly allows the pipe being joined to cool before welding is completed, and that allows cracks to form in the welding joint.

But Mr. Worland reports that PG&E's welders usually took an hour or more to make root-pass welds—10 times slower than required—and they failed to meet welding-speed and temperature requirements on the subsequent passes. Poor workmanship like this jeopardizes pipeline integrity.

Moreover, ASME B31.8 requires that for piping to be operated at hoop stress of 20% or more

SMYS, welders and welding procedures shall be qualified under API 1104 or ASME IX. This means for pipelines operating ***under*** 20% of SMYS, welders may not have been adequately qualified.[37] All welders, whatever gas pipeline they work on, should be qualified under API 1104 or ASME IX.

API 1104 requires that all welders take and pass a welding test whenever they first report for pipeline welding work. Welders are tested on both the speed and quality of their welding.

It is essential that welding tests be administered fairly and objectively. They should not be administered by the pipeline operator, but by an independent testing facility. The Commission should require that welding tests be administered independently, not by PG&E as is PG&E's current practice.[38] Doing so is necessary to pipeline integrity.

C. Qualification of Contractors

Contractors should have their own quality assurance plans that meet or exceed the requirements of the pipeline operator. Contractors' plans should incorporate all of the pipeline operator's, governmental and industry standards (including API Standard 1104 and ASME B31.8) that apply to their work for the operator. Contractors should have personnel that are competent, knowledgeable, independent, committed to public safety, and free of conflicts of interest and favoritism.

Contractors' employees should be free of unwarranted pressure and repercussions when performing their jobs. They should be encouraged to step forward and report failures to adhere to the applicable standards. They should also have whistleblower protections from retaliation.

49 CFR 192.911 requires each Integrity Management Program to include a quality assurance process as outlined in ASME B31.8S, Section 12.[39] The Commission should set specific rules

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[37] This provides all the more reason to test these lines. To ensure the safety of future welding, PG&E should not rely on the hoop stress-based exclusion.

[38] See PG&E's Response to the U.A. Local Unions' Discovery Request 1, Question B.2, attached hereto as Exhibit B-1.

[39] Section 12 of ASME B31.8S requires the pipeline operator to:

1. Determine the documentation required for and included in the program.
2. Ensure that the personnel involved in the integrity management are <u>competent</u>, aware of the program and <u>all</u> of its activities, and are <u>qualified</u> to execute the program. Documentation of such competence, awareness and qualifications, and processes for achieving program goals, must be part of the quality control plan.

addressing each of the foregoing concerns in Phase I of this Rulemaking, because each concern will affect the quality of the work done and the integrity of PG&E's pipelines.

The testimony of Mike Mikich and Marshall Worland demonstrate that reports from the job site, made by knowledgeable, responsible workers, are invaluable to pipeline safety and integrity. Those workers should be encouraged to speak out, and they should be protected from any reprisals.

VIII. Changes to Decision Tree

The decision tress of PG&E should be simplified as described in Exhibit E filed herewith. Based on the data and studies I have reviewed above, and my 48 years of pipeline experience, I recommend changes to PG&E's decision tree as shown in Exhibit E. Based on my hoop stress study, I recommend that PG&E eliminate the exemption for transmission pipelines operating at less than 20% of SMYS, as shown in Exhibit E, p.2.

A. Changes to Manufacturing Threats Decision Tree

In looking at manufacturing threats, PG&E should ask whether a segment is pre-1980, not pre-1970. As other experts have concluded, poorly constructed EW pipe was manufactured and available as late as 1980.[40] It should be replaced.

As discussed in the hoop stress and EW studies, pipe with possible manufacturing threats should be tested to at least 2 x MAOP. HCAs should be recalculated with a more realistic PIR standard, and they should be prioritized along with Class 3 and 4 locations, and Class 2 locations that are nearby, or more efficient to test at the same time as Class 3 and 4 locations, based on their relationship to Class 3 and 4 pipeline segments. Class 1-2 locations can be strength tested in phase 2 as a matter of priority.

Additionally, in addressing manufacturing problems, PG&E should not distinguish between pipes operating at over 30% of SMYS and those operating under that. Sub-standard pipe is still

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3. Make periodic internal audits of the integrity management program and its quality plan are recommended. An independent third party should review the entire program.
4. When an operator chooses to use outside resources to conduct any process that affects the quality of the integrity management program, the operator must ensure control of such processes and document them within the quality program.

[40] See Kiefner, *Dealing with Low-Frequency-Welded ERW Pipe and Flashwelded Pipe with Respect to HCA-Related Integrity Assessments*, Paper No. ETCE2002/PIPE-29029, February 4-6, 2002, available at http://www.kiefner.com/downloads/ERW.pdf, p. 2.

problematic, even when the pipe is operating at a low pressure, as hoop stress is not the only factor affecting the life of the pipe. Studies in support of the 30% of SMYS distinction have been based on testing conditions, not on service conditions.

Finally, for those pipes requiring fatigue analysis, such analysis should include external load assessment (thermal effects, external loads, non-seismic ground movement and seismic ground movement), all sources of stress (not just hoop stress), and should be based on fatigue growth rates for below-ground piping, not above-ground piping.

B. Changes to Fabrication and Construction Threats Decision Tree

In making a decision about fabrication and construction threats, PG&E should consider whether pipes were constructed before 1975, not before 1960. In 1970, new federal regulations went into effect governing fabrication techniques.[41] But contractors and pipeline companies did not immediately upgrade their construction practices. A pre-1975 inquiry should capture all poor construction, assuming contractors may have taken a few years to come into compliance with the regulations. Wrinkle bends and certain other sub-standard construction practices should be eliminated regardless of when they happened, and some sub-standard practice occurred well into the 1970s. Quality welding involves butt welds, and no bell and spigot joints, oxyacetylene welds, and no chill rings. Quality construction requires a utility to create written specifications; design drawings; welding qualifications; independent inspection; radiographic weld testing; pressure testing; and complete records on design materials, construction, and testing.

