BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	Rulemaking 11-02-019 (Filed February 24, 2011)

TECHNICAL REPORT OF THE CONSUMER PROTECTION AND SAFETY DIVISION REGARDING THE SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS AND ELECTRIC COMPANY PIPELINE SAFETY ENHANCEMENT PLAN

Respectfully submitted,

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Executive Summary

On August 26, 2011, as required by California Public Utilities Commission (CPUC or Commission) Decision 11-06-017 (D.11-06-017), Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) (collectively referred to as Companies) submitted their unified Pipeline Safety Enhancement Plan (PSEP or Implementation Plan) detailing their proposals for:

1) testing or replacing their transmission pipeline facilities lacking complete, accurate, and verifiable documentation related to their established operating pressures;
2) determining locations for modifying existing automated valves, adding additional automated valves and equipment to monitor pressures and flows throughout its system, along with communications equipment, in order for the Companies to be able to better detect, identify, and provide a timely response and reduce the consequences, in a densely populated area, of any significant breach to the integrity of a transmission pipeline;
3) implementing enhancements, that go beyond the directives of D.11-06-017, which the Companies believe they could take to improve the safety of their gas systems;
4) researching alternative methods that the Companies believe could be equivalent to, or better than, the testing or replacement measures being pursued by the CPUC; and
5) developing and implementing a program to manage the significant amount of complex projects, human resources, and materials procurement necessary to carry out the incremental work, above normal operations, the PSEP will entail on the Companies.

As required by the November 2, 2011 Assigned Commissioner Scoping Ruling, the Consumer Protection and Safety Division (CPSD) performed a technical review examining the decision making process and the reasonableness of the actions and prioritizations proposed in the PSEP. CPSD examined the likelihood of these actions being achieved as intended, identified possible modification or elimination of elements of the proposals that will not unduly increase public risk, and raises other issues which the CPUC should be aware of.

Based on its review, the CPSD believes that:

- Generally, the PSEP addresses the directives of D.11-06-017; however, CPSD believes that at least another 23 miles of the Companies' pipeline needs to be included in, and evaluated in, the PSEP;

- At least some of the projects included in the PSEP result, improperly, in lower priority segments being addressed before those with higher priority;

- The alternative methods to pressure testing proposed in the PSEP do not comply with GO 112-E, federal gas pipeline standards related to the strength testing of pipelines, and undermine the test or replace policy established in D.11-06-017;

- Many, but not all, of the PSEP's enhancement proposals that go beyond the proposals that directly address the requirements of D.11-06-017, should be pursued; however, not all;

- The Companies understand the enormity and complexity of what the PSEP entails and are putting processes in place that should allow for completion of the PSEP; however, the many unknowns related to the work in the PSEP do not allow CPSD to confirm that the schedules proposed in the PSEP will be met with any certainty;

- Any work performed on 20 miles of pipeline segments installed between July 1, 1961 and 1970, that do not have documentation to show pressure testing was performed in compliance with the Commission's General Order 112, should be required to be pressure tested or replaced, at the Companies' expense.

Procedural Background

In response to the September 9, 2010 gas incident involving PG&E's Line 132 in San Bruno, the CPUC instituted Rulemaking 11-02-019 to examine regulatory changes and other actions that CPUC regulated gas transmission[1] pipeline operators Pacific Gas & Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively Operators) needed to take to improve the safety of their systems. A significant part of the CPUC's efforts to improve pipeline safety are focused on Operators validating that all their transmission pipeline segments have their maximum allowable operating pressure (MAOP) established on accurate, complete, and verifiable documentation.

In D.11-06-017, the CPUC directed Operators to identify their respective transmission pipeline segments that have their MAOP established using methods other than pressure testing, those with deficiencies in pressure testing documentation, those with testing performed to levels inferior to those that would apply to the segment today, as well as other concerns important to the particular operator, and to prioritize the identified segments for pressure testing, replacement, or other consideration. The CPUC's decision requires Operators to determine where the installation of automated valves, primarily in Class 3 and 4 locations[2], could help in mitigating the consequences of a significant pipeline breach. D.11-06-017 ordered Operators to prepare and file, by August 26, 2011, Implementation Plans detailing their proposals for pressure testing, replacing, or taking other actions to address the CPUC's concerns about inadequately tested transmission pipeline segments, the installation of automated valves, cost estimates for the activities included in the Implementation Plans, along with a proposal for cost recovery.

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[1] By definition in 49 CFR, Part 192, §192.3, transmission facilities include those that: 1) operate at pressures which subject these facilities to stresses of 20% or more of SMYS; or 2) primarily supply gas to customers who consume large volumes of gas or resell the gas which they obtain from the line to another party.

[2] Class locations, which are defined in Title 49 Code of Federal Regulations, Part 192, §192.5 , refer to population densities in the vicinity of a pipeline. Class 1 locations are least densely populated areas while Class 4 locations are considered most densely populated.

The Companies' Integrated Natural Gas System

SoCalGas and SDG&E exist as two separate entities, but operate an integrated transmission system which delivers natural gas to over five million customers, located in 242 cities and 13 counties, and covers an area of approximately 20,000 square miles of southern and central California. As is common with large gas utilities companies that operate transmission facilities, SoCalGas receives natural gas from its suppliers at very high pressures at multiple points located on the periphery of its transmission system. In turn, SoCalGas, as the primary supplier of gas to SDG&E, provides gas into the SDG&E system at its northern most point in Moreno Valley.

Large diameter gas pipelines, the largest of which is 36-inches for SoCalGas, assisted by compressor stations to help boost the pressure of gas as it travels down the pipelines, transport the gas from receipt points to distribution load centers, primarily the Los Angeles basin, Imperial Valley, San Joaquin Valley, and the central coast for SoCalGas, and San Diego County for SDG&E. The transmission lines feed gas at lower pressures to smaller diameter distribution pipelines[3], which feed service lines that, ultimately supply gas to the end consumers.

The Companies' transmission lines are interconnected at various locations in order to facilitate the flow of gas to parts of the service territory where it is needed. The lines are also connected in order to be able to access four large underground storage fields where gas is stored, and from where it can be retrieved, as operating conditions require. Interconnection of pipelines also allows for re-direction of gas in order to minimize service disruptions in case a section of a pipeline has to be taken out of service. There can be circumstances, however, in which a segment of pipeline cannot be taken out of service without a service disruption. An example of this is the Companies Line 1600 which, because it serves as a sole source of natural gas for several large customers and a distribution system in San Diego, is required by operations to flow large volumes of gas on a fairly constant basis.

As part of their integrity management program (IMP), the Companies have worked to make much of their pipeline mileage "piggable" for inline inspection (ILI) devices. Per 49 CFR, Part 192, subpart O (the integrity management rule), ILI devices constitute one of three assessment methods operators can use to assess the integrity of their

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[3] By definition in 49 CFR, Part 192, §192.3, distribution pipelines include those that: 1) operate at pressures which subject these facilities to stresses less than 20% of SMYS.

pipelines, with the other two methods being pressure testing or direct assessment. ILI devices look for corrosion, dents, and other anomalies from within the pipeline, and without taking the pipeline out of service.

The Companies have a combined total of approximately 347 manual, 208 automatic shut-down valves (ASVs), and over 30 valves, in locations on various points of their systems which, when needed, can be used in remote control valve (RCV) mode to provide some control over the system. The automated valves range from 5-20 miles in spacing, with the spacing currently averaging ten miles in length. The Companies state that approximately 50% (2,000 miles) of their transmission pipelines are protected by its 208 ASVs. Data related to pipeline pressures, flows, and valve positions is measured at various points on the system and communicated to the operators in the Companies' gas control center; however, data related to conditions in-between these measuring points, which can be many miles apart, is limited.

<u>The Pipeline Safety Enhancement Plan (PSEP)</u>

As required by D.11-06-017, on August 26, 2011, The Companies submitted their unified Pipeline Safety Enhancement Plan. Since the scope of D.11-06-017 is limited to transmission pipeline segments, the Companies' PSEP proposal primarily addresses transmission pipeline facilities. However, CPSD notes that the PSEP includes various enhancements related to distribution facilities. These include: 1) implementation of system modifications to prevent backflow of gas from supply lines connected to transmission lines; 2) installation of meters to measure flow at distribution taps and pipeline interconnections to other transmission pipelines; 3) expansion of existing SCADA system to support enhanced system management; and 4) expanding the coverage area of the Companies' private radio networks so they can serve as back-up to commercially available means of communications with the newly installed valves and, thereby, increase system reliability.

According to the Companies, estimated charges for PSEP Enhancements 2-5 are completely allocated to distribution facilities because Enhancements 2 and 3 "… will generally require assets to be installed at facilities historically operated by distribution organizations…" and due to the fact that these, and Enhancements 4 and 5, are improvements which directly benefit all distribution customers, regardless of specific customer class.

From among approximately 3,622 total transmission system miles, the Companies identified and reviewed records for approximately 1,622 miles of pipelines which they determined to be located in Class 3 or high consequence areas.[4] The Companies categorized the findings from their review of the 1,622 miles, into four categories:

- Category 1 – 953 miles hydro-tested in compliance with D.11-06-017;
- Category 2 – 256 miles pressure tested in compliance with D.11-06-017 using a medium other than water;
- Category 3 – 23 miles the Companies believe have been in-service strength tested with MAOP reduction[5]; and
- Category 4 – 385 miles which the Companies identified as requiring pressure testing or replacement because pressure testing documentation does not sufficiently satisfy modern requirements and directives of D.11-06-017.[6]

The PSEP describes how the Companies developed the decision trees they used to prioritize the testing or replacement of the 385 miles in Category 4 and for evaluating locations where automated valves would be considered for placement, if not already existing. The Companies estimate that 561 valve locations would be addressed through: 1) upgrades in valve mechanisms or communications additions to an existing 541 manual or automated valves; and 2) the installation of 20 new automated valves. CPSD believes the Companies intend to upgrade or install a majority of the valves in remote control mode. This includes converting 94 existing automatic shut-off valves (ASVs) to also be operable as remote controlled valves (RCVs).

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[4] SoCalGas and SDG&E do not operate any transmission pipelines in Class 4 locations.

[5] Current MAOP of the segment has been lowered to a level that would be permitted, assuming a pressure test to a level of 1.25xMAOP had been performed on the segment, and using as the test pressure the highest actual historic pressure at which the segment was operated. The total mileage currently in this category only applies to SoCalGas Line 1026 which is operating under 20% of SMYS.

[6] 377 miles were constructed prior to 1970; 8 miles were constructed post-1970. The Companies are not seeking costs for testing or replacement for the post-1970 construction. Approximately 20 miles of pipe constructed pre-1970 was installed between July 1961 and 1970. CPSD believes these 20 miles of pipe should have testing documentation that meets GO 112 standards effective starting July 1, 1961, otherwise this mileage should also be tested or replaced at the Companies' cost.

The Companies propose to carry out the PSEP through two phases. Phase 1 starts in 2012 and continues until 2021. Phase 2 starts in 2016 and continues to an undefined end date. Phase 1 is further split into Phases 1A and 1B. In general, Phase 1 is intended to address the pipeline segments located in more densely populated areas that are the highest priority for pressure testing or replacement.

In Phase 1A, which begins in 2012 and continues through 2015, the Companies propose to pressure test or replace all transmission segments missing sufficient documentation to demonstrate that their current "pressure-carrying" capability is ≥ 1.25xMAOP of the segments. If the segments are less than 1000 feet in length, the Companies propose to conduct a complete examination of the segments in lieu of pressure testing[7]; otherwise, the ability to take a segment out of service would dictate whether the segment is pressure tested or replaced. During Phase 1A, the Companies would also begin their valve enhancement work; technological improvement installations; and the development and implementation of their Comprehensive Enterprise Asset Management System.

In Phase 1B, which begins in 2016 and continues to 2021, the Companies propose to complete work that would have been Phase 1A work if not for the longer lead time required to get the work underway (i.e., permits, engineering, outage planning, etc.); complete any work carried over from Phase 1A (i.e., intermediate projects started towards the end of Phase 1A or large projects which are expected to span five years or more); and replace all pre-1946 transmission pipe that is not piggable, regardless of the pipe's class location, diameter, or operational stress.

Phase 2 overlaps with Phase 1B, beginning in 2016 and continues to an undefined end date. In general, Phase 2 is intended to address post-1946, piggable segments, located in Class 1 and 2 locations, that have not been pressure tested to a level of 1.25xMAOP or post-1946 pipeline segments in Class 3 locations which have been pressure tested to a level of 1.25xMAOP, but which do not meet current GO 112-E requirements. The Companies expect to identify the segments that would be included in Phase 2 sometime in July 2012.

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[7] SoCalGas has 1.64 miles and SDG&E has 0.05 miles of total pipeline segments that are less than 1000 feet in length. The Companies estimate potential savings of $5-15 million if this mileage were to be directly examined in its entirety vs. replacement; however, estimates included in the PSEP assume segments would be replaced.

As an interim safety measure, in 2011 the Companies began performing bi-monthly leak surveys and patrols over pipeline segments that do not have sufficient documentation of pressure testing. The Company proposes to continue performing these activities for segments until their safety margins are confirmed through one of the methods proposed within the PSEP.

In an effort to reduce the amount of pressure testing or replacement of pipelines that may be needed in Phase 2, the PSEP proposes allowing the Companies to perform an in-line inspection on piggable pipelines, using a transverse field inspection (TFI)[8] tool prior to any pressure testing being performed on currently piggable pipelines or those that could be readily made piggable. The Companies propose to use the results from these ILI runs in "…mitigating potential sources of pressure test failures before conducting the pressure test…" in order to "…avoid the pitfalls associated with entering into a cycle of pressure test failures." The Companies also propose to use the data from the TFI runs to support their position that the CPUC should allow TFI data to be used in lieu of pressure testing.

Within the PSEP, the Companies also express concern about the Commission's intent to eliminate 49 CFR, Part 192, Section 192.619(c), often referred to as the "grandfathering clause" as a method that can be used to determine a pipeline's MAOP. The Companies propose language, which they believe the Commission should add to GO 112-E, in order to gradually ease reliance on Section 192.619(c) and to codify GO 112-E acceptance of their proposed alternatives (pressure reductions, in-service testing, non-destructive testing, etc.) to pressure testing.

The Companies also urge the Commission to explore ways that it could use its authority to help in streamlining, and providing some level of uniformity, to the varying permitting processes throughout the state which have the potential to delay completion, and significantly increase costs, for the Companies' PSEP projects.

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[8] A TFI tool is a "smart" pig which has its magnetic field oriented such that it can help identify axially oriented flaws such as crack like features or certain anomalies in the long seams of pipe.

CPSD Review of the PSEP Pipeline Testing and Replacement Decision Process

The PSEP pipeline testing and replacement process starts by asking if the current MAOP of a given segment has sufficient documentation to show that its current "pressure-carrying" capability is equivalent to a pressure test ≥ 1.25xMAOP of the segment. Any segments located in Class 3 or high consequence areas (HCA)[9] that do not have sufficient documentation are moved into the Phase 1A portion of the decision tree for further prioritization for testing or replacement. CPSD notes that the PSEP definition of "pressure carrying" capability is not the same as actual documentation of a pressure test to a level of 1.25xMAOP of the segment.[10] For example, a segment that has had its MAOP officially reduced by 20% of its historical operating capacity could meet the definition of demonstrated "pressure-carrying" capability, but not have an official pressure test record on file.

The use of a documented pressure test of 1.25xMAOP, at the start of the PSEP decision tree process, is a conservative, first-cut, approach to move segments into the evaluation process for prioritizing in Phase 1A. Although a pressure test to a level of 1.25xMAOP does not meet modern requirements of 1.5xMAOP in Class 3 locations, research has shown that such a test, if performed, can provide some level of assurance as to the stability of the longitudinal seams on a pipeline. Placing pipe segments with a documented pressure test to a minimum level of 1.25xMAOP, even though that test level does not meet current standards, in a lower priority than pipe without documentation of a test, is a logical outcome.

> **FINDING**: Overall, the PSEP's decision tree for prioritization in Phase 1A, and the sub-prioritization process included therein, appears to result in reasonably prioritized segments. However, CPSD believes the sub-prioritization methodology could be enhanced by having it also consider previous findings (i.e., in-service leaks on seam or girth welds or pressure excursions over MAOP) from routine operations and the presence of combined threats on a segment, as part of the prioritization process.

With respect to the decision tree for prioritization in Phase 1B, CPSD believes the Companies' proposal to replace all pre-1946 transmission pipe that is not piggable,

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[9] HCA is defined in 49 CFR, Part 192, Section 192.903

[10] Section IV-D of PSEP testimony mentions a "post-construction pressure test of at least 1.25*MAOP"

regardless of the pipe's class location, diameter, operational stress, or documentation of pressure testing is not reasonable. D.11-06-017 does not mandate that all non-piggable, pre-1946 pipe, be replaced. CPSD believes automatically replacing this pipe could result in the replacement of lower priority Class 1 and 2 pipe before that of Class 3 or HCA pipe that does not have a documented pressure test to a level that meets current GO 112-E requirements. Although the Commission directed operators to "consider retrofitting pipeline to allow for inline inspection tools" in D.11-06-017, it does not suggest that operators do so in a way that places lower priority on pressure testing or replacement of Class 3 or HCA pipelines that do not meet current 49 CFR, Part 192, Subpart J pressure testing requirements. CPSD believes that PSEP Steps F, G, and H, of Phase 1B currently contribute to a lower priority being placed on pressure testing or replacement of pipeline in Class 3 and HCAs.

> **FINDING**: The PSEP's decision tree process for Phase 1B needs to evaluate the pressure testability of pre-1946 non-piggable pipe. In particular, the Companies need to evaluate if certain portions of Class 1 or 2, low stress (SMYS less than 30%) pre-1946 non-piggable pipe can be pressure tested rather than replaced. For pipe that is then selected for replacement, the PSEP needs to add sub-priorities to Step F to prioritize the replacement of pre-1946, non-piggable, Class 3 pipe, operating at 30% SMYS or higher, above other replacements.

<u>Sample Review of Segment Prioritization Results</u>

As part of its review, CPSD sampled four segments, included for pressure testing and/or replacement in Phase 1, to determine the effectiveness of the PSEP's decision process in prioritizing projects that address highest priority miles (i.e., non-pressure tested Class 3 lacking records) above lower priority miles. CPSD expected that the majority of segments/miles in a given Phase 1 project would be primarily Category 4 miles, but this result did not always hold true, as shown in the below list.

Line 49-15 -- Category 4 miles -- 1.98; Category 1 & 2 miles -- 4.62

Line 49-16 -- Category 4 miles -- 0.72; Category 1 & 2 miles -- 8.87

Line 49-28 -- Category 4 miles -- 1.80; Category 1 & 2 miles – 3.10

Line 1600 ----Category 4 miles -- 29.7; Category 1 & 2 miles -- 15.0

CPSD believes it reasonable to include within the scope of a high priority project, short sections of lower priority segments on the ends of the high priority segments, or "sandwiched" between them. This can provide operational as well as cost efficiency in project implementation, improve overall reliability and safety, reduce public inconvenience, and perhaps lower risk of employee injuries associated with multiple projects. However, CPSD believes, with few exceptions, that projects need to be prioritized to address high priority pipe first and it is this pipeline mileage that should drive the scope of, and get completed in, Phase 1 projects. In three of the four projects it sampled, CPSD found that the high priority mileage did not appear to dictate the scope of the project.

Projects for Lines 49-15, 49-16, and 49-28 sampled by the CPSD had a vast majority of lower priority Category 1 and 2 miles, which the Companies refer to as "accelerated miles" than higher priority Category 4 miles, which the Companies refer to as "criteria miles." Project 49-15 is a $20.3 million dollar project to replace 1.98 criteria miles of pipeline, but also include hydro-testing of 0.306 accelerated miles of pipeline located between sections being replaced. There is insufficient information at this stage to allow CPSD to understand why 0.306 miles of Line 49-15 can be hydro-tested as proposed in the PSEP, and what prevents pressure testing the remainder of the 1.98 miles the PSEP estimates for replacement. CPSD has similar questions regarding Project 49-16 which has short sections in between other sections that appear to have been replaced over many years since the line was installed. Inclusion of Category 1 and 2 miles in Project 49-28S appeared reasonable in light of the noncontiguous Category 4 mileage addressed by the project and, what appears to be difficult access to the location in which it is to be performed.

When asked by CPSD how the Companies justified prioritizing projects in Phase 1 that addressed far more accelerated miles than highest priority miles, the response was: "Operations subject matter experts were consulted to develop the PSEP scope in order to provide initial cost estimates. This included the application of engineering judgment and operational system knowledge to determine the accelerated miles to be included in phase 1A. Firm criterion for the determination of miles to be accelerated in Phase 1A, including cost/benefit analyses, will be performed during the engineering, design, and execution planning phase of the project."

The Line 1600 project was the fourth project sampled by CPSD. This is a large, Phase 1B project, and it is the only project that is the outcome of Box 6 of the decision tree for Phase 1. Through this project, the Companies intend to install a replacement line, to take up the load normally supplied by Line 1600, and then modify and pressure test Line 1600. This project has approximately 29.73 of Category 4 miles for and 14.97 Category 1 and 2 miles. CPSD noted that the Companies intend to spend $4.3 million in Phase 1A to make the line piggable and run a TFI tool, replace the 16-inch diameter Line 1600 with a 36-inch diameter pipeline at a cost of $325 million and then spend another approximately $10.1 million to pressure test a line that would appear not to be needed due to the abundant capacity provided by the 36-inch diameter line installed in Phase 1B.

Considering excavation costs, permitting, and public convenience, it could be prudent when replacing pipe, to replace it with a larger diameter pipe; however, an increase from a 16-inch to a 36-inch diameter pipeline appears to CPSD to be a project more to increase capacity than to address the types of safety improvements expected by D.11-06-017. Throughout the years, SDG&E records show it has slowly replaced portions of Line 1600, some as long as a ½ mile in length, which appear to constitute the 14.97 Category 1 and 2 miles of Line 1600 noted earlier. CPSD suggests that it may be possible to replace the remainder of Line 1600 (i.e., the 29.73 Category 4 miles estimated for replacement in the PSEP) as has been done when sections were replaced on this line in the past, but perhaps on a more accelerated schedule.

> **FINDING**: The projects sampled by CPSD raise a concern that some of the Companies' prioritized projects, especially the large project related to Line 1600 included in the PSEP for Phase 1, may not be targeting the highest priority pipe segments. CPSD believes that a significant portion of the estimated costs for these projects appear to be inappropriately targeted towards testing or replacing low priority pipe. In the case of Line 1600 alone, of the approximately $325 million to replace Line 1600 and $14.4 million to make the line piggable, pig it, and then hydro-test it, considerable portions of these estimated costs are attributable to addressing lower priority sections of pipe and to increasing pipeline capacity.

<u>CPSD's Review of the PSEP Valve Enhancement Process</u>

In response to the over 90 minutes it took for manual valves to be closed to isolate section of PG&E's Line 132 which ruptured in the September 9, 2010 incident, D.11-06-017 requires Operators to determine where automated valves could be placed on their transmission lines in order to reduce the time necessary to isolate a breach to the pipeline that results in a significant amount of gas leakage into densely populated areas.

Automated valves can generally be configured to operate in two modes: automatic shut-off valve (ASV) mode in which the valve operates on its own trigger points and doesn't require the valve to receive a command to close from the operator, and remote controlled shut-off valve (RCV) mode in which the valve has to receive a command from the operator before it begins to close.

CPSD believes the Companies' have used a sound approach towards determining where automated valves should be installed, in order to reduce the consequences of a major pipeline breach. This approach appropriately considers pipeline diameter, the operating stress of the line, and geological threats as part of the determination process. Under their approach, the Companies intend to limit the spacing of valves in order to be able to isolate a segment in a Class 3, 4, or HCA location to no more than eight miles in length.

The Companies' plan to support the automated valve installations with additional telemetry installations which obtain real time data (i.e., pressures, flows, etc.) and installations of backflow prevention devices necessary to better identify and isolate a segment. The number of automated valves to be installed under the Companies' PSEP, however, appears to be high in comparison to the spacing proposed for such valves in federal legislation now under consideration. As proposed, the Companies PSEP relies primarily on the installation of 20 new RCVs, upgrading of 347 manual valves to ASV/RCV, the installation of communications onto 100 ASV, and converting 94 ASVs to RCVs. Under the PSEP, the Companies would complete this work over a ten year period.

The Companies' proposed spacing of RCVs is intended to limit gas flow to approximately 5-15 minutes after the last valve necessary to isolate a breached segment closes. The size of the breach, and its operating pressure when breached, will affect the amount of time it actually takes to stop the gas flow, but the proposed spacing would generally allow gas in the line to be evacuated in ten minutes, following valve closure.

The approximate time of ten minutes to evacuate the line of gas is independent of the amount of time it would take an operator to identify, determine, and act to close the particular valves necessary to isolate a breached segment. CPSD believes that the additional data sensing points the Companies propose to install are necessary to enable automated processes to help operators quickly and accurately determine the location of a breach. However, even with this additional information, the Companies believe it could take an operator at least 15 minutes to make the decision to shut-in a breached section of pipe using RCVs. This means that for a full breach, the time to completely stop the flow of gas would be approximately 25-30 minutes.

Based on general concerns expressed by first responders, CPSD believes that first responders would consider 30 minutes to completely stop gas flow as being reasonable. Additional data sensing points would provide the Companies with the ability to calculate flow conditions and gas evacuation times, in real time, and be able convey this information to first responders. According to first responders, this information is crucial to allow them to more effectively plan their actions in response to a pipeline event.

Due to Companies' concerns and experience regarding false trips, they intend a majority of the 561 valves to be used in RCV mode. However, CPSD believes that the Companies' proposed number of automated valve installations could potentially be decreased if they were to install ASVs at less frequent spacing than that at which they now propose to install RCVs.

As an example, a separation of 16 miles for ASV valves, versus a spacing of 8 miles for RCV valves, entails twice the amount of gas that would have to be evacuated through a rupture location. However, the time to evacuate the gas between the two ASVs would generally be the same as for RCVs spaced at half the separation. This is because an ASV begins to close on its own without direction from an operator, once its trip parameters are reached and maintained. Eliminating the time needed for an operator to act entails a time difference of approximately 10-15 minutes. The same 10-15 minutes in which gas would have continued to flow pending an operator's determination would then be used to evacuate the gas from a longer section (i.e., 16 miles vs. 8 miles) of pipeline.

There is no denying that significant gas disruptions, and customer inconvenience, can occur from a false closure of an ASV. These conditions are compounded if a false trip occurs under high gas demand conditions, which are the very types of conditions that raise the risk of an ASV falsely closing. Because the Companies do not have sufficient historical, real time, flow data for critical points throughout its transmission system, it is not possible for CPSD to identify locations where ASVs could be installed without triggering potential for ASVs to falsely close. Unfortunately, there are no known studies or examples which provide for such insight at this stage.

In the absence of guidance from previous studies or models of installations, similar to that now being pursued by the Companies, CPSD finds it difficult to quantify any precise numbers of telemetry installations and new or retrofitted automated valves that are required. The absence of any benefit-to-cost studies for the proposed number of total installations further limits our ability to form a definitive opinion. Nonetheless, CPSD believes that the Companies' systems are already configured to provide a good level of isolation ability, as has been demonstrated by their ability to isolate a rupture that occurred on its system in 2011 after it was struck and damaged by a party excavating above the system.

> **FINDING**: The additional enhancement measures related to automated valves, as proposed by the Companies, would improve current performance and CPSD recommends that the CPUC allow the Companies to proceed with their proposal to install telemetry facilities and backflow prevention devices at all locations as planned. CPSD believes these readings are crucial because they allow for pin-pointing failure locations and will assist in first response efforts to any failure events.

> **FINDING**: If the CPUC is willing to accept some risk of false closure, the number of automated valves proposed in the PSEP could be reduced with the installation of ASVs, at intervals longer than those being proposed by the Companies for RCV installations, and still ensure that gas flow is stopped within 30 minutes of a full breach of the pipeline. If the CPUC decides that the risk of false closure is too high, CPSD believes the Companies' PSEP valve program will allow gas flow from a full breach to be extinguished within 30 minutes from the time of the breach, provided that the Companies close all RCVs necessary to isolate the affected section of pipe, within 15 minutes of the breach.

<u>Other Methods Proposed to Validate Pipeline Strength In Lieu of Pressure Testing or Replacement</u>

The Companies request approval alternative methods for validating the safety margins for their pipelines other than pressure testing or replacement. Proposed methods include obtaining data related to the condition of the longitudinal seams, girth welds and other conditions on the pipe through TFI tools; "in-service" pressure tests; or other non-destructive methods that allow for the collection of data.

The Companies request modification of GO 112-E to recognize the Companies' suggested alternative methods and allow for their use in validating the Maximum Allowable Operating Pressures (MAOP) the Companies have established on their transmission segments under the "grandfathering clause" provision of 49 CFR, Part 192, Section 192.619(c). The Companies believe that this way Operators can gradually transition off the provisions of Section 192.619(c) without the need to entirely eliminate Section 192.619(c) from being referenced, and accepted, by GO 112-E.

The Companies concerns, that the Commission intends to exclude Section 192.619(c) appear to stem from their belief that language in D.11-06-017, Ordering Paragraph 4, signals the Commission's intent to exclude subsection 192.619(c) from GO 112-E. CPSD does not believe that is the Commission's intention, because to do so would also impact distribution facilities on which MAOPs may also have been grandfathered under the provisions of Section 192.619(c).

CPSD believes that unlike transmission pipelines, which experience much higher operating stresses throughout their lifetime, distribution facilities, by definition, operate at much lower stresses and if breached, leakage, and not rupture, is the primary mode of failure. CPSD is not aware of data to support elimination of the provisions of 192.619(c) for distribution facilities and, in turn, for the elimination of GO 112-E's reference to Section 192.619(c), in its entirety. Although CPSD understands the Companies' concerns regarding the exclusion of Section 192.619(c), it does not agree that there is a need to add the language proposed by the Companies in the PSEP to GO 112-E.

CPSD also believes that the language proposed on page 46 of the Companies' amended testimony in support of the PSEP, would cause GO 112-E to conflict with 49 CFR, Part 192, which is referenced and adopted by GO 112-E. This is because GO 112-E acceptance of a 1.25xMAOP pressure test, or any of the other conditions (with perhaps the exception of Condition 4) proposed in the PSEP for validating the stability of the long seam, would conflict with seam stability validation methods allowed by the integrity management rule (i.e., 49 CFR, Part 192, Subpart O). In fact, Condition 2 would even be in conflict with GO 112 which, prior to November 12, 1970, required a pressure test to a level of 1.5xMAOP in a Class 3 location and did not accept something equivalent to 1.39xMAOP.

CPSD does not agree that the proposed alternative methods provide an equivalent basis for the strength testing required by D.11-06-017. Most of the alternative methods detailed by the Companies in the PSEP are understood by regulatory bodies and the pipeline industry. In fact, many of them are used by industry, one way or another, as part of their pipeline integrity management programs, to validate the on-going integrity of their pipelines. CPSD believes that because these alternatives, like pressure testing, have recognized strengths and weaknesses, they should be used to complement pressure testing of pipelines, as required by D.11-06-017, and not as a substitute for it.

GO 112-E requires every new transmission line built by the Companies today, even those built using materials, construction methods, and welding and testing standards that are state-of-the art, to be strength tested through a static pressure test to a level that assures significant safety margins during operations. Since such rigorous pressure testing is applied to brand new, state-of-the-art pipelines, CPSD believes it is imperative that pipelines built to standards less rigorous be pressure tested to today's standards or replaced and CPSD believes that is precisely what D.11-06-017 requires the Companies to do.

> **FINDING**: Adopting the change proposed by the Companies to GO 112-E would allow pipelines that have not been pressure tested to have their MAOP validated without a pressure test.

> **FINDING**: As described below, the proposed alternatives to pressure testing or replacement are not functionally equivalent to pressure testing or replacement and may ultimately delay the implementation of the CPUC's pressure test or replace policy.

The PSEP proposes to run a TFI tool prior to pressure testing to identify and remove potential weaknesses from the pipeline before it is pressure tested. The Companies state the estimated costs of these TFI runs is incremental to currently planned ILI runs related to their integrity management program (IMP).

CPSD does not believe that running the TFI tool prior to pressure testing, as required by Box 5 of Phase 1A, is necessary. This process prolongs the pressure testing schedule and does not appear to justify the costs related to it. CPSD believes the Companies already have ILI data, mainly axial tool data and some TFI data, from ILI runs performed as part of the Companies' historical IMP, for many of the segments to be pressure tested under the PSEP.[11] CPSD suggests that this information, even though not all of it is TFI data, could be used by the Companies for their intended purpose- to identify and remove some of the potential weaknesses from the pipeline before it is pressure tested. If such weaknesses are removed and then have the test pressures applied to them for the durations required by GO 112-E, CPSD does not see how having TFI data supports and validates its sole use in Phase 2 in-lieu of hydro-

[11] Axial tools are most effective at identifying circumferential (girth) anomalies. TFI tools are most effective at identifying longitudinal (long seam) anomalies.

testing or replacement. PG&E's pressure testing on approximately 160 miles of transmission lines was successfully performed without any ILI prior to pressure testing, thus it is unclear why this data is necessary for the Companies to conduct pressure tests.

The costs to run TFI tools on all piggable lines to be pressure tested may be justifiable if the Companies can use the TFI results, and then perform pressure testing to levels acceptable for IMP assessment purposes. In other words, if as part of PSEP the Companies perform a TFI run, and if they conduct a pressure test to a level sufficient to meet integrity management regulations, then the PSEP results could also be used to meet the integrity management requirements for segments that may be due for IMP reassessment shortly following the completion of the PSEP activities.

> **FINDING**: The Companies have not justified running a TFI tool on all piggable lines prior to pressure testing unless such a run allows them to supplant IMP activities for that segment.

> **FINDING**: There may be opportunities, not addressed by the PSEP, where, with proper planning and coordination, PSEP activities could supplant some of the activities and costs related to the Companies' ongoing IMP activities.

The Companies request the Commission approve the use of an "in-service" test for grandfathered pipelines as an alternative to pressure testing. Segments that the Companies propose for an in-service test make up the Category 3 miles of the PSEP. These segments, which are currently operating at less than 20% of their historical MAOP, are noted by the Companies as having gone through an "in-service" pressure test. An in-service functional equivalency test has only been applied to 23 miles of Line 1026, which constitute the entire Category 3 miles identified in the PSEP. The Companies believe that although pipeline segments placed in Category 3 do not actually have documented pressure tests to a level of 1.25xMAOP, the difference between the current MAOP and that at which Category 3 segments historically operated is significant enough for the highest historical operating pressure to have provided an "in-service" natural gas pressure test that the Companies believe is functionally equivalent to a strength test of 1.25xMAOP. However, in recognition of "…the fact that operational pressure measurements are not static and portions of the pipeline may not have experienced the measured highest pressure…" the Companies propose that the margin between the lowered MAOP and the historical operating pressure be required to provide an equivalent pressure reduction of at least 1.39xMAOP.

GO 112-E, and 49 CFR, Part 192, Subpart J only recognize and accept a static pressure test (no fluid flowing) as validation of the strength of a pipeline. A static pressure test ensures that every point exposed to the test pressure actually experienced the pressure applied. An in-service operation cannot provide a static test pressure as required by GO 112-E and is, therefore, inherently not equivalent to the regulatory requirements. Whether the Companies apply their functional equivalency of 1.25xMAOP or 1.39xMAOP, neither would be capable of finding existing damage that pressure testing would reveal, such as the mechanical damage found during hydro-testing on PG&E's Line 132 during 2011, but which any level of functional equivalency like an in-service test would allow to remain in place.

> **FINDING**: The CPUC should require static pressure tests as a validation method consistent with the federal pipeline safety regulations. If the CPUC allows in-service pressure levels to substitute for static pressure testing, then the minimum in-service pressure equivalency of no less than 1.7xMAOP should be considered adequate by the CPUC. This would result in a 1.5xMAOP test for Class 3 locations with an equivalent safety margin as proposed by the Companies in their proposal for a 1.39xMAOP historical pressure functional equivalency.

> **FINDING**: Because the PSEP utilizes "pressure carrying" capability of 1.25xMAOP rather than a documented pressure test to the same level as its first screen, the decision tree excludes 23 miles of Category 3 pipeline segments from SoCalGas' Line 1026 from consideration in Phase 1A, even though these segments do not have a documented pressure test to a level of 1.25 times the segments' current MAOP. If the CPUC requires static pressure tests as recommended above, the Category 3 miles in the PSEP should be rescreened for placement into the correct phase of the PSEP. If the CPUC allows an in-service functional equivalency test, the Category 3 miles should be rescreened to ensure that the functional equivalency is to 1.7xMAOP.

The PSEPs proposes to directly examine segments of pipe of less than 1000-feet in length, in lieu of pressure testing or replacement because it will result in lower costs. CPSD believes that the Companies' cost saving potential of $5 million from examining, instead of replacing, 1.69 miles of short length segments, could be significantly less than forecast if asbestos abatement or repairs necessitated by the examinations, which are currently not factored into cost saving estimates, become concerns and results in permitting or construction issues that delay even a small number of the almost 100 locations where short segments need to be addressed as part of the PSEP. Also, the full length excavations, and related permits, that will be required for direct examinations also create ideal opportunities for the testing or replacement of the segments intended to be examined.

> **FINDING**: Segments less than 1000-feet in length should be pressure tested or replaced rather than directly examined in light of the limited cost savings associated with direct examination for these shorts.

Technological Enhancements For Incident Detection

Within the PSEP, the Companies propose to install fiber-optic right-of-way monitors and methane leak detection units, along with a data collection and management system (DCMS) to receive and store data from these and other monitors, as part of their efforts to become aware of potential problems or damages to their transmission pipelines as soon as possible after a potential problem exists.

CPSD believes that work and materials related to the installation of fiber-optic sensors and the DCMS may have value. The greatest cost of placement of fiber-optic cable, which must be buried slightly above the pipeline, is the cost of the excavation itself. The costs for material and installation justify placing the cable in the ground even if it is not connected to monitors right away. However, even if the Companies place the fiber-optic cable in all the locations where pipe is replaced, and install the required monitors, it appears to CPSD that the additional protection will be functional in only a very small part of the Companies' system.

CPSD suggests that the benefits of the 2,100 proposed methane leak detection monitors may not justify the costs at this time. Additional leak surveys being performed as interim measures are already providing increased assurance of pipeline safety and will continue to do so until pressure testing and replacement are completed. The Companies have indicated that the installation of the methane detectors will not result in the reduction of current leak detection work or any accompanying savings that might have accrued from normally scheduled leak survey activity being displaced by the installation of the methane detectors. There are no indications that the Companies' current processes and procedures related to leak surveys, odorization, and emergency response are not adequate to enable the Companies' personnel or the public to detect gas leaks, or the Companies' personnel being unable to respond to a gas smell call in a timely manner.

Finally, maintaining the calibration of methane detection devices currently in use by SoCalGas has proven to be labor intensive. This is so even though units are installed in a relatively well controlled environment. In the open environment, as proposed in the PSEP, the units would be exposed to all kinds of hydrocarbon, such as gasoline and even car exhaust. The very low sensitivity to which the methane detectors are intended to be calibrated, 1/20 of the normal human sense of smell, will likely result in numerous false alarms requiring a response and unit maintenance.

> **FINDING**: The Companies should continue evaluating next generation methane detection technologies. Any technology that shows promise in regard to accuracy, reliability, maintenance needs, and cost should be tested through a pilot program through which the units are evaluated in actual, varying, field conditions, to support wide scale deployment throughout the system.

Program Management Office

The sheer volume of the work included in the PSEP; the need to coordinate engineering, operations, permitting, public outreach, procurement of materials, equipment, and human resources, testing, and construction; and to provide assurance that the PSEP work is executed on schedule and within estimates and contingencies, will require strict, disciplined oversight. To provide this oversight, the Companies intend to execute the PSEP under the framework of a Project Management Organization (PSEP PMO). The Companies have been seeking an engineering consulting firm to assist in establishing, managing, and performing several of the tasks to be performed under the PMO; however, as of now, CPSD does not know which, if any, firm has been hired by the Companies to head the PMO.

According to the Companies, the most difficult challenges the PMO will have to contend with are permitting issues and procurement of qualified labor resources critical to the execution of the PSEP. Due to the current condition of the economy, the Companies do not believe procurement of pipeline and materials will be as big an obstacle as other issues. Nonetheless, the Companies understand that there will be competition for many of the same resources certainly within the state, and potentially within the nation, if federal regulations begin mandating similar pipeline safety requirements as being mandated by the Commission. CPSD believes that the Companies are approaching the need to manage the PSEP in a reasonable manner and that the PMO will be critical to the proper execution of the PSEP. CPSD intends to review PSEP activity on an on-going basis and part of its review will be to confirm that the PMO, at a minimum, continues to effectively review schedules, costs, contingency drawdown, and all aspects of quality related to the program and quickly implements changes to correct any deficiencies identified through its own review.

Line Downtime

The 2-6 weeks of line downtime (clearance) estimated by the Companies appears excessive when compared to the average of 17 days of clearance experienced by PG&E for the approximately 160 miles of pipeline pressure testing that company performed throughout 2011. Each pressure test can have its own unique challenges, clearance requirements, and failures from the test. Nonetheless, CPSD believes that the Companies' long estimated clearance times may push certain segments into the replacement category unnecessarily by assuming that activities, such as removal of wrinkle bends or Oxy-Acetylene Girth welds, are required to perform a pressure test. CPSD believes that clearance times could be reduced if activities performed during the clearance are strictly limited to those essential to the performance of the pressure test. In other words, CPSD recommends that the Companies confirm that activities such as removal of wrinkle bends or Oxy-Acetylene Girth welds are not the primary drivers of the extensive clearance times which are then used as the basis for replacing a segment rather than performing a pressure test on it.

> **FINDING**: Discretionary activities, such as removal of wrinkle bends or Oxy-Acetylene Girth welds, may be drivers of the extensive clearance times the Companies have identified for pressure tests which are then used as the basis for replacing a segment rather than performing a pressure test on it.

Interim Measures

The Companies are currently performing both patrols and leak surveys on a bi-monthly basis for segments lacking sufficient documentation. CPSD suggests that the Commission allow the Companies to continue performing bi-monthly leak surveys over transmission pipeline segments lacking sufficient documentation of pressure testing, until the strength of the segment is validated through a pressure test or replacement. However, the costs of bi-monthly patrols may be an area where costs reductions, albeit small, may be possible, by changing to a semi-annual frequency.

While a leak survey is performed using an instrument to detect for gas leakage and migration, the primary purpose of patrols is to look for third-party excavations occurring near an operator's pipeline. Since the main threat being addressed through the PSEP is manufacturing, followed by construction/fabrication threats, it appears to CPSD that patrols could be performed on a semi-annual frequency, unless the transmission line is located where quarterly patrols are required by code.

> **FINDING**: Some cost savings could be realized by changing the frequency of patrols to semi-annual from bi-monthly.

<u>Cost Responsibility</u>

The PSEP proposes for the Companies to absorb costs related to pipeline segments installed after 1970 that do have insufficient pressure test documentation, but does not propose similar treatment for segments installed between July 1, 1961 and 1970 with similar deficiencies. Segments installed in this time period fell under requirements of the Commission's General Order 112 which codified safety requirements for transmission pipelines in California at that time. The Companies have identified approximately 20 miles of transmission pipelines that were installed under GO 112 before federal regulations came into being.

> **FINDING**: If the Companies cannot provide records showing that the 20 miles of pipeline segments installed between July 1, 1961 and 1970 were tested and documented per GO 112 requirements, the segments lacking documentation must be tested or replaced at the Companies' expense.