Rulemaking No.:	11-02-019
Exhibit No.:	
Witnesses:	M. Allman
	D. Bisi
	G. Lenart
	R. Morrow
	J. Rivera
	D. Schneider
	C. Shepherd

(U 904-G) and (U 902-M)

TESTIMONY OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF PROPOSED NATURAL GAS PIPELINE SAFETY ENHANCEMENT PLAN

Before the

Public Utilities Commission of the State of California

August 26, 2011

#258316

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

Section	Page	Witness

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

Testimony in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan

Table Of Contents

I.

INTRODUCTION AND EXECUTIVE SUMMARY

In the aftermath of the September 9, 2010 pipeline rupture in San Bruno, the Commission opened this Rulemaking in "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[1] In the Order Instituting this Rulemaking, the Commission expresses immense concern for those affected by the pipeline rupture, emphasizing that "the depth of this tragedy is the source of our resolve to take all actions necessary to ensure that it never happens again."[2]

SoCalGas and SDG&E share the resolve of the Commission to take those actions necessary to avoid the recurrence of the San Bruno tragedy and fully support the Commission's effort in this Rulemaking to implement forward-looking policies and procedures to enhance gas pipeline safety and reliability throughout California. Since September 9, our pipeline integrity engineers and supporting personnel have been focused on learning from that event, re-assessing our existing pipeline integrity program and the status of our system, and identifying ways that we might further enhance our own system. Eleven months later, and after completing our review of records in response to Safety Recommendations issued to Pacific Gas and Electric Company (PG&E) by the National Transportation Safety Board (NTSB), we remain confident in the integrity and safety of our system and are proud of the work performed by our employees, including our team of engineers and supporting field and operations staff. Safety is, and has always been, paramount at SoCalGas and SDG&E, and our safe operating history and culture are a clear reflection of that.

Although we remain confident in our existing transmission pipeline integrity program and are proud of our excellent safety record, in light of the events in San Bruno and the Commission's directives in this Rulemaking, SoCalGas and SDG&E acknowledge that we can always do more

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1 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, issued February 24, 2011 (Order Instituting this Rulemaking), p. 1.

2 *Id.*

and we can always improve. Indeed, an emphasis on continuous improvement is an essential part of our company culture.

In the Chapters that follow, SoCalGas and SDG&E propose a comprehensive Pipeline Safety Enhancement Plan that identifies several opportunities for increasing confidence in, and further enhancing the integrity of, our transmission pipeline system. The Pipeline Safety Enhancement Plan is founded upon four overarching objectives.

First, as has been our practice, SoCalGas and SDG&E strive to fully comply with the directives of the Commission. Accordingly, the Pipeline Safety Enhancement Plan ties closely to the requirements set forth in D.11-06-017 and sets forth a proposed process for meeting the Commission's directives. SoCalGas and SDG&E strive to be proactive and innovative in our approach to pipeline safety and reliability. Therefore, our proposed plan also offers proposals to enhance our system beyond the measures strictly required under D.11-06-017, and includes alternatives that can be adopted by the Commission to reduce costs for our customers.

Second, the proposed Pipeline Safety Enhancement Plan is designed to enhance public safety. While SoCalGas and SDG&E are confident in the safety and integrity of our system, we recognize that the pipeline rupture in San Bruno raises questions about the safety of natural gas pipelines in the State. As a result, the industry is re-evaluating existing regulations and protocols, and State and Federal regulators and legislators are considering elevated safety standards and more stringent regulations. We are monitoring these developments and intend to meet or exceed heightened industry standards and regulations as they evolve. Clearly, there are lessons to be learned, and we are following the NTSB's investigation into the San Bruno pipeline rupture closely and will incorporate those lessons into our practices as they come to light.

Third, the Pipeline Safety Enhancement Plan is designed to minimize customer impacts. We are proud of our long history of providing reliable service to our customers, and remain mindful of the fact that our customers depend on the reliability of our service, not only to heat their homes and fuel essential appliances, but also to maintain the reliable operation of California's electrical grid, the production of fuel and other commercial and industrial uses that support California's economy.

Fourth, the Pipeline Safety Enhancement Plan seeks to maximize the cost effectiveness of infrastructure investments for the benefit of our customers. Having been in the business of providing reliable natural gas service to our customers for over 100 years, we recognize the need to carefully invest in our system in a manner that complements previous investments in our system, avoids short-sighted or reactive actions that could result in unnecessary or duplicative expenditures, and enhances the long-term safety and reliability of our system.

We believe our proposed Pipeline Safety Enhancement Plan achieves all of these objectives and seek Commission approval to begin the work of executing the plan as soon as possible. Specifically, SoCalGas and SDG&E seek express Commission approval of the following key elements of our proposed Pipeline Safety Enhancement Plan:

1. Our proposed phasing approach and prioritization process for the pressure testing or replacement of transmission pipeline segments. As required by the Commission, our proposed phasing approach and prioritization process prioritize pipelines operating in populated areas ahead of pipeline segments in less populated areas.
2. Our proposed criteria for determining whether to pressure test or replace pipeline segments. This includes a proposal to use non-destructive examination methods, such as radiography, ultrasonic inspection, and magnetic particle testing, as an appropriate alternative to pressure testing or replacement for those pipeline segments less than 1,000 feet in length.
3. The use of state-of-the-art in-line inspection tools, as part of our pressure testing and assessment process. Because we have already invested in an ambitious in-line inspection program as part of our existing pipeline integrity management program, many of the pipelines identified for testing or replacement are already retrofitted to allow for in-line inspection. We propose to perform additional in-line inspections to more thoroughly assess those pipelines as part of our testing and replacement process, and to analyze data obtained through this process to demonstrate that advanced in-line inspection technologies achieve the same standard of safety as pressure testing. If the Commission ultimately determines that the data we obtain through this process

demonstrates that advanced in-line inspection technologies provide the same standard of safety as pressure tests and authorizes the use of in-line inspections as an alternative to pressure testing, which could significantly reduce costs for our customers over the long term.

4. The continued use of our proposed interim safety measures. We have already implemented our safety enhancements measures, which include pressure reductions, more frequent (bi-monthly) ground patrols and leakage surveys, and in-line inspections. In addition, we continue to assess and monitor all transmission pipelines under our existing transmission pipeline integrity management program.
5. The enhancement of our valve infrastructure through the retrofit of existing valves, installation of additional remote control and automated shutoff valves, and installation of supporting equipment and system features on transmission pipelines greater than twelve inches in diameter. We propose to implement these valve system enhancements at intervals of eight miles or less (for an average of six miles) to enhance our ability to monitor our pipeline systems and reduce our response time in the event of an unanticipated pressure change.
6. The retrofitting of our transmission pipelines to include advanced fiber optic and methane detection technology. During the execution of our plan, hundreds of miles of pipeline will either be exposed for examination or testing, or will be replaced as part of this plan. This presents a unique opportunity to retrofit these pipelines with state-of-the art monitoring technology to enhance our ability to detect conditions in real-time that could ultimately place our pipelines at risk.
7. The design of an Enterprise Asset Management System that will integrate our historical and current transmission pipeline data and systems in order to further the Commission's goal of having all transmission pipeline documentation readily available.

The scope of work required to implement the Commission's directives is considerable. Table I-1 below details the miles of transmission pipelines to be pressure tested, replaced, and in-line inspected, as well as the number of valve enhancements under our proposed Pipeline Safety Enhancement Plan during the years 2012 through 2015.

Table I-1
Summary of Transmission Miles and Valves to be Enhanced During the Years 2012 through 2015

SoCalGas	2012	2013	2014	2015	Total
Pipeline Replacement (miles)	25	73	74	74	246
Pressure Testing (miles)	73	96	96	96	361
In-Line Inspection (miles)	133	178	178	178	667
Valve Retrofit/Installation (valves)	30	40	51	52	173
SDG&E	**2012**	**2013**	**2014**	**2015**	**Total**
Pipeline Replacement (miles)	5	14	15	15	49
Pressure Testing (miles)	<1	<1	<1	<1	1
In-Line Inspection (miles)	-	-	54	-	54
Valve Retrofit/Installation (valves)	7	7	8	8	30

The projected costs of implementing our proposed Pipeline Safety Enhancement Plan are also projected to be significant. Table I-2 below provides a summary of the projected direct costs to be incurred by SoCalGas and SDG&E during the years 2011 through 2015.

Table I-2
Summary of Projected Direct Costs of Implementing the Proposed Pipeline Safety Enhancement Plan During the Years 2011 through 2015
(In Millions of 2011 Dollars)

	2011	2012-2015		
	O&M	Capital	O&M	Total
SoCalGas	6	1,184	256	1,446
SDG&E	1	229	7	237
Total	7	1,413	263	1,683

We seek Commission authorization to recover the costs of implementing the Pipeline Safety Enhancement Plan from our customers as follows:

1. Authorize the recovery of costs incurred to date, and to be incurred up to the time the Commission issues a decision approving our proposed plan, for the review of transmission pipeline records and for implementation of our interim safety

enhancement measures. To date, we have incurred costs of approximately $3 million and forecast that we will spend a total of about $7 million by year-end.

2. Approve direct Capital forecasts for implementation of the Pipeline Safety Enhancement Plan during the time period of 2012 through 2015 of approximately $1.2 billion for SoCalGas and $229 million for SDG&E, and direct Operation and Maintenance (O&M) forecasts for implementation of the Pipeline Safety Enhancement Plan during the time period of 2012 through 2015 of approximately $256 million for SoCalGas and $7 million for SDG&E.
3. Approve the revenue requirements resulting from our Capital and O&M forecasts for the years 2011 through 2015.
4. Authorize us to include a request to approve the Capital and O&M forecasts and resulting revenue requirements for subsequent years of our Pipeline Safety Enhancement Plan in our respective General Rate Cases or other appropriate proceedings, as needed.
5. Approve our proposal to track the costs of implementing our Pipeline Safety Enhancement Plan separately from other pipeline system costs and to allocate those costs to our customers using the Equal Percent of Authorized Margin (EPAM) method.
6. Approve our request to identify the costs of implementing our Pipeline Safety Enhancement Plan as a separate item, a "PSEP Surcharge," on our customers' bills.
7. Approve our proposal to submit an annual status report to the Commission by March 31 of each year, beginning in 2013 that includes (a) information on work completed during the previous year; (b) work planned for the upcoming year; (c) discussion of progress made; and (d) confirmation of the Commission's approved annual budget for the Pipeline Safety Enhancement Plan.

Whether the Commission adopts the Pipeline Safety Enhancement Plan as proposed, or with modifications, SoCalGas and SDG&E intend to execute the plan approved by the Commission as expeditiously as possible.

In the Chapters to follow, we provide a more detailed description of our proposed Pipeline Safety Enhancement Plan. In Chapter II, we provide an overview to our approach to developing the proposed Pipeline Safety Enhancement Plan and explain how our proposed plan satisfies the directives of the Commission while also meeting our objectives to enhance public safety, minimize customer impacts and maximize cost effectiveness. We discuss the overall costs associated with implementation of the proposed plan and offer a proposed approach to appropriately allocating those costs to our customers. We also describe our proposed timeline and phased approach to implementing the plan and offer suggestions for how the Commission might help expedite the implementation process.

In Chapter III, we provide an overview of our natural gas transmission system. We believe it is important to begin our discussion of the Pipeline Safety Enhancement Plan with a description of the unique attributes of our natural gas pipeline infrastructure, so that our Pipeline Safety Enhancement Plan can be evaluated within the context of that system.

In Chapter IV, we set forth a plan to test or replace pipeline segments that do not have sufficient documentation of a pressure test to meet the standards set forth by the Commission in D.11-06-017. In addition, we request authorization to abandon any non-piggable[3] pipeline segments that were installed prior to 1946. This testing or replacement plan is designed to prioritize pipeline segments located in populated areas, and is divided into three categories according to an assessment of the demonstrated margin of safety, the characteristics and piggability of the pipeline segments, and the completeness of the documentation available and pressure test thresholds experienced to validate system confidence. Second, our Pipeline Safety Enhancement Plan incorporates interim safety enhancement measures that we have already implemented to provide even greater confidence in the integrity of our system.

In Chapter V, we propose a Valve Enhancement Plan to augment SoCalGas and SDG&E's existing automatic shutoff valves and remote control valves, for the purpose of minimizing the time required to stop the flow of gas in the event of a pipeline rupture.

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3 Piggable pipelines are pipelines that have already been retrofitted to accommodate in-line inspection tools under our existing in-line inspection program. Our use of in-line inspection tools is described in greater detail in Chapter IV.

In Chapter VI, we offer a forward-looking proposal to invest in technologies to further enhance the safety of our system by augmenting our ability to assess the conditions of our transmission pipelines in real-time. Specifically, we seek authorization to invest in fiber optic right-of-way monitors and methane detection monitors. These monitors can provide rapid notification of potential activity near transmission pipelines and of pipeline failures, thus decreasing the time required to identify, investigate and prevent the effects of such events. Although not expressly required under D.11-06-017, we believe these proactive and innovative technology investments can further enhance the safety of our pipeline system and therefore offer these proposals for the Commission's consideration.

In Chapter VII, we seek authorization to invest in the development of an Enterprise Asset Management System to integrate operational data so that such data can be made "readily available."[4] This proposed Enterprise Asset Management System will integrate operations data from several sources including maintenance and inspection systems, geographical information systems, purchasing systems and historic records.

In Chapter VIII, we describe our plan for executing the Pipeline Safety Enhancement Plan, including a description of how we will manage the numerous projects to be executed as part of the plan, how we will maintain material and construction quality assurance, how we select and approve contractors, and how we maintain supplier diversity.

In Chapter IX, we describe the estimated costs of executing the Pipeline Safety Enhancement Plan. The estimated investment required to implement the Pipeline Safety Enhancement Plan is approximately $1.5 billion in direct costs for SoCalGas and $240 million in direct costs for SDG&E during the next four years. We believe these investments are prudent in light of recent events and evolving industry standards, and seek Commission authorization to make these investments on behalf of our customers.

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4 D.11-06-017, pp. 19-20 ("At the completion of the implementation period, all California natural gas transmission pipeline segments must be (1) pressure tested, (2) have traceable, verifiable, and complete records readily available, and (3) where warranted, be capable of accommodating in-line inspection devices.")

Finally, in Chapter X we provide a ratemaking proposal for recovery of the costs of executing the Pipeline Safety Enhancement Plan. We ask that the Commission issue a decision approving this plan and authorizing us to recover costs already incurred, and the estimated costs of implementing the proposed Pipeline Safety Enhancement Plan from now until we have a decision in our respective 2016 General Rate Cases, wherein we will propose to recover the costs for implementing our plan during that rate cycle. We suggest that these costs be identified in a monthly "PSEP Surcharge" on our customers' bills, so that the objectives and costs of these investments will be transparent to our customers. In addition, we propose to file annual reports with the Commission, beginning on March 31, 2013, to provide updates regarding the status of our implementation of the proposed Pipeline Safety Enhancement Plan.

II.

OVERVIEW OF THE PROPOSED SAFETY ENHANCEMENT PLAN

A. The Proposed Pipeline Safety Enhancement Plan is Designed to Meet Four Key Objectives

The Pipeline Safety Enhancement Plan was developed to accomplish four overarching objectives: (1) compliance with the Commission's directives; (2) enhancement of public safety; (3) minimization of customer impacts; and (4) maximization of cost effectiveness.

1. The Proposed Pipeline Safety Enhancement Plan Complies With the Commission's Directives

In D.11-06-017, the Commission describes several key elements that must be included in our proposed Pipeline Safety Enhancement Plan. These key elements are: (1) the completion of the review of records in response to NTSB Safety Recommendations; (2) a plan to test or replace all pipeline segments that do not have sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d); (3) the prioritization of pipeline segments in populated areas and segments with the highest risk; (4) an expeditious timeline; (5) retrofitting to allow for in-line inspections and, where appropriate, improved valves; (6) interim safety enhancement measures; (7) best available expense and cost projections for each plan element; and (8) a rate proposal that provides detailed information regarding projected rate impacts. Our proposed Pipeline Safety Enhancement Plan includes all of these required elements, as summarized below.

a) The Proposed Pipeline Safety Enhancement Plan Includes a Description of the Completion of Our Review of Records in Response to NTSB Safety Recommendations

In D.11-06-017, the Commission directs SoCalGas and SDG&E to "complete their work in response to the National Transportation Safety Board's [NTSB] recommendations and the Commission's Resolution L-410."[5] Accordingly, in Section IV.C below, we provide a

[5] D.11-06-017, Ordering ¶ 2.

description of the records review process we completed in response to the NTSB's recommendations and Commission Resolution L-410, and further describe the status of the records review process with respect to the remaining pipeline segments that were not addressed in the NTSB's Safety Recommendations or Commission Resolution L-410, but must nevertheless be addressed per D.11-06-017.

b) The Proposed Pipeline Safety Enhancement Plan Includes a Plan to Pressure Test or Replace All Pipeline Segments That Do Not Have Sufficient Documentation of Pressure Testing In Accordance with 49 CFR 192.619(a)(b) or (d)

D.11-06-017 requires SoCalGas and SDG&E to propose a plan "to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c)."[6] This proposed plan must "set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[7] And a pressure test record "must include all elements required by the regulations in effect when the test was conducted. For pressure tests conducted prior to the effective date of General Order 112, one hour is the minimum acceptable duration for a pressure test."[8] SoCalGas and SDG&E's proposed plan to meet this objective is set forth in Section IV.D. below.

c) The Proposed Pipeline Safety Enhancement Plan Prioritizes Pipeline Segments in Populated and High Consequence Areas and Those Operated at Higher Stress Levels

The proposed plan must "start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing."[9] Moreover, the plan must prioritize "critical pipelines that must run at or near [MAOP] values which result in hoop stress levels at or above

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6 *Id.*, Ordering ¶ 4.
7 *Id.*, Ordering ¶ 6.
8 *Id.*, Ordering ¶ 3.
9 *Id.*, Ordering ¶ 4.

30% of Specified Minimum Yield Stress."[10] "Although not the determinative factor, improved safety effects for amounts expended must be considered in prioritizing projects. Segments with the highest risk, however, must be tested or replaced first.[11] The decision-making and prioritization process described in Section IV.D meets these requirements.

d) SoCalGas and SDG&E Propose an Expedited Timeline for Implementation of the Proposed Pipeline Safety Enhancement Plan

The plan "must reflect a timeline for completion that is as soon as practicable."[12] SoCalGas and SDG&E comply with this requirement by proposing an aggressive schedule for the completion of their proposed Pipeline Safety Enhancement Plan in Section IV.D. The Commission can greatly enhance our ability to meet this ambitious schedule by authorizing the establishment of a Pipeline Safety and Reliability Memorandum Account, as requested in our pending Motion filed May 4, 2011, so that we can begin implementing the Commission's clear directives in D.11-06-017 right away.

In addition, later in this Chapter, we describe some of the execution challenges that may hinder our ability to meet our proposed schedule, and propose ways in which the Commission may help alleviate some of those challenges.

e) The Pipeline Safety Enhancement Plan Includes Proposals for Retrofitting Pipelines to Allow for In-line Inspection and Enhancing Shut-Off Valves

The plan "must consider retrofitting pipeline to allow for inline inspection tools and, where appropriate, improved shut off valves."[13] The Pipeline Safety Enhancement Plan addresses this requirement by proposing to design newly-constructed pipelines to accommodate in-line inspection tools, and by proposing a valve enhancement plan that expands upon our existing valve program. These aspects of the Pipeline Safety Enhancement Plan are set forth in Section IV.D and Chapter V, respectively.

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10 *Id.*, Ordering ¶ 5.
11 *Id.*, Ordering ¶ 9.
12 *Id.*, Ordering ¶ 5.
13 *Id.*, Ordering ¶ 8.

f) The Pipeline Safety Enhancement Plan Includes Proposed Interim Safety Enhancement Measures

The plan must “include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions. . . , and other such measures that will enhance public safety.”[14] In Section IV.E, the Pipeline Safety Enhancement Plan describes interim safety enhancement measures, including increased frequency of patrols and leak surveys, pressure reductions, and in-line inspections, which have already been implemented to address identified pipeline segments in populated areas, and will be implemented for pipelines in the less populated areas, as segments that do not have sufficient documentation of a pressure test to meet the directives of D.11-06-017 are identified through the ongoing records review process.

g) The Proposed Pipeline Safety Enhancement Plan Includes Best Available Expense and Cost Projections for Each Plan Component

The proposed plan “must include best available expense and capital cost projections for each Plan component and each year of the implementation period.”[15] The proposed Pipeline Safety Enhancement Plan includes best available expense and cost projections for each plan component in Chapter IX below.

h) The Proposed Pipeline Safety Enhancement Plan Includes a Rate Proposal and Provides Detailed Information Regarding Projected Rate Impacts

The plan “must also include a rate proposal with the following: a. For Pacific Gas and Electric Company only, proposed cost allocation between shareholders and ratepayers; b. Specific rate base and expense amounts for each year proposed to be included in regulated revenue requirement; c. Proposed rate impacts for each year and each customer class; and d. Other such facts and demonstrations necessary to understand the comprehensive rate impact of the Implementation Plan.” In Chapter X, we offer a rate proposal that is supported by detailed rate impact analyses for the proposed Pipeline Safety Enhancement Plan. In addition, for comparative purposes, we provide detailed cost and rate impact analyses for a “Base Case” which solely

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14 *Id.*, Ordering ¶ 5.

15 *Id.*, Ordering ¶ 9.

includes the work required under D.11-06-017, without the additional safety enhancing elements proposed by SoCalGas and SDG&E that are not required under D.11-06-017.

2. The Proposed Pipeline Safety Enhancement Plan Enhances Public Safety

Safety is a top priority at SoCalGas and SDG&E. Although we are confident in our existing transmission pipeline integrity program and are proud of our excellent safety record, in light of the events in San Bruno and the Commission's directives in this Rulemaking, SoCalGas and SDG&E propose a thoughtful plan that identifies opportunities for increasing that confidence and further enhancing the integrity of the transmission pipeline safety. Consistent with this public safety objective, and the Commission's directives in D.11-06-017, the Pipeline Safety Enhancement Plan identifies pipeline segments in populated and High Consequence Areas that require additional documentation of pressure testing to satisfy the Commission's requirements set forth in D.11-06-017 and proposes a plan to pressure test or replace all such segments. This plan prioritizes pipeline segments in more populated areas ahead of pipeline segments in less populated areas, and also prioritizes pipeline segments based on a comprehensive evaluation of risk factors. Because we have already invested significantly in retrofitting our existing pipelines to accommodate in-line inspection tools, other than replacing pipelines that cannot be retrofitted to accommodate in-line inspection tools, there is little room for proposing further enhancement of our transmission system to allow for in-line inspection. We do propose in our Pipeline Safety Enhancement Plan, however, to take advantage of these prior investments and perform in-line inspections of identified retrofitted pipelines as part of our implementation of the plan. In addition, as directed by the Commission, we propose to enhance our current valve system through a proposed Valve Enhancement Plan to reduce the time required to isolate a pipeline segment in the event of a rupture.

Consistent with our innovative and proactive approach to pipeline safety, the Pipeline Safety Enhancement Plan also identifies opportunities for further enhancing the integrity of the transmission pipeline system that are not strictly required to meet the Commission's directives in D.11-06-017. Specifically, we propose to retrofit pipelines that will be exposed for testing and newly constructed pipelines with fiber optic technology, which can further enhance the safety of our system by enabling us to monitor pipeline right-of-way activity in real-time and help drive decisions to send operational crews to investigate when a suspected dig-in has occurred that might, acutely or with some latency, pose a risk to a pipeline's structural integrity. In addition, we propose to retrofit our pipelines to include methane detection monitors, which will enable us to detect gas/air concentration levels approximately ¼ or less of what is typically detected by the human sense of smell of natural gas odorant. More timely identification of gas leaks will support the dispatch of operations personnel to specific locations along the pipeline system when methane is detected. Although these proposed technology enhancements will increase the costs of implementing the proposed Pipeline Safety Enhancement Plan above the Base Case, the completion of the work directed by the Commission in D.11-06-017 presents a unique opportunity for us to cost effectively retrofit our transmission pipelines with the latest state-of-the-art technology for sensing conditions that could lead to a pipeline failure long before such a failure might occur.

3. <u>The Proposed Pipeline Safety Enhancement Plan Minimizes Customer Impacts</u>

A third foundational element of our proposed plan is minimization of customer impacts. The implementation of our Pipeline Safety Enhancement Plan will require more work on our infrastructure over a ten-year period than has probably ever occurred during a similar time period ever before in our history. Every element of the Proposed Safety Enhancement Plan described below takes into account potential customer impacts and strives to minimize those impacts as much as possible.

In general, our proposals are guided by policies to provide uninterrupted gas service to customers whenever possible while the plan is being implemented. It is recognized that some of the planned pressure testing may have an impact on supply availability for some customers. We commit to work with our customers on the scheduling of the work and to do all that is reasonable to provide uninterrupted service.

When lines are required to be taken out of service, SoCalGas and SDG&E make every effort to minimize the impact on customers and will continue to do so during our execution of the proposed Pipeline Safety Enhancement Plan. As work is being planned on the gas transmission pipeline system, project managers work internally with Public Affairs who liaison with government agencies. Customer service account managers work with customers as the projects are planned. We make every attempt to work around customer schedules (*e.g.*, planned outages for maintenance and construction) as much as possible. We work with the California Independent System Operator (CAISO) eighteen months to two years in advance for planned outages that could affect electric generator availability, and make every attempt to schedule the outage during the low demand shoulder months (i.e., April and November). For large customers, our intent is to keep in constant communication up to, during and after the shutdown and have often provided alternate feeds if outages of any duration are unacceptable. We meet with local city councils to inform them of pending projects, hold "Town-Hall" meetings to inform residents of pending projects and allow them to ask questions, and we provide contact information at each end of the job site. At some locations, we work at night to minimize impacts on traffic and business.

As a general guideline, notice for suspension of service to firm noncore customers, and in this instance, affected core customers, would be provided at least thirty days prior to any scheduled service outages required for implementation of the Pipeline Safety Enhancement Plan. Notice for suspension of service to interruptible noncore customers would be provided at least three business days in advance of any scheduled service outages to accommodate electric generators' CAISO noticing requirements.

Although we are constantly inspecting and maintaining our pipelines, customers and the community in general will be seeing more work being performed on pipelines. This may raise questions and concerns about pipeline safety, and requires that we proactively communicate with our customers and the community at large about these programs – what is being done and why. Additionally, targeted communications will be required for residents and businesses in areas where the work will be performed to keep them informed of what is being done and how it might affect them. In order to achieve this, the proposed Pipeline Safety Enhancement Plan will be supported by a comprehensive customer and public outreach effort.

In order to reach the many key customer groups, this plan encompasses use of a comprehensive blend of communications channels. This will include in-person customer meetings, news releases, community print ads, special events, e-mails and e-newsletters, social, interactive and mobile media, direct mail, bill messages and newsletters, as well as a dedicated microsite on both www.socalgas.com and www.sdge.com. Specific outreach efforts in areas where there will be significant work will include local and community meetings, direct mailed letters sent to residents and businesses prior to commencement of the project, door hangers, email blasts, and news releases all directing the customer to view the dedicated microsite that will include interactive maps indicating project locations and timing. Messages will be delivered in English and Spanish, and other in-language messages will be developed based on the geographic area of the projects.

Each of these outreach efforts will include basic information on pipeline safety, the importance and benefits of the work being done, and how the project will impact nearby residents and businesses. Additionally, an important part of the education is the explanation of the philosophy and framework of how the cost of the program is distributed across customers.

4. The Proposed Pipeline Safety Enhancement Plan Maximizes the Cost Effectiveness of Investments in the SoCalGas/SDG&E Transmission System

Cost effectiveness is the final major guiding principle of our Pipeline Safety Enhancement Plan. From the onset of this effort, the SoCalGas and SDG&E approach has been anchored in the philosophy that the goal of our work should be comprehensive system enhancements/ improvements to achieve long-term safety and cost effectiveness. SoCalGas and SDG&E further this goal by crafting a plan that avoids duplication of efforts, complements existing infrastructure and prior investments in the SoCalGas and SDG&E pipeline system, and looks to technological advances in pipeline safety. We believe our plan proposed in the Chapters that follow achieves this objective.

B. The Proposed Scope of the Pipeline Safety Enhancement Plan is Comprehensive and the Schedule is Ambitious

In D.11-06-017 the Commission outlines a framework for California to lead the nation in natural gas pipeline safety by exceeding current Federal regulations and requiring that all in-service California transmission pipelines have documentation of pressure testing to meet strict regulatory standards that, prior to the issuance of D.11-06-017, only applied to pipelines constructed and placed in service after 1970.

Prior to the issuance of D.11-06-017, in response to the safety recommendations issued by the NTSB to PG&E on January 3, 2011, SoCalGas and SDG&E initiated a thorough review of transmission pipeline segments located in Class 3 and 4 locations and Class 1 and 2 High Consequence Areas to identify those pipeline segments that do not have sufficient documentation of pressure testing to meet modern safety standards. Combined, SoCalGas and SDG&E reviewed the records for a total of 1,622 miles of transmission pipelines operating in Class 3 and 4 location and High Consequence Areas and identified approximately 385[16] miles of transmission pipeline that did not have sufficient documentation of pressure testing to satisfy modern requirements. All of these pipeline segments must be tested or replaced in order to satisfy the directives set forth in D.11-06-017.