Again, the 30% of SMYS hoop stress distinction should be eliminated, because these problematic fabrication techniques are a problem regardless of the operating pressure of the line. A past pressure test is not sufficient to protect against the inadequacies of bell-bell chili rings, pre-1940 arc welds, oxyacetylene welds and bell spigots, so these pipeline features should be replaced. These types of welds limit and/or prohibit pigging of a pipeline. Those pipelines in HCAs, Classes 3-4 and related Class 2 segments should be prioritized for phase 1, with the remaining work in phase 2.

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[41] *See* Subpart G—General Construction Requirements for Transmission Lines and Mains, 49 CFR § 192.301 et seq.

C. Changes to Corrosion and Latent Damage Decision Tree

Since 1970, federal regulations have required that all failures in pipelines be investigated and that continuing surveillance be performed by pipeline operators to evaluate the physical condition of each pipeline and determine if corrective action should be taken.[42] These processes have been essential elements for threat identification and corrective action for all pipelines. PG&E past activities to perform or not perform these activities will have a significant bearing on the adequacy of their compliance programs and the CPUC's assessments of their responsibility to pay for upcoming work due to past negligence.

With regard to ongoing maintenance, some fatigue models for defect growth do not consider the effects of stress other than hoop stress and cannot be considered as being reliable. These models also used fatigue growth rates for above-ground piping that are inappropriate for underground piping. Reassessment intervals may be shorter for underground piping than for above-ground piping.

The possibility of mechanical damage should be considered as shown in Exhibit E, page 8. For each pipeline segment, PG&E should investigate whether a mechanical damage program comparable to 49 CFR § 192.614, and a pipeline patrol program comparable to 49 CFR 192.703 have been in place during the life of the pipeline. A mechanical damage program should, at a minimum, include a written mechanical damage program; dissemination of the program to contractors, excavators, and the public; person-to-person contact with excavators and contractors at excavation sites; damage prevention procedures; inspection of excavation activities in the vicinity of the pipeline; and inspection of the pipeline before, during and after any excavation and construction activities are completed. For pipelines in HCAs, PG&E should implement a frequent pipeline patrol program (FPPP) to ensure that surface conditions are patrolled on a regular basis to prevent damage.[43]

Analysis of external corrosion should look at whether a pipeline's coating complies with 49 CFR 192.461; whether the pipeline has been under cathodic protection under 49 CFR § 192.463; and whether an in-line inspection for corrosion has occurred. To address internal corrosion, an internal corrosion control program (ICCP) should be implemented. At a minimum, an ICCP program should include: (1)

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[42] *See* 49 CFR § 192.617.
[43] *See* 49 CFR § 195.412.

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analyzing the gas stream for corrosive components, (2) pigging to remove liquids, (3) analyzing removed liquids for corrosive components, (4) using internal corrosion coupons at moisture accumulation locations, (5) using corrosion control inhibitors when corrosive conditions are indicated by the gas stream analysis and corrosion coupons, (6) monitoring leakage surveys and failure investigations for indications of internal corrosive, and (7) preparing and following a detailed and prescriptive internal corrosion control program based on "worse-case indications of corrosion" and corrosion growth as required by ASME B31.8S. Where necessary, PG&E should conduct direct assessment of potential areas of corrosion, and conduct ground level and below-ground leak surveys in conformance with 49 CFR § 192.273.

To address corrosion and latent damage threats, PG&E again should not distinguish on the basis of 30% of SMYS. PG&E should take additional steps to address corrosion as outlined in Exhibit E, pages 5, and 7-10.

IX. Ratemaking

Myriad technical issues necessary to ensure the safety of PG&E's gas transmission pipelines remain for the Commission to define and establish. These issues include setting the correct methodology for pressure testing , determining how much pipe is to be pressure tested, determining the criteria for pipeline replacement, determining when and where ASVs or RCVs should be used and the appropriate locations of whichever valves are selected, and determining to what extent PG&E's lines should be piggable, as discussed above. Determining the appropriate technology for smart pigs and for shut-off valves comprises a prodigious effort in itself.

The Commission should also evaluate the additional work and changes in pressure-testing methodology that I demonstrate above are necessary before it can determine the ratemaking consequences of what work is required. Other parties also will advance important improvements to PG&E's Implementation Plan that require Commission evaluation prior to ratemaking.

It is critical for the Commission to examine fully the limitations of federal regulations and to develop its own prescriptive rules for pipeline evaluation, pressure testing, repair and replacement. The

Commission has recognized in numerous proceedings[44] that PG&E's extensive lack of historical records for testing, evaluation, operation and repair has hampered if not made impossible a thorough evaluation of the kind of historical data upon which performance-based rules could be developed.

Without complete historical data, performance-based rules should not be employed. Only prescriptive rules and worst-case interpretations can be employed.[45] The NTSB concurs that the lack of data and historical knowledge hampered the development of requisite safety rules.[46]

Thus, relying on the federal performance-based criteria -- which presume that there are accurate historical records from which to evaluate performance -- is not an option if the Commission is to ensure the safety of PG&E's gas transmission pipeline system.

I have been informed that, during the last decade, PG&E's revenue requirements for its gas pipeline and storage system have been set by settlement agreements between the parties that were approved by the Commission.[47] Practically speaking, the Commission's approval of PG&E Gas Accord settlements throughout the past decade, especially without detailed evidentiary hearings testing the proposed cost estimates by project and account, hinders its examination and oversight of the true costs

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[44] See the Commission's own Orders Instituting Investigation with respect to various PG&E practices in: I.011-02-16; I.11-12 -009; I.12-01-007; CPUC Consumer Protection & Safety Division, *Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno,* California, Jan. 12, 2012; CPUC Consumer Protection & Safety Division sponsored *Focused Audit of PG&E Gas Transmission Pipeline Safety-Related Expenditures for the Period 1999 to* 2010, prepared by Overland Consulting, submitted December 30, 2011; CPUC Consumer Protection and Safety Division, *Technical Report of the Consumer Protection and Safety Division Regarding PG&E's Pipeline Safety Enhancement Plan,* December 23, 2011, p 3 ("CPSD cannot establish whether each segment has been properly placed or prioritized because the resulting output from the decision trees is only as good as the accuracy of the data which is put through the model. . . . certain information required to verify compliance with the decision tree framework was not available."); CPUC Consumer Protection and Safety Division sponsored *Assessment of PG&E's Pipeline Safety Enhancement Plan,* prepared by Jacobs Consulting, Dec. 23, 2011, p. 9 ("At the time of Jacobs review, information to verify compliance with the decision tree and prioritization process was not available. . . . To date, not all pipeline facilities have been validated; therefore PG&E has used existing GIS data, which may not be accurate, towards planning included in its [implementation plan].")

[45] *See* ASME B31.8S.

[46] National Transportation Safety Board, *Pipeline Accident Report, PG&E, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, Sept. 9, 2010* (Aug. 30, 2011).

[47] Overland Report, p. 27, Table 2-2 shows that four of the five PG&E gas & transmission rate cases were approved through a settlement.

of ensuring gas pipeline safety. The Commission's own recent "focused audit" report, conducted by Overland Consulting for the Consumer Protection & Safety Division, (see fn. 1, *supra*), details significant overpayments to PG&E above its authorized rate of return for the operation of its gas pipeline transmission system. By its own acknowledgement, the Overland "focused audit" is not comprehensive.[48]

Before the Commission can accurately determine whether ratepayers should pay additional costs, it should first examine what unused and excess ratepayer monies PG&E has received that should properly be used to fund the pipeline testing, upgrades and replacement necessary to ensure the safety and proper operation of PG&E's gas transmission pipeline system.

A. Applying Ratemaking Principles to Evaluate the Necessary Costs of the PG&E Implementation Plan.

In evaluating the cost estimates in PG&E's Implementation Plan, I use what I understand to be the usual principles for utility rate reasonableness, relying on Peter Bradford's testimony, served herewith. I have previously demonstrated that additional work is required to ensure the safety of PG&E's pipeline system. (See Sections I-V, above). Some of this work has not been required under the federal rules to date.

Additionally, the Commission must consider the installation of automatic or remote control shut-off valves. While I believe that the evaluation and determination of the specific technology to be required should be considered more thoroughly in Phase II of this rulemaking, the costs of installing whatever technology the Commission requires will need to be allocated according to the Commission's analysis of whether the technology constitutes a new requirement or not.

1. Applying Principle 1 results in the following adjustments:

Peter Bradford's testimony sets out basic ratemaking principles that I suggest that the Commission use. Principle 1 states that the Commission should perform a prudence review of all ratepayer money PG&E received to make sure that the money was properly spent before the Commission allocates additional revenues. Following this principle will result in the re-allocation of

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[48] Overland Report, p. 1-2.

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$430 million in revenues that PG&E received above its authorized rate-of-return. I suggest that money be used to fund Phase I critical work.

- Overland Consulting's focused audit found that PG&E received a total of $430 million in excess of its revenue requirements for its gas transmission pipeline and storage system, over and above the amounts necessary to meet its authorized rate of return.[49] The Commission should apply this excess $430 million to help pay for the gas pipeline infrastructure upgrades, testing and repair work that the Commission requires be performed in this rulemaking.
- The Commission should obtain PG&E's workpapers and documentation that PG&E developed to support the ultimate revenue requests that it submitted to the Commission in the past in requesting gas transmission pipeline revenues through the Gas Accord process. Those workpapers should contain estimates for the federally-required Integrity Management Plan work (required since December 2004), which should be used to determine what amount of money PG&E has already obtained from ratepayers to perform that required work. Despite the 2008-2010 Gas Accord settlement being a "black box" settlement where the authorized monies are not earmarked by line item or account,[50] it is reasonable to assume that PG&E anticipated and planned that it would obtain at least some money through the PUC revenue authorization processes to implement its Integrity Management Plan, and that PG&E used at least some ratepayer revenue to implement its Integrity Management Plan in the past.

  Obtaining and evaluating PG&E's internal workpapers, and allowing parties to comment on those work papers, would give the Commission a more reliable estimate of previously-obtained revenues to be considered before the Commission authorizes additional ratepayer revenues to ensure safety on the PG&E gas pipeline system.

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[49] Overland Report at p. I-1-I-12.

[50] See Overland Report, p. 2-10, "The GA IV settlement was a black box settlement. The settlement rates were calculated by applying negotiated escalation factors to 2007 rates and are not supported by detailed cost-of-service analysis." See also p. 2-10 "The settlement is a black box that does not identify any adjustments to the litigation forecast. The settlement workpapers do not include any O&M or capex forecasts."

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2. Applying principle 2, ratepayers should not be made to pay twice for the same work, results in the following adjustments:

- As part of its 2009 rate case, PG&E asked for $13 million for in-line inspection work; PG&E asserted that it planned to perform ILI by 2014. The NTSB noted that PG&E's own engineer stated that it takes 3-4 years to prepare a line for ILI, including engineering upgrades, replacing components such as valves and fittings, and cleaning the pipeline.[51] I question whether it actually takes that long to retrofit a pipeline for ILI use. But if it did in fact take that long, it appears that PG&E has already received $13 million for ILI work that would necessarily be included in PG&E's Implementation Plan proposal to retrofit 235 miles of pipeline to accommodate in-line inspection tools.
- PG&E maintains significant unspent funds from prior Commission gas transmission pipeline revenue authorizations that should be applied to reduce ratepayers' responsibilities to pay for the work to be authorized. The Commission's own CPSD Incident Investigation Report recommends that PG&E use the $39.257 million that exists in unspent gas O&M revenues and the $95.37 million that exists in unspent gas capital expenditures to fund future pipeline transmission O&M and capital expenditures.[52] CPSD and Overland treated these amounts as not duplicative of the excess rate-of-return revenues identified by Overland's focused audit. These unspent gas transmission monies should be used to pay for the costs of the O&M and capital work that the Commission authorizes in this rulemaking.

3. Applying Principle 3 produces the following results:

- **Records and Data Management Program Proposals**: CPUC General Order 112-E (GO 112-E, updated 2008) requires PG&E to maintain pipeline integrity and safety and incorporates the USDOT federal pipeline safety regulations. P.U. Code § 461 requires PG&E to maintain specific records necessary to establish that the testing, evaluation and repair work has been

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[51] NTSB Report, p. 66.

[52] See CPSD Incident Investigation Report, p. 168 (referencing the Overland Report at p. 3-3, Table 3-2 and at p. 4-2, Table 4-1). CPSD notes that these unspent funds are different from the $430 million Overland identifies as revenues that PG&E received in excess of its authorized rate-or-return.

properly performed.[53] Because PG&E was required to create and maintain adequate records and data and failed to do so, PG&E should pay for all proposed data & records management work to create and maintain accurate records of its pipelines' properties and its pipelines' operational details. I recommend that the requested $307 million in GTAM and GIS information technology and data management systems upgrades be paid for by PG&E shareholders.[54] Ratepayers should not be made to pay for work that PG&E was required to do, was paid for, but failed to do properly. (Nov. 2, 2011 ACR, Questions 3, 5, at p. A1)

- **The costs for verifying MAOP where missing or inaccurate**: PG&E should not be able to recover from ratepayers the $162.3 million in costs[55] to verify the maximum allowable operating pressure of its existing transmission lines because PG&E should have, but failed to keep valid and appropriate internal design pressure records of the determination of the MAOP of its transmission pipelines. Industry standards dating from 1935 required each pipeline company to keep records to determine the internal design pressure rating of the pipeline.[56] The reason for this requirement is that the pipeline operator needs to know the specifications of the pipeline in the ground to determine the design pressure and calculate the design limits of the pipeline. Thus, PG&E was required to keep these records since 1935. It is an obligation for which PG&E has already been paid through past ratemakings. If PG&E is missing those records, shareholders should pay to create accurate basic records.
- **HCA classification verification costs**: Integrity Management Plan rules required PG&E accurately to determine and update all high consequence pipeline segments.[57] PG&E has repeatedly admitted its failure to maintain accurate records of which of its pipelines were located in designated high consequence areas. CPSD found that PG&E failed to designate pipeline

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[53] CPUC, G.O. 112-E, p. 1, available at http://docs.cpuc.ca.gov/published/Graphics/20757.PDF; Cal. Pub. Util. Code § 461.
[54] See explanation of costs in Jacobs Consulting Report, p. 43, fig. 1 & p. 45, Table 5-3.
[55] *Id.*, at p. 43, fig. 1 & at p. 44, Table 5-6.
[56] American Standards Association, ASA, sponsored by ASME, Code for Pressure Piping, Section 2, Gas & Air Piping Systems (1935) and subsequent versions. This standard continued until 1955 when ASME B31.1.8 was issued pertaining to gas pipelines only.
[57] See 49 CFR § 192.901 et seq.

classifications accurately.[58] The Commission has recognized PG&E's failure accurately to classify HCA locations in opening its most recent investigation, I.12-01-007.

Determining accurate class locations, which is an essential element of the determination whether a pipeline is located in a high consequence area, has been required in ASME B31.1.8 since 1955. While the question whether PG&E should be fined for its failures will be considered in I.12-01-007, the decision as to who should pay to establish accurate location classifications can properly be determined in this rulemaking pursuant to principle 3. Using this framework, shareholders should pay for all work necessary to establish accurate and updated HCA designations.

- **Treatment of pressure testing expenses:** PG&E requests $393.2 million in expenses and $18 million in capital expenditures to perform pressure testing of its system in Phase I of its Implementation Plan.[59] Pressure-testing cost review is complicated by the fact that different federal and state rules applied to pressure-testing during different time periods. 49 CFR §192, Subpart J, first published in 1970, sets forth the records each gas pipeline utility must create and maintain.
    - No dispute exists that from 1970 forward, PG&E should have maintained pressure test records conducted at the time of pipe installation.[60] Post 1970, federal regulations required both a pressure test to be conducted pursuant to Subpart J at the time of installation and records to be kept of that pressure test. If those records are not available, the shareholder should pay the costs of both the pressure-testing, which presumably includes the cost to develop and maintain the record of that test. PG&E does not request ratepayer payment of the costs of pressure-testing pipelines installed after 1970.[61]

[58] CPSD Incident Investigation Report, p. 44-47.
[59] PG&E testimony, p. 3-65 and Attachment 3-A. PG&E estimates that it needs to pressure test 783 miles of pipeline in Phase I. Implementation Plan, p. 3.
[60] PG&E testimony, pp. 1-13.
[61] PG&E testimony, pp. 3-65—3-66. "Costs to strength test or replace any pipe installed post-1970 without verifiable test records have been excluded from PG&E's request for cost recovery . . . . Post-1970 segments to be strength-tested and their associated costs, $11.8 million, have been removed from the forecast . . . ."

- Cost attribution becomes more difficult when assessing who should pay for the cost of testing pre-1970 pipelines. I agree with PG&E that pre-1970 pipelines must be pressure-tested to ensure the safety of the system. Above, I demonstrate above that a broader range of pipe should be tested than that proposed by PG&E, and also that more stringent testing methodologies be used to perform those pressure-tests. To accurately determine the answer to who should pay for pressure testing work requires a review of the industry standards and codes in existence at times prior to 1970.
- **Pressure-testing pipelines installed between 1961 and 1969:** PG&E was required to pressure-test its gas transmission pipelines pursuant to California law, starting in 1961. [62] Thus, PG&E shareholders should pay for the portion of the pressure-testing and records development costs that relate to pipe installed from 1961-1969 if it was not tested and it operated above 30% of SMYS.
- For my analysis of who should pay to pressure test pipelines installed prior to 1961, see section 4, below. There we discuss two additional categories of pressure-testing costs for which the ratepayer should pay. These groupings include pipes that have operated below 30% of SMYS, which were and still are exempted from pressure testing under industry standards and federal regulations (the "grandfathered" pipelines)[63] and pressure testing pipelines that have had a pressure test performed, but that for demonstrated safety reasons should have additional pressure tests performed.

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[62] See the discussion of California law in D.11.06.017**.**

[63] To illustrate the complexity of determining the ratemaking treatment for pressure testing, note that the grandfathering exemption for pipelines operating at less than 30% of SMYS was not explicitly stated until the advent of federal regulations in 1970. The industry codes did not exclude pipelines operating at less than 30% of SMYS until 1955. In 1955, ANSI B31.1.8 included for the first time the 30% exemption from pressure-testing. However, ANSI B31.1.8 also created MAOP determination requirements, explicitly defining required pressure-testing to determine an accurate MAOP for pipeline operation for those pipelines running above 30% of SMYS. Thus, the 1955 ANSI standards tied pressure testing explicitly to the determination of MAOP required for pipeline operation.

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4. Applying Principle 4 produces the following results:

Principle 4 acknowledges that not all costs of the Implementation Plan and other pipeline system safety work should be borne by PG&E shareholders. Where PG&E adequately maintained its gas pipeline system, but new requirements and additional work are necessary for safety and the prudent operation of PG&E's gas transmission pipeline system, ratepayers should pay for the work. Applying this principle requires detailed consideration of the specific facts of each Implementation Plan project component.

- **Pressure testing pre-1961 pipelines**. The Commission has determined that no pressure tests were required to be conducted. See. D.11.06.017, at p. 27, as discussed above. In that same decision, the Commission ordered all "natural gas transmission operators to pressure test pipeline that has not been [ ] tested." *Id.* at p. 28. Relying on the Commission's findings results in ratepayers paying all pressure test costs for pre-1961 pipelines, a conclusion we support.[64]
- **Pressure testing pipelines that operate below 30% of SMYS**. There is a key gap in the Commission's decision in D. 11.06.017, requiring additional pressure testing of California's gas pipelines – namely, that the Commission decision continues the "grandfathering" testing exemption that still exists in federal regulations. The NTSB concluded that the grandfathering exemption has no safety justification and urges elimination of any exemption from testing

[64] However, facts exist for the Commission to delve further into historical industry standards to determine cost allocation. Industry standards for pressure testing exist that apply to pre-1961 pipelines. Requirements to pressure test certain gas pipelines first appeared in 1935 industry rules. See ASA Code for Pressure Piping, Section 2, Gas & Air Piping Systems (1935), sponsored by ASME. After 1935, industry standards merely required a pressure test to be conducted, but did not explicitly require records of the pressure test.

But in 1955 industry standards and codes required records of pressure testing as part of the methodology of establishing MAOP. Although industry codes did not contain an explicit record-keeping requirement detailing the methodology of the pressure test, the pipeline operator had to have a bona fide basis to calculate MAOP to operate each pipeline, which could only be properly achieved with a pressure test. The Commission could conclude from a consideration of the 1955 industry requirements to calculate MAOP that pressure testing was unavoidably required in order to follow industry standards in pipeline operation. If the Commission takes this more comprehensive view of industry standards existing as of 1955, then PG&E should have pressured tested its lines to establish the correct MAOP to operate and shareholders should pay to test post-1955 pipelines.

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pursuant to this grandfather exemption. If the Commission agrees with the NTSB recommendations, and with my data and analysis supporting the elimination of grandfathered exemptions from pressure testing, then the costs of pressure testing previously-grandfathered pipelines constitutes a new requirement properly paid for by ratepayers. Ratepayers should pay for pipeline pressure-testing that to date was exempted from pressure-testing.

- **Pressure testing pipelines that have had a pressure test performed, but that for safety reasons should have additional pressure tests performed.**

If PG&E possesses documentation indicating that a pressure test was performed on a pre-1961 pipeline, even without the actual records of the test results, the ratepayers should pay to pressure test the pipe again when required.

It is inaccurate to assume that a single pressure test at the time of installation is all that is ever needed to assure the safety and performance of a pipeline throughout its life. For numerous reasons I discuss above (a leak detected in a leak survey; corrosion detected through pigging or direct physical examination; to increase operating pressures) a pipeline may need to be pressure tested well after installation. PG&E has identified many instances, and estimates additional situations, where additional pressure tests should be performed on pipelines that were pressure-tested at installation. These projects should be evaluated on their individual merits and should be paid for by the ratepayers unless it is shown that PG&E's failure to run adequate corrosion control and mechanical damage prevention programs created the need for subsequent pressure tests.

- **Direct assessment and leak survey proposals:** As I discuss above, all four methods of assuring pipeline integrity (physical inspection, on-the-ground instrumented leak surveys, rigorous pressure testing, and in-line inspections) are necessary components of an integrated integrity management system. Although PG&E may well have performed direct assessment examinations in lieu of required pressure testing,[65] continued expenditures for direct physical examination of transmission pipelines remain a necessary part of a complete safety system and as such, PG&E's

[65] *See, e.g.*, CPSD Incident Investigation Report, pp. 38-40; 42-47.

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requests for funding should be authorized and paid for by ratepayers. Similarly, PG&E's proposal to increase its leak surveys is meritorious, and should be approved with respect to survey methodologies that employ on-the-ground, instrumented leak detection equipment. However, the usefulness of aerial leak surveys is highly questionable and should be rejected.

- **Replacement of EW pipelines**: PG&E in its Implementation Plan proposes an innovative and necessary program to replace all pre-1970 EW pipelines and other inferior pipelines that operate at more than 30% of SMYS (relying on the federal regulations' 30% threshold trigger for additional inspections.) I have shown above that while early EW pipelines and other inferior pipelines are allowable under the current federal pipeline safety rules, those rules are inadequate to ensure safety. The operational safety of early EW pipe and other inferior pipe cannot be assured without extensive and expensive testing using rigorous methodologies. At base, early EW pipelines and other inferior pipelines do not measure up to 21st Century needs and to 21st Century safety expectations. Pursuant to my analyses detailed above, even more early EW and other inferior pipeline replacement is warranted than that proposed by PG&E.

  Given the amount of work needed to ensure the quality and serviceability of EW pipe, it may well be more cost-effective to simply replace all EW pipe than to test it and then likely have to replace the pipe as well. If the Commission agrees that early EW pipelines and other inferior pipelines should be replaced, ratepayers should pay for the replacement costs as they embody a needed new safety upgrade. Of course, if a particular early EW pipeline or inferior pipeline must be replaced due to PG&E's lack of corrosion control or damage prevention efforts, then the shareholders should pay for that cost. But unless PG&E failed to adequately care for that pipe, the ratepayers should pay for early EW pipeline and other inferior pipeline replacement costs. The inherent structural weaknesses of early EW and other inferior pipe result in the conclusion that this type of pipe should be replaced as a normal requirement of pipeline safety assurance.

- **Ensuring inspector independence and worker qualifications**: I demonstrate the need for the Commission to require all gas pipeline inspectors to be truly independent of PG&E to ensure the quality of gas pipeline work performed by PG&E. The evidence provided by the U.A. Local Unions also demonstrates the need for sufficient worker qualifications to ensure the quality of

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the gas pipeline work to be performed. Any additional costs over PG&E's current Implementation Plan estimates and current gas Accord V revenue authorizations should be negligible, as PG&E already pays for non-independent inspectors, and independent worker qualification programs exist now[66] without PG&E spending additional funds. However, all these costs should be paid for by ratepayers as a normal operating expense.

- **Valve installation costs**: should generally be shared by the ratepayers as a new and necessary improvement. New state laws require the Commission to consider requiring the installation of either automatic or remote shut-off valves. The NTSB recommends the installation of shut-off valves throughout PG&E's gas transmission pipeline system. PG&E proposes one installation system; Jacobs Consulting suggests another.[67] CPSD recommends that PG&E should perform a study of installing RCVs and ASVs and appropriately spaced pressure and flow transmitters on critical transmission line infrastructure and implement the results.[68] Usually, in paying for a new state mandate, the ratepayer would pay the total costs of the required system upgrade, especially as no explicit shut-off valve requirement exists in the federal regulations.
    - However, 49 C.F.R. §192.615, requiring emergency response plans, has long required pipeline operators to have the capability to perform "emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property".[69] The use of rapidly-operated pipeline isolation valves provides both shutdown and pressure reduction capability, but the federal regulations do not specify how a pipeline operator must meet the performance requirement of ensuring emergency shut-down and pressure reductions. During the San Bruno incident, PG&E did not have this capability. Therefore, the cost of adding valves and adapting existing valves should not be totally borne by the ratepayers.[70]

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[66] See Testimony of Mike Mikich on behalf of the U.A. Local Unions, ¶¶ 4-5.
[67] See discussion of ASV and RCV valves in Jacobs Consulting Report, pp. 27-29, 33-34.
[68] CPSD Incident Investigation Report Recommendation 27, p. 168.
[69] This requirement has been in the federal rules since at least 1985.
[70] The U.A. local unions possess insufficient data to advise the Commission as to the portion of the costs to be apportioned between ratepayers and the shareholders, but the Commission should apportion the costs because the federal performance-based emergency response requirement was

- This cost conundrum provides another real-world example of how performance-based safety requirements inject uncertainty when trying to establish what the pipeline operator was required to do. The Commission could substantially lessen confusion and conflict by setting prescriptive regulations detailing PG&E's gas pipeline safety duties in the future.

5. Applying Principle 5 produces the following results:

Principle 5 encompasses situations where PG&E failed to perform required work but did not receive money to perform that work. Here, the Commission must assess on an individualized basis what the cost of the work would have been if PG&E had done what is should have, and compare that amount to what the costs are now. Ratepayers should receive a deduction from the second cost that takes into account the first cost, with adjustments. Accurately calculating the applicable deductions and exceptions can be quite difficult, given the state of the historical record with respect to both costs and the condition of PG&E gas transmission pipelines.

- **Pipeline replacement projects**: pipelines need to be replaced from time to time. They have a reasonable life, but in time they will lose their usefulness because of a variety of factors, including additional gas transportation demands. When those factors occur, the ratepayers normally pay for that infrastructure upgrade. Ratepayers should pay for the replacement of any pipe that fails, or otherwise needs replacement, unless PG&E failed adequately to maintain the pipeline. The Commission must further investigate and examine the pipeline replacement projects proposed, once completed, to establish the factors that caused the need for the pipeline replacement before it can judge to whom the costs should be assessed.
  - Replacement costs should largely be borne by ratepayers, as they have received the cost benefit of not having to replace these pipes earlier, unless a failure to follow standards is shown to have created the need for that replacement. In that situation, shareholders should pay those replacement costs.
  - I have not yet seen maintenance records sufficient to determine adequacy of corrosion

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not met by PG&E. Complicating the allocation of valve installation costs is the issue of incremental cost calculation. If an adequate number of valves had been originally installed and equipped for remote operation to meet the performance requirement, the incremental cost would have been less than retrofitting the pipeline now.

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control and mechanical damages prevention programs to be able to assess whether any of the replacement costs should be attributed to shareholders.

- **Upgrading needed pipeline repairs to accommodate future growth** is an efficient use of ratepayer money. All pipeline replacement and retrofitting undertaken pursuant to the Commissions' orders should be consistent with the likely future gas transportation needs in California. For example, if a pipeline is to be replaced in an area of rapid growth, a larger replacement pipeline should be considered. It doesn't make economic or operational sense to replace an old pipeline in-kind with the same type of pipeline, if that pipeline will need additional capacity in the near future. The incremental cost to the ratepayers for a larger pipeline now, when a replacement is needed anyway, will be much less than building an additional future new pipeline. Therefore, PG&E (and indeed each California pipeline operator) should develop short-term and long-term gas transportation plans that allow the Commission to make decisions today that are compatible with future needs to minimize costs to ratepayers over time. All capital work authorized by the Commission in this rulemaking should be consistent with future gas transmission needs in California.
- **In-line inspection upgrades:** PG&E states in its Implementation Plan that 80% of its gas transmission pipeline system is not piggable. A logical assumption to be drawn from this fact is that PG&E has not requested revenues to conduct in-line inspection work in 80% of its pipeline system, as those pipelines could not accommodate in-line inspection (ILI) tools (commonly called pigs.) The NTSB recommends that PG&E retrofit its pipeline system to accommodate ILI tools as a necessary component of PG&E's Integrity Management Program. I agree with the NTSB conclusion, and as discussed above, contend that retrofitting PG&E's gas transmission pipeline system to accommodate inspections by pigs is necessary to check effectively for internal corrosion and problems with welds.
    - Since 1955, industry standards required that pipelines be piggable to remove liquids from the pipeline for internal corrosion control. Since 1970, federal performance-based requirements have resulted in the need for pigs to maintain effective internal corrosion

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control and to detect all potentially hazardous leaks during pressure testing.[71] While no specific performance requirement specifies the use of pigs, to meet internal corrosion control obligations, PG&E's lines should have been piggable.

In attempting to deconstruct what the various performance-based requirements require in practice, I suggest that the Commission needs to examine whether an indispensable component of an effective internal corrosion program under the federal performance standards involves the use of cleaning pigs.

I suggest that the Commission should apportion the costs of retrofitting for in-line inspection capability between shareholders and ratepayers. PG&E shareholders should pay for the costs to make PG&E's gas transmission pipelines at least piggable for internal corrosion control and high-quality hydrostatic tests. Ratepayers should pay for the additional costs beyond internal corrosion control to modify a pipeline to effectively run in-line tools. Ratepayers should also continue to pay the cost to conduct the in-line inspection surveys.

B. Assuring the Reasonableness of the Cost Estimates of the PG&E Implementation Plan.

1. Establishing an annual feed-back mechanism is essential to getting the costs correct and to allocating ratemaking responsibility.

Because of the extraordinary lack of records as discussed above, the Commission cannot currently determine the reasonableness of specific costs with a sufficient degree of confidence. Yet the Commission must move forward to determine what additional work needs to be accomplished to ensure the safety of PG&E's gas transmission pipeline system. The Commission asks for comment on how to assure the reasonableness of the costs it approves. U.A. local unions suggest that the Commission should re-visit the proposed cost estimates for Phase I and Phase II once the first baseline assessments are done in 2012.

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[71] These requirements pertained to pigging with cleaning or displacement pigs that are considerably shorter and more flexible than in-line tools. For passage of in-line tools, longer pig launchers and receivers are required. Passage of in-line tools through wrinkle bends, miters, stubs, non-butt-welded pipe, valves, tees, and elbows & bends is limited compared to cleaning and displacement tools.

After two years of Phase I work, the Commission should gather and assess what the facts are to determine the ratemaking principles for Phase II work. The pressure-testing records on failures and ruptures will provide invaluable facts to be able to ascertain who should pay. For example, failures due to the inadequate corrosion control and damage prevention should not be the responsibility of ratepayers. The PUC should require PG&E to perform thorough failure analyses on each pressure-testing failure that occurs in order to develop sufficient data to evaluate the ratemaking question under principle 4 – did PG&E adequately maintain its pipeline system to result in ratepayers properly paying for additional needed safety work?

Establishing an annual feed-back loop to examine the actual facts about costs and testing results, as they are developed, is critical for the Commission to obtain fair and accurate answers to the pending questions of who should pay for all the necessary work to assure the safety of PG&E's gas transmission pipeline system. The Commission should create a continuing process of evaluation for both Phase I and Phase II to evaluate what is being done, whether it is performed correctly, and then, who should pay. For example, once a sufficient number of pressure tests are completed at the pressure levels proposed herein, the Commission will possess much more data on the likely number of leaks existing in PG&E's pipelines of various vintages. The Commission will also have more accurate data to know what the future pipeline replacement requirements will be in Phase II. I forecast that there will be much more variance in potential costs of a satisfactory pressure testing program than in estimates for pipeline replacement costs.

2. Contingency costs are too high by industry standards. PG&E's calculation magnifies the worst case scenario without any acceptable statistical or estimating basis for doing so.

PG&E's cost estimates contain too large a contingency factor. Those contingency factors are not justified by historical experience. The information presented is inadequate to evaluate the contingency estimate. The information submitted from PG&E asserts that their error has been 20% with a 90% confidence. On individual projects there will be unknowns about pressure testing results and what they find when they dig up the pipe. But the contingency estimates should be justified by individual projects, not generalized over all projects proposed.

Statistical methodologies show us that the error for one project should not be multiplied to apply to one hundred projects. The average itself does not apply to all projects into the future. Through its use of its worst-case contingency factor, PG&E is essentially saying that 100% -- or every one of their projects' costs -- will be substantially underestimated. This projection is not statistically sound; it does not comply with accepted statistical methodologies for determining cost contingencies.

Additionally, PG&E's contingency computation shows that PG&E is disregarding the learning curve principle – a basic principle of cost estimating -- that as they perform the work and find actual results of costs that they will adjust the costs as they learn more. Given the unwarranted assumptions contained in the contingency estimates, PG&E's contingency costs should be accepted for the first year of Phase I only. The Commission should then use the feed-back review mechanism described above continuously to evaluate the estimated versus actual cost contingencies experienced each year.

C. Additional Comments as to Questions Contained in the November 2, 2011 Assigned Commissioner Ruling.

1. In the November 2, 2011 ACR, The Commission asked how to deal with the level of uncertainty of cost estimates provided in PG&E's Implementation Plan. (Nov. 2, 2011 ACR, question 1, at p. A1). A generally accepted method of determining costs includes a continuous feed-back loop where costs are adjusted continuously based on actual historical experience. The Commission can address the costs uncertainties at this time by establishing an on-going review of actual costs in years 1, 2 and 3 of Phase I of PG&E's Implementation Plan and can adjust the cost forecasts for subsequent years based on the actual historical experience of PG&E as it implements the new safety mandates. At this point, we cannot know the accuracy of the estimates from any reliable historical data until after the fact, which is why a continuing process is crucial to managing costs.
2. The Commission asks for comment on PG&E's proposal for essentially what amounts to a one-way balancing account. (Nov. 2, 2011 ACR, question 10, at p. A2) Because of the extent of the unknowns from the lack of historical project data, the CPUC should at least receive periodic reports on the status of this balancing account and perform at least an annual review of cash flows of the account. Moreover, PG&E needs to perform work where no history exists – valve installation, use of higher pressures in the pressure testing methodologies. Given the new

components of this safety work and the lack of historical data, the balancing account should be flexible, but reviewed in the context of the feed-back loop described above. Some mechanism should allow reasonable costs to be met without too great a delay, or the needed safety work will never be accomplished in the time frame that California needs.

3. PG&E should not be allowed to shift revenues for pipeline safety projects from Phase I to Phase II without submitting information to the Commission in this proceeding specifying what funds are requested to be delayed and why the approved projects and revenues were not spent as originally allocated. This information submittal should be followed by a cost review process that at minimum includes an evidentiary hearing and a formal Commission decision. (Nov. 2, 2011 ACR, questions 2, 3, at p. A1) Allowing Phase I funds to be shifted automatically will provide an incentive to delay Phase I projects and will result in Phase I projects being dangerously delayed.
4. The Commission asks for comment on PG&E's proposed shareholder sharing of proposed expenditures (Nov. 2, 2011 ACR, question 20, at p. A3.) PG&E's proposal to cap shareholder payments for gas pipeline safety costs should be rejected because it is both arbitrary and premature. For all the reasons contained in my testimony, the Commission cannot properly or fairly determine which costs should be borne by ratepayers or which costs should be borne by shareholders until it can apply the ratemaking principles set forth here.
5. The Commission asks for comment whether the outside engineers involved in Preparation of the IP be available as witnesses in addition to the PG&E employees sponsoring the IP testimony. (Nov. 2, 2011 ACR, question 30, at p. A4.) Absolutely. The Commission and the parties need to be informed to the fullest extent possible, which can only occur if all persons who helped develop the Implementation Plan are made available to unpack the details and assumptions underlying the Implementation Plan.

X. CONCLUSION

A. A focus on hoop stress alone will not ensure safety.

Hoop stress due to internal pressure, by itself, is a poor and incomplete measure of pipeline integrity issues, particularly for underground pipelines which experience stress from other sources. My research shows that hoop stress alone is not a strong predictor for pipeline incidents. Thus, the CPUC should eliminate hoop-stress-based exemptions from its hydrotesting requirements.

All pressure testing exemptions based on hoop stress due to internal pressure should be eliminated. Hoop stress limits, by themselves, as used for various class locations are an inadequate method to control the risk of pipeline failures to the public. PG&E threat assessment models that include hoop stress exemptions will be inadequate in ensuring public safety.

Particularly in California, pipeline integrity solutions must address the effects of stress from sources other than just internal pressure, including old fabrication and construction techniques, and the impact of external loads, non-seismic soil movement, and seismic soil movement.

B. Old electric-weld pipe should be pressure tested to high levels and operated at low levels, or completely eliminated.

Pre-1980 electric weld pipe (EW) pipe and other types of inferior pipe contain manufacturing defects that are ticking time bombs. As I explain above, failure of such pipe is not related solely to length in service or pressure. Present pressure testing requirements are inadequate to protect the public from the failure of this type of pipe.

ASME B31.8 provides guidance on stresses from sources other than internal pressure. It should be considered as a starting point for integrity solutions. Older pipelines are likely to have higher stresses due to factors other than internal pressure, such as earth movement, subsidence, corrosion and other factors. They need more frequent integrity assessment than newer pipelines. Older pipelines are more likely to contain leaks than newer pipelines. More rigorous pressure testing and integrity assessments are needed to ensure the safety of older pipelines.

C. Grandfathering must be eliminated. Merely reducing the MAOP or operating pressure of a pipeline is not a reliable method to ensure safety when a pipeline is found to be in unsatisfactory condition.

Exempting old pipelines from hydrotesting requirements ("grandfathering") must be eliminated. To accomplish this task, PG&E should not be allowed to rely on prior pressure tests that do not meet today's standards. Such tests do not adequately ensure the safety of the pipe.

In my study of data publicly reported to the DOT, the vast majority of ruptures and leaks

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occurred when the pipes were operating at less than the maximum allowable operating pressure (MAOP). Similarly, a reduction in the MAOP of a pipeline is not a reliable method to ensure the safety of that pipeline over the long-term. While this may be taken as an interim safety measure, it cannot ensure the long-term safety of a pipe. Instead, high-pressure pressure testing should be required for all pipelines.

D. An Implementation Plan that fails to adequately ensure safety of pipelines will do a disservice to ratepayers.

It is of utmost importance that Implementation Plan funds be spent wisely, regardless of the precise allocation of costs. Pressure tests must be conducted properly, to sufficiently high test pressures, and using proper methods to ensure "each potentially hazardous leak has been located and eliminated" (49 CFR 192.503). Otherwise, significant expenditures will be made without doing anything meaningful to ensure the safety of ratepayers.

R.D. Deaver