In addition to addressing these 385 miles of transmission pipelines located in Class 3 and 4 locations and Class 1 and 2 High Consequence Areas, in order to satisfy the directives set forth in D.11-06-017, SoCalGas and SDG&E will also need to test or replace all remaining pipeline segments that do not have sufficient documentation of pressure testing to satisfy modern standards. Based on preliminary review of records and assumptions based on the review of pipelines located in Class 3 and 4 locations and High Consequence Areas, SoCalGas and SDG&E estimate that about an additional 2,000 miles of transmission pipeline segments will need to be assessed to determine whether they require pressure testing or replacement.

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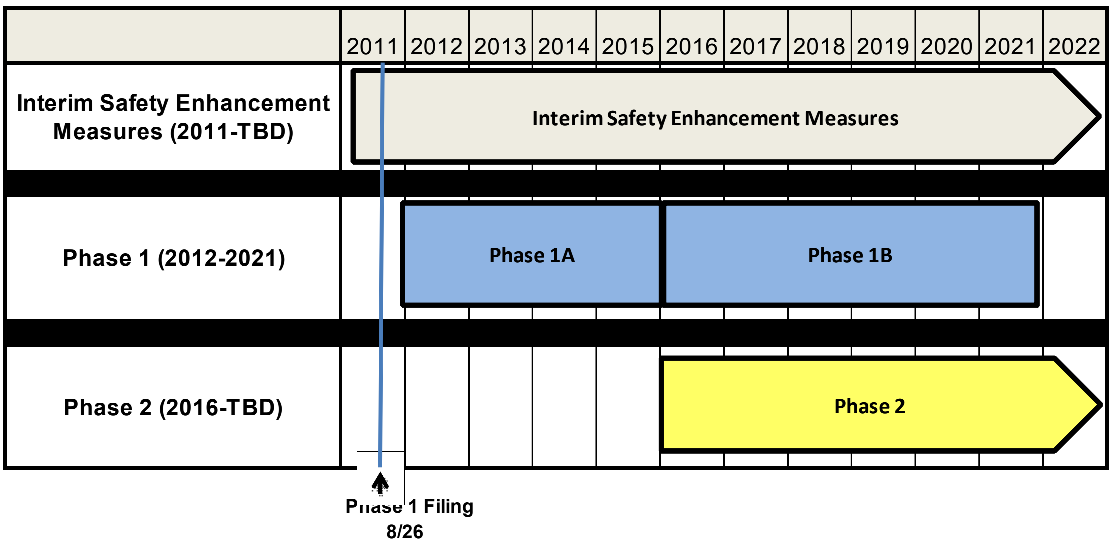
16 This figure includes approximately 377 miles of pre-1970 and 8 miles of post-1970 pipelines, as of June 24, 2011. This proposed Pipeline Safety Enhancement Plan does not include any costs for testing or replacing pipelines constructed post-1970.

Because of the scope and complexity of work required to implement the Commission's directives, and to satisfy the Commission's prioritization requirements, we propose to implement our Pipeline Safety Enhancement Plan in two separate phases. Phase 1 covers the ten-year period from 2012 through 2021. This phase includes the pressure testing or replacement of those pipelines in Class 3 or 4 locations and Class 1 and 2 High Consequence Areas that do not have sufficient documentation of pressure testing to satisfy the Commission's directives. Phase 1 also includes the placement of additional remote control and automatic shut-off valves on the transmission system, and installation of technology enhancements to enhance our ability to monitor our transmission pipeline system. As discussed above, and in greater detail in Chapter IV, our Pipeline Safety Enhancement Plan includes a proposal to replace pre-1946 pipeline segments that were manufactured using non-state-of-the-art construction and fabrication methods. This proposal, which is also proposed to be implemented in Phase 1, addresses the Commission's stated goal of bringing all transmission pipelines in-service in California into compliance with modern standards, and the directive to consider retrofitting our pipelines to accommodate in-line inspection tools.

Phase 1 has been broken down into two parts. In Phase 1A, which spans 2012 through 2015, we propose to pressure test or replace the 385 miles of transmission pipelines located in Class 3 and 4 locations and High Consequence Areas that do not have sufficient documentation of pressure testing to satisfy modern standards. Any Phase 1A pipeline segments that cannot be tested or replaced with manageable customer impacts during the 2012 through 2015 timeframe will be addressed in Phase 1B, which spans the years 2016 through 2021. Also in Phase 1B, SoCalGas and SDG&E propose to replace pre-1946 pipeline segments that were manufactured using non-state-of-the-art construction and fabrication methods.

In Phase 2, we propose to address all remaining transmission pipelines that do not have sufficient documentation of pressure testing to satisfy the Commission's directives. The review of the records for these pipeline segments will be completed by July 2012, and we propose to begin implementing Phase 2 in parallel with Phase 1B, beginning in the year 2016. The proposed phased timeline for the Pipeline Safety Enhancement Plan is illustrated in Figure II-1 below. As noted in the timeline, our interim safety enhancement measures have already been implemented this year, and we propose to continue implementing those measures until the execution of our proposed Pipeline Safety Enhancement Plan is complete. These measures, if approved as part of this plan, will be implemented for Phase 2 pipelines upon completion of the Phase 2 records review process.

Figure II-1
Proposed Pipeline Safety Enhancement Plan Timeline



C. <u>The Commission Should Authorize the Recovery of Costs Incurred in 2011</u>

The Commission should authorize us to recover the costs we have incurred to date, and will incur, by the time the Commission issues a decision approving our proposed plan. Although the San Bruno pipeline rupture did not occur in our service territory and there are no indications that our existing transmission pipeline integrity management program is not effectively managing the integrity of our transmission pipeline systems, we have been called upon to swiftly and proactively implement costly measures in response to the San Bruno pipeline rupture. On January 3, 2011, noting a potential discrepancy in the pipeline records obtained during the course of its investigation of the San Bruno pipeline rupture, the NTSB issued Safety Recommendations to PG&E directing PG&E to conduct an exhaustive review of pipeline records for all transmission pipelines operated in Class 3 and 4 locations and High Consequence Areas. Although the NTSB Safety Recommendations were not directed at us, at the request of the Commission, we also conducted an exhaustive review of our records for pipelines operated in Class 3 and 4 locations and High Consequence Areas, and incurred costs above and beyond those anticipated in our most recent General Rate Cases. To support the Commission's efforts, we conducted this review as quickly as possible, incurring significant costs in the process.

Following that records review, we voluntarily and proactively implemented several safety enhancement measures on pipeline segments for which we do not have sufficient documentation of pressure testing to validate that the pipelines are operating within an appropriate margin of safety. Again, although we knew we would incur significant costs, we voluntarily implemented these measures to support the Commission's efforts to restore public confidence in the integrity of the California natural gas pipeline system.

Our proactive approach to safety did not begin on September 9. We have consistently demonstrated a proactive approach to maintaining the integrity of our transmission pipelines in a manner that meets or exceeds regulatory requirements. In D.11-06-017, the Commission directs California pipeline operators to consider retrofitting their transmission pipelines to allow for internal inspection tools. The capability, reliability and availability of these in-line inspection tools have greatly improved over the last ten years. In recognition of these improvements, we have already implemented an extensive and concerted effort to retrofit our transmission pipeline system to allow the use of this technology. Currently approximately 50% of our transmission system is configured to allow for internal inspection tools, with additional retrofits that are outside the scope of this proceeding in progress.

The Commission should authorize the recovery of those costs we have and will incur, as a direct result of the San Bruno pipeline rupture, that are above and beyond those forecast in our most recent General Rate Cases. To date, we have incurred costs of approximately $3 million and forecast that we will spend a total of about $7 million by year-end above and beyond those forecast in our most recent General Rate Cases. All of these costs are attributable to our review of records and our implementation of interim safety enhancement measures.

D. The Costs of the Pipeline Safety Enhancement Plan Will Benefit All Customers, Not One Group More Than Another

The costs of enhancing California's natural gas transmission pipeline system to exceed current Federal and State regulations and lead the nation in natural gas pipeline safety are projected to be significant. The estimated direct costs for implementing Phase 1 (both Phase 1A and Phase 1B) of the proposed Pipeline Safety Enhancement Plan are projected to be approximately $2.5 billion for SoCalGas customers and $600 million for SDG&E customers.

Implementing these new safety enhancements will benefit all customers. Accordingly, the costs of the Pipeline Safety Enhancement Plan should be allocated in a manner that, on a percentage rate impact basis, is relatively equitable across our different customer classes. Fundamentally, all customers in our service territories will benefit equally from these investments in transmission pipeline safety.

Therefore, we propose that the incremental costs of implementing these new safety standards be tracked separately from other pipeline system costs and allocated on an equal percent of margin basis.[17] Furthermore, we propose that these costs be identified as a surcharge in each customer's monthly bill. Recovery of these costs through a line-item surcharge will provide transparency to our customers regarding the purpose for these costs. SoCalGas and SDG&E estimate that by 2015, Phase 1A will result in a $2.82/month surcharge on residential bills for SoCalGas and $2.83/month surcharge on residential bills for SDG&E.[18]

Today, a majority of transmission costs are allocated to large electric generators, manufacturers, refineries, and other large businesses that have very few employees—relative to the overall service territory population. The costs being ordered by the Commission, such as those associated with pressure testing, replacement of pipelines and automated valves, go beyond current Federal safety standards for pipelines. Industries and businesses will not realize

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17 Equal Percent of Authorized Margin (EPAM) is the same cost allocation approach taken with the recovery of increases in margin requirements during cost allocation periods.

18 This surcharge will almost double through the rest of the decade as the investments contemplated in Phase 1B are made, but it will eventually decline in the following decade as O&M work is completed and those investments begin to depreciate.

significant improvements in transmission service from these safety-related investments; therefore, it would be inappropriate to allocate these costs to these large throughput non-core customers in the same manner that transmission costs are allocated today. Furthermore, such an approach would likely encourage most, if not all, of these customers to eventually seek service from FERC-regulated transmission pipelines that are not required to recover the additional pipeline safety costs being ordered in this California proceeding.

E. The Commission Can Help Mitigate Some Execution Challenges and Risks that May Increase Costs and/or Delay Implementation

1. General Construction Permitting Challenges

SoCalGas and SDG&E operate transmission and distribution pipelines in 242 cities and 13 counties. Execution of the implementation plan will involve or lead to a substantial amount of construction activity within numerous cities and counties that will have permitting authority over various aspects of the plan projects. Various State and Federal agencies such the California Department of Transportation, California State Lands Commission, Federal Aviation Administration, California Department of Transportation, California Highway Patrol, as well as, county and municipal building and safety, public works, environmental health and safety and local fire departments, may all have permitting authority, depending on the location of a particular project.

Where required under local jurisdictions, SoCalGas and SDG&E currently apply for and obtain local ministerial permits. This process can often take considerable time and effort. The timing associated with a local jurisdiction's review and approval process is beyond the control of the utilities, and will significantly impact planning and scheduling. Continuing budget constraints and resource issues can hinder the ability of a local jurisdiction to review and approve permits in a timely manner. In addition, permit conditions and requirements will also have significant impacts on construction costs and project scheduling. One common example of a local jurisdiction construction permit requirement that may significantly impact construction costs and project scheduling is the imposition of paving requirements that go beyond the actual trench limits. Another common example is the imposition of restrictive work hour limitations that significantly limit construction progress each day. The more restrictive the permit conditions, the more time consuming and costly a project is likely to be.

In addition, there is the potential for significant local public resistance to the issuance of permit approvals needed to complete projects. Local permitting agencies often attempt to regulate the utilities beyond the ministerial permitting level, and in turn, subject SoCalGas and SDG&E to various discretionary approval processes as part of various construction activities. These approval processes can escalate to become contentious and can even lead to legal challenges that must be overcome. Further, these discretionary permitting processes have the potential to preclude a project from being constructed all together. Although there is a very real possibility that some projects may experience such significant permit delays and challenges, such delays and challenges are not considered "normal" and are not normally included in preliminary planning, scheduling and cost estimates. These construction permitting challenges further demonstrate the importance of having an extensive external communication program to support pipeline testing and replacement activities.

2. Availability of Materials and Qualified Personnel

To meet the Commission's directives in D.11-06-017, California's natural gas pipeline operators will be required to simultaneously undertake an unprecedented volume of pressure testing and construction work on an expedited schedule. Critical material components, such as pipe, valves and fittings, may be in short supply due to increased demand. This is especially true where, as here, multiple utilities will be striving to complete similar work simultaneously, and on an aggressive schedule, thus competing for the same resources. Additionally, qualified personnel, both internal company labor and contractor personnel, may not be available in the time required to support the planned schedule for this volume of work. In order to execute this effort, it is anticipated that SoCalGas and SDG&E will need to employ over 200 additional full-time employees during a relatively short time period. Hiring increases of this magnitude in an expedited timeframe may be particularly difficult to implement if other State utilities are seeking to employ additional employees with similar qualifications as well. Shortages in the availability and materials and qualified personnel could not only delay completion of the plan, but could also increase costs beyond those initially contemplated.

3. <u>Environmental Permitting Challenges</u>

Similar to the general construction permitting context, the environmental permitting processes that may be required for many of the projects set forth in the plan are fraught with challenges. Unless Federal, State and local jurisdictions make each project's particular environmental permitting a matter of utmost priority, then environmental permitting has the potential to significantly delay and incrementally increase the cost of implementing many of the larger projects contemplated under the plan. This emphasis on prioritization extends to the need to maintain sufficient staffing to support the permitting process and provide certainty and consistency with respect to the various regulatory requirements throughout the numerous jurisdictions in which SoCalGas and SDG&E operate.

For example, a pipeline replacement project within the coastal zone that has the potential to impact sensitive coastal resources would likely trigger multiple Federal, State, and local permits/approvals. This complex regulatory environment requires project proponents to overcome significant agency coordination challenges and navigate a process that may include conflicting policies and procedures. Moreover, within individual agencies there are often multiple departments with conflicting regulatory objectives.

Projects crossing lands under Federal jurisdiction provide another example of environmental and land use permitting challenges that may affect the timely execution of the Implementation Plan. Projects in these geographical areas must also comply with a host of additional laws and regulations including the National Environmental Policy Act, Federal Mineral Leasing Act and the Federal Land Policy and Management Plan. These laws and regulations are administered by an additional suite of regulatory agencies, including the Bureau of Land Management, National Park Service and United States Forest Service. Federal agency involvement with Implementation Plan projects present additional coordination challenges between State and Federal agencies. In addition, Federal agency priorities may hinder timely execution of the Implementation Plan. For example, the Bureau of Land Management has been directed by the Secretary of the Interior to give renewable energy projects the highest priority when processing permit requests. SoCalGas and SDG&E request that the Commission support an outreach and education effort with applicable Federal agencies to emphasize the purpose of and need for timely execution of the Implementation Plan to enhance public safety and agree to prioritize the processing of the necessary project approvals.

4. <u>Proposals for Commission Alleviation of Implementation Challenges</u>

We believe that a strong partnership with the Commission is essential to successfully overcoming these challenges to project implementation. Although there is little the Commission can do to help alleviate constraints on the availability of materials and qualified personnel, there are several actions that the Commission can take to alleviate many of the permitting challenges that California pipeline operators will face as they begin executing their proposed implementation plans.

First, to minimize the potential for construction permitting delays and challenges, the Commission should expressly state in its decision approving the Implementation Plan that execution of the approved Implementation Plan is a matter of statewide concern, and as such, the Commission has preemptory authority over conflicting local zoning regulations, ordinances, codes or requirements to the extent that such local authority would deny, or significantly delay execution of the Pipeline Safety Implementation Plan, while affirming that California natural gas pipeline operators are required to obtain all necessary non-preempted permits prior to commencing construction.

Second, the Commission can help communicate to all agencies responsible for issuing permits that these projects are a priority because they will enhance public safety and the integrity of an essential public service. The Commission, with support by the utilities, should create a plan to educate State, Federal and local agencies that will be called upon to provide environmental approvals of Implementation Plan projects, so that these projects may receive priority treatment in the permit application approval process. This simple request to all applicable agencies to make Implementation Plan projects a priority will provide direction and guidance for those agencies that are subject to the demands of various competing project applicants. Moreover the

Commission should partner with the natural gas utilities in developing and conducting outreach and education efforts to communicate the purpose and need for timely execution of the Implementation Plan.

Third, the Commission can request that applicable permitting agencies set aside personnel and consultant resources that can be funded by the natural gas utilities to focus on these infrastructure projects. Under current economic conditions, all levels of government are resource constrained. The natural gas utilities will rely on agencies to process their permits in a timely and responsive manner. Often, however, human resource availability is intermittent or constrained. Examples of permitting State agencies that may face human resource constraints include the California Department of Fish and Game (CDFG) and the State Water Resources Control Board and associated Regional Water Quality Control Boards.

Recent experience indicates that resource constraints are likely to pose a significant challenge to timely execution of the Pipeline Safety Enhancement Plan. For example, SoCalGas has had an agreement drafted to fund a CDFG resource to process a programmatic permit for over a year; yet, the resource deficit is so dire at CDFG, that no one is available at the agency to review or approve execution of the funding agreement. Unfortunately, many agencies have suffered significantly in terms of resources during these economic times. The Commission can help alleviate this challenge, however, by assigning someone to work with the agencies to establish funding agreements that will set aside specific resources to process the permit applications and greatly expedite the timely issuance of permits.

Fourth, the Commission can request that all environmental agencies develop, or expeditiously approve pending applications for programmatic permits that will ensure consistent permit conditions and mitigation requirements for these projects to create certainty for planning purposes. The activities involved with these safety infrastructure projects are similar from one project to another. Nevertheless, the utilities may be required to obtain permits that reflect dramatically different conditions and mitigation requirements from one region to another for the same activity. This creates uncertainty in the planning process for these projects and can create significant delays and/or unnecessary costs. In some cases, compensatory mitigation must be acquired prior to project commencement, which could take years if, for example, the mitigation requires the acquisition of land. The Commission can support creating certainty in project conditions and mitigation by assigning someone to support the natural gas utilities at all levels within these agencies to develop programmatic permits, such as for pressure testing.

As explained herein, the scope of work to be completed to satisfy the Commission's objectives is large. Our proposed schedule for executing this plan is necessarily ambitious in order to meet the Commission's directive to develop a plan to test or replace identified pipelines "as soon as practicable." In order to adhere to our proposed schedule, we must begin the work of planning and permitting individual pressure testing and replacement projects right away. Accordingly, SoCalGas and SDG&E urge the Commission to issue a decision authorizing us to begin executing our proposed Pipeline Safety Enhancement Plan as soon as possible.

III.

THE INTEGRATED SOCALGAS/SDG&E TRANSMISSION PIPELINE SYSTEM

A. Introduction

In D.11-06-017, the Commission directs all California natural gas pipeline operators to file and serve proposed Implementation Plans "to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c)."[19] The Decision further requires that the Implementation Plan "must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[20]

As explained in greater detail in Chapter IV, in order to comply with this new requirement, which exceeds all prior State and Federal regulations, SoCalGas and SDG&E must either pressure test or replace hundreds of miles of in-service transmission pipelines. Such an undertaking will have dramatic system impacts that, if not carefully managed, could jeopardize reliability of service to natural gas customers. Accordingly, as will be explained in further detail in Chapter IV, SoCalGas and SDG&E propose a plan that carefully considers potential customer impacts and attempts to minimize negative customer impacts to the extent possible, while complying with the Commission's directives, enhancing the safety of the SoCalGas and SDG&E transmission pipeline system, and maximizing the cost effectiveness of planned investments.

This chapter provides an overview of the SoCalGas and SDG&E transmission pipeline system. The SoCalGas and SDG&E proposed Pipeline Safety Enhancement Plan must be evaluated within the context of this system, because a key criterion for determining whether an identified pipeline will be tested or replaced is whether the pipeline can be removed from service for testing without negatively impacting customers or the California electric grid. If a pipeline cannot be removed from service for pressure testing, then system enhancements or a pipeline replacement may be required in order to meet the directives of D.11-06-017.

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[19] D.11-06-017, Ordering ¶ 4.

[20] *Id.*, Ordering ¶ 6

B. Description, Design, and Operation of the SoCalGas/SDG&E Gas Transmission System

SoCalGas and SDG&E own and operate an integrated gas transmission system consisting of pipeline and storage facilities. With their network of transmission pipelines and four interconnected storage fields, SoCalGas and SDG&E deliver natural gas to over five million residential and business customers.

A map of the SoCalGas transmission system is attached as Figure III-1. The transmission system extends from the Colorado River on the eastern end of SoCalGas' approximately 20,000 square mile service territory, to the Pacific Coast on the western end; from Tulare County in the north, to the U.S./Mexico border in the south (excluding parts of San Diego County).

The SoCalGas transmission system was initially designed to receive and redeliver gas from the east, to the load centers in the Los Angeles basin, Imperial Valley, San Joaquin Valley, north coastal areas, and San Diego County. As our customers sought to access new supply sources in Canada and the Rocky Mountain region, we modified our system to concurrently accept deliveries from the north. As a result, the system today can accept up to 3,875 million cubic feet per day (MMcfd) of interstate and local California supplies on a firm basis. Primary supply sources are the southwestern United States, the Rocky Mountain region, Canada, and California on- and off-shore production. The interstate pipelines that supply the SoCalGas transmission system are El Paso Natural Gas Company (El Paso), North Baja Pipeline (North Baja), Transwestern Pipeline Company (Transwestern), Kern River Gas Transmission Company (Kern River), Mojave Pipeline Company (Mojave), Questar Southern Trails Pipeline Company (Southern Trails), and Gas Transmission Northwest via PG&E's intrastate system (PG&E/GTN). The SoCalGas transmission system interconnects with El Paso at the Colorado River near Needles and Blythe, California, with North Baja near Blythe, California, and with Transwestern and Southern Trails near Needles, California. SoCalGas also interconnects with the common Kern/Mojave pipeline at Wheeler Ridge in the San Joaquin Valley and at Kramer Junction in the high desert. At Kern River Station in the San Joaquin Valley, SoCalGas maintains a major interconnect with the PG&E intrastate pipeline system, and receives PG&E/GTN deliveries at that location.

SoCalGas operates four storage fields that interconnect with its transmission system. These storage fields – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey – are located near the primary load centers of the SoCalGas system. Together they have a combined inventory capacity of 134.1 billion cubic feet (Bcf), a combined firm injection capacity of 850 MMcfd, and a combined firm withdrawal capacity of 3,195 MMcfd.

A schematic of the SDG&E gas transmission system is shown in Figure III-2. The SDG&E gas transmission system consists primarily of two high-pressure large diameter pipelines that extend south from Rainbow Station, located at the Riverside/San Diego County border. Both pipelines terminate at the San Diego metropolitan area.

The pipelines are interconnected approximately at their midpoint and again near their southern terminus. The northern cross-tie runs between Carlsbad and Escondido, with the southern cross-tie running through Miramar.

A large diameter pipeline extends from the cross-tie at Miramar to Santee. At Santee, another large diameter pipeline extends to the Otay Mesa metering station at the U.S./Mexico border. At Otay Mesa, the SDG&E system interconnects with the Transportadora de Gas Natural, S.R.L. pipeline, providing another receipt point for supplies into the SoCalGas/ SDG&E system.

A small diameter, lower pressure pipeline owned by SoCalGas also extends south from Orange County down to San Diego.

Two compressor stations are also a part of the SDG&E gas transmission system. SDG&E's Moreno compressor station, located in Moreno Valley, boosts pressure into the SoCalGas transmission lines serving Rainbow Station. A much smaller compressor station is located at Rainbow Station.

SDG&E has no storage fields in its service territory. As a consequence, SDG&E is more dependent on the availability of its gas transmission system for system reliability than is SoCalGas.

Figure III-1
SoCalGas System Map

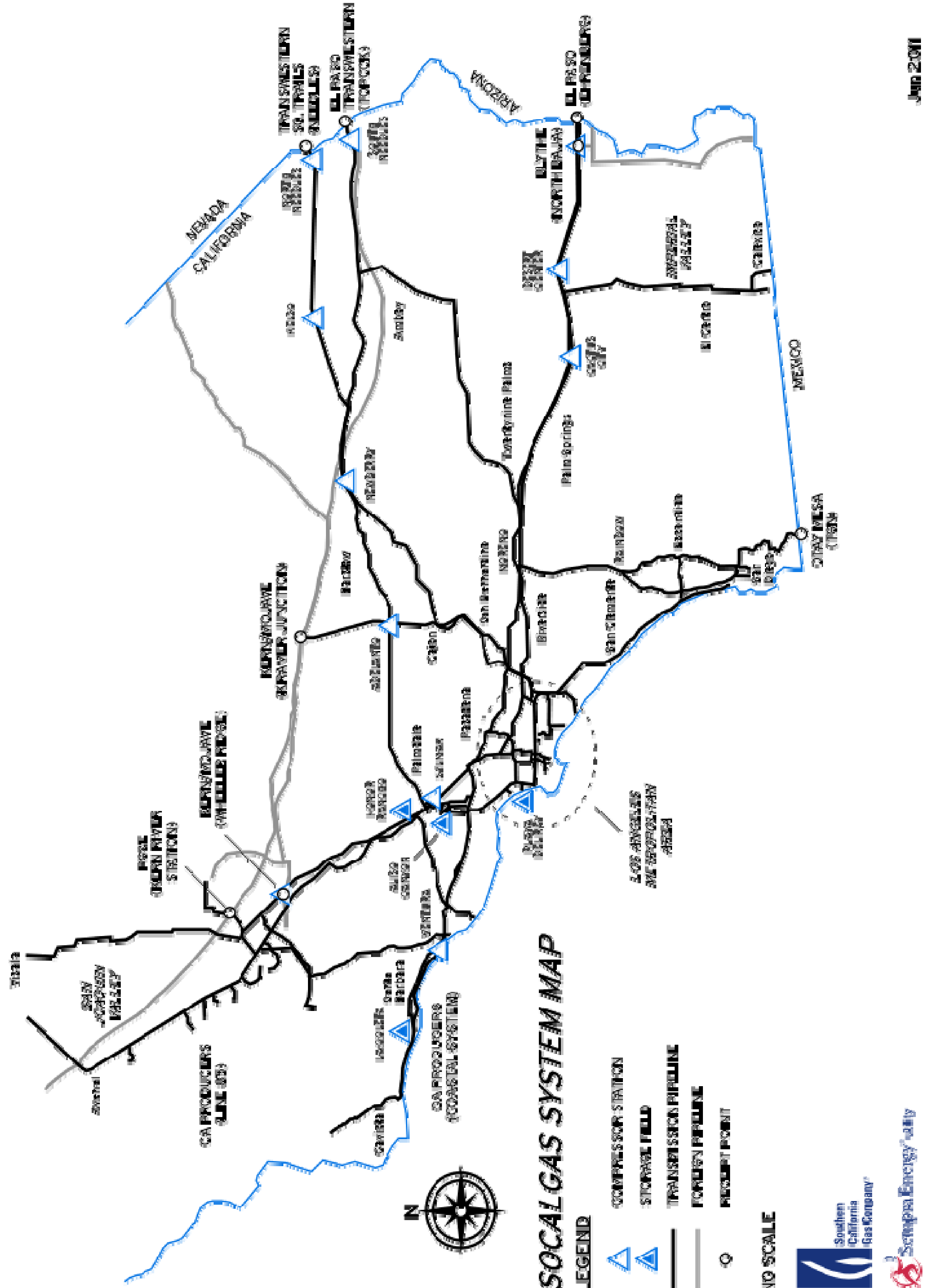
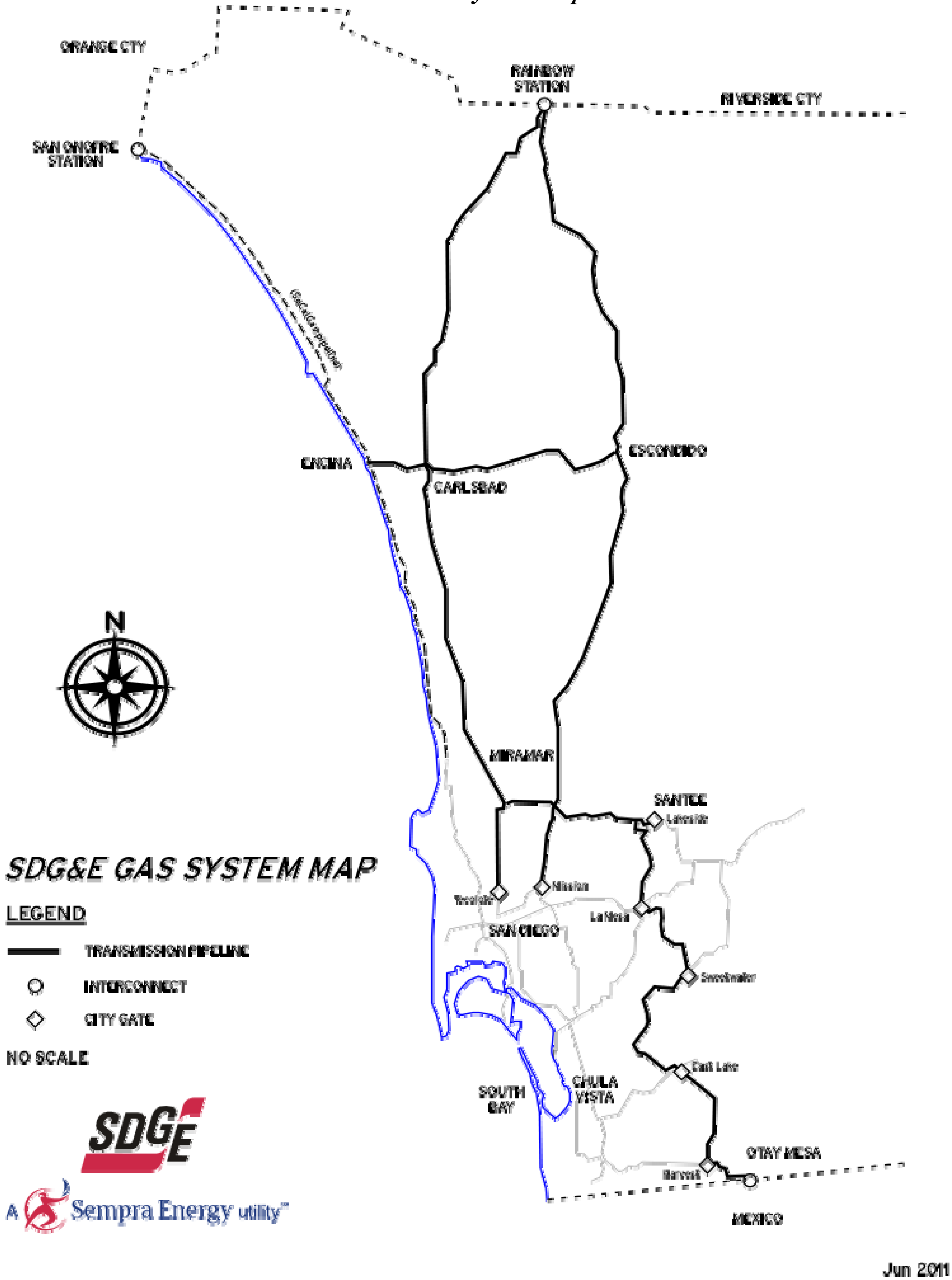


Figure III-2
SDG&E System Map



As explained previously, the SoCalGas system was designed to transport supplies primarily received on the fringes of its service territory to its load centers, with the largest load center being the Los Angeles metropolitan area. This is also true of the SDG&E system; its system was designed to transport supplies received from SoCalGas on the fringes of its service territory to the primary load center in San Diego.

As a result, the gas transmission systems of both utilities consist of pipelines with "telescoping" operating pressures as gas supplies move from the receipt point(s) towards the load center(s). In other words, the maximum allowable operating pressures (MAOP) of pipelines are higher at the receipt points and lower near the load centers. As gas supply is transported in the pipelines, pressure declines as a function of volume transported and distance traveled. It is this pressure differential that allows gas supplies to flow in a pipeline to the load centers. Pipeline system designers take advantage of this physical fact to maximize the cost/benefit ratio of the pipeline network and use pipeline with lower MAOP limits where possible.

Mainline compressor stations are then used to boost the pressure in the transmission lines as necessary so that the gas supply arrives at the load centers with sufficient pressure for redelivery to the distribution systems and customers. The SoCalGas system has ten mainline compressor stations that perform this function, and the SDG&E system has two.

Highly interconnected pipeline networks serve the metropolitan load centers of Los Angeles and San Diego. These metropolitan pipeline networks are each referred to as a "Loop System" by each utility. The pipelines within both the Los Angeles and San Diego Loop Systems operate at a common pressure, which affords a great deal of operational flexibility.

The Loop Systems are supplied by major pressure limiting stations, which are interconnects between the Loop Systems and the transmission pipelines that ultimately interconnect with interstate pipelines. SoCalGas has five such pressure limiting stations surrounding the Los Angeles metropolitan area, while SDG&E has seven. The operating pressure of the Loop Systems can only be controlled at these pressure limiting stations; neither SoCalGas nor SDG&E have the ability to isolate a pipeline that is part of a Loop System to operate it at a different pressure.[21] Absent the installation of new facilities, lowering the pressure of a single pipeline within the Loop System requires lowering the pressure of the entire Loop System at the pressure limiting stations.

The SoCalGas transmission and storage system currently has sufficient capacity to serve a demand of 6.0 Bcf/day through a combination of flowing supply and stored gas (provided sufficient flowing supply is delivered to the system by our customers). Based on the current winter demand forecast, the SDG&E transmission system currently has sufficient capacity to serve 630 MMcfd of customer demand.

C. Reliability of Service to Customers

In D.06-09-039, the Commission upheld the SoCalGas and SDG&E planning standards for their transmission and storage systems. SoCalGas and SDG&E design their systems to provide service to core customers during a 1-in-35 year peak day condition, under which both firm and interruptible noncore transportation service is curtailed. The systems are also designed to provide for continuous firm noncore transportation service under a 1-in-10 year cold day condition, during which only interruptible noncore transportation service is curtailed. Both design standards are expected to occur during the winter operating season when core customers' gas usage is the greatest.

Lowering the operating pressure on SoCalGas or SDG&E pipelines may impact the capacity of the system and/or service to customers. Consider, as an example, the impact of lowering the pressure to the Loop Systems at the pressure limiting stations. SoCalGas' Loop System is designed to operate between the MAOP of 465 psig and the minimum operating pressure (MinOP) of 200 psig. If the maximum pressure is restricted to a pressure less than 465 psig, SoCalGas will not be able to maintain MinOP during periods of high demand, and will need to curtail noncore customer use (*e.g.*, refineries and electric generation facilities) to maintain service to core customers. The MAOP of SDG&E's Loop System was recently lowered from 375

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21 Both SoCalGas and SDG&E operate pipelines within the Loop Systems that serve a specific customer or area and operate at a different pressure. From a system perspective, however, these pipelines can be viewed as a sub-set of the Loop Systems and do not contribute to the interconnectivity or flexibility of the Loop Systems.

psig to 320 psig, and while this did not result in a firm capacity loss on the system, noncore customer operations were impacted that had come to rely upon the higher operating pressure of SDG&E's pipelines.

Outside of the Loop Systems, isolating and lowering the pressure of a transmission pipeline may not have an impact to customers due to system flexibility to flow gas from other sources (particularly on the SoCalGas system, less so on the SDG&E system) but may still have an impact on capacity affecting shippers, customers and the gas market in general. For example, when SoCalGas removed its Transmission Line 235-2 from service in 2009 for needed repairs, there was no interruption in customer service but receipt capacity at its North Needles and Topock receipt points was cut from 1,340 MMcfd to 800 MMcfd for an extended period.

SoCalGas and SDG&E exercise the same concern for customer service and operations when planning a pressure test of a pipeline. A pipeline may be a likely candidate for a pressure test in an area with a high level of network flexibility in which the customer impact can be mitigated using an alternate supply source or served via compressed natural gas bottles when demand is small, or where the impact from the pipeline outage is only to a single delivery point. In other situations, a parallel pipeline must be installed to maintain customer service or to uphold system pressures before the pressure test can be performed.

IV.

PROPOSED TRANSMISSION PIPELINE ENHANCEMENT PLAN

A. Introduction and Summary

In this Chapter, we describe our proposed approach to testing or replacing transmission pipeline segments that do not have sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d). First, we provide an overview of current pipeline integrity regulations and their existing transmission pipeline integrity management program, and suggest an approach for the Commission to eliminate reliance by California pipeline operators on the grandfathering provisions of current Federal pipeline regulations to enhance the safety of California's natural gas pipeline system. Second, we describe the results of our review of records in response to the NTSB's January 3, 2011 Safety Recommendations to PG&E and Resolution L-410. Third, we propose a plan for testing or replacing all transmission pipeline segments that were not pressure tested or lack sufficient details related to the performance of any such test. Finally, we discuss the safety enhancement measures that we have already implemented, and propose to continue to implement those interim safety enhancement measures, until execution of the proposed Pipeline Safety Enhancement Plan is complete.

B. Overview of Transmission Pipeline Integrity Regulations

Natural gas is used to meet almost one third of California's energy requirements. As such, it plays a vital role in meeting California's energy needs. All modes of transportation (road, rail, air, maritime, pipeline, etc.) pose safety risks that must be managed. While the overall safety record of natural gas transmission pipelines is good and methods for maintaining the integrity of pipelines continue to improve, the events in San Bruno must be evaluated and acted upon to drive additional testing and pipeline improvements to further enhance pipeline safety in California.

1. The Evolution of Transmission Pipeline Integrity Regulation

The roots of pipeline safety trace back to March of 1926 when the American Engineering Standards Committee initiated Project B31 to develop a safety code for pressure piping. By 1951, the name of the organization had been changed to the American Standards Association, and in November of that year, the Sectional Committee B31 authorized the separate publication of a code dealing with gas transmission and distribution piping. The purpose of this new publication, known as B31.8, was to provide a document for gas transmission and distribution piping that would be complete and not require cross referencing to other sections of the code. The first edition was published in 1952 and since then, has been revised many times to reflect changes in materials, methods of construction and operations.

The strength testing of gas transmission pipelines in California first became regulated July 1, 1961, when General Order 112 went into effect. This does not imply, however, that there were no standards in place to govern pressure test activity prior to 1961. Indeed, at the time, operators followed industry testing standards such as American Standards Association B31.8, which subsequently became the American Society of Mechanical Engineers B31.8. In adopting General Order 112, the Commission integrated a portion of the American Standard Code for Pressure Piping ASA B 31.8 – 1958 and set the rules that govern the "design, testing, maintenance and operation of utility gas transmission and distribution piping systems"[22] in California. As explained by the Commission in the Order Instituting this Rulemaking, "[t]his GO is the linchpin of the Commission's regulation of natural gas pipelines."[23]

In 1970, Federal regulations, specifically, 49 CFR 192 (Part 192), went into effect. Part 192 prescribes the minimum safety requirements for pipeline facilities and the transportation of gas, including regulations governing the establishment of the maximum allowable operating pressure (MAOP) of a pipeline segment. Subsequently, General Order 112 was modified to incorporate Part 192. Since 1970, the Federal Code has been changed over time to reflect changes in materials, methods of construction and operations, and General Order 112, which incorporates Part 192, has also been updated accordingly.

In 2003, Subpart O "Gas Transmission Integrity Management" was added to Part 192. Subpart O is additive to the existing code and includes the incorporation by reference of a supplement to B31.8, known as B31.8S, "Managing System Integrity of Gas Pipelines."

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22 OIR, p. 9.

23 *Id*.

2. Transmission Pipeline Integrity Regulations to Enhance the Safety of California's Natural Gas Pipeline Infrastructure

a) Assessing Potential Threats to Pipeline Stability

Code provisions and regulations have been developed and continuously improved to provide for the safe delivery of natural gas. Under current Federal regulations, potential threats to the safe operation of a pipeline are categorized by nine potential failure modes.[24] The nine potential failure modes are grouped by three time factors: (1) Time Dependent; (2) Time Independent; and (3) Stable. Time Dependent threats are generally those related to corrosion and include external corrosion, internal corrosion and stress corrosion cracking. Time Independent threats include third party/mechanical damage, incorrect operational procedure, and weather-related and outside force. Stable threats are manufacturing-related, welding/fabrication-related or equipment-related.

Current Federal regulations specify assessment, prevention and repair methods for all types of potential threats. The assessment methods referenced in the current pipeline integrity regulations are direct assessment, pressure testing, and in-line inspection. Each method has relative strengths and weaknesses, and is selected singularly or in combination depending upon the particular threat characteristics of the pipeline in question. Direct assessment methods are limited to assessment of Time Dependent threats (i.e., corrosion). Time-Independent threats are typically managed through the use of correct operating procedures and the on-going maintenance of pipeline systems (*e.g.*, correct pipeline marking to prevent third party damage, routine valve maintenance to ensure equipment-related threats are minimized, regular procedure review and training to prevent operator error, etc.). Neither Time Dependent threats nor Time-Independent threats fall within the scope of the Commission's directives in D.11-06-017.

The pipeline rupture in San Bruno has focused attention on the regulation of potential threats identified as Stable under Federal regulations, which relate to the manufactured long seam of a pipe and girth welds. A long seam is the joining of two edges of steel plate that has been

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24 *See* 49 CFR 192.917(a).

rolled to form a cylinder. A long seam is typically forty feet long, and is fused together at the pipe mill during the manufacturing process using a variety of methods to form a continuous, pressure-tight length of pipe that is open at both ends and ready for shipment. A girth weld is the physical point at which two segments of pipe are fused together at the ends to form a single, larger section of continuous pipe. The ends are fused circumferentially using both heat and filler metal to weld the pipe ends together and form a pressure tight joint. Typically transmission pipeline welds are produced through the use of an electrical current to generate heat that melts and fuses the pipeline steel, or for older pipelines, by burning a gaseous mixture of oxygen and acetylene.

There are three potential methods for assessing Stable threats: (1) pressure testing; (2) in-line inspection; and (3) non-destructive examination.

Pressure Testing. A successful pressure test removes all critically sized flaws at a specified stress level that is higher than the operating stress– and in this manner establishes a know margin of safety for the pipeline. Pressure testing removes critically sized flaws by causing them to fail (leak or rupture) through the application of internal pressure. The pressure is induced through a test medium (typically water, through other media such as air, nitrogen, and natural gas can be used), and upon pressurization a critical flaw incapable of containing the pressure will fail suddenly and release the test medium. The escaping test medium is detected—typically in the form of wet spots or running water in the case of a hydrostatic pressure test. In this manner, the critical defect is discovered and repaired prior to service. Pressure testing removes a wide range of defects, and is particularly beneficial for the removal of long seam flaws. However, pressure testing has limited benefit for construction or fabrication flaws, and is not sensitive to small defects that can survive at test pressures.

In-Line Inspection. In-line inspection or "smart pigging" refers to a broad range of pipeline inspection devices that travel through the pipeline internally and detect signals caused by pipeline flaws. The most common type of smart pig utilizes a method called magnetic flux leakage (MFL). MFL pigs use strong magnets to saturate a pipeline with a magnetic field, and subsequently detect disturbances in the field that are caused by defects. The relative size, shape, and location of the defects can then be determined and used for repair planning. Among MFL tools, two common variations exist: 1) axial field MFL which induces magnetism lengthwise along the axis of the pipeline, and 2) transverse field MFL (or transverse field inspection – TFI), which induces magnetism around the circumference of the pipeline. The types of flaws that each tool is sensitive to is directly affected by the direction of the magnetic field. In the context of long seam flaws, which are the focus of D.11-06-017, the TFI tool provides greatly enhanced detection capability compared to the axial MFL tools. When compared to pressure testing, TFI tools can provide equivalent detection capability for critically sized defects, and better detection capability for small defects – and can be performed without the need to remove the pipeline from service. Results require validation or prove-up by exposing and measuring detected flaws to measure the performance of the smart pig. The pipeline also must be "piggable" meaning there must be enough pressure to push the tool through the pipeline, and that the pipeline has been retrofitted to ensure that the smart pig will not get stuck at obstructions.

Non-Destructive Examination. Non-destructive examination or "NDE" refers to evaluation of a pipeline using a number of inspection methods that are typically performed manually on exposed pipeline surfaces. Radiography, Ultrasonic Inspection, and Magnetic Particle Inspection are the main NDE methods utilized to assess Stable threats. Radiography uses X-rays or Gamma Rays to expose film and created images of pipe flaws in the same manner that X-rays are used to evaluate patients in the medical profession. Ultrasonic Inspection utilizes sound waves that travel through the pipe wall and creates echoes at defects that can be used to locate and size flaws – this method is essentially the same technology used in the medical profession for fetal exams. Magnetic Particle Inspection uses magnetism to force small particles of iron to collect at surface flaws such as cracks. The particles are visible as dark lines on the pipe surface and provide visual detection of cracks and crack-like flaws. Each of these methods is highly sensitive to different flaw types, and when used in combination, are capable of detection sensitivity that exceeds both pressure testing and ILI. As a result, NDE methods are commonly used to validate the results of both pressure testing and ILI, and are thus capable of stand-alone performance for detection of critical flaws. These methods are dependent upon direct access to the pipeline, and are typically limited by the economics of full pipeline exposure.

A summary of the capabilities and limitations of pressure testing, in-line inspection, and non-destructive examination is provided Table IV-1in below.

Table IV-1
Summary of Benefits and Limitations of Assessment Methods
for Girth Welds and Long Seams[25]

Assessment	Benefits	Limitations
Hydrotest	• Appropriate for wide range of defect types and conditions • Predictable results • High certainty within limit of tested stress level	• Line must be taken out of service • Does not inform about flaws that do not fail during test • Water inside pipe a problem • Not effective for small defects
In-Line Inspection	• As effective as HT for detecting large defects • Better than HT for smaller defects • No service interruption	• Line must be piggable • Many anomaly digs necessary • More than one tool type may be necessary • Not effective for very small defects
In-ditch NDE	• More accurate than ILI • No service interruption	• Line must be exposed • Operator skill dependent • Only practical over limited lengths

The pressure testing required under D.11-06-017 will validate long seam stability, but may not necessarily address other known Stable threats. Construction/ fabrication threats (i.e., girth weld defects, wrinkle bends[26] and acetylene girth welds[27]) are somewhat unique, in that the stability of construction defects cannot be fully assessed through the performance of a pressure test. As explained in a 2007 report prepared for the United States Department of Transportation:

25 Table Source – PowerPoint Presentation titled: Application of Integrity Assessment, Michael J. Rosenfeld, Kiefner & Associates, Inc, presented at the Commission's In-line Inspection Symposium, San Francisco, June 24, 2011.

26 Wrinkle bends are formed through the obsolete practice of bending pipe in the field to conform to the contours of the terrain, or to make other necessary changes in direction. The wrinkles take on the appearance of circumferentially oriented ripples that are located at the intrados or inside radius of the bend.

27 Acetylene girth welds are produced by burning a mixture of oxygen and acetylene gas with a torch. The heat is used to melt and fuse two pipe ends together to form a larger, continuous section of pressure-tight pipe. Early vintage pipeline construction often used this method of girth welding to joint pipe.

> The stability of construction defects is largely controlled by longitudinal stress (or strain) rather than by hoop stress (i.e., internal pressure). Accordingly, construction defects seldom cause failures in pipelines buried in stable soils where little or no longitudinal or lateral movement can take place. In addition, the application of a hydrostatic test to a pipeline has little or no beneficial effect on the stability of construction defects because the hydrostatic test may cause no increase in strain on the defects. Construction defects tend to remain stable in service unless the pipeline is caused to move longitudinally or laterally by settlement, landslides, earthquakes, or other soil-movement phenomena.[28]
>
> Girth weld defects: These are not affected significantly by internal pressure. They could cause failure in a pipeline if the pipeline is subjected to large longitudinal stains, as for example, from landslides or settlement. In that case, unstable soil or slope movement constitutes an interacting threat."[29]
>
> Wrinkle bends: . . .When they are involved in a failure, it is usually because either the bend has been over-strained by longitudinally or laterally imposed deformation or some other mechanism . . . Whether or not the pipeline has been subjected to an adequate pre-service hydrostatic test would not seem to make much difference.[30]
>
> Acetylene girth welds: Acetylene girth welds were generally used prior to the advent of electric-arc girth welding. Such welds were not used to construct high-pressure pipelines after World War II. These welds are inherently brittle and sensitive to longitudinal strain imposed on the pipeline. . . .As is the case with girth welds in general, the defects or inherent weaknesses associated with acetylene welds would likely contribute to failure only when the pipeline is subjected to unusual longitudinal strain. The contribution of internal pressure to such failures would likely be insignificant. Thus, whether or not the pipeline has been subjected to an adequate pre-service hydrostatic test or a pressure increase would not seem to make much difference.[31]

External forces that could adversely affect construction and fabrication threats are typically construed as harmful movement of the pipe. In other words, as long as the pipe is

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28 *Final Report on Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, April 26, 2007, *prepared for* the United States Department of Transportation Office of Pipeline Safety *by* John. F. Kiefner of Kiefner and Associates, with the Assistance of the Natural Gas Association of America, p. 2.

29 *Id*., p. 9.

30 *Id*., p. 10.

31 *Id*., p. 11.

stationary and not subject to movement, construction and fabrication threats are considered stable. At a certain point, all engineered structures are subject to failure if the magnitude of ground shaking or movement is large enough, and engineered pipeline structures are no exception. Accordingly, pipelines that have construction/fabrication defects (e.g., oxy-acetylene-welded pipelines), will be more prone to ground-shaking-induced failure due to their inherent properties.

In recognition of the fact that San Bruno raises concerns regarding construction/fabrication threats as well as long seam stability, SoCalGas and SDG&E propose a plan that is not limited to solely addressing long seam stability. As explained in greater detail below, SoCalGas and SDG&E's Pipeline Safety Enhancement Plan includes a proposal to abandon all non-piggable, transmission pipelines constructed prior-1946, as those older pipelines were constructed using non-state-of-the-art methods that present potential construction/fabrication threats.

b) Eliminating Reliance on the "Grandfather Clause" to Establish the Maximum Allowable Operating Pressure of Pipeline Segments

As explained above, Part 192 of the Federal Code of Regulations prescribes the minimum safety requirements for pipeline facilities and the transportation of gas, including regulations governing the establishment of the MAOP of pipeline segments. When Part 192 was adopted in 1970, in apparent recognition of the fact that it would be difficult, if not infeasible, to bring all existing in-service pipelines into compliance with these new regulations, Part 192 contained what is commonly referred to as a "Grandfather Clause" for establishing the MAOP of pipelines placed in-service prior to adoption of Part 192. This Grandfather Clause provides that the MAOP of a transmission pipeline may be established as the highest actual operating pressure to which the segment was subjected during the five-year period preceding November 12, 1970.[32] Specifically, 49 CFR 192.619(c) states:

> The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest

[32] 49 CFR 192.619(c).

> actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3)of this section. An operator must still comply with Sec. 192.611."

The effect of this clause is to allow operators to maintain the MAOP of pipelines that were installed prior to the implementation of Part 192 in lieu of testing or de-rating.

As expressed in their opening comments on the Order Instituting Rulemaking, in light of the pipeline rupture in San Bruno, SoCalGas and SDG&E support additional testing and validation of pipelines with MAOPs that were established under the Grandfather Clause. In D.11-06-017, the Commission directs all California pipeline operators to propose a plan "to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, <u>excluding subsection 49 CFR 192.619(c)</u>."[33] SoCalGas and SDG&E believe the Commission's directives in D.11-06-017 are intended to require California's natural gas transmission pipeline operators to propose a plan to cease to rely on the Grandfather Clause of Part 192. By excluding subsection 192.619(c) entirely, however, the Decision precludes the use of technology and inspections to validate the pressure-carrying capability of the pipeline at its currently-established MAOP. Compliance with Part 192, as so modified, would be less cost effective than compliance with Part 192 if solely the Grandfather Clause were removed.

Therefore, in accordance with the belief that the goal of the Commission in D.11-06-017 was to eliminate the Grandfather Clause and providing for alternatives that demonstrably achieve the same standard of safety as a pressure test, SoCalGas and SDG&E propose that in lieu of eliminating the ability of California pipeline operators to follow 49 CFR 192.619(c), the Commission revise General Order 112-E to exceed the requirements of 49 CFR 192.619 and require the following:

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33 D.11-06-017, Ordering ¶ 4. (emphasis added)

All transmission pipelines shall meet one of the following conditions to validate the stability of the long seam within a set period of time after the adoption of these requirements:[34]

1. A post construction strength test to at least 1.25 MAOP; this pressure test shall:
   a) For pipe pressure tested before November 12, 1970, provide records of the test medium and test pressure.[35]
   b) For pipe pressure tested after November 11, 1970, provide records in accordance 49 CFR 192.517 that verify compliance with 192.505 or 192.507, as applicable.[36]

OR

2. For pipelines placed in service prior to November 12, 1970 the MAOP shall have been lowered to a value ≤ 72%[37] of the documented highest actual operating pressure in the 5 years preceding the pressure reduction[38]

OR

3. A complete non-destructive examination using an inspection method capable of seam anomaly detection, and subsequent remediation of seam defects with predicted failure pressures ≤1.39[39] * MAOP

OR

4. Once transverse field magnetic flux leakage in-line inspection has been expressly validated by order of the Commission, an in-line inspection using a transverse field

[34] Alternatives may be considered singularly for approval by the Commission and shown here grouped together to represent how the alternatives could complement one another to address grandfathered pipelines.

[35] This is consistent with American Society of Mechanical Engineers B31.8 requirements, and applies to all grandfathered pipelines.

[36] This clause would require a 1.25 times MAOP pressure test in Class 1 areas, which is beyond the 1.1*MAOP standard required under the Federal code and American Society of Mechanical Engineers B31.8.

[37] American Society of Mechanical Engineers B31.8S code identifies thresholds for pressure testing. The value of 1.39 times MAOP is the next value higher than the 1.25 times MAOP and was chosen to establish an additional safety margin to address the fact that "in-service" pressure measurements are used. The 72% pressure reduction is equivalent to a 1.39 times the recorded pressure. See section IV.D.1 below for further discussion of the 1.39 times MAOP safety factor.

[38] The highest operating pressure may be equal to the MAOP.

[39] American Society of Mechanical Engineers B31.8S code identifies thresholds for pressure testing. The value of 1.39 times MAOP is the next value higher than the 1.25 times MAOP and was chosen to establish an additional safety margin to address the fact that non-destructive testing methods are used. See section IV.D.1 below for further discussion of the 1.39 times MAOP safety factor.

inspection tool followed by validation using non-destructive evaluation methods capable of seam anomaly detection, and remediation of seam defects with predicted failure pressures ≤1.39 * MAOP.

Adopting the requirements proposed above into General Order 112-E would validate that the long seam of a pipeline is stable at the MAOP, while providing greater flexibility and improved cost effectiveness for the testing of pipelines, especially those in non-populated locations to be scheduled during Phase 2 as described later in this testimony. We look forward to working with the Commission and other stakeholders to develop these alternatives that demonstrably achieve the same standards as a pressure test.

Further, adding requirements to General Order 112 beyond the requirements of 49 CFR 192.619, as opposed to striking subpart (c), would eliminate the unintended consequence of affecting how various sections of Federal Code work together and preserves the flow of that regulation.

c) Existing Transmission Pipeline Integrity Program Requirements

Subpart O of Part 192 requires natural gas pipeline operators to implement a comprehensive Transmission Integrity Management Program or "TIMP." The TIMP requirements codified in Subpart O are broad, and in addition, Subpart O incorporates by reference activities required by other sub parts of the Federal Code as well. These additional requirements incorporated into Subpart O primarily pertain to transmission pipelines that pass through "High Consequence Areas" or "HCAs."

In general, High Consequence Areas are locations where the number of dwellings intended for human occupancy within a specified distance of a pipeline exceed a specified threshold. Pipelines in High Consequence Areas are subject to additional inspection requirements when compared to transmission pipelines that traverse sparsely or non-populated areas.

Current regulations require that all pipeline segments in High Consequence Areas receive a baseline assessment followed by a reassessment at least once every seven years.[40] These

[40] *See* 49 CFR Subpart O.

baseline assessments can be completed using in-line inspection tools, direct assessment methods and/or pressure testing. Often, it is neither practical nor prudent to limit the baseline assessment solely to the segment of pipeline in the High Consequence Area. For example, the launch and receive locations of an in-line inspection device are selected based upon the configuration and operation of the pipeline network. Under such circumstances, SoCalGas and SDG&E will gather pipeline information for the entire pipeline length, rather than limit the inspection to the High Consequence Area mileage. A summary of the baseline assessment of High Consequence Area transmission miles, by assessment method, is provided in Table IV-2 below. Although not currently required under either Federal or State regulations, SoCalGas and SDG&E also perform baseline assessments on pipeline segments operated non-High Consequence Areas. A summary of the inspection of non-High Consequence Area transmission miles, by assessment method, is summarized in Table IV-3 below.

Table IV-2
Summary of Baseline Assessment of High Consequence Area Miles

	In-Line Inspection	External Corrosion Direct Assessment	Pressure Test	Total HCA Miles Baseline Assessed	Total HCA Miles	% HCA Baseline Assessed
SoCalGas	807	143	19	969	1,178	82%
SDG&E	26	84	0	110	178	62%
Total	833	227	19	1,079	1,356	80%

Table IV-3
Summary of Baseline Assessment of Non-HCA Miles

	In-Line Inspection	External Corrosion Direct Assessment	Pressure Test	Total non-HCA Assessed	Total non-HCA	% non-HCA Baseline Assessed
SoCalGas	1,059	25	1	1,085	2,579	42%
SDG&E	4	0	0	4	73	5%
Total	1,063	25	1	1,089	2,652	41%

In addition to completing these inspections and assessments in accordance with Subpart O, SoCalGas and SDG&E perform numerous maintenance activities to validate the integrity of their transmission pipelines, including leak surveys, pipeline patrols, participation in damage prevention programs and the monitoring of corrosion control measures. These maintenance activities build upon the safety measures taken during the design and construction of the pipelines.

While our existing TIMP focuses on pipelines traversing High Consequence Areas in compliance with current regulations, the January 3, 2011 Safety Recommendations issued by the NTSB to PG&E in response to the San Bruno pipeline rupture address Class 3 and 4 Non-High Consequence Area segments, in addition to High Consequence Area segments. Pipelines in Class 3 and 4 locations that are not identified as High Consequence Areas are typically smaller-diameter, lower-pressure transmission pipelines and operate at low stress levels (i.e., below 30% of the specified minimum yield strength or "SMYS").

The NTSB's criterion exceeds the miles of pipelines operated in High Consequence Areas by SoCalGas by 247 miles and the pipelines operated by SDG&E in High Consequence Areas by 37 miles. In other words, the NTSB directives apply to 284 miles of transmission pipelines operated by SoCalGas and SDG&E that are not part of our existing Transmission Pipeline Integrity Management Programs, and exceed those requirements by about 21%.

In D.11-06-017, the Commission directs all California pipeline operators to propose a plan to address all transmission pipelines in-service in California. Thus, the Commission's criterion exceeds the miles of pipelines operated by SoCalGas and SDG&E in High Consequence Areas. Accordingly, the Commission's decision is much broader in scope than our current Transmission Pipeline Integrity Management Programs, and was not contemplated as part of our most recent General Rate Case Applications.

C. Review of Pressure Test Records

On April 15, 2011, SoCalGas and SDG&E submitted a report to the Commission detailing the actions taken in response to the NTSB's Safety Recommendations issued to PG&E on January 3, 2011. An integral part of the actions taken in response to the NTSB recommendation was a records review of pipeline segments subject to the NTSB recommendations (i.e. pipeline segments located in Class 3 and 4 locations and Class 1 and 2 High Consequence Areas, herein referred to as "NTSB Criteria Miles").

Although the possibility remains that additional records will be evaluated as part of the detailed planning of the pressure testing or abandonment of pipelines, SoCalGas and SDG&E have completed their active review of pressure test records for the NTSB Criteria Miles. The results of the pressure test records review for NTSB Criteria Miles are summarized in Table IV-4 below.

Table IV-4
Summary of Review of Records for NTSB Criteria Miles

	Demonstrated Safety Margin[41]			Safety Margin to Be Verified	
	Category 1	Category 2	Category 3	Category 4	
	Hydro-Statically Tested (NTSB P-10-2)	Strength Tested with Nitrogen or Other Medium	In-Service Strength Tested with MAOP Reduction	Activities in Progress to Validate Safety Margin (NTSB P-10-4)	Total[42]
SoCalGas	817	248	23	322[43]	1,410
SDG&E	136	8	0	63[44]	206

The records review of transmission segments in non-High Consequence Area Class 1 and 2 locations is underway and is expected to be completed by July 2012.

D. Proposed Prioritization and Criteria for Testing or Replacing Transmission Pipeline Segments

Our proposed plan to test or replace pipeline segments that do not have sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d) prioritizes pipeline segments located in populated areas, and is divided into three phases. First, in Phase 1A, all transmission pipelines in populated areas that do not have sufficient documentation to validate a post-construction pressure test of at least 1.25*MAOP are scheduled to be addressed.

41 Total has been adjusted to exclude six miles of pipe that was abandoned after the filing of our April 15 Report on Actions Taken in Response to NTSB Recommendations.

42 May not add due to rounding.

43 152 miles of these pipelines in Category 4 have been in-line inspected.

44 Maximum operating pressures have been reduced.

These segments represent the highest priority work and will be pressure tested or replaced, provided that existing infrastructure can support that work with manageable customer impacts.

In Phase 1B, SoCalGas and SDG&E will address those pipeline segments that would otherwise be addressed in Phase 1A, but cannot be addressed in the near-term due to the need to construct new infrastructure to maintain system reliability. These lines will be addressed in parallel within Phase 1B to account for the estimated lead times required for the design and permitting of new infrastructure. Also in Phase 1B, SoCalGas and SDG&E propose to replace all non-piggable transmission pipeline segments installed prior to 1946 to address the construction and fabrication defects discussed above in Section IV.D.2 (i.e., oxy-acetylene girth welds and wrinkle bends).

In Phase 2, which is expected to run in parallel with and extend past the completion of Phase 1B, remaining transmission pipeline segments that do not have sufficient documentation to validate post-construction pressure tests to 1.25*MAOP and all other remaining transmission pipelines that have not been strength tested in accordance with the Commission's directives in this Rulemaking will be addressed. Phase 2 pipeline segments are scheduled to be addressed after Phase 1A pipeline segments in order to prioritize pipeline segments located in more populated areas.[45] As described in greater detail below, SoCalGas and SDG&E seek the flexibility to propose alternative assessment methods using advanced inspection methods and emerging technologies for Phase 2 pipeline segments in their 2016 General Rate Case, should such alternative assessment methods be demonstrated by that time to provide confidence that is equal to or greater than pressure testing. Because such alternative methods may provide a more cost effective means of achieving the Commission's safety objectives, SoCalGas and SDG&E urge the Commission to allow California's natural gas pipeline operators the flexibility to request authority to utilize such methods in future years.

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45 In some circumstances, Phase 2 pipeline segments may be addressed as part of Phase 1, in light of operational and economic considerations. For example, a relatively long pipeline segment may run through both heavily populated areas and sparsely populated areas. In such cases, it may be more economical and practical to pressure test that entire segment at one time, rather than to remove the line from service to pressure test solely the portions that run through populated areas in Phase 1, and then remove the line from service a second time in Phase 2 to pressure test the portions that run through less populated areas.

1. **Phase 1A**

As explained above, Phase 1A pipeline segments include all transmission pipelines in populated areas that do not have sufficient documentation to validate a post-construction pressure test of at least 1.25*MAOP. These segments represent the highest priority work and will be pressure tested or replaced, provided that existing infrastructure can support that work with manageable customer impacts.

All Phase 1A pipeline segments fall into one of three categories: (1) pipeline segments that are 1,000 feet or less in length; (2) pipeline segments greater than 1,000 feet in length that can be removed from service for pressure testing; and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing. In many cases, consistent with our objective to maximize the cost effectiveness of our investments, the length of the segment to be tested or replaced will be increased to include adjoining pipeline that is in more sparsely populated areas due to operational necessity and project efficiency. These adjoining segments are, in essence, accelerated into phase 1A even though they are identified to be addressed in a later phase, and are referred to as “accelerated” segments. The mileage of pipeline for each of these three categories to be addressed in phase 1A is summarized as follows:

Table IV-5
Summary of Pipeline Mileage to Be Addressed in Phase 1A

	Total 2012-2015	
	Phase 1A Miles	Accelerated Miles
SoCalGas		
≤1,000 ft.	2	0
≥ 1,000 ft. and able to remove from service for testing	176	184
≥ 1,000 ft. and unable to remove from service for testing	143	115
Total Transmission	321	299
SDG&E		
≤1,000 ft.	0	0
≥ 1,000 ft. and able to remove from service for testing	1	0
≥ 1,000 ft. and unable to remove from service for testing	32	21
Total Transmission	33	21

The proposed plan to address these three types of Phase 1A pipeline segments is described below.

a) <u>Pipeline Segments Less Than 1,000 Feet in Length</u>

(1) <u>Replacement</u>

For short segments of pipe, the logistical costs associated with pressure testing (permitting, construction, water handling, service disruptions for non-looped system) can approach or exceed the cost of replacement. Therefore, for pipeline segments that are 1,000 feet or less in length it will typically be more cost effective to abandon and replace those segments rather than perform a pressure test. In such circumstances, replacement affords a more cost effective approach to achieving compliance with D.11-06-017, while providing equal safety enhancements benefits. Moreover, installation of the new segment can usually be performed while the existing service is maintained to customers, thereby avoiding service disruptions that may otherwise occur during pressure testing. The existing segment may then be abandoned upon commissioning of the new length of pipe. Accordingly, in the proposed Pipeline Safety Enhancement Plan all segments 1,000 feet or less in length are scheduled for replacement followed by abandonment. The estimated costs associated with these segments are provided in Chapter IX.

(2) Proposed Alternative: Non-Destructive Examination

As an alternative to replacement and abandonment of short segments, SoCalGas and SDG&E propose to have the option to perform a complete inspection of the pipeline segment using non-destructive examination (NDE) methods (such as ultrasonic, radiographic and magnetic particle inspection techniques). Non-destructive examination offers an equivalent means to validate the strength of the pipeline segment. If approved, the use of these techniques will reduce the time, costs, customer impacts and construction hazards associated with replacement.

Non-destructive examination methods have been used for years as a proven means to inspect pipelines for injurious anomalies. These non-destructive examination methods are typically more direct, reliable, and provide a higher level of anomaly discrimination when compared to pressure testing or in-line inspection. As a result they are commonly employed as part of the overall process to investigate pressure test failures and are also used to validate in-line inspection data. It follows that if these methods provide the reference for validation of other inspection methods, they are viable alternatives for providing the same level of reliable fitness-for-service evaluations.

The limitation of non-destructive examination methods for buried pipelines typically lies in the economics of application. Since these methods require direct access to the pipe surface, are slower, and are manually-operated, they usually are not economical for evaluation of long pipe lengths. However, for short segments of pipe these non-destructive examination techniques may be more practical and timely for long seam and weld validation. Direct examination of the pipeline also has the added benefit of providing additional information that pressure testing cannot, such as coating condition, corrosion, and other sub-critical defects that would not be detected through a pressure test. Additionally, the disadvantages of replacement of these short segments, namely the construction of temporary by-pass piping and service disruptions, can be avoided. All of these factors combine to make direct examination of short segments a reliable and cost-effective alternative to pressure testing.

b) Pipeline Segments Greater Than 1,000 Feet in Length That Can Be Taken Out of Service for Pressure Testing

For pipeline segments that are longer than 1,000 feet in length, a preliminary review was completed to determine if the pipeline could be taken out of service for a period of 2 to 6 weeks to complete pressure testing. Where removal from service is feasible, the Pipeline Safety Enhancement Plan identifies these pipeline segments for pressure testing. Where service disruption is not feasible, the pipelines are either scheduled to be pressure tested once new replacement pipelines have been installed to maintain service to customers, or those pipelines segments are identified for abandonment.

(1) Surgical Replacement of Oxy-Acetylene Girth Welds and Wrinkle Bends

As discussed in Section IV.D, SoCalGas and SDG&E believe construction and fabrication threats should be addressed as part of their proposed Pipeline Safety Enhancement Plan. The stability of oxy-acetylene girth welds and wrinkle bends cannot be fully assessed with pressure testing and in-line inspection tools. The removal from service for pressure testing, combined with the logistics already committed to preparing for pressure testing, provide a window of opportunity for SoCalGas and SDG&E to mitigate these features. Accordingly, the Pipeline Safety Enhancement Plan includes provisions for surgical removal of historic girth welds and wrinkle bends as part of the preparation for a pressure test while the pipeline is out of service.

Execution of the Pipeline Safety Enhancement Plan provides a particularly opportune time for this type of mitigation in High Consequence Areas and urbanized environments where access and logistics continue to narrow such windows of opportunity. Once the oxy-acetylene girth welds and wrinkle bends have been removed and replaced, the remaining pipeline segments will be pressure tested to finalize the validation of the entire segment. This will result in a fully validated and upgraded pipeline for safe and reliable operation. The cost of this effort will be minimized through synergies with the mobilization that will already take place to support the pressure test. The removal of these historic features will also provide for more reliable service and a lower likelihood of disruption to customers that may have otherwise resulted from pressure test failures.

(2) In-Line Inspection Using Transverse Field Inspection Tools and Pressure Testing of Piggable Lines

Phase 1A pipelines that have already been retrofitted to accommodate in-line inspection technology, commonly referred to as "Piggable Lines," will be inspected using transverse field inspection (TFI) tools and will also be pressure tested. Leveraging prior investments by SoCalGas and SDG&E in in-line inspection technology in this manner will enable SoCalGas and SDG&E to achieve the Commission's pressure testing objectives in a more timely and cost effective manner.

Two major logistical issues affect the timeline for completion of a successful pressure test—pre-planning before the test and the successful completion of the test. The timelines associated with both issues can be extensive. Pre-planning requires the operator to address numerous logistical issues (such as excavation, traffic control, tests of section lengths and the effects of elevation differences on test pressure, water storage and disposal for thousands of gallons of water, complete dewatering and drying of the pipeline, etc), obtain and comply with all necessary permits, and develop an approach and schedule that will minimize negative impacts to customers (*e.g*., working at night, arranging for temporary gas supply for single-source feed lines, installing new lines to ensure looping and proper gas handling). All of these pre-planning factors combine to limit or delay ready access to a pipeline segment for pressure testing. In some instances, single feed or pressure-limited pipeline systems will need to be reconfigured to provide service to impacted customers during pressure testing, and this may require considerable time to accomplish.

Successful completion of a pressure test poses additional timing challenges. While SoCalGas and SDG&E are confident in the safety of their pipeline system, pressure testing will expose pipelines to pressure levels well in excess of pressures typically experienced in-service. Although pressure testing is capable of exposing small leaks, identifying the location of such leaks can be challenging and time consuming when the volume of water released is small (*e.g.*, water seepage at a pinhole weld defect). In addition to the difficulty involved with locating test failures, follow-on work involves several undesirable consequences, including the need to move through at least one and sometimes several cycles of leak detection, dewatering, repair, re-fill, and retesting that can be both lengthy and costly.

Fortunately, much of the SoCalGas/SDG&E transmission system has already been retrofitted to accommodate in-line inspection tools, which allows for ready access to these pipelines to perform an in-line inspection. These inspections can occur in parallel with the preparation for pressure testing. During mobilization for the pressure test, knowledge obtained though in-line inspection using a TFI tool can be used to facilitate proactive mitigation of any pipeline anomalies that may lead to a potential pipeline failure at higher pressure test levels. By mitigating potential sources of pressure test failures before conducting the pressure test, planners can avoid the pitfalls associated with entering into a cycle of pressure test failures. In this manner, in-line inspection using TFI technology prior to the pressure test can augment and improve the likelihood of a successful pressure test, thereby reducing both the time and the costs.

Moreover, SoCalGas and SDG&E seek authorization to analyze the data obtained through this in-line inspection process to validate TFI as an equivalent means of validating the long seam stability of in-service pipelines. This technology has not yet been recognized by the Commission as an equivalent means to validate the safety margin of a pipeline. SoCalGas and SDG&E seek to analyze and compare the results of pressure testing with the results of in-line-inspections in Phase 1, in order to demonstrate that TFI provides an equivalent alternative to pressure testing for Phase 2 pipelines. Particularly for Phase 2 pipelines that are already piggable, this may present an opportunity to greatly reduce the costs of achieving compliance with the Commission's directives in this Rulemaking.

(3) <u>Pressure Testing of Non-Piggable Lines</u>

For non-piggable lines that may be removed from service for pressure testing, SoCalGas and SDG&E propose to conduct such testing in Phase 1A. Replacement may be considered in lieu of pressure testing for pipelines identified with pre-1946 construction and fabrication threats, where it is feasible to complete the replacement within the Phase 1A four-year timeframe.

c) Pipeline Segments Greater Than 1,000 Feet in Length That Cannot Be Taken Out of Service for Pressure Testing

(1) In-Line Inspection of Piggable Lines Using Transverse Field Inspection Tools as an Interim Safety Enhancement Measure

Some pipeline segments that would otherwise be addressed in Phase 1A cannot be addressed in the near-term due to the need to construct new infrastructure to maintain system reliability. If construction of the new facilities needed to maintain service to customers during pressure testing cannot begin within the Phase 1A timeframe, such pipeline segments may need to be addressed as part of Phase 1B. These lines are included as a parallel effort within Phase 1B to account for estimated lead times required for the design and permitting of the new infrastructure.

Much of the SoCalGas/SDG&E system has already been retrofitted to accommodate in-line inspection tools, which allows for ready access to the pipeline to perform in-line inspections. During Phase 1A, all such pipelines that have already been retrofitted to allow for in-line inspection, or that can be readily converted for doing so, will be in-line inspected using TFI technology. In-line inspection using TFI technology will provide interim validation of the pipeline's integrity until the pressure test can be performed. These inspections can occur in parallel with the preparation for construction of the new facilities needed to allow for pressure testing of the pipeline segment. Work in parallel will minimize service disruptions to customers and allow for enhanced long-term system flexibility for minimal additional cost, as compared to replacement alone. Once installation of the new infrastructure is complete, the existing pipeline may then be pressure tested to validate its condition and retained to provide system flexibility. The safety of the existing pipeline segment will be enhanced by the performance of both an in-line inspection and a pressure test to validate its safe operation.

(2) Abandonment of Non-Piggable Lines

All non-piggable pipeline segments that cannot be taken out of service for pressure testing with manageable customer impacts will be replaced and/or abandoned once new piggable facilities are constructed and placed in-service. Construction and installation of the new replacement segment can take place while service is maintained to customers on the existing pipeline segment, thereby avoiding the service disruptions that would otherwise occur if the pipeline segment were removed from service for pressure testing. The newly installed systems will be constructed using state-of-the-art methods and to modern standards, including current pressure test standards.

(3) Proposed Alternative: Authorization of Use of In-Service Pressure Test as an Alternative to Replacement

We request that the Commission consider the development and approval of reductions in a grandfathered pipeline's MAOP to serve as an "in service" pressure test as an alternative to the performance of a pressure test that would require the pipeline to be taken out of service. While MAOP may not be set above certain code-defined limits, the ceiling can be set at lower values by the Operator, and system capacity requirements may allow a pipeline's MAOP to be reduced further to achieve the equivalency of a pressure test and validation of the stability of the long seam. For example, changes in customer demand and pipeline system improvements over time have allowed some pipelines to operate at a subsequently reduced MAOP, because higher pressures are no longer needed to meet demand. For pipelines such as these, where recorded pressures over the past five years support a previous maximum in-service pressure of at least 1.39 times or greater than the established MAOP, the pipeline's long seam stability has been validated and further testing should not be required. This in-service natural gas pressure test is functionally equivalent to a strength test of the pipeline to 1.39 times the reduced MAOP.

While the standard threshold to validate the stability of a long seam is 1.25 times MAOP, a pressure reduction that would result in the equivalent pressure of at least 1.39 times MAOP is proposed. This additional safety factor is prudent to account for the fact that operational pressure measurements are not static and portions of the pipeline may not have experienced the measured highest pressure. In addition, the maximum highest actual operating pressure experienced in the five years preceding the lowering of MAOP would be used to account for concerns that the MAOP may be set well above the pressures the pipeline has recently experienced. Such an

MAOP reduction validates the safety of the long seam without the service disruption and cost associated with a hydrostatic or other pressure test.

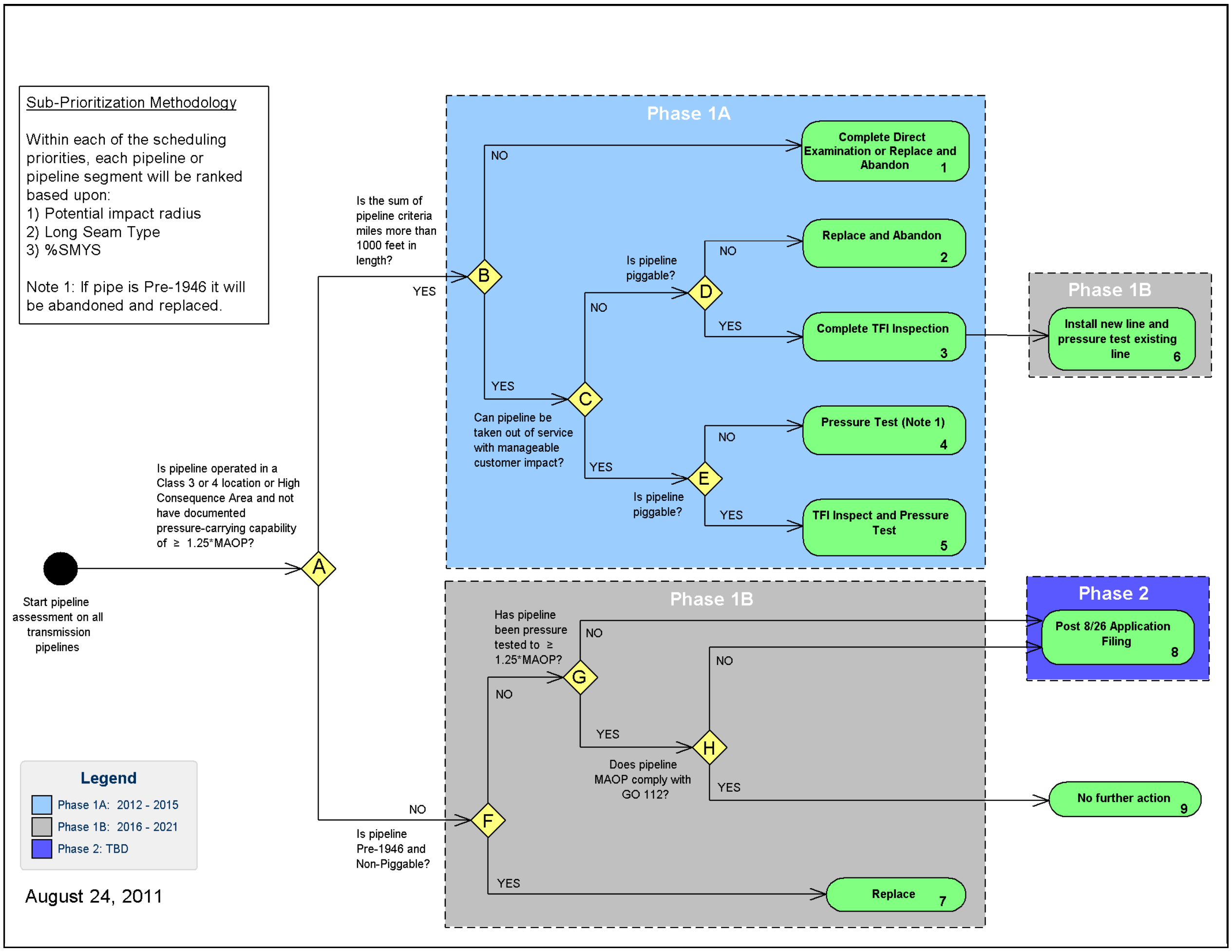
SoCalGas and SDG&E would like the opportunity to work with Commission Staff and other stakeholders to develop a standard for determining when a pressure reduction may be used as an alternative to pressure testing or replacement. Because such a standard could potentially reduce Pipeline Safety Enhancement Plan implementation costs for our customers, while providing equivalent safety benefits, SoCalGas and SDG&E request that the Commission consider this issue in the next phase of this proceeding.

2. Phase 1B

Pipeline segments in Phase 1B are comprised of those pipeline segments that would otherwise be addressed in Phase 1A, but cannot be addressed in the near-term due to the need to construct new infrastructure to maintain service during pressure testing (see box 6 in Figure IV-1 below). In addition, non-piggable transmission pipelines segments that were installed prior to 1946 will be replaced. As part of the work previously completed during implementation of Subpart O, SoCalGas and SDG&E have already identified, retrofitted and in-line inspected all pre-1946 transmission pipelines that were constructed using acceptable welding techniques and are operationally suited to in-line inspection. The remaining pre-1946 segments in the SoCalGas/SDG&E system are not suited for in-line inspection, likely have non-state-of-the-art welds, and would require significant investment for retrofitting to accommodate in-line inspection tools. Accordingly, consistent with the Commission's directive to "consider retrofitting pipeline to allow for inline inspection tools," and consistent with our overarching objectives of enhancing the safety of our pipeline system in a proactive, cost effective manner, SoCalGas and SDG&E propose to replace all remaining pre-1946 non-piggable pipelines as part of Phase 1B.

Figure IV-1 below comprehensively illustrates our proposed Pipeline Safety Enhancement Plan prioritization and decision-making process for testing or replacing pipeline segments.

Figure IV-1
Pipeline Safety Enhancement Plan Test/Replace Decision Tree



3. <u>Phase 2</u>

In Phase 2, which is expected to run in parallel with and may extend past the completion of Phase 1B, remaining transmission pipeline segments that do not have sufficient documentation to validate post-construction pressure tests to 1.25*MAOP and all other remaining transmission pipelines that have not been strength tested in accordance with the Commission's direction will be addressed. These pipeline segments are scheduled to be addressed after Phase 1A pipeline segments, in order to prioritize pipeline segments located in more populated areas that were either not pressure tested or lack sufficient details related to the completion of a pressure test.[46] As

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[46] In some circumstances, Phase 2 pipeline segments may be addressed as part of Phase 1, in light of operational and economic considerations. For example, a relatively long pipeline segment may run through both heavily populated areas and sparsely populated areas. In such cases, it may be more economical and (*Continued*)

described in above, SoCalGas and SDG&E propose the use of non-destructive examination methods as an alternative to pressure testing to validate the long seam integrity of shorter pipeline segments. In addition, SoCalGas and SDG&E will analyze the results of in-line inspection using TFI tools in Phase 1A to validate the use of in-line inspection using TFI as an alternative to pressure testing. If use of non-destructive examination methods on shorter pipeline segments is approved as part of this plan, and if TFI results demonstrate its viability as an alternative equivalent to pressure testing, SoCalGas and SDG&E will seek authorization to complete Phase 2 using in-line inspection, non-destructive examination, and in-service pressure tests in their 2016 General Rate Case. SoCalGas and SDG&E will solely propose alternative methods that can verify a pipeline's pressure carrying capability in a manner that is equivalent to or better than pressure testing.

4. Proposed Sub-Prioritization Process for All Segments

Each of the numbered boxes in the decision tree represents an inventory of pipeline segments that share the same outcome. Accordingly, after priorities have been broadly established for all lines as described in the phased approach above, within each numbered box, detailed planning will be conducted in rank order based upon segment-specific characteristics that reflect the dominant risk factors for that segment. The rank order for detailed project planning will be based upon the potential impact radius for each pipeline segment divided by its long seam factor. This approach is consistent with pipeline risk principles, where risk is commonly defined as the product of the likelihood of failure (LOF) and the consequence of failure (COF), or Risk = LOF x COF. Likelihood of failure is closely related to the specific characteristics and anticipated threats of each pipeline segment. Consequence of failure is related to the energy in each pipeline and the population density potentially affected by a failure. In this manner, the pipeline segments

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Continued from the previous page

practical to pressure test that entire segment at one time, rather than to remove the line from service to pressure test solely the portions that run through populated segments in Phase 1, and then remove the line from service a second time in Phase 2 to pressure test the portions that run through less populated areas.

are sub-ranked for scheduling purposes primarily based on the consequence of failure of each segment.

Potential impact radius refers to the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property and is dependent upon the pipeline's diameter and MAOP. A larger potential impact radius typically affects proportionally larger numbers of people, and in this manner, calculation of the segment specific potential impact radius provides an effective means to rank segments by their potential energy and possible affect on population density.

Long seam factors will be applied to raise the score for certain pipeline segments, as specified in 49 CFR 492.113.

When segments have the same score, the pipeline segment that operates at a higher percentage of the specified minimum yield strength at MAOP will be given a higher priority.

These prioritization and sub-prioritization processes were developed for planning purposes. The final implementation schedule is subject to changes related to system conflicts, logistical coordination, and incorporation of information obtained through interim inspections and assessments.

E. Proposed Interim Safety Enhancement Measures

As described above, execution of Phase 1A is targeted for completion by 2015. As required by the Commission,[47] SoCalGas and SDG&E offer the following proposed interim safety measures to enhance public safety during the implementation period.

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47 *See* D.11-07-016, p. 21 ("The Implementation Plan must. . . include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions and prioritization of pressure testing for pipelines that must run at or near Maximum Allowable Operating Pressure Values which result in hoop stress levels at or above 30% of Specific Minimum Yield Stress, and other such measures that will enhance public safety during the implementation period.")

1. Continued Implementation of Transmission Integrity Management Program[48]

As explained in Section IV.B.2 above, our transmission integrity management program is an ongoing program for continually assessing and managing the safety and integrity of a gas pipeline transmission system by periodically assessing and addressing the nine categories of threats to natural gas pipelines identified in 49 CFR 192 Subpart O, including corrosion, third-party damage and weather-related and outside force. The periodic review and inspection of these and other pipeline threats is designed to detect changes in a pipeline's environment and structural integrity that could otherwise go undetected. Detection of a change in any of the nine categories will be documented and addressed as part of our ongoing transmission integrity management program. We believe our safe operating history is a reflection of the effectiveness of their transmission integrity management program.

2. More Frequent Ground Patrols and Leakage Surveys

In our April 15 Report, we committed to increase the frequency of ground patrols and leakage surveys for identified pipelines to bi-monthly. These additional patrols and surveys are in process, and will continue until the testing or abandonment of the pipe has been completed. SoCalGas and SDG&E utilize a variety of instruments and methods to conduct leakage surveys, such as infrared gas indicators, optical methane detectors, and barhole surveys.

Ground patrols are a non-instrumented subset of leakage surveys wherein company personnel utilize their visual and olfactory senses to detect evidence of leakage. The employee travels along the pipeline route to find indications of: (1) visual evidence of dead or dying vegetation; (2) dust blowing from fissures in the ground; (3) the smell of odorant, or (4) an unusually high concentration of flies in the vicinity of the pipeline.

Both ground patrols and leakage surveys are used to detect and report early signs of leakage, for follow-on investigation. In this manner, leaks resulting from pre-1970 pressure tests

48 This program is authorized through our respective General Rate Cases and funding is not requested through this filing.

without the 8 hour hold for leak check, or leaks resulting from any time-dependent mechanism (such as corrosion) can be mitigated before they develop into potentially larger issues.

Ground patrols and leakage surveys are normally conducted on a schedule that ranges from one to four times annually, depending upon specific code requirements. Following the issuance of Urgent Safety Recommendations to PG&E by the NTSB in January 2011, in an effort to provide greater confidence to the public and the Commission in the integrity of our pipeline systems, the schedules for ground patrols and leakage surveys of pipelines that do not have sufficient documentation of pressure testing have been modified to occur at a bi-monthly rate until the operating safety margins of those pipelines can be validated by one of the methods proposed in the Pipeline Safety Enhancement Plan. As indicated in our June 24, 2011 update to their April 15, 2011 Report, the first round of bi-monthly inspections of all identified pipelines was completed prior to June 24.

3. <u>Pressure Reductions</u>

SoCalGas and SDG&E have had and continue to have a practice of reducing the MAOP of pipelines when system changes allow for a lower maximum pressure to minimize the stress in the pipeline and provide an enhanced safety margin. In accordance with our April 15 Report on Actions Taken in Response to NTSB Recommendations, we have implemented pressure reductions where operational constraints permitted SoCalGas and SDG&E to take immediate action. Work continues to review pipelines to determine where other pressure reductions are possible while meeting capacity requirements and service reliability.

4. <u>In-Line Inspection</u>

As explained in Section IV.D above, some pipeline segments that would otherwise be addressed in Phase 1A cannot be addressed in the near-term due to the need to construct new infrastructure to maintain system reliability. In the interim, until new facilities can be constructed to allow for pressure testing of these pipelines, all such pipelines that have already been retrofitted to allow for in-line inspection, or that can be readily converted for doing so, will be in-line inspected using TFI technology. The performance of an in-line inspection using TFI technology will provide interim validation of the pipeline’s integrity until the pressure test can be performed.

V.

PROPOSED VALVE ENHANCEMENT PLAN

A. Introduction

The San Bruno pipeline rupture and fire has focused considerable attention at both the State and Federal level on protocols for pipeline isolation in the event of a pipeline rupture. In D.11-06-017, the Commission orders all California natural gas pipeline operators to consider retrofitting pipelines to allow for improved shut off valves. In response to this directive, and in light of concerns raised by the rupture in San Bruno, SoCalGas and SDG&E offer a proposed Valve Enhancement Plan as part of the Pipeline Safety Enhancement Plan. The Valve Enhancement Plan is a plan to augment our more than 200 existing automatic shutoff valves (ASV) and remote control valves (RCV), for the purpose of reducing response time following a pipeline rupture. As with the proposed Pipeline Safety Enhancement Plan as a whole, the Valve Enhancement Plan is founded upon the four primary objectives of: (1) compliance with Commission directives; (2) enhancement of public safety; (3) minimization of customer impacts; and (4) maximization of cost effectiveness.

B. Overview of Existing Valve Infrastructure

SoCalGas and SDG&E currently employ over 800 mainline valves to isolate and sectionalize transmission pipelines for operational and emergency conditions in the areas discussed in this proposal. This includes about 600 manually-operated valves and more than 200 ASVs and RCVs to meet and/or exceed the requirements of 49 CFR 192.179.

A manually-operated valve is one that requires physical interaction by qualified field personnel to operate and physically close it. In the experience of SoCalGas and SDG&E, this process can take upwards of two hours from the time an operator identifies the need to close a system valve.

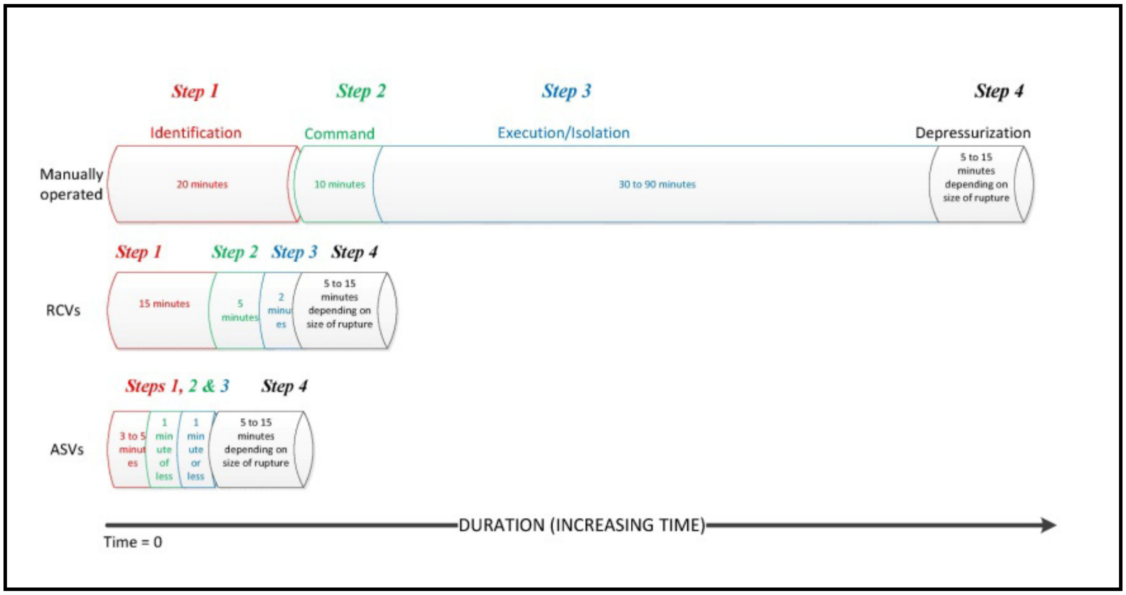
An ASV is equipped with a control device that is pre-programmed to sense a pipeline rupture. For example, these valves can automatically close when an excessive pressure drop—typically 10-30 psig per minute—occurs along the associated pipeline section or can be programmed with some other parameters. An ASV does not require human intervention to operate or to send a signal to activate its closure. The time required for an ASV to respond to a pipeline rupture depends upon the size of the rupture, the distance between the valve and the rupture site, and the logic and sensitivity programmed into the control device. As deployed by SoCalGas and SDG&E, ASVs can detect and isolate a pipeline rupture in less than ten minutes.

An RCV is a valve equipped with electric or gas powered actuators to operate (open or close) the valve based on a command (signal) from a remote location, such as a gas control room. The RCV does require human intervention to evaluate the circumstances and ultimately send a signal to operate the valve or valves. In the experience of SoCalGas and SDG&E, when this evaluation time is factored in, RCVs require at least fifteen minutes in elapse process time to isolate a ruptured pipeline.

Both valve options compare favorably with timing associated with manual isolation and depressurization of a fully ruptured pipeline, which can take anywhere from thirty minutes to two hours following a rupture. The time variation depends upon the pipeline length, operating pressure, rupture characteristics, connected pipelines within the isolated section, and the operator's ability to access valve locations.

Figure V-1 below depicts the relative timelines of the systematic process associated with ASVs, RCVs, and manually-operated valves as it pertains to swiftness of response to a pipeline rupture. There are four distinct steps taken in response to a rupture. Step 1 is to identify that an event has occurred. Step 2 is to issue a command order that includes verification of the rupture. Step 3 is to execute valve actions by closing valves, which isolate the ruptured pipeline section. Step 4 accounts for the time it takes for an isolated section to depressurize. Although the time required varies for each valve type and action step taken, the final step, Step 4, typically takes about the same amount of time once all necessary valves have been closed as part of Step 3.

Figure V-1
Typical Isolation Timelines by Valve Type



Operators have long been subject to regulatory requirements to maintain the ability to isolate damaged sections of pipelines with shutoff valves at specific space intervals, depending on Class Location. Specifically, 49 CFR 192.179 prescribes minimum distances, of between five and twenty miles, at which valves need to be deployed for this purpose.

Currently, there are no Federal or State regulations prescribing the use or spacing of ASVs or RCVs on gas transmission pipelines to enhance swiftness of response. There is general guidance in Subpart O, however, that ASVs or RCVs should be considered as a mitigation option to contend with potential associated threats and consequences.[49]

For over forty years, and prior to the adoption of Subpart O, SoCalGas and SDG&E have incorporated ASVs and RCVs into their system operations. The valve design philosophies of SoCalGas and SDG&E are based on their experience that ASVs and RCVs can reduce response time and enhance their ability to contend with a significant pipeline rupture. In addition, ASVs and RCVs can facilitate the ability of an operator to contend with simultaneous ruptures triggered in an event, such as a major earthquake. For these reasons, approximately 50% (2,000 miles) of our high-pressure transmission lines are currently covered by 208 ASVs, which are installed at

49 *See* 49 CFR 192.935(c).

intervals averaging ten miles in length, but which range between five and twenty miles in spacing. Figure V-2 below depicts an overview of the current coverage of the SoCalGas/SDG&E transmission pipeline system by ASVs. A large percentage of these ASV-covered pipelines reside in Class 1 and 2 locations outside of the Los Angeles Basin, San Diego, and other population centers. This ASV control closure scheme is augmented by over thirty mainline valves, pressure limiting stations, and/or compressor shutdown controls that can be operated remotely by Gas Control personnel in a matter of five to fifteen minutes (or less) to restrict gas flow to a ruptured pipeline section.

ASVs are deployed by SoCalGas and SDG&E on large transmission pipelines specifically to mitigate the consequences of pipeline ruptures caused by earthquakes, landslides or third party impact, while taking into consideration and minimizing the risk of wide-scale gas delivery loss to customers in the event of an errant closure. To minimize adverse customer impacts, this evolved deployment approach has resulted in focusing installation of such control capability in areas where gas flow patterns are highly predictable, sufficient pipeline supply diversity exists, and the ability to readily re-route impacted supplies exists.

Figure V-2
Automatic Shutoff Valve Coverage on Major SoCalGas and SDG&E Transmission Pipelines-Overview[50]

Most of the ASVs shown in Figure V-2 are currently not equipped with telemetry and/or Supervisory Control and Data Acquisition or "SCADA"[51] system remote data monitoring capabilities. Therefore, a control room operator's knowledge about a valve closure, which is principally based on observed pressure changes, can trail the event occurrence by up to thirty

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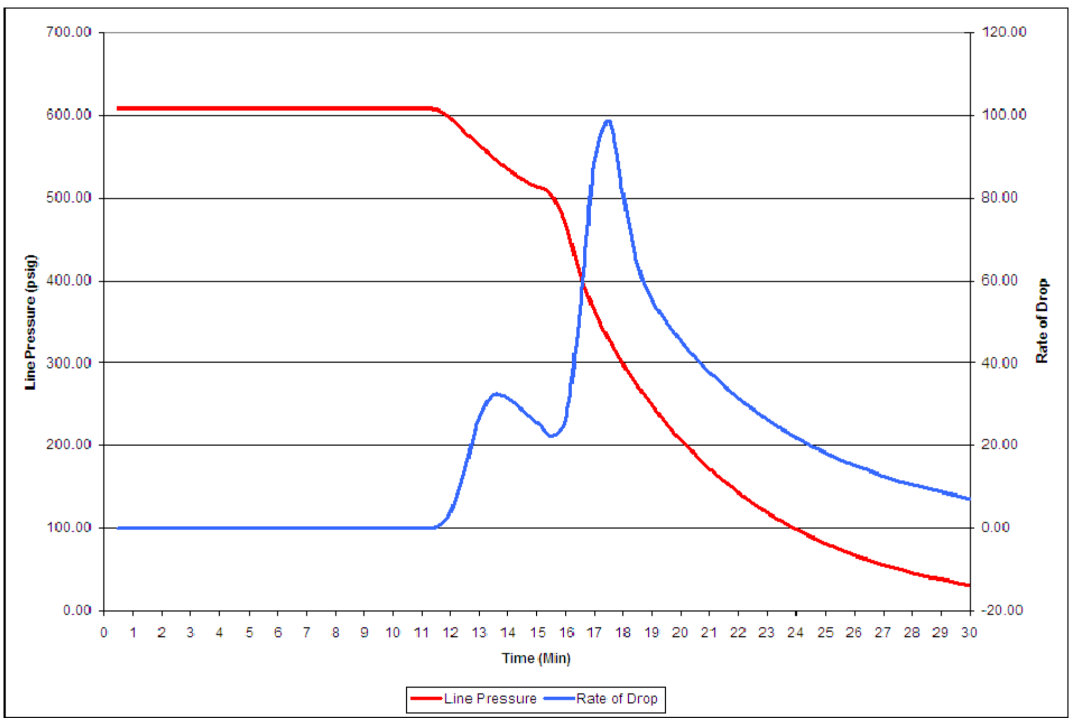
50 All illustrated pipelines are eight inches in diameter or greater. Not all valves/pipelines are shown, where pipelines operate in parallel.

51 A SCADA system is a computer-based system used by an operator to collect and display pertinent information about the operator's pipeline system. It also provides the operator with the ability to send commands back to the pipeline system.

minutes. This is true whether the pressure change is due to a pipeline rupture or equipment failure.

ASVs, as deployed by SoCalGas and SDG&E, generally facilitate the automatic closure, isolation and depressurization of a pipeline section in less than thirty minutes from the first pressure effects associated with a pipeline rupture, depending on the section length and effective rupture size, provided no additional source is present. A recent example of the benefits and isolation capabilities of ASVs is provided in Figure V-3 below. Figure V-3 depicts actual data recorded following the July 11, 2011 rupture of an eighteen-inch SoCalGas pipeline after the pipeline was accidentally struck by heavy equipment.

Figure V-3
Camarillo CA, 18" pipeline rupture, July 2011



The pipeline was operating at 600 psig prior to the rupture (red line). An initial drop in pressure to about 500 psig occurred when the pipeline was breached by third-party intrusion. The ASVs sensed the rupture immediately and took about three minutes to evaluate the pressure change to confirm the rupture through their pre-programmed logic (at Time=11) and closed within five minutes after the rupture. Following the valve closures, the rapid gas depressurization initiated and, as illustrated in Figure V-3, the drop in pressure in the isolated pipeline section was dramatic. The near-full rupture of this ten-mile section, ASV-equipped pipeline was depressurized to below ten psig within twenty minutes from the time of rupture. If this same break were to occur on a pipeline section that had not been equipped with ASVs, it might take one to two hours to secure the same full isolation. In summary, the net time difference between these two processes is one of the major quantifiable benefits provided by ASVs. It should be noted that there was no personal injury or ignition associated with this rupture.

C. Challenges Associated with the Deployment of ASVs/RCVs

There are significant challenges associated with the deployment of ASVs/RCVs on gas transmission pipelines, as noted by the Independent Review Panel formed by the Commission following the San Bruno pipeline rupture [52] and further described by the American Gas Association in a March 11, 2011 white paper.[53] Indeed, because of these significant challenges, the Independent Review Panel recommended in its June 9, 2011 Report to the Commission that pipeline operators address these challenges in thoughtfully developed plans, rather than through one-size-fits-all legislation or regulations.

The SDG&E and SoCalGas ASV/RCVs system of controls described earlier, while providing rapid isolation for covered pipelines, sustains three to four false or errant valve closures each year due to a variety of reasons. Although control technology and equipment reliability have improved through the years, errant closures remain an operational risk and must be incorporated into the deployment strategy.

When these issues arise in complex pipeline networks, where flow patterns are bi-directional and/or pipelines are operating at near-full capacity, they can compromise the ability of SoCalGas and SDG&E to serve customers reliably. Closures can occur due to equipment failure, spurious pressure waves, or other operational issues that create a condition that simulate a rupture due to an electro-mechanical device sensing only a pressure-drop rate in a pipeline. Given their experiences with control system failures, SoCalGas and SDG&E have historically avoided

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52 *Report of the Independent Review Panel San Bruno Explosion*, prepared for the Commission by Jacobs Consultancy, June 8, 2011, p.13.

53 *ASVs and RCVs on Natural Gas Transmission Pipelines*, AGA Transmission and Distribution Engineering Committee, March 25, 2011.

installing ASVs on pipelines where there are multiple taps and pipeline interconnection points or where a pipeline is critical to serving customers. SoCalGas and SDG&E propose to address these challenges and risks in their proposed Valve Enhancement Plan through the co-deployment of significant gas-pipeline monitoring technologies (i.e., additional SCADA system and system visibility components), and accordingly, will propose to add ASV and RCV capability in such areas.

D. Guiding Principles of Proposed Valve Enhancement Plan

As ordered by the Commission, SoCalGas and SDG&E have reviewed their current isolation capabilities and propose to expand the use of ASVs and RCVS as part of the Pipeline Safety Enhancement Plan. SoCalGas and SDG&E propose to accomplish this work in a ten-year timeframe, commencing in 2012. As stated, the Valve Enhancement Plan is designed to achieve four objectives: (1) compliance with Commission directives; (2) enhancement of public safety; (3) minimization of customer impacts; and (4) maximization of cost effectiveness.

1. Compliance with Commission Directives

In D.11-06-017, the Commission orders all California pipeline operators to "consider retrofitting pipeline to allow for inline inspection tools and, where appropriate, improved shut off valves."[54] This proposed Valve Enhancement Plan represents our compliance with that directive.

2. Enhancing Public Safety

Through their proposed Valve Enhancement Plan, SoCalGas and SDG&E propose to enhance public safety by accelerating their ability to isolate and contain escaping gas in the event of a pipeline rupture in areas currently supported by manually-operated valves. In addition, SoCalGas and SDG&E propose to enhance the swiftness of their response to a pipeline rupture by converting a large number of manually-operated valves to ASVs or RCVs and, where appropriate, installing additional valves with these capabilities.

By installing additional ASVs, SoCalGas and SDG&E will reduce the time required to for control operators to identify and characterize a pressure drop as a pipeline rupture and to provide

[54] D.11-06-017, Ordering ¶ 8.

for automatic closure locally, thus eliminating any latency in SCADA system operations requiring communication to and from the control room. This ASV isolation process can take as little as ten minutes upon rupture.

By installing additional RCV capability and the required companion pressure monitors to be installed with each ASV/RCV upgrade as proposed herein, SoCalGas and SDG&E will reduce the time required to identify and characterize a pressure drop as a pipeline rupture. SoCalGas and SDG&E will enhance their ability to isolate a ruptured pipeline section more rapidly by eliminating the manual process and effectively address the technical challenges associated with ASV/RCV technology.

The Valve Enhancement Plan also secures complete large pipeline section isolation by addressing the issue of backflow. Backflow occurs when a ruptured pipeline section has more than one supply point and/or receipt point within the section to be isolated. Although the primary means to stop gas from flowing into a ruptured pipeline section are the mainline valves, there may be other interconnecting pipelines. Without terminating gas flow from these other interconnecting pipelines, gas will continue to flow back into the ruptured pipeline section. SoCalGas and SDG&E propose to address backflow prevention in the Valve Enhancement Plan through the installation of added RCVs serving subsidiary pipelines, and through installation of check valves and other comparable equipment installations along its large transmission pipelines.

In addition, SoCalGas and SDG&E considered population density and heat intensity in developing their proposed Valve Enhancement Plan. Population density is taken into account by focusing on Class 3 locations and High Consequence Areas for deployment of additional ASVs/RCVs. As for heat intensity resulting from a rupture, SoCalGas and SDG&E address this issue through the use of Potential Impact Radius as a principal metric in determining which pipelines should be embodied by this Valve Enhancement Plan.

3. <u>Minimizing Customer Impacts</u>

As recommended by the Independent Review Panel, SoCalGas and SDG&E have taken into consideration lessons learned from the San Bruno pipeline incident and have also considered recent advancements in technology in developing this Valve Enhancement Plan. Moreover, SoCalGas and SDG&E have re-evaluated the technical aspects and risks that accompany ASV/RCV implementation in locations characterized by complex piping networks and believe such isolation capability can be effectively managed if best-in-class instrumentation, monitoring and supplemental equipment are installed in conjunction with transmission valve closure capability. This specifically includes: (1) adding more pressure/flow measurements and valve status indication along its pipeline network, including along supply lines served via large gas transmission pipelines; (2) incorporating some redundancy in the instrumentation and control systems serving its SCADA system and remote control capability; and (3) installing some control valves, check valves or other controls on supply lines served from transmission pipelines to prevent backflow from continuing to feed a ruptured transmission pipeline from other large system pipelines.

4. Maximizing Cost Effectiveness

The proposed Valve Enhancement Plan satisfies the objective of maximizing cost effectiveness in two key manners. First, the proposed plan focuses on those pipeline segments that are most likely to yield higher public safety benefits—larger-diameter, higher-pressure pipelines located in Class 3 locations or High Consequence Areas that have higher potential impact radii. Specifically, the scope of the proposed Valve Enhancement Plan is limited to transmission pipeline segments with MAOPs at or above 200 psig that are either (1) equal to or greater than twenty inches in diameter; or (2) equal to or larger than twelve inches in diameter where the pipe wall thickness and material grade and the MAOP equate to a hoop stress of 30% or more of SMYS. The corresponding potential impact radii for all these pipeline segments range between approximately 120 and 200 feet.

In reviewing alternatives to these criteria, SoCalGas and SDG&E found diminishing return for widely-deploying similar valve control technology on smaller pipelines due to the following reasons. First, because the potential impact radius is generally less than 120 feet for pipelines below this threshold, access to such pipelines by responders is more easily managed. Second, isolation valves tend to be more readily accessible at closer intervals and are easier to manually-operate on smaller pipelines. In addition, there is less potential for losing gas service to a large numbers of customers (*e.g.*, 500,000 or more) under a rupture scenario where smaller pipelines are affected.

Second, the Valve Enhancement Plan maximizes the cost effectiveness of proposed valve investments by leveraging SoCalGas and SDG&E's existing system of over 800 manually-operated valves located along transmission pipelines in Class 3 or High Consequence Areas wherever possible, and maintaining the current eight-mile-or-less Department of Transportation prescriptive isolation section lengths for valve spacing.[55] Both SoCalGas and SDG&E's pipeline systems have been constructed through the years to meet this eight-mile-or-less criterion in Class 3 locations. Thus, eight-mile-or-less spacing is a natural spacing fit that will optimize cost, program logistics and, ultimately, plan effectiveness.

In determining proposed valve spacing, SoCalGas and SDG&E reviewed the effective time difference between isolating an eight-mile pipeline section and five-mile pipeline section, as contemplated in proposed legislation. Our analysis shows little time difference in the depressurization associated with a reduction in valve spacing from eight to five miles. For example, a 36-inch-diameter pipeline operating at 300 psig, the difference in depressurization time (elapsed) between an eight-mile and five-mile section equates to a couple of minutes.

Based on such analyses, and the incremental costs associated with this reduction in valve spacing, SoCalGas and SDG&E determined that further reduction in valve spacing would not yield significant benefits and would be inconsistent with their objective of maximizing the cost effectiveness of their propose Valve Enhancement Plan.

SoCalGas and SDG&E believe this proposed valve spacing provides improved response time for valve closures in Class 3 and 4 locations and High Consequence Areas while focusing on pipelines that carry the greatest consequence under a rupture scenario.

E. Criteria for Proposed Valve Enhancement Plan

Consistent with our four overarching objectives, we developed the following criteria for selecting pipeline segments to be retrofitted with enhanced ASV/RCV capabilities.

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55 As explained in Section V.B above, although current Federal regulations do not require installation of ASVs or RCVs, current regulations do prescribe valve spacing requirements of eight miles or less in Class 3 locations. *See* 49 CFR 192.179.

First, we determined that the Valve Enhancement Plan should focus solely on transmission pipeline segments, as defined by the United States Department of Transportation. Application of the Department of Transportation's definition limits the scope of the Valve Enhancement Plan to those pipeline segments that are operated at a hoop stress of twenty percent or more of SMYS.[56] This is consistent with the Commission's directives in D.11-06-017, which focuses solely on transmission pipelines. This is also consistent with the objectives of enhancing public safety and maximizing cost effectiveness, because, by definition, transmission lines are of larger diameter and are operated at a higher operating pressure.

Second, we focus the scope of the proposed Valve Enhancement Plan on those pipeline segments that are operated in Class 3 locations or High Consequence Areas. This is consistent with the focus of the National Transportation Safety Board in its January 3, 2011 Safety Recommendations to PG&E.[57] By focusing on those pipeline segments in populated and/or High Consequence Areas, SoCalGas and SDG&E satisfy their objectives of enhancing public safety and maximizing cost effectiveness.

Third, the proposed Valve Enhancement Plan complements the use of existing valves, RCVs, ASVs and other infrastructure, where possible.

For all transmission pipeline segments located in Class 3 locations or High Consequence Areas, we developed a decision-making process to determine whether those pipeline segments should be retrofitted as part of this Valve Enhancement Plan. As described below, this decision-making process distinguishes between those pipelines that are twenty inches in diameter or larger and those pipeline segments that are less than twenty inches in diameter.

1. Transmission Pipeline Segments Twenty Inches in Diameter or Larger

In our Valve Enhancement Plan, we propose to address all transmission pipeline segments greater than or equal to twenty inches in diameter that are located in Class 3 locations or High Consequence Areas that are not already equipped with ASV/RCV capability. All such pipeline

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56 *See* 49 CFR 192.3.

57 The January 3, 2011 NTSB Safety Recommendations to PG&E pertain to Class 3 and 4 locations and Class 1 and 2 High Consequence Areas. Because we do not operate any pipelines in Class 4 locations, we focus solely on Class 3 locations and High Consequence Areas.

segments are identified for installation of ASV/RCV capability at intervals of approximately eight miles or less.

2. Transmission Pipeline Segments Less Than Twenty Inches in Diameter

Pipeline segments less than twenty inches in diameter are subjected to secondary analysis to determine whether those pipeline segments should be retrofitted with ASV/RCV capability as part of the proposed Valve Enhancement Plan. If such a pipeline segment is at least twelve inches in diameter and operates at 30% or more of SMYS, then that pipeline segment is identified for installation of ASV/RCV capability at approximate intervals of eight miles or less as part of the Valve Enhancement Plan.

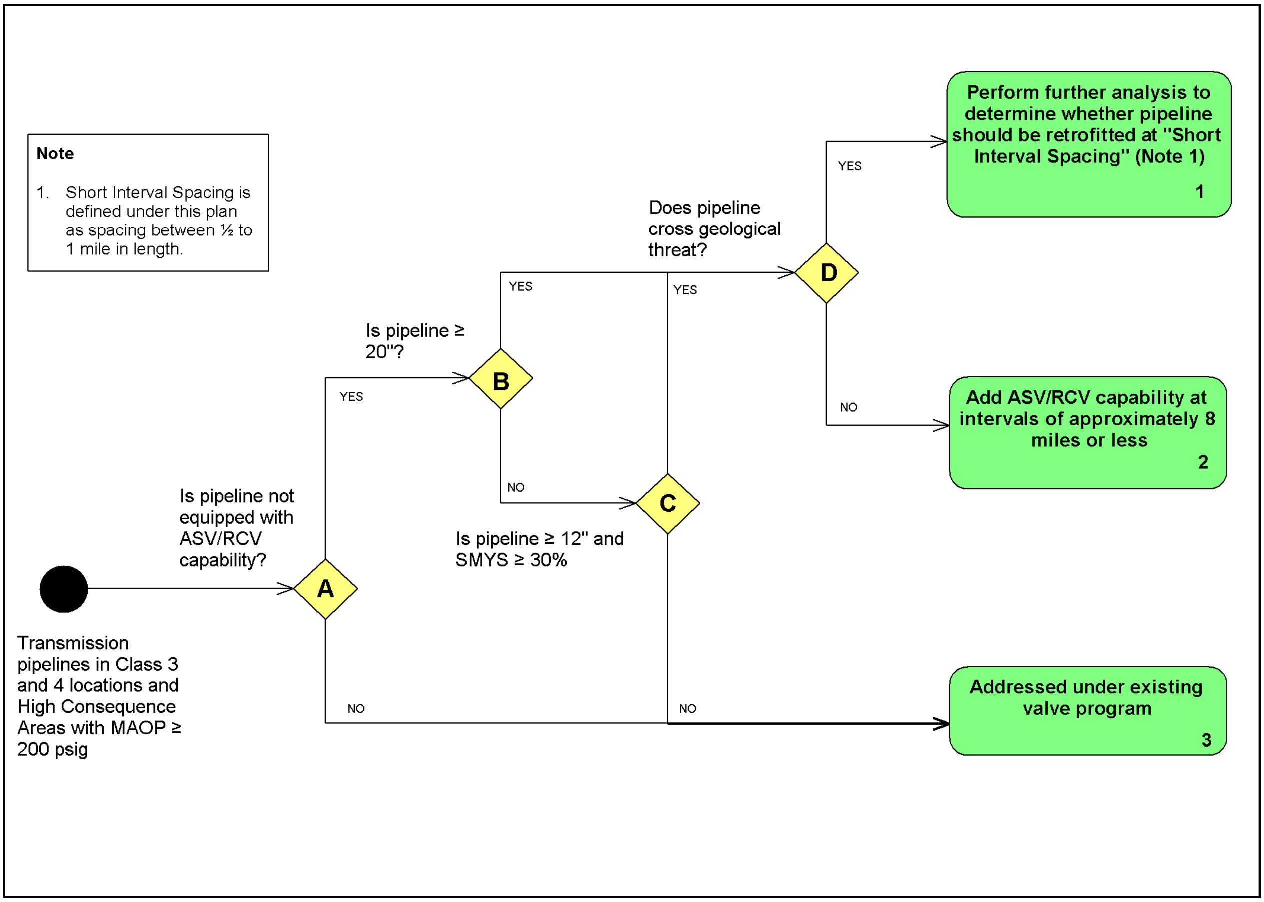
Pipeline segments that are less than twelve inches in diameter and/or are not operated at 30% or more of SMYS, are addressed under our existing valve program and are not identified for modification as part of this Valve Enhancement Plan.

3. Transmission Pipelines that Cross a Known Geological Threat

Pipelines that meet the above criteria for retrofitting under the Valve Enhancement Plan that also cross a known geological threat (*e.g.*, earthquake faults, landslide areas, washout areas and other potential geologic or man-made hazards) are identified for further analysis to determine whether the pipeline segment should be retrofitted at "Short Interval Spacing." Short Interval Spacing is defined under this plan as spacing between ½ and one mile in length. We propose to install ASV/RCV capability at Short Interval Spacing on no more than twenty pipeline segments. Consistent with the objectives of public safety enhancement and maximization of cost effectiveness, these twenty Short Interval Spacing segments will be selected based on the specific circumstances of the geological threat identified, the diameter of the pipeline and the potential impact radius.

Figure V-4 below illustrates the proposed evaluation process and installation criteria for the Valve Enhancement Plan.

Figure V-4
Evaluation Process for Transmission Pipeline Valve Safety Optimization



Preliminary plans to address pipeline segments using the above criteria are subject to change, as we continue to refine our engineering plans for pipeline replacements and/or retention of older pipelines based on forthcoming pressure test and internal inspections results. For example, if the MAOP of a pipeline segment is either increased or decreased as part of the execution of the testing and replacement process described in Section IV.D above, this may impact whether the pipeline segment satisfies the above criteria for enhancement.

When the installation of all valve work proposed in this plan is completed, we will have segmented 1,866 miles of pipe with 306 new ASV or RCV-equipped isolation sections at nominal six-mile intervals. This pipeline work will provide rapid isolation for 1,226 net miles of pipeline in Class 3 locations and High Consequence Areas. Table V-1 below summarizes the scope of work to be completed in Phase 1 under our proposed Valve Enhancement Plan.

Table V-1
Summary of Proposed Phase 1 Control Valve Work

Installation Type	SoCalGas	SDG&E	Total
Upgrade Existing Manual Control Valves to ASV/RCV	273	74	347
Upgrade Existing ASV with RCV Functionality	94	0	94
Upgrade Existing ASV with Communications only	100	0	100
Add New ASVs/RCVs to Pipeline System	20	0	20
Total Valve Sites Addressed	487	74	561

F. Proposed System Enhancements to Support Valve Enhancements

The proposed Valve Enhancement Plan is designed to ensure that sufficient information and control options will be provided to SoCalGas and SDG&E Gas Control Center and Operations personnel to support more timely and informed management decisions in the event of a confirmed (or suspected) pipeline rupture. In order to achieve this goal, supporting equipment and features must be installed as part of the Valve Enhancement Plan. Accordingly, as part of the Valve Enhancement Plan, SoCalGas and SDG&E propose to: (1) install metering stations to help further identify extraordinary flow patterns and track the results of actions taken to isolate a rupture while sustaining gas deliveries to customers; (2) implement system modifications to prevent backflow of gas from supply lines feeding ruptured gas transmission lines; (3) install meters at taps and pipeline interconnections to measure flow from transmission pipelines; (4) expand their existing SCADA system to support enhanced system management; and (5) expand the coverage area of private radio networks currently planned or employed by SoCalGas and SDG&E to assure a higher level of reliability in communications to valves and sensing devices used to support this proposed Valve Enhancement Plan.

1. Installation of Metering Stations to Support Valve Operations

SoCalGas and SDG&E currently measure gas flow at approximately thirty intermediary points (not including delivery or receipt locations) on approximately 4,000 miles of transmission pipeline to provide Gas Control personnel with information to manage system operations. As discussed above, SoCalGas and SDG&E anticipate encountering added risks of errant closures as a result of increasing the number of operational control valves (both RCV and ASV) on their transmission systems. Flow changes will be more dramatic and complex as valves are operated remotely, or in some instances close automatically to isolate pipeline ruptures. Proper management of the proposed 367 added transmission remote-control capable valve locations must be supplemented by expanded visibility into transmission system flows by Operations personnel. Accordingly, SoCalGas and SDG&E propose to provide their operators with twenty additional real-time flow measurement reference points along transmission pipelines to support pipeline system management.

2. Implementation of System Modifications to Prevent Backflow of Gas from Supply Lines Feeding Ruptured Gas Transmission Lines

The complexities of isolating and managing a section of ruptured transmission pipeline are greatly compounded when the pipeline section contains multiple supply and/or receipt points. As previously discussed, any transmission pipeline section isolation must eliminate significant sources of backflow and minimize service interruptions resulting from these supply point interconnections. This is of particular importance where large supply lines are designed to be fed from multiple transmission lines, or via multiple feeds (sometimes miles apart) from the same transmission pipeline.

To address backflow concerns, SoCalGas and SDG&E propose to retrofit 160 pipeline locations with one of three control features to prevent backflow in the event of a pipeline rupture: (1) regulator station pilot system controls to enable regulator stations directly tapped from the transmission pipeline to be shut in; (2) check valve and manual bypass for medium-sized pipelines where regulator modification is impractical or there is no regulator station serving the connected pipeline; or (3) RCVs serving taps or feeds where there is no regulator station to modify with controls, and where the pipelines are greater than ten inches in diameter and the supply line being served is also fed from another direction and/or normally served from both sides of a mainline valve via a "bridle assembly." Option 3 is the most complex and highest-cost solution, which is best employed at connection points where a transmission mainline valve is being upgraded with ASV/RCV controls and communications.

3. Installation of Meters at Taps and Pipeline Interconnections to Measure Flow from Transmission Pipelines

SoCalGas and SDG&E propose to install metering at their forty largest supply pipelines interconnected to major transmission pipelines. The information provided by these meters will support verification of a rupture event by operating personnel, its location, and its impacts on the various sections of transmission line.

4. Expansion of Existing SCADA System to Support Enhanced System Management

SoCalGas and SDG&E propose to provide for ASV/RCV features at 367 total valve locations on their pipeline system, and to provide Gas Control operators and field operations personnel with additional flow, pressure and valve status data in real-time to support effective management of this infrastructure. This requires considerable SCADA system expansion. Overall, SoCalGas and SDG&E estimate there will be over 9,000 new data fields associated with this system expansion – discreet pieces of information, such as pressure, valve position, rate of pressure drop, etc., that must be transmitted, received and managed by operators in near-real time.

5. Expansion of the Coverage Area of Private Radio Networks to Assure a Higher Level of Reliability

SoCalGas and SDG&E propose to expand the coverage area of private radio networks currently planned or employed to assure a higher level of communications system reliability. Private radio networks support valve operations by providing backup communication pathways in the event of an emergency and/or in the event of a loss of commercial communication networks. Overall 630 remote control and monitoring points will be served in some capacity by expanded radio system coverage by the time the proposed Valve Enhancement Plan is completed.

G. Prioritization and Schedule

The work proposed in the Valve Enhancement Plan will be prioritized based on five criteria: (1) highest potential energy of pipeline segment as represented by its potential impact radius; (2) active geological hazards such as earthquake fault crossings; (3) high density facilities, which may be difficult to evacuate under an emergency condition; (4) most expedient locations to retrofit because of few encumbrances; and (5) potential impact to customers (*e.g.*, some valve work may be reprioritized to later in the schedule or coordinated with other planned work to minimize the impacts to customers).

VI.

PROPOSED TECHNOLOGY ENHANCEMENTS

A. Introduction and Summary

SoCalGas and SDG&E have reviewed the scope of existing and emerging technologies and believe near-real-time monitoring of events and conditions along their pipelines using instrumentation can be effectively employed to provide advance warning of potential pipeline failures, as well as decrease the time for SoCalGas and SDG&E to identify, investigate, prevent and remedy/manage the effects of such events.

Historically, SoCalGas and SDG&E employed real-time monitoring of their transmission pipelines exclusively where such activity was directly associated with pipeline operation and the control of gas flow therein—classic SCADA operations. SoCalGas and SDG&E believe monitoring events and pipeline system status for purposes of safety enhancement, as opposed to solely for operational purposes, can provide added value in the management of the integrity of their pipeline assets.

Accordingly, SoCalGas and SDG&E propose to install fiber optic cabling and methane detection instruments over a ten-year period.

B. Proposal to Install Fiber Optic Right-of-Way Monitors

Fiber optic right-of-way monitors will help SoCalGas and SDG&E identify when intrusions into their pipeline rights-of-way have occurred or when a pipeline (or right-of-way) has experienced movement that might pose a threat to pipeline structural integrity. Advancement in fiber optic signature analysis now allows an operator to pinpoint to within several feet when a direct buried (twelve to eighteen inches above the pipeline) fiber cable has been disturbed or otherwise has picked up abnormal vibrations (or is severed) from right-of-way activity, such as by construction crews working in an area, or when a sizeable pipeline leak occurs. This signature interpretation can be used to monitor pipeline right-of-way activity in real-time and help drive decisions to send operational crews to investigate when a suspected incident has occurred that might, acutely or with some latency, pose a risk to a pipeline's structural integrity. SoCalGas and SDG&E propose to install about 280 miles of fiber optic technology in association with pipeline replacements during Phase 1. SoCalGas and SDG&E will install permanent monitoring stations as each contiguous pipeline section equipped with fiber optics reaches five miles in length.

Although fiber optic technology can be used to enhance the safety of a pipeline system, it is not cost-effective to install fiber technology on pipelines that are already buried and in service in congested areas. Installation of fiber optic technology is cost-effective, however, when the pipeline is already exposed, as during new construction or rehabilitation. Accordingly, SoCalGas and SDG&E propose to install fiber optic technology on all pipelines twelve inches in diameter and larger that will be exposed for testing or repairs and on new pipelines twelve inches in diameter and larger to be constructed as part of the proposed Pipeline Safety Enhancement Plan. In addition, any new pipelines constructed by SoCalGas and SDG&E that are twelve inches or larger in diameter, and that are not part of the Proposed Pipeline Safety Enhancement Plan, will also be fitted with fiber optic sensing in the future.[58]

In light of the high costs associated with retrofitting in-service pipelines with fiber optic technology, SoCalGas and SDG&E are closely following the development of other technologies that may potentially monitor legacy pipelines located in heavily congested rights-of-way in the future. A few of these emerging technologies center around acoustic monitoring of pipelines (essentially listening to pipelines) with geophones or hydrophones to determine if a rupture or impact event has occurred. While no cost for this technology is requested in this filing, SoCalGas and SDG&E will continue to evaluate these emerging technologies and may request funding for such enhancements in a future General Rate Case or in another appropriate Commission forum. The radio and information technology systems infrastructure enhancements proposed in Section D below will be designed to support such future deployment of emerging technologies with little to no incremental capital cost beyond the field systems themselves.

C. <u>Proposal to Install Methane Detection Monitors</u>

The safety of the SoCalGas/SDG&E system may be further enhanced through the addition of real-time pipeline right-of-way gas detection monitors near facilities that are high-occupancy

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58 The scope and associated costs for those future additions (unknown) are not included in this proposed Pipeline Safety Enhancement Plan, but will be requested as part of the normal rate case process.

and pose evacuation challenges, particularly where those facilities are located within 220 yards[59] of a high-pressure, large-diameter gas transmission pipeline. The methane sensors proposed to be deployed will be capable of reliably detecting gas/air concentration levels approximately ¼ or less of what is typically detected by the human sense of smell of the odorant. More timely identification of gas leaks will support the dispatch of operations personnel to specific locations along the pipeline system when methane is detected. SoCalGas and SDG&E have identified approximately 2,100 general locations that fit this proposed criterion for installing methane detection devices.

While the cost for reliable and accurate methane sensors for continuous use are considerable, SoCalGas and SDG&E continue to monitor market development of this technology to identify lower-cost, mass-produced methane detection devices that might meet their technical, accuracy and reliability objectives in the future. The Pipeline Information Monitoring System proposed below is designed to be able to incorporate information and alarms from any future devices with little incremental capital costs, other than the field installation expenditures.

D. Proposal to Develop a Pipeline Infrastructure Monitoring Data Collection and Management System to Support Field Monitoring Sensors

SoCalGas and SDG&E propose to develop a new data collection, storage, alarm-processing and data management system to collect information from the field monitoring sensors described above. The proposed data collection and management system (DCMS) will serve both SoCalGas and SDG&E and will serve several functions. Several of the key benefits and functions to be provided by the proposed DCMS are as follows: First, the DCMS will provide periodic (at minimum daily) health/status monitoring of all fiber optic and methane detection monitors by way of daily status reporting and remote data collection. Second, the DCMS will receive alarm information initiated by any fiber optic or methane detection monitor with a latency of less than two minutes. Third, the DCMS will report alarms to appropriate dispatch personnel for review, call-out and resolution, as required. Fourth, the DCMS will track alarm

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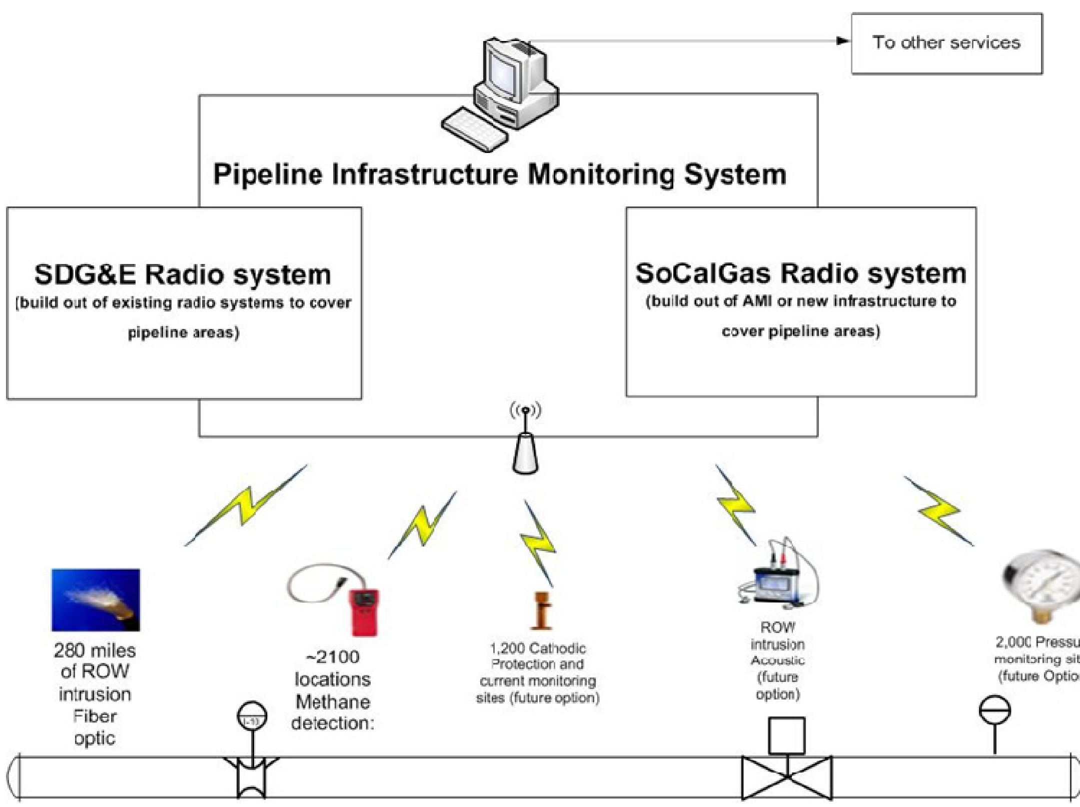
59 This 220-yard figure is based on class location distances set forth in 49 CFR 192.5.

acknowledgement and status. Fifth, the DCMS will provide permanent storage of all events with appropriate time and date stamping of events. Sixth, the DCMS will provide system-wide viewing of current alarm information to help field and operations personnel reconcile fiber optic and methane detection monitor information with SCADA and other field observations during an emergency situation. Seventh, the DCMS will accommodate future expansion to 10,000 monitoring points and multiple sensor types, including remote Cathodic Protection, acoustic monitoring and pressure alarm. Finally, the DCMS will provide for export/routing of information to support near real-time graphical viewing presentation of alarms on SoCalGas/SDG&E mapping products and provide connectivity with automated customer notification systems.

An overview of the proposed radio system expansion to support field monitor data collection is provided in Figure VI-1 below.

Figure VI-1
Overview of Proposed Radio System Expansion



SoCalGas and SDG&E envision using the Advanced Metering Infrastructure and Smart metering Radio System expansions proposed under the Valve Enhancement Plan to support data gathering from the fiber optic cable and methane detection sensors. The Radio system build-outs to support SCADA back-up capability and polling of latent pipeline information will provide adequate coverage for all Pipeline Infrastructure Monitoring sensors to be polled.

VII.

PROPOSAL TO DESIGN A COMPREHENSIVE ENTERPRISE ASSET MANAGEMENT SYSTEM

The Commission's decision directing the filing of proposed implementation plans states that at the end of the implementation period, each pipeline operator will have their transmission pipeline records "readily available."[60] SoCalGas and SDG&E support the Commission's goal of having pipeline data readily accessible. While the data required to operate and maintain the SoCalGas/SDG&E natural gas transmission pipeline system are currently readily available, supporting data (meta data) and documents, which are often paper records, are not readily available. Existing systems for storing and accessing data, which have evolved over time, are not integrated and are often in different formats. To have all such data, and supporting data, integrated and readily available, various data repositories, including maintenance and inspection systems, geographical information systems, purchasing systems, and paper records must be connected, and interrelated. Accordingly, SoCalGas and SDG&E propose to design and develop a comprehensive Enterprise Asset Management System as an integral part of their Pipeline Safety Enhancement Plan.

1. Background

SoCalGas and SDG&E maintain many types of pipeline-related data, which fall into two broad categories: (1) Asset Data; and (2) Inspection, Maintenance and Operating Data. Asset Data is information about a physical pipeline—size, wall thickness coating, valve information, other pipeline equipment related information. Asset Data also includes initial manufacturing information, construction information, and testing information. Inspection, Maintenance and Operating Data are records about the inspections that have occurred on the assets and any planned or unplanned maintenance and operation of the system. Inspection Data includes such information as results of internal line inspection devices. Maintenance Data includes information

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60 D.11-06-017, p. 9.

such as the history of maintenance of regulation and control systems. Operating Data includes information such as operating pressure history.

All the above data reside in numerous files and databases. Although some files are electronic, others are in paper form. Electronic files tend to be those that record information generated after computers became prevalent in the 1980s, for example, post-1980 inspection and maintenance records. Paper files tend be those created prior to the 1980s, such as construction and material records for pipelines built prior to the 1980s. An obvious advantage of electronic files is speed of recovery of the information. There are other notable advantages such as prevention of deterioration of the original documents, ability to store huge amounts of information in a much smaller space (computer hard drive), and easy duplication and transmittal of the data.

Once our proposed Pipeline Safety Enhancement Plan is approved by the Commission, we will undertake a large volume of construction and testing work to comply with the Commission's directives. This large volume of construction and maintenance activities will span many years and generate large volumes of additional pipeline infrastructure data. This presents an opportunity to utilize leading records management practices to capture this new information and to integrate existing records and information into the new systems. Moreover, even with all that has been done up to this point regarding converting data into electronic format and developing systems to retrieve and display this information, there is more that can be done. Accordingly, SoCalGas and SDG&E propose to design a comprehensive Enterprise Asset Management System as an integral part of their Pipeline Safety Enhancement Plan to:

1) Enable SoCalGas and SDG&E to efficiently and effectively manage the increased volume of pipeline work and associated records driven by the Pipeline Safety Enhancement Program;
2) Provide SoCalGas and SDG&E personnel with secure anytime, anywhere access to integrated critical pipeline information and associated data capture, reporting and analysis tools;

3) Enhance existing records and data governance practices by embedding these practices and controls into the Enterprise Asset Management System and applications; and
4) Provide enhanced pipeline data analytics to support continuous improvement of SoCalGas and SDG&E's pipeline integrity and safety programs.

2. <u>Development of the Enterprise Asset Management System</u>

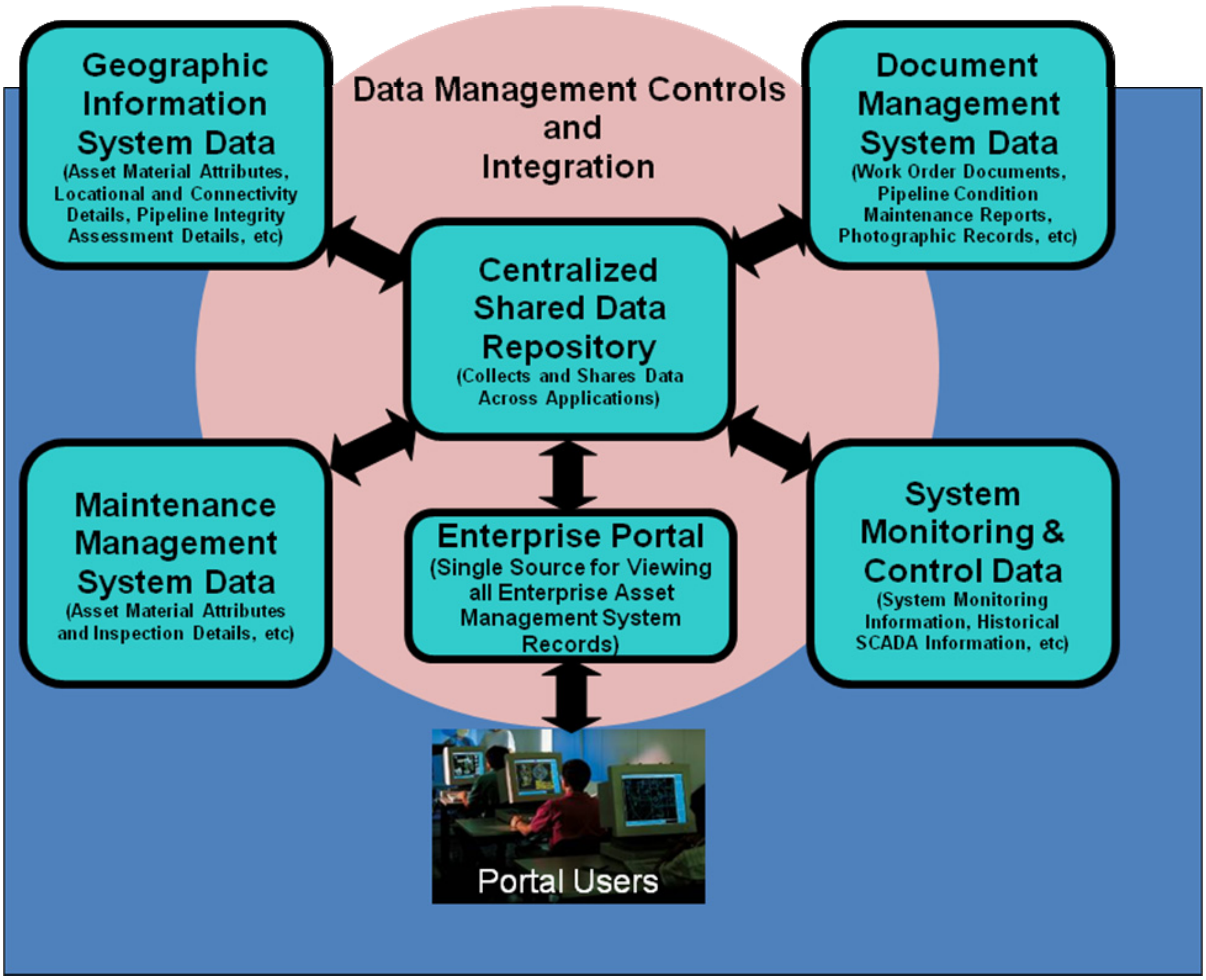
The Enterprise Asset Management System will focus on applying industry leading records management practices and information technology solutions to govern, record, store, secure, maintain, access, search and analyze transmission pipeline system data. The system will support leading records and data governance practices and controls; ensure the validity, traceability and completeness of pipeline data; and provide SoCalGas and SDG&E personnel with secure anytime, anywhere access to critical pipeline system data.

Leading records management solutions start with strong data governance and control practices that are embedded into business policies, training programs, processes and supporting information management systems. Leading data governance and controls will be embedded into the Enterprise Asset Management System. A governance blueprint incorporating leading Enterprise Asset Management System practices will be developed as an initial program step. The blueprint will also identify master data record sources, data ownership, data management processes and accountabilities within SoCalGas' and SDG&E's organization. This governance framework will ensure the Enterprise Asset Management System enhances traceability, completeness and the overall integrity of SoCalGas and SDG&E pipeline records and information throughout their life-cycle.

Pipeline records and information to be addressed under this system include system planning, construction inspection, maintenance, compliance and operating records. These records and information include both spatial (Geographic Information System or "GIS") and digital data, which will be managed throughout the life-cycle of the pipeline infrastructure that they are associated with. Existing paper records will be converted to digital format and records in those systems being replaced will be migrated into the new Enterprise Asset Management System.

Figure VII-1 below illustrates how the Enterprise Asset Management System will integrate information and data stored in various systems throughout each company.

Figure VII-1
Overview of Enterprise Asset Management System



The proposed Enterprise Asset Management System will provide SoCalGas and SDG&E personnel with secure, remote, anytime, anywhere access to critical pipeline information through a web portal using a variety of mobile computing devices. Spatial and digital pipeline data from multiple applications and databases will be capable of being accessed through the portal application. Enhanced pipeline information search and navigation capabilities will be incorporated into the portal. The system will also support improved data capture in the field to improve data accuracy, traceability and completeness.

An Enterprise Asset Management System will also improve the efficiency of completing complex data analytics and modeling required for pipeline system integrity risk and threat assessments and development of potential mitigation plans or programs. Examples of these complex analytical tasks include:

- Performing risk assessments that incorporate pipeline design, condition, operating and land use statistics into the analysis process.
- Analyzing the maintenance history of a specific item of equipment or material that is installed in pipeline assets throughout the SoCalGas and SDG&E transmission systems.
- Developing a remediation plan for a specific item of purchased equipment or material that is affected by a manufacturer's recall or safety notice.
- Developing and executing scenario-based emergency response plans that incorporate pipeline and valve station locations as well as the configuration and operating instructions for specific valves or valve types.

Enhanced data analytic capabilities will enable SoCalGas and SDG&E personnel to continuously assess and improve the Pipeline Safety Enhancement Plan.

3. Approach and Schedule

SoCalGas and SDG&E propose to develop the detailed architecture and design of the Enterprise Asset Management System over the next six to twelve months. The program will begin with a blueprint planning phase and build from the work that has been proposed in our 2012 General Rate Case Applications. During this phase, Enterprise Asset Management System objectives and guiding principles will be finalized; records and information management governance policies and procedures will be refined and reinforced; organizational roles and responsibilities related to records and information management will be updated; and the records and information management master data model will be updated. The output from this phase will form the basis for a proposed Enterprise Asset Management System to be submitted for approval by the Commission in a subsequent filing.

VIII.

EXECUTION OF THE PROPOSED PIPELINE SAFETY ENHANCEMENT PLAN

A. Key Elements of the Execution Plan

The Implementation Plan consists of a mixture of small, intermediate, and large scale projects, which will take varying lengths of time to complete. Although the actual construction period is typically one to six months, the project planning, permitting, and contractor bid and selection process takes 24 to 36 months for an intermediate project, assuming no significant ministerial or environmental permit delays. The significant number of additional projects required to implement this plan will have a major impact on the need and availability of internal and external resources for successful execution.

1. Project Planning and Scheduling

The proposed implementation plan contains an aggressive list of potential safety enhancement pipeline projects. The planning and scheduling of these projects can be significantly impacted by outside issues such as permits, material availability, gas system capacity/scheduling and public resistance. These potential delays and impacts are difficult to predict and plan for. The following general planning and scheduling guidelines are offered as a normal anticipated project schedule assuming normal routine conditions. The vast majority of the implementation plan projects fall into the small and intermediate scale project planning and scheduling life cycles described below.

The number, varying lengths, locations and impacted jurisdictional permit agencies for the types of replacement and pressure testing projects being proposed can be described in the following very generic planning and scheduling terms. The fact each project is subject to specific individual circumstances, stakeholders and logistical issues, no matter the "size," can make even what appears to be a small simple project, considerably more complex to execute effectively while mitigating all stakeholder concerns. Pressure testing of large capacity transmission piping for example, can have a significant impact on the gas delivery system. The associated reduction in system availability and capacity is impacted while piping is deactivated and removed from service for several days, or weeks, as preparation and testing takes place. The pressure testing schedule is further complicated due to system availability as this work may be confined to off peak delivery shoulder months for completion when system capacity demands are not as critical for customer reliability.

In general, a small-scale project will be described as relatively simple, with minimal or no customer/stakeholder impacts, generally smaller-diameter pipe, shorter length (less than 1,000 linear feet) of pipe replacement, a valve retrofit, or a short pressure test section. A small-scale project management schedule would proceed through a three to six month project life cycle. Detailed planning and design would identify the materials and permits required to complete the project. Logistical concerns for project construction location, or locations, are identified, such as water fill source, storage tank needs, de-water locations and potential traffic control plans identified. The permit drawing package would be developed and submitted to the appropriate agency for review and approvals. Necessary materials would be concurrently procured while permit submittal, review and approval are obtained. Any specific traffic control plan needs will be addressed. When Agency permits and work conditions are received, the project "Request for Proposal" bid package is developed and sent to pre-qualified contractors for submittal of project bid proposals. Project proposals are evaluated and the project awarded. This type of project would typically experience a one to four week construction schedule with the completed replacement pipe, or tested pipe, being placed into service. This schedule should be considered a "best case" project life cycle schedule and duration for smaller, simpler and less obtrusive projects.

In general, the intermediate scale project would be described as more complex, due to customer or stakeholder impacts, larger diameter pipe, and longer-length (1,000 linear feet to five linear miles) of pipe replacement or pressure test length. The intermediate size project management schedule would typically proceed through a 6- to 36-month project life cycle. Generally, the pressure test project would fall into the shorter end of this life cycle and the replacement pipe project will require more time. The detailed planning, design and execution will follow the same general path as outlined above with the small scale project with additional time required for all of the larger scale associated project coordination activities. The larger diameter, longer length and more obtrusive nature of these projects require longer lead times to develop detailed design, routing and project logistics. Material procurement lead times for the larger pipe, valves and fittings are increased. Agency permit reviews become much more critical and time consuming as stakeholder concerns and community impacts are mitigated. Customer and gas delivery system impacts are increased and require significantly more coordination and resolution. The construction execution of this project will generally fall between one and six months in length. Agency Encroachment Permit work conditions and requirements have a significant impact on construction timing and cost for these projects. Typical Encroachment Permit conditions require night work with restricted work hours of 9:00 AM through 2:00 PM to address traffic issues. Also, slurry backfill and/or significant paving requirements all have a major impact on construction timing delays and additional construction costs. This general schedule should be considered a "best case" project life cycle for these intermediate scale projects.

In general, the large scale project described will be the most complex, i.e., larger diameter pipe, longest length (five to fifty linear miles) of replacement pipe or new pipe installation. These large-scale projects will have the longest project management life cycle, three to five or more years, and may be completed in multiple "phases" or "sections." The size of these projects will also increase the expected risks associated with permit delays, stakeholder opposition and community impacts. The initial detailed planning, routing, material procurement and design will target to complete five to fifteen miles in the first two to three years, as outlined with the intermediate project schedule above. Additional "phases" or "sections" of ten miles or more will be constructed each subsequent year until overall project completion. The on-going project "phase" or "section" installation target footage is dependent upon logistical planning issues such as permitting constraints, material availability and logical segment break points based on agency jurisdiction and our existing system tie-in points. These projects will be the most obtrusive and potentially volatile projects to the impacted stakeholders with considerable delays and costs incurred as project issues are mitigated and resolved.

2. Project Management

Due to the size, scale, and complexity of the Pipeline Safety Enhancement Plan, SoCalGas and SDG&E plan to execute the plan under the framework of a Project Management Organization (the PSEP PMO). The PSEP PMO will be a separate organization comprised of a group of staff dedicated solely to execution of the Pipeline Safety Enhancement Plan. The PSEP PMO will be comprised of internal SoCalGas and SDG&E personnel, who will reside in a dedicated task force area, and will be supplemented by external engineering companies, consultants, and construction contractors. The primary objectives of the PSEP PMO will be to assure compliance with Commission requirements and assume responsibility for overall plan integration, execution of scope, schedule, budget, performance monitoring and reporting, contract administration, financial controls and corporate and regulatory compliance. The PSEP PMO will develop and implement procedures to ensure that the PSEP is executed safely and to the required level of quality in engineering, supply of materials, and in construction. Additionally, the PSEP PMO will institute disciplined project controls procedures for estimating, cost control, and planning/scheduling to assure that costs (actual and forecast) and schedules are continuously updated and given critical analysis to facilitate accurate project reporting.

The PSEP PMO will be a critical focal point for the execution of the Pipeline Safety Enhancement Plan. Some of the functions and specific responsibilities within the PSEP PMO are described as follows:

1. Project Management. Development and management of the overall scope, schedule, budget, execution plan, and resources.
2. Engineering. Development of engineering and design work for the various aspects of the Pipeline Safety Enhancement Plan, including the establishment of project cost controls and reporting, and the evaluation of alternatives and cost effectiveness in design. Establish protocols to manage the estimating, cost control, and planning/scheduling functions. This includes assuring consistency in reporting among the various projects that will be executed simultaneously and the ability to roll-up and produce consolidated reporting.

3. Supply Management. Develop the procurement and contract strategies and procedures, approved bidder lists, procurement and contracting policies, expediting, quality assurance/quality control, and logistics activities.
4. Environmental. Develop the environmental permit strategies and plan and manage the environmental activities through the permitting phase and construction.
5. Construction Management. Development of construction execution strategy and plan and management of all aspects of field construction including construction progress, cost, and inspection activities.
6. Operations. Dedicated operations teams in each of the regions will be responsible for the planning of some of the project work, gas handling and tie-in procedures, outage scheduling, tie-in surveillance, construction surveillance, and reporting.
7. Customer and Public Outreach. Development and management of public and customer outreach programs including press releases, scheduling town hall, customer and public meetings, mailings, advertisements, notifications, websites and other activities.

Although not necessarily dedicated to the PSEP PMO, support from other functions within SoCalGas and SDG&E such as legal, regulatory, land and right-of-way, finance, information technology, and human resources will be required to execute the Pipeline Safety Enhancement Plan.

3. Material and Construction Quality Assurance and Control

The critical materials required to successfully implement our proposed safety enhancements would follow the current rigorous material specification and quality assurance program currently being followed by SoCalGas and SDG&E. The companies' current material specifications for critical components, such as valves, pipe and fittings, ensure that procured materials meet all regulatory requirements and other applicable requirements and guidelines. These applicable material specifications are included in our general requirements for each project and provided to any and all potential manufacturers and/or suppliers. Documentation affirming that a material component meets our strict material specifications is required from the manufacturer and supplier and is included and maintained with the material component purchase records.

Critical material components can only be procured from approved manufacturers, suppliers and vendors. These critical material providers are pre-screened and approved through our quality assurance assessment process. This quality assessment process includes physical on-site evaluation of raw material selection, manufacturing process, and quality control for the specific manufacturer, vendor or supplier facility.

We also ensure the material quality assurance process with an aggressive material and component inspection process. Critical materials and components are physically inspected at critical points during the manufacture and delivery process to visually verify the material components, workmanship and product quality meet our strict specifications.

We have existing policies and procedures in place to address and ensure the quality of the construction of, and fitness for purpose of, the activities and facilities proposed in the Pipeline Safety Enhancement Plan. We will use existing and proven construction management techniques, along with on-site Company representatives, which have previously demonstrated the ability to effectively and safely provide construction over sight activities required to ensure the Pipeline Safety Enhancement Plan facility improvement construction quality. These Pipeline Safety Enhancement Plan projects will receive full time construction inspection and oversight to ensure these facility enhancements are constructed and tested in compliance with our rigorous standards, policies and regulatory requirements.

4. <u>Contractor Approval and Selection</u>

Contractors for this work will be selected according to existing company policies and procedures that govern the contractor selection process for pipeline work of this nature. Consistent with existing policies, for the types of valve retrofit, pipe installation and pressure testing being proposed, SoCalGas and SDG&E will utilize pre-approved contractors who have demonstrated the ability to successfully complete such projects. Our contractor approval process involves the complete review of the contractor's demonstrated ability, expertise, equipment, facilities and financial backing to complete and appropriately warranty the types of construction projects the contractor will be approved to engage in on behalf of the company. We also have an ongoing contractor performance review process used to document, address and correct contractor performance deficiencies experienced over time.

5. Company Labor Qualifications

SoCalGas and SDG&E employees will be actively engaged as an integral part of the Pipeline Safety Enhancement Plan activities and facility improvements. We have extensive existing policies, gas standards, procedures and training programs, which address the qualifications and quality of work required of and provided by our internal labor forces. Company labor resources will be subject to these extensive policies, training requirements and operator qualifications to ensure Pipeline Safety Enhancement Plan activities are completed with the high level of skill, quality and compliance needed to ensure the continued safety of our gas delivery system.

6. Supplier Diversity

We plan to extend our highly successful Diverse Business Enterprises (DBE) practices to implement the Pipeline Safety Enhancement Plan. SoCalGas and SDG&E will employ the proven model used to develop supplier capacity in traditionally challenging areas to improve Pipeline Safety Enhancement Plan DBE involvement. SoCalGas and SDG&E will:

1. Determine the technical certifications and other safety requirements needed to perform the various work activities;
2. Hold a series of technical assistance meetings with the existing DBE supplier base currently engaged in other pipeline construction activities to explain requirements;
3. Determine which existing suppliers are ready (from a certification and training perspective) for prime and subcontractor roles to support execution of the Pipeline Safety Enhancement Plan;
4. Collaborate with business organizations, Community-Based Organizations and local and national minority supplier developments councils to identify new potential suppliers to attend similar technical assistance meetings to explain requirements;

5. Partner with experienced transmission line prime contractors to hold project-specific matchmaking events to develop subcontracting network;
6. Establish an overall DBE spending percentage aspiration specific to implementation of the Pipeline Safety Enhancement Plan and adjust that percentage annually as implementation of the plan moves forward;
7. Include the spending aspiration in the performance plans of every employee involved with implementing the Pipeline Safety Enhancement Plan with procurement responsibilities at all levels of management;
8. Include the spending aspiration in every new contract developed with prime suppliers;
9. Hold semi-annual meetings with potential suppliers to review upcoming competitive bid opportunities related to the Pipeline Safety Enhancement Plan;
10. Devote a portion of the DBE Technical Assistance budget to educate suppliers on the Pipeline Safety Enhancement Plan related business opportunities and how to work with SoCalGas and SDG&E and their procurement processes.
11. Include a Pipeline Safety Enhancement Plan component to all other DBE matchmaking events held with larger prime majority suppliers.

IX.

COST ESTIMATES

A. Overview and Summary

As described in the Chapters above, SoCalGas and SDG&E seek approval of their "Proposed Case" Pipeline Safety Enhancement Plan, which includes a plan to test or replace pipeline segments that do not have sufficient documentation of pressure testing to meet the requirements set forth in D.11-06-017, a plan to replace pipeline segments that contain pre-1946 construction and fabrication techniques, interim safety enhancement measures, which have already been implemented, a plan to in-line inspect (ILI) piggable pipelines, a Valve Enhancement Plan to install additional ASV/RCV capability on larger-diameter, higher-pressure transmission pipeline segments, proposed technology enhancements to detect third-party damage and provide earlier leak-detection capability, and a proposal to design a comprehensive Enterprise Asset Management System to ensure that all pipeline-related documentation is integrated and readily available.

All costs indicated in this Chapter are direct costs (in 2011 unloaded dollars). The cost projections are based on full approval of the Phase 1A scope in the first quarter of 2012. The cost estimates are "all-inclusive" and include construction labor and materials, third-party engineering, procurement, construction management and consultant costs, and internal company costs. Internal company costs include, but are not limited to, internal labor costs such as those mentioned in section VIII.A.2, office space for the PSEP PMO, public and customer communication and outreach costs, information technology infrastructure for the PSEP PMO, vehicles for incremental operations personnel, warehousing space for materials, and operations tools and equipment. Cost estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning. As described in the chapters above, the Phase 1A schedule is very aggressive, and subject to potential execution challenges that could impact costs.

The capital cost estimate for the Proposed Case Pipeline Safety Enhancement Plan for Phase 1A is $1.2 billion for SoCalGas and $229 million for SDG&E. The O&M cost estimate for the Proposed Case Pipeline Safety Enhancement Plan for Phase 1A is $256 million for SoCalGas and $7 million for SDG&E. The overall Phase 1 cost summaries for the Proposed Case Pipeline Safety Enhancement Plan are shown by element and year in Table IX-1 for SoCalGas and Table IX-2 for SDG&E. A more detailed Capital and O&M cost forecast for the Proposed Case Pipeline Safety Enhancement Plan for Phase 1 is provided in Appendix B.

Table IX-1
SoCalGas Estimated Phase 1 Pipeline Safety Enhancement Plan Proposed Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	183	-	-
Pipe Replacement	-	818	-	-	-
In-Line Inspection	-	-	58	-	-
Interim Safety Enhancements	6	-	5	-	-
Remote Control & Automatic Shutoff Valves	-	121	2	180	12
Implementation Costs	-	-	< 1	-	-
Mitigation of Pre-1946 Construction Methods	-	200	-	884	-
Technology Enhancements	-	45	2	12	5
Enterprise Asset Management System	-	-	6	-	-
Total	$6	$1,184	$256	$1,076	$17

Table IX-2[61]

SDG&E Estimated Phase 1 Pipeline Safety Enhancement Plan Proposed Case Costs

(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	< 1	-	10
Pipe Replacement	-	197	-	318	-
In-Line Inspection	-	-	4	-	-
Interim Safety Enhancements	1	-	< 1	-	-
Remote Control & Automatic Shutoff Valves	-	26	1	35	2
Implementation Costs	-	-	< 1	-	-
Mitigation of Pre-1946 Construction Methods	-	-	-	-	-
Technology Enhancements	-	6	< 1	2	1
Enterprise Asset Management System	-	-	< 1	-	-
Total	$1	$229	$7	$354	$13

For comparison purposes, SoCalGas and SDG&E also provide "Base Case" estimated costs for the work required under D.11-06-017, without the additional safety enhancing elements proposed by SoCalGas and SDG&E that are not required under D.11-06-017. Specifically, the Base Case includes costs associated with a plan to test or replace pipeline segments that do not have sufficient documentation of pressure testing to meet the requirements set forth in D.11-06-017, proposed interim safety enhancement measures, a plan to in-line inspect (ILI) piggable pipelines, and a Valve Enhancement Plan to install additional ASV/RCV capability on larger-diameter, higher-pressure transmission pipeline segments. The Base Case does not include costs associated with the replacement of pipeline segments to mitigate pre-1946 construction and manufacturing methods, costs associated with proposed technology enhancements, or costs associated with the development and design of an Enterprise Asset Management System.

61 Numbers made not add due to rounding.

The forecast total capital cost for the Base Case Pipeline Safety Enhancement for Phase 1A is $939 million for SoCalGas and $223 million for SDG&E. The forecast total O&M cost for the Base Case Pipeline Safety Enhancement Plan for Phase 1A is $247 million for SoCalGas and $6 million for SDG&E. The total estimated investment required to complete Phase 1 for the Base Case is summarized in Table IX-3 for SoCalGas and in Table IX-4 for SDG&E. A more detailed Capital and O&M cost forecast for the Base Case for Phase 1 is provided in Appendix C.

Table IX-3[62]
SoCalGas Estimated Phase 1 Pipeline Safety Enhancement Plan Base Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	183	-	-
Pipe Replacements	-	818	-	-	-
In-Line Inspections	-	-	58	-	-
Interim Safety Enhancements	6	-	5	-	-
Remote Control & Automatic Shutoff Valves	-	121	2	180	12
Implementation Costs	-	-	< 1	-	-
Total	$6	$939	$247	$180	$12

Table IX-4
SDG&E Estimated Phase 1 Pipeline Safety Enhancement Plan Base Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	< 1	-	10
Pipe Replacements	-	197	-	318	-
In-Line Inspections	-	-	4	-	-
Interim Safety Enhancements	1	-	<1	-	-
Remote Control & Automatic Shutoff Valves	-	26	1	35	2
Implementation Costs	-	-	< 1	-	-
Total	$1	$223	$6	$353	$12

B. Phase 1 Base Case Cost Estimates

1. Estimated Costs to Test or Replace Pipeline Segments

62 Numbers may not add due to rounding.

a) Pressure Testing

Both the Proposed Case Pipeline Safety Enhancement Plan and the Base Case include estimated costs for SoCalGas and SDG&E to pressure test 206 miles of transmission pipeline segments located in Class 3 and 4 locations or High Consequence Areas. SoCalGas and SDG&E utilized the assistance of a third party engineering firm, System Planning Engineering and Consulting Services (SPEC Services), to develop the cost estimates for pressure testing. These estimates include the costs for pressure testing not only these 206 miles of pipe, but also mileage associated with those segments that similarly lack sufficient documentation of pressure testing, but are located in Class 1 and 2 non-High Consequence Areas. These associated miles, which would otherwise be addressed in Phase 2, were included within the scope of Phase 1 to maximize the cost effectiveness and minimize the impacts to customers of execution of the proposed Pipeline Safety Enhancement Plan. In addition, a small number of other segments were included, as necessary, to facilitate continuity of the testing. In total, 407 miles of transmission pipeline will be pressure tested in Phase 1 at a cost of $194 million. Table IX-5 below summarizes the scope of pressure testing work to be completed in Phase 1.

Table IX-6 below summarizes the O&M costs associated with the execution of this pressure testing work.

Table IX-5
Phase 1 Pressure Test Mileage

	Criteria Miles	Accelerated Miles	Total
SoCalGas	176	185	361
SDG&E	30	16	46
Total	206	201	407

***Table IX-6*[63]**
Phase 1 Pressure Test O&M Costs
(In Millions of Dollars)

	Phase 1A				Phase 1B						
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas	37	49	49	49	-	-	-	-	-	-	$183
SDG&E	0	0	0	0	-	-	-	10	-	-	$11
Total	37	49	49	49	-	-	-	10	-	-	$194

Pressure testing cost estimates were developed based on proposed pressure test mileage and certain pipeline system data, such as pipeline diameter, provided by SoCalGas and SDG&E to SPEC Services for each pipeline segment contained within the proposed scope of work. Estimating factors include segment size, pipeline profile, water supply, equipment, personnel, materials, etc. See Appendix D for a more detailed description of the pressure testing cost estimating methodology and assumptions.

b) Pipeline Replacement

Both the Base Case and the Proposed Case Pipeline Safety Enhancement Plan require SoCalGas and SDG&E to replace approximately 156 miles of pipeline segments located in Class 3 and 4 locations or High Consequence Areas. SoCalGas and SDG&E utilized the assistance of SPEC Services to develop the cost estimates for pipeline replacements. These estimates assume replacement of not only these 156 miles of pipeline, but also mileage associated with those segments, similarly lacking sufficient documentation of pressure test records, in Class 1 and 2 non-High Consequence Areas. These associated miles, which would otherwise be addressed in Phase 2, were included within the scope of Phase 1 to maximize the cost effectiveness and minimize the impacts to customers of execution of the proposed Pipeline Safety Enhancement Plan. A small number of other segments were included, as necessary, to facilitate continuity in construction. In total, 348 miles of transmission pipeline will be replaced in Phase 1 at a cost of $1,333 million. Table IX-7 below summarizes the scope of pipeline replacement construction to be completed in Phase 1.

63 Numbers may not add due to rounding.

Table IX-8 below summarizes the Capital costs associated with the execution of this pipeline replacement work.

Table IX-7[64]
Phase 1 Transmission Pipeline New Construction Summary

	Criteria Miles	Accelerated Miles	Total Cost
SoCalGas	128	118	$818 million
SDG&E	28	74	$515 million
Total	156	192	$1,333 million

Table IX-8[65]
Phase 1 Transmission Pipeline New Construction Capital Cost Summary
(In Millions of Dollars)

	Phase 1A				Phase 1B						
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas	90	243	243	243	-	-	-	-	-	-	$818
SDG&E	23	58	58	58	106	106	106	-	-	-	$515
Total	113	301	301	301	106	106	106	-	-	-	$1,333

Replacement cost estimates were developed based on proposed replacement mileage and certain pipeline system data, such as operating pressure and diameter, provided by SoCalGas to SPEC Services for each pipeline contained within the proposed scope of work. GIS Maps of each pipeline were studied to identify the location and type of construction applicable for each relocation area. See Appendix E for pipeline replacement estimate assumptions.

2. <u>In-Line Inspections</u>

SoCalGas and SDG&E currently operate approximately 200 miles of transmission pipeline segments located in Class 3 and 4 locations or High Consequence Areas that lack sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d) that are already configured to allow for in-line-inspection. These pipelines have already been inspected with a magnetic flux leakage (MFL) in-line inspection tool as part of our existing pipeline integrity management program, with re-assessments scheduled to occur over the next

64 Numbers may not add due to rounding.
65 Numbers may not add due to rounding.

five years. During the re-assessment, in addition to running the MFL tool, a transverse flux in-line inspection (TFI) tool will also be utilized to allow for evaluation of the condition of the long seam as well. In order to assess these 200 miles of pipe in Class 3 and 4 locations or High Consequence Areas with existing launchers and receivers, a total of 721 miles will be inspected in 27 separate in-line inspection runs.

Following these in-line inspections, a pressure test will be performed. The inspection results from the in-line inspection and the pressure test will be aligned to demonstrate the effectiveness of locating long seam defects that would fail a pressure test, with the ultimate goal of proving that an in-line-inspection can substitute for a pressure test, while improving cost effectiveness, on similar pipelines in other parts of the SoCalGas and SDG&E transmission system (i.e., Phase 2 pipeline segments).

The incremental cost to run a TFI tool through the pipeline is estimated at $200,000/run. In addition, costs for two validation digs per run (at $50,000/dig) and one excavation and repair ($75,000) per mile were added to the total cost. These values are based on historical costs observed on prior company projects. Table IX-9 below summarizes these Phase 1 in-line inspection costs.

Table IX-9
Phase 1 In-Line Inspection O&M Costs

Cost Element	Unit Cost (in thousands)	Quantity	O&M Costs
TFI Runs	$200/run	27	$5 million
Validation Digs	$50/dig	54	$3 million
Repairs	$75/repair	721	$54 million
		Total	$62 million

3. <u>Interim Safety Enhancement Measures</u>

As described in Section IV.E above, SoCalGas and SDG&E undertook an extensive records review of all transmission pipeline segments located in Class 3 and 4 locations and High Consequence Areas, and have already implemented interim safety enhancement measures for those pipeline segments that do not have sufficient documentation of pressure testing to meet the requirements set forth in D.11-06-017. Specifically, SoCalGas and SDG&E propose, in addition to continuing to manage the integrity of all identified transmission pipelines under their existing pipeline integrity program, to increase the frequency of ground patrols and leakage surveys to bi-monthly, implement pressure reductions where feasible, and perform in-line inspections.[66]

Incremental costs are being incurred and tracked since February 2011, as a result of increased efforts above and beyond the existing pipeline integrity management program. These costs include employee overtime pay to implement the additional leak surveys and pipeline patrols, costs for contractors to assist in the record review process, incremental costs associated with coupon sampling to determine material properties, and incremental costs associated with the installation of pressure control equipment to facilitate the lowering of pressure on some segments. These costs are shown in Table IX-10.

Table IX-10
Phase 1 Interim Safety Enhancement Measures O&M Cost Summary
(In Thousands of Dollars)

	2011	2012	2013	2014	2015
SoCalGas	5,900	4,200	200	150	100
SDG&E	900	500	8	8	8

4. Valve Enhancements

This Section covers estimated Phase 1 costs to implement the proposed Valve Enhancement Plan. As shown in Table IX-11, a total of 367 valves in sizes ranging from 12 to 36 inches in diameter will be modified, replaced, or newly added. Another 94 valves will be equipped with enhanced electronic monitoring and controls. There are also an additional 100 ASV locations on the SoCalGas pipeline system that currently do not have remote communications installed to allow operators to determine if they are opened or closed. The proposed Valve Enhancement Plan includes a proposal to install remote monitoring capabilities at these 100 valve locations. In total, SoCalGas and SDG&E propose to enhance 561 valve locations pursuant to the Valve Enhancement Plan. In addition, SoCalGas and SDG&E propose to install companion equipment to allow their operators to better view system operations and

66 All in-line inspection costs are included in the cost estimates provided in Section IX.A.2 above and are not included in this section.

better manage valve closures, ruptures and other extraordinary events. Table IX-11 below provides a summary of the scope of work proposed under the Valve Enhancement Plan.

Table IX-11
Summary of Proposed Phase 1 Control Valve Work

Installation Type	SoCalGas	SDG&E	Total
Upgrade Existing Manual Control Valves to ASV/RCV	273	74	347
Upgrade Existing ASV with RCV Functionality	94	0	94
Upgrade Existing ASV with Communications only	100	0	100
Add New ASVs/RCVs to Pipeline System	20	0	20
Total Valve Sites Addressed	487	74	561

A summary of the Capital and O&M expenditures for the Valve Enhancement Plan, including system enhancements, is presented in Table IX-12 below. A more detailed, element-by-element, summary of the Capital and O&M estimates for the Valve Enhancement Plan is presented in Table IX-13.

Table IX-12[67]
Phase 1 Valve Enhancement Plan Cost Summary
(In Thousands of Dollars)

SoCalGas	Phase 1A				Phase 1B						Total
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Capital	$ 26,254	$ 28,474	$ 32,719	$ 33,321	$ 32,323	$ 31,653	$ 29,353	$ 28,661	$ 28,883	$ 29,327	$ 300,967
O&M	$ 64	$ 192	$ 730	$ 945	$ 1,269	$ 1,958	$ 2,054	$ 2,060	$ 2,152	$ 2,247	$ 13,671
Total	$ 26,318	$ 28,666	$ 33,449	$ 34,266	$ 33,593	$ 33,611	$ 31,407	$ 30,721	$ 31,035	$ 31,574	$ 314,639
SDG&E	Phase 1A				Phase 1B						Total
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Capital	$ 5,342	$ 6,367	$ 7,120	$ 7,120	$ 5,821	$ 5,821	$ 5,821	$ 5,702	$ 5,702	$ 5,702	$ 60,519
O&M	$ 17	$ 102	$ 253	$ 267	$ 262	$ 277	$ 293	$ 308	$ 324	$ 339	$ 2,443
Total	$ 5,360	$ 6,469	$ 7,373	$ 7,387	$ 6,082	$ 6,098	$ 6,114	$ 6,011	$ 6,026	$ 6,041	$ 62,962

67 Numbers may not add due to rounding.

Table IX-13[68]

Phase 1 Valve Enhancement Plan O&M and Capital Cost Summary by Element

(In Thousands of Dollars)

	Phase 1A				Phase 1B			
	Years 2012-2015				Years 2016-2021			
	SDG&E Capital	SoCalGas Capital	SDG&E O&M	SoCalGas O&M	SDG&E Capital	SoCalGas Capital	SDG&E O&M	SoCalGas O&M
Valve Enhancements								
367 RCV and ASV installations and retrofits	20,792	93,895	93	335	31,187	140,843	262	947
94 ASV-to-RCV upgrades	0	6,662	0	59	0	14,212	0	390
Communications to 100 existing ASVs	0	55	0	8	0	164	0	89
System Enhancements								
Added volume measurement stations on larger pipelines	365	2,126	3	17	547	3,189	13	76
New pilot controls, check valves, RCVs for backflow prevention controls	933	5,436	4	24	2,479	14,445	38	221
Added volume measurement stations on tapped/ interconnected pipelines	237	1,384	2	13	356	2,076	21	121
Central SCADA system expansion	549	3,201	228	1,329	0	0	864	5,033
Communication system enhancements	3,074	8,010	309	145	0	5,271	606	4,863
Totals	25,949	120,768	640	1,931	34,569	180,200	1,803	11,741

Estimated Capital and O&M costs for proposed valve installations and upgrades (discussed in Section V.E) were developed from a review of recorded costs (where available and applicable) from historical valve and control system installations and replacements of similar size and complexity, and estimates from contractor(s) providing consulting estimates for planned valve work. Where historical costs were considered, a reduction in costs was factored in to account for expected economies-of-scale on a managed program of this size, as opposed to individual valve installations. The O&M costs presented in Table IX-13 include labor and non-

68 Numbers may not add due to rounding.

labor incidentals for technicians to perform scheduled and unscheduled maintenance on installed control valve assets.

Estimated capital and O&M costs for supporting valve system enhancements (discussed in Section V.F) were developed from a review of recorded costs (where available and applicable) for historical system installation and replacements of similar size and complexity; and estimates from contractor(s) and equipment vendors.

5. Implementation Costs to Modify Billing Systems

SoCalGas and SDG&E estimate increased O&M costs in the amount of $478,000 will be incurred in 2012 to modify the billing systems of both utilities to accommodate line item billing of the PSEP Surcharge proposed in Chapter X below. This estimate is based upon 4,330 programming hours at a rate of $100 per hour and training on the enhancements of 600 hours at $75 per hour. Prior efforts to change and enhance the billing systems of SoCalGas and SDG&E were considered in formulating this cost estimate.

C. Phase 1 Cost Estimates for Additional Elements Proposed as Part of the Pipeline Safety Enhancement Plan

1. Replacement of Pre-1946 Pipeline Segments

As explained in Chapter IV, in an effort to further enhance public safety, non-piggable pipelines that were installed prior to 1946 using historic welding and construction practices that are no longer industry standard are targeted for replacement under the proposed Pipeline Safety Enhancement Plan. Specifically, we propose to address pipeline segments that contain oxy-acetylene girth welds and/or wrinkle bends. All pipeline segments known to have these properties are operated by SoCalGas. Some transmission pipelines that meet this criteria also lack sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d), and therefore, are scheduled to be replaced under both the Base Case and Proposed Case. All non-piggable pre-1946 pipeline segments that have not already been identified for replacement under the Base Case are scheduled for replacement as part of the Proposed Case Pipeline Safety Enhancement Plan. Replacement of wrinkle bends located on pipelines that are scheduled to be pressure tested will be coordinated with the pressure testing, so as to take advantage of the pipeline already being removed from service for testing. These coordinated activities may therefore occur in Phase 1A. Remaining wrinkle bends will be targeted for replacement in Phase 1B. Table IX-14 below summarizes the costs proposed to be incurred by SoCalGas to replace pipeline segments constructed using these construction and manufacturing methods.

Table IX-14
Phase 1 Pipeline Replacements to Mitigate Pre-1946 Construction/Fabrication Methods
(Cost in Millions of Dollars)

SoCalGas	Phase 1A				Phase 1B					
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Cost	29	57	57	57	167	167	167	128	128	128
Miles	-	-	-	-	38	38	38	27	27	27
Wrinkle Bends (#)	580	1140	1140	1140	200	200	200	200	200	200

Replacement costs for pre-1946 pipeline segments were estimated using a cost matrix provided by SPEC Services. This matrix combines pipeline diameter with replacement length to arrive at a replacement cost per foot. The cost estimates will require refinement during Phase 1A and prior to execution in Phase 1B. Wrinkle bend replacement costs are consistent with historically-observed pipeline repair costs.

2. <u>Technology Enhancements</u>

In Chapter VI of this Pipeline Safety Enhancement Plan, SoCalGas and SDG&E propose to install fiber optic cabling, methane detection monitors and a computer-based remote monitoring system to collect and manage information and alarms from these sensor technologies. The costs presented in this section are for the Capital and O&M requirements to install, operate and manage these assets. Table IX-15 below provides a summary of the Phase 1 Capital and O&M cost estimates for the installation and maintenance of these technology enhancements.

Estimated Capital costs for Fiber Optic Right-of-Way Monitoring were developed based on unit cost information provided by fiber system vendors for fiber optic cabling and field instrumentation, historical utility costs for communication systems of similar size and complexity and construction cost based on vendor installation requirements. The O&M costs presented in Table IX-15 include labor and non-labor incidentals for technicians to perform scheduled and unscheduled maintenance on installed field monitoring equipment and communications equipment.

Estimated Capital costs for Methane Detection Monitors were developed based on unit cost information provided by methane detection system vendors for unit costs, historical utility costs for communication systems of similar size and complexity and construction cost based on vendor installation requirements and experience with installing monitoring equipment. The O&M costs for Methane Detection Monitoring presented in Table IX-15 include labor and non-labor incidentals for technicians to perform annual inspections and calibration of equipment and unscheduled maintenance on detector and communications equipment.

Table IX-15[69]
Phase 1 Technology Enhancement Cost Summary
(In Thousands of Dollars)

	SoCalGas		SDG&E		Total	
	Capital	O&M	Capital	O&M	Capital	O&M
Fiber Optic Monitors	23,526	1,194	3,229	164	26,755	1,358
Methane Detectors	8,462	791	1,161	109	9,624	900
Monitoring System	24,826	5,342	3,407	733	28,233	6,075
Totals	56,815	7,327	7,797	1,006	64,612	8,333

3. Enterprise Asset Management System

We estimate O&M costs of approximately $6.5 million in 2012 to design a comprehensive Enterprise Asset Management System. High-level Enterprise Asset Management System requirements and the cost and scale of similar projects were considered when determining the cost and scope of this blueprint-planning proposal. Costs are allocated to SoCalGas and SDG&E based on miles of transmission pipeline to be addressed in Phase 1, 97.3% and 6.7% respectively.

69 Numbers may not add due to rounding.

D. Projected Cost Savings if Direct Examination is Authorized as an Alternative to Pressure Testing of Shorter Pipeline Segments

For pipeline segments less than or equal to 1,000 feet that do not have sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d), SoCalGas and SDG&E propose that the Commission authorize SoCalGas and SDG&E to assess the segments using Direct Examination instead of pressure testing or replacement.

SoCalGas and SDG&E utilized the assistance of SPEC Services to develop the cost estimates for performing these Direct Examinations. Items covered in these estimates include the cost of excavation, coating removal, non-destructive evaluation of pipe wall, girth welds, and long seams, re-coating, and backfill/site restoration. It is estimated that the integrity of approximately 1.64 miles of pipelines for SoCalGas and 0.05 miles for SDG&E covered in Phase 1 of this Pipeline Safety Enhancement Plan could be validated through Direct Examination more economically and with less system and customer impacts as compared to pressure testing or replacement. Using direct examination methods in lieu of replacement or pressure testing on this mileage could reduce the Pipeline Safety Enhancement Plan costs by approximately $5-15 million. If this method is approved, SoCalGas and SDG&E would study additional areas to apply this method with the potential for additional savings. It should be noted that these cost reductions are not reflected in either the Base Case or Proposed Case.

E. Phase 2 Cost Estimates

Phase 2 of the proposed Pipeline Safety Enhancement Plan is expected to run in parallel with, and may extend past, the completion of Phase 1B, and addresses all remaining pre-1970 transmission pipeline segments not fully addressed in Phase 1 that lack sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d). In total, the scope of Phase 2 is estimated to include approximately 2,000 miles of SoCalGas transmission pipeline and less than 100 miles of SDG&E transmission pipeline. An assessment of these lines is underway, and will not be completed until July 2012. Based on a preliminary review, it is anticipated that some of these pipeline segments will require pressure testing or replacement to meet the Commission's directives in D.11-06-017. The costs to pressure test or replace these pipelines in less populated areas will vary based on pipeline size, location and operational requirements. Assuming Phase 2 costs are similar to Phase 1 costs, we estimate the following average testing and replacement costs:

New Construction or Replacement:	\$3.5 - 4 million / mile (Capital)
Pressure Testing:	\$0.5-0.6 million / mile (O&M)
In-Line-Inspection:	\$86,000 / mile (O&M)

Because we have not yet completed our review of records for Phase 2 pipelines, we are unable to provide Phase 2 cost estimates to any level of certainty. If we assume that 40% of Phase 2 transmission pipelines will be addressed using either pressure testing or replacement, and apply the same pressure test versus replacement ratio as Phase 1 pipeline segments, the total cost would be in the range of \$1.5 – 3 billion or more for SoCalGas and about \$100 million for SDG&E. These speculative estimates are provided prior to the completion of our review of records for Phase 2 pipeline segments, and prior to clarification by the Commission of the scope of required pressure testing and replacement in Phase 2,[70] solely to comply with the Commission's directives in D.11-06-017,[71] and SoCalGas and SDG&E cannot warrant their accuracy.

These rough cost estimates are based on the assumption that approximately 200 miles of SoCalGas pipelines constructed/fabricated using pre-1946 methods will be replaced in Phase 1B, per the scope of the Proposed Case Pipeline Safety Enhancement Plan. To the degree these pre-1946 pipeline segments are not addressed in Phase 1, the pipelines will be carried over to Phase 2, increasing the Phase 2 cost for SoCalGas by approximately \$700 million.

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[70] On page 18 of D.11-06-017, the Commission states "…all natural gas transmission pipeline in service in California must be brought into compliance with modern standards for safety." In addition, Ordering Paragraph four of D.11-06-017 directs all California pipeline operators to file a plan "to comply with the requirement that all in-service natural gas transmission pipeline in California have been pressure tested <u>in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c)</u>." (emphasis added) On the other hand, Ordering Paragraph three of D.11-06-017 provides that for "…pressure tests conducted prior to the effective date of General Order 112, one hour is the minimum acceptable duration for a pressure test." It is unclear from these statements what the Commission will recognize as "modern standards for safety" as part of this proceeding. Due to this uncertainty, SoCalGas and SDG&E included pipelines that were not required to be pressure tested in accordance with current industry practice and code requirements in Phase 2.

[71] *See* D.11-06-017, Ordering ¶ 4.

As discussed in Section IV.D above, SoCalGas and SDG&E propose to validate the use of TFI as an alternative to pressure testing in Phase 1, and may subsequently seek Commission authorization to utilize TFI in lieu of pressure testing or replacement in Phase 2. It is estimated that almost 56% of the Phase 2 miles are already retrofitted to accommodate in-line inspections. If in-line inspection using TFI technology is validated through the process proposed herein and adopted as an authorized alternative to pressure testing by the Commission, this would reduce the amount of mileage requiring pressure testing or replacement potentially saving hundreds of millions of dollars.

In addition, adoption of our proposal to modify General Order 112-E to eliminate reliance on the Grandfather Clause, in lieu of precluding California pipeline operators from utilizing 49 CFR 192.619(c), would further reduce the scope and costs of Phase 2.

X.

RATEMAKING AND REGULATORY ACCOUNTING TREATMENT

This chapter is to request approval and recovery of the revenue requirements resulting from the Capital and O&M forecasts of the Pipeline Safety Enhancement Plan for the years 2011 through 2015, to coincide with SoCalGas' and SDG&E's anticipated next General Rate Case cycles.[72] The Phase 1A Proposed Case interim revenue requirements for the years 2011 through 2015 totals $594 million for SoCalGas and $62 million for SDG&E.

Pipeline Safety Enhancement Plan funding requests for the remaining years will be reassessed and approved in our next General Rate Cases, subsequent rate case cycles, or in other applicable proceedings, as needed. We propose for the authorized Pipeline Safety Enhancement Plan revenue requirement and post-test year spending requests to have a separate attrition mechanism and the regulatory accounting treatment to be handled as described below.[73]

We propose to recover the costs of implementing our Pipeline Safety Enhancement Plan through a separate line-item "PSEP Surcharge" to be reflected on our customers' bills on a monthly basis. Even though approval of Pipeline Safety Enhancement Plan costs for 2016 and beyond will be rolled into other proceedings, we propose to continue to recover those costs through the PSEP Surcharge. Should there be a delay of our 2016 General Rate Cases, we request approval to continue recovering the Pipeline Safety Enhancement Plan revenue requirements consistent with the proposal laid out in our ten-year Phase 1 plan, for the time period not addressed due to a delay in the General Rate Case(s).

A. Revenue Requirement

The revenue requirements associated with the Pipeline Safety Enhancement Plan are derived from the forecasted incremental Capital costs related to the Pipeline Safety Enhancement Plan as well as estimates of incremental O&M costs. The costs provided in previous sections are

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[72] References to the next rate case cycles as having 2016 test years herein is based on a proposal by SoCalGas and SDG&E in their 2012 General Rate Case Applications now pending before the Commission, and subject to Commission approval.

[73] This is similar to how the generation revenue requirement is authorized for SDG&E in its General Rate Case proceeding and recovered and tracked in SDG&E's Non-Fuel Generation Balancing Account through its commodity rates.

direct costs only; they do not include overhead, escalation or other necessary costs to support the investment. In order to illustrate the full impact of Phase 1 cost recovery of the Pipeline Safety Enhancement Plan, the revenue requirements for the entire investment are provided in the tables below.

The incremental Capital and O&M costs for the Proposed Case and Base Case are adjusted to include applicable overhead rates and escalation rates. Overhead rates are applied to each direct cost input, according to its classification as company labor, contract labor, purchased services and materials. Overhead rates are estimated using Year 2010 actuals, but are only intended to be indicative for forecasting purposes; actual overhead rates each year will be used in the calculation of the actual revenue requirement. Only overheads that are considered incremental to each Pipeline Safety Enhancement Plan Case are included. For example, overheads associated with incremental labor and additional procurement activities are included.[74] Table X-1 below shows overhead rates that were applied in this analysis.

Table X-1
SoCalGas and SDG&E Pipeline Safety Enhancement Plan Overhead Loaders

Overhead Category	SoCalGas	SDG&E	Loading Base
Payroll Taxes	7.73%	7.27%	Direct Labor
Vacation and Sick Time	17.44%	15.67%	Direct Labor
Benefits (non-balanced only)	19.74%	18.85%	Direct Labor
Workers' Compensation	5.74%	1.46%	Direct Labor
Public Liability / Property Damage	2.80%	3.33%	Direct Labor
Incentive Compensation Plan	18.17%	17.79%	Management and Associate Direct Labor
Purchased Services and Materials	1.28%	0.40%	Contract Labor, Services and Purchased Materials
Administrative and General	4.27%	2.05%	Capital Direct Costs

Overhead-loaded constant-dollar values for the Proposed Pipeline Safety Enhancement Plan Case and Base Case incremental costs are escalated for inflation using the following escalation factors for Years 2012 through 2021.[75] As these factors vary over the ten-year horizon, Table X-2 shows the range of annual escalation rates applied to each cost type.

74 Pension and Post-Retirement Benefits Other Than Pensions overhead costs are excluded, as these costs are subject to a separate balancing account mechanism and addressed in connection with the our General Rate Cases.

75 *See* IHS Global Insight's 1st Quarter 2011 Utility Cost Forecast.

Table X-2
SoCalGas and SDG&E Pipeline Safety Enhancement Plan Escalation Rates[76]

Cost Category	Escalation Factor	Range of Annual % Change		
Capital (Labor & Non- Labor)	Gas Plant (Various)	-0.1%	-	3.9%
O&M (Labor)	Gas Utility Labor O&M	2.3%	-	2.7%
O&M (Non-Labor)	Gas Utility O&M Non-Labor	2.3%	-	2.9%

The revenue requirement evaluation assumes all Capital costs, including Allowance For Funds Used During Construction, are recovered through depreciation[77] over the book-life of the assets and assumes that O&M is recovered in the period it is spent. In addition to the actual expenditure amounts, the revenue requirements include all other expenses required to support the investment, including authorized return on investment, income and property taxes, franchise fees, uncollectibles, and working cash associated with O&M.[78] The SoCalGas revenue requirement calculation reflects the current authorized rate of return of 8.68% based on 10.82% return on equity. The rate of return for SoCalGas reflects the rate of return authorized for SoCalGas, as submitted for filing and approval in Advice Letter 3199-A, Supplemental Performance Based Regulation, Market Indexed Capital Adjustment mechanism. This supplemental filing was made in compliance with Decision 97-07-054. The SDG&E revenue requirement calculation reflects the current authorized rate of return of 8.40% based on 11.10% return on equity. The rate of return for SDG&E reflects the rate of return authorized per the 2008 Test Year Cost of Capital proceeding Decision 07-12-049 and implemented in Advice Letters 1954-E and 1740-G for electric and gas services, respectively.

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76 Factors shown are from escalation indices published in IHS Global Insight's 1st Quarter 2011 Utility Cost Forecast.

77 The revenue requirements reflect the incorporation of the bonus depreciation provisions recently enacted as part of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 ("Tax Relief Act of 2010"). The Tax Relief Act of 2010 is an economic stimulus tool that President Obama called on Congress to enact in 2010. The Tax Relief Act 2010 was signed on December 17, 2010.

78 The revenue requirement components and rate base calculations may be found in the Workpapers supporting Chapter X.

1. <u>Revenue Requirement for the Proposed Pipeline Safety Enhancement Plan</u>

Table X-3 below summarizes the direct costs for the proposed Pipeline Safety Enhancement Plan from Chapter IX.

Table X-3
Direct Costs Summary for Proposed Pipeline Safety Enhancement Plan
(In Millions of 2011 Dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	159.80	345.42	339.53	338.92	200.75	201.25	198.73	158.13	158.36	158.80	2,260
SoCalGas - O&M	5.93	59.16	64.82	65.80	65.99	2.07	2.78	2.89	2.92	3.03	3.15	279
Total SoCalGas	**5.93**	**218.96**	**410.24**	**405.33**	**404.91**	**202.82**	**204.03**	**201.62**	**161.05**	**161.39**	**161.95**	**2,538**
SDG&E - Capital	-	30.40	66.58	65.94	65.78	112.12	112.28	112.25	5.92	5.92	5.92	583
SDG&E - O&M	0.88	1.09	0.22	4.76	0.46	0.37	0.39	0.41	10.51	0.44	0.46	20
Total SDG&E	**0.88**	**31.49**	**66.80**	**70.70**	**66.23**	**112.49**	**112.67**	**112.65**	**16.43**	**6.37**	**6.39**	**603**

The direct costs are then loaded and escalated into expected nominal spend with the factors described in Table X-1 and Table X-2. Table X-4 below summarizes the loaded and escalated direct costs from Table X-3.

Table X-4
Loaded and Escalated Costs Summary for Proposed Pipeline Safety Enhancement Plan
(In Millions of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	180.40	393.22	398.62	408.85	251.01	256.66	259.44	213.16	219.19	225.66	2,806
SoCalGas - O&M	6.15	64.07	71.68	75.10	77.52	3.25	4.20	4.47	4.64	4.92	5.21	321
Total SoCalGas	**6.15**	**244.47**	**464.90**	**473.72**	**486.37**	**254.26**	**260.86**	**263.91**	**217.80**	**224.11**	**230.88**	**3,127**
SDG&E - Capital	-	33.30	73.88	75.41	77.00	131.69	134.81	138.56	7.93	8.14	8.35	689
SDG&E - O&M	0.89	1.21	0.30	5.63	0.69	0.60	0.64	0.68	13.45	0.77	0.81	26
Total SDG&E	**0.89**	**34.51**	**74.18**	**81.04**	**77.69**	**132.29**	**135.45**	**139.24**	**21.38**	**8.91**	**9.16**	**715**

Table X-5 below summarizes the necessary revenue requirements for SoCalGas and SDG&E to implement the projects with the loaded and escalated costs shown in Table X-4.

Table X-5
Revenue Requirement Summary for Proposed Pipeline Safety Enhancement Plan
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
SoCalGas	**6.37**	**57.91**	**100.49**	**182.58**	**247.01**	**233.95**	**266.30**	**296.51**	**325.83**	**350.43**	**375.87**	**396.61**	**6,581.51**	**9,421**
SDG&E	**0.92**	**0.35**	**5.19**	**24.53**	**30.73**	**44.15**	**64.43**	**83.69**	**116.82**	**100.32**	**98.77**	**96.04**	**1,762.75**	**2,429**

2. Revenue Requirement for Base Case

Table X-6 below summarizes the direct costs for the Base Case from Chapter IX.

Table X-6
Direct Costs Summary for Base Case
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	115.96	271.27	275.51	276.11	32.32	31.65	29.35	28.66	28.88	29.33	1,119
SoCalGas - O&M	5.93	52.73	64.51	65.00	65.16	1.27	1.96	2.05	2.06	2.15	2.25	265
Total SoCalGas	**5.93**	**168.68**	**335.78**	**340.51**	**341.28**	**33.59**	**33.61**	**31.41**	**30.72**	**31.04**	**31.57**	**1,384**
SDG&E - Capital	-	28.30	64.24	64.99	64.99	111.89	111.89	111.89	5.70	5.70	5.70	575
SDG&E - O&M	0.88	0.64	0.18	4.65	0.34	0.26	0.28	0.29	10.39	0.32	0.34	19
Total SDG&E	**0.88**	**28.94**	**64.42**	**69.64**	**65.34**	**112.16**	**112.17**	**112.19**	**16.09**	**6.03**	**6.04**	**594**

The direct costs are then loaded and escalated into expected nominal spend with the factors described in Table X-1 and Table X-2. Below is a summary of the loaded and escalated direct costs from Table X-6.

Table X-7
Loaded and Escalated Costs Summary for Base Case
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	131.27	309.08	324.48	333.75	41.84	41.90	39.69	39.75	41.18	43.01	1,346
SoCalGas - O&M	6.15	56.84	71.15	73.84	76.21	1.98	2.86	3.07	3.17	3.38	3.61	302
Total SoCalGas	**6.15**	**188.11**	**380.23**	**398.32**	**409.96**	**43.82**	**44.76**	**42.76**	**42.92**	**44.56**	**46.62**	**1,648**
SDG&E - Capital	-	30.91	71.13	74.30	76.09	131.43	134.34	138.13	7.65	7.85	8.05	680
SDG&E - O&M	0.89	0.70	0.23	5.47	0.51	0.43	0.46	0.50	13.26	0.56	0.60	24
Total SDG&E	**0.89**	**31.61**	**71.36**	**79.76**	**76.61**	**131.86**	**134.81**	**138.62**	**20.90**	**8.41**	**8.65**	**703**

Table X-8 below summarizes the necessary revenue requirement for each utility to implement the projects, with the loaded and escalated costs in Table X-7.

Table X-8
Revenue Requirement Summary for Base Case
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Total SoCalGas	**6.37**	**58.86**	**95.82**	**150.97**	**205.75**	**182.57**	**181.93**	**183.54**	**183.93**	**184.48**	**185.25**	**182.44**	**2,731.89**	**4,534**
Total SDG&E	**0.92**	**0.98**	**5.27**	**22.32**	**28.56**	**41.92**	**62.38**	**82.17**	**115.84**	**99.33**	**97.75**	**95.22**	**1,749.47**	**2,402**

B. Regulatory Accounting Treatment

In this Section, we seek approval of our proposed regulatory accounting treatment. We also propose to file an Update Report with the Commission each year.

The costs to be recovered through the PSEP Surcharge described below will be incorporated into rates on January 1 each year and will continue until Pipeline Safety Enhancement Plan investments are fully recovered. In connection with SoCalGas' and SDG&E's annual regulatory account balance update filings, the current-year forecasted year-end balance in a proposed "Pipeline Safety Enhancement Plan Cost Recovery Account," combined with the revenue requirement for the coming year, will be incorporated into rates, as necessary, to ensure appropriate recovery of the revenue requirement in between rate case cycles. Any residual balance will be amortized in rates at the completion of the Pipeline Safety Enhancement Plan.

1. Pipeline Safety Enhancement Plan Cost Recovery Account

As indicated above, we propose to establish a Pipeline Safety Enhancement Plan Cost Recovery Account for each utility to recover costs associated with the Pipeline Safety Enhancement Plan. These will be interest bearing accounts that are recorded on SoCalGas' and SDG&E's respective financial statements. These accounts will record the difference between the authorized revenue requirements collected through the PSEP Surcharge and actual O&M and capital-related revenue requirements associated with implementation of the Pipeline Safety Enhancement Plan.

2. Pipeline Safety Enhancement Plan Implementation and First Year of PSEP Surcharge

Upon approval of the Pipeline Safety Enhancement Plan, SoCalGas and SDG&E each propose to file an advice letter to implement the Commission's decision. These advice letters shall include updated revenue requirements and timing to reflect any decision-ordered changes to the Pipeline Safety Enhancement Plan. This will allow SoCalGas and SDG&E to reflect any delays and incorporate the surcharge into rates, should approval of the Pipeline Safety Enhancement Plan occur after January 1, 2012.

This will also include the Pipeline Safety Enhancement Plan costs recorded in the Pipeline Safety and Reliability Memorandum Accounts, proposed in our joint motion filed May 4, 2011, if approved in sufficient time; and, any costs that would have been recorded in these memo accounts, if it had been approved in sufficient time.

3. Cost True-Up Proposal and Expedited Advice Letter

As stated above, in connection with our annual regulatory account balance update filings in October of each year, the current-year forecasted year-end balances in the Pipeline Safety Enhancement Plan Cost Recovery Accounts, combined with the revenue requirements for the coming year, will be incorporated into rates, as appropriate. We propose to file expedited advice letters requesting approval for any adjustments to the overall level of Pipeline Safety Enhancement Plan funding requirements previously approved. These advice letters will include an explanation for changes from the original revenue requirements, as previously proposed and approved. We also propose to use this advice letter process in requesting any additional revenue requirement associated with the Enterprise Asset Management System or the expansion of the Pipeline Safety Enhancement Plan for pipeline safety enhancement activities not covered by this filing that may subsequently be adopted by the Commission.

4. Annual Pipeline Safety Enhancement Plan Update Report

Beginning in 2013, we propose to provide an annual status report to the Commission on or before March 31 each year that will include the following:

1. Information on any work completed during the previous year (scope and cost);
2. Work planned for the upcoming year (scope and cost);
3. Discussion of progress made to date in order to keep the Commission informed and provide transparency to the public regarding our progress; and
4. Confirmation of our Commission-approved annual Pipeline Safety Enhancement Plan budget.

C. Rates

1. Introduction and Summary

In this Section, SoCalGas and SDG&E present the customer rate impacts resulting from the proposals in this filing. These rates are for illustrative purposes only and will be adjusted to reflect actual costs and schedules when placed into rates.

We propose to recover all Pipeline Safety Enhancement Plan costs through a PSEP Surcharge. The surcharge will be comprised of the estimated revenue requirements for that year, as proposed in Section X.A, which in the initial year will include costs being incurred in 2011, combined with the balance in the Pipeline Safety Enhancement Plan Cost Recovery Account to be incorporated into rates, as appropriate. The PSEP Surcharge will be implemented upon Commission approval and updated on January 1 of each year as part of SoCalGas and SDG&E's respective Annual Consolidated Rate Update Filings.

The costs to be recovered each year through the PSEP Surcharge will be allocated to customer classes using the Equal Percent Authorized Margin method proposed in Chapter II. The PSEP Surcharge will be a separate line item on customers' bills. The illustrative surcharges at the end of Phase 1A are summarized in Table X-10.

2. Review of Current Rates

The following is a brief description of existing transportation rates and recent relevant filings.

a) Authorization

The Commission is responsible for regulating investor-owned electric, natural gas, telecommunications, and water utilities. The Commission sets retail natural gas rates and allocates costs for different categories of gas customers through traditional General Rate Cases and/or cost allocation proceedings.

b) 2009 Cost Allocation Proceeding Decision

Pursuant to D.09-11-006, SoCalGas and SDG&E established the currently-effective natural gas transportation rates. The rate design models for SoCalGas and SDG&E allocate to customer classes, the authorized revenue requirements that are determined in General Rate Cases.

The rate design models then further incorporate transmission system integration and other costs incurred by SoCalGas and SDG&E to provide basic transportation services to their customers during the forecasted cost allocation period. These other costs include Fuel Use, Advanced Meter Infrastructure, and Commission-authorized regulatory account amortizations.

c) <u>2010 year-end Consolidated Advice Letter Filing</u>

Advice letters are commonly used by utilities to make changes to their tariffs. The purpose of a consolidated advice letter filing is to consolidate several previously-filed advice letters and Commission decisions that reflect gas rate changes for the upcoming calendar year. These are primarily for updating the regulatory account amortizations and updating the authorized revenue requirement.

Consolidated Advice Letters AL-4190 (for SoCalGas), and AL-2002-G (for SDG&E) established the following class-average rates in Table X-9:

Table X-9
Current Natural Gas Transportation Rates
Class Average Rates for SoCalGas and SDG&E
($/therm, Except as Noted)

	SoCalGas	SDG&E
Core Rates		
Residential	$0.53611	$0.67411
Average Residential Bill $/month	$39.08	$38.76
Commercial & Industrial	$0.31532	$0.24933
Natural Gas Vehicles	$0.08894	$0.08722
Gas Engine	$0.10407	N/A
Gas Air Conditioning	$0.08353	N/A
Non-Core Rates		
Commercial & Industrial – Distribution	$0.07408	$0.14050
Electric Generation – Distribution	$0.03674	$0.03832
Transmission Level Service	$0.02517	$0.02517
Firm Access Rights $/dth/day	$0.03802	N/A
SDG&E	$0.00769	N/A
Enhanced Oil Recovery	$0.03220	N/A
System Average Rates		
	$0.20041	$0.23461

d) Firm Access Rights Update Filing

In D.06-12-031, the Commission approved the request of SoCalGas and SDG&E to establish a system of Firm Access Rights and, among other things, required the utilities to file a joint application eighteen months after the initial Open Season concluded in order to initiate a review of the Firm Access Rights system to assess how it has been working, and whether any changes or modifications are needed.

On March 29, 2010, SoCalGas and SDG&E filed a joint application to initiate Commission review of Firm Access Right service implemented pursuant to D.06-12-031. On April 19, 2011 in D.11-04-032, the Commission issued a decision that assessed the performance of the Firm Access Right system, adopted operational changes to improve the system, and established the revenue requirement, rate design, and rates for natural gas Backbone

Transportation Service for the period from October 1, 2011 until the effective date of rates established in the next Triennial Cost Allocation Proceeding.

The Backbone Transportation Service rate is not reflected in this filing, since it has not yet been implemented. The Backbone Transportation Service rate is scheduled to be implemented on October 1, 2011.

e) <u>2012 General Rate Case</u>

Our 2012 General Rate Case Applications are currently before the Commission and are not reflected in this filing.

f) <u>2016 General Rate Case</u>[79]

We anticipate filing our General Rate Case Applications for test year 2016 in late 2014. It is estimated that a decision in our 2016 General Rate Cases will be implemented on around January 1, 2016. While these rate cases are not directly reflected in this filing, they are referenced as proceedings to request funding beyond 2015.

3. <u>PSEP Surcharge</u>

The PSEP Surcharge will include Pipeline Safety Enhancement Plan costs based upon:

(i) The Pipeline Safety Enhancement Plan revenue requirements, as proposed in Section X.A above, which include costs to be tracked in the Pipeline Safety and Reliability Memorandum Account proposed in our joint motion filed May 4, 2011;

(ii) Any balance in the Pipeline Safety Enhancement Plan Cost Recovery Account to be incorporated into rates, as appropriate.

These Pipeline Safety Enhancement Plan costs will be incorporated into rates upon implementation of the Commission's decision; and on January 1 of each subsequent year, as part of the Annual Consolidated Update Filing. Costs will be allocated among customer classes via the Equal Percent Authorized Margin method and recovered through the PSEP Surcharge.

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79 The reference to the next rate case cycle as having a 2016 test year is based on a proposal by SoCalGas and SDG&E in their 2012 General Rate Case Applications now pending before the Commission, and subject to Commission approval.

SoCalGas and SDG&E propose to charge a flat monthly surcharge for residential customers and a volumetric surcharge for non-residential customers. Since it is not practical to develop a single flat-monthly or volumetric surcharge that would apply to all customers in all rate classes using an Equal Percent Authorized Margin allocation, a different surcharge is required to be calculated for each customer class. The surcharges for customers within each customer class may be flat monthly surcharges, volumetric surcharges, or a combination. Since the residential market is a relatively homogeneous market in terms of natural gas demand, SoCalGas and SDG&E determined that a fixed monthly PSEP Surcharge is reasonable for this class. Due to the wide range of demand profiles among the non-residential customer classes, a volumetric surcharge is more reasonable for these customers. Wholesale customers, along with others on the transmission-level service rate, will be charged the PSEP Surcharge, however, SDG&E will not be charged the PSEP Surcharge as part of wholesale service. This is due to the integration of the Pipeline Safety Enhancement Plan between the two utilities, with the Surcharge being determined on a combined cost and demand basis.

As stated earlier, rates will be adjusted on January 1 each year as part of our proposed Annual Consolidated Rate Update Filings. See Appendix G for illustrative PSEP Surcharges for each year of Phase 1. We propose to apply this PSEP Surcharge methodology until the assets are fully recovered.

Table X-10 below shows an illustrative PSEP Surcharge for the year 2015. A summary rate table showing the PSEP Surcharges resulting from the proposed Pipeline Safety Enhancement Plan revenue requirements through the year 2022 is shown in Appendix F. Also, Table X-13, which summarizes the consolidated rate impacts of the proposed Pipeline Safety Enhancement Plan, shows that the allocation of Phase 1A costs is fairly even among residential and non-residential classes. By the end of the four-year period of Phase 1A, most rates will increase by approximately ten to thirteen percent.

Table X-10[80]
SoCalGas and SDG&E PSEP Surcharges for Phase 1A

	Proposed Case	Base Case
SoCalGas		
Monthly PSEP Surcharge ($/mo)		
Residential	$2.82	$2.38
Volumetric PSEP Surcharges ($/th)		
Core Commercial & Industrial	$0.03484	$0.02939
Gas Air-Conditioning	$0.00987	$0.00832
Gas Engine	$0.01270	$0.01071
Natural Gas Vehicle	$0.01030	$0.00869
Noncore C&I - Distribution Level Service	$0.00973	$0.00821
Electric Generation Distribution Level Service	$0.00435	$0.00367
EOR - Distribution Level Service	$0.00435	$0.00367
Transmission Level Service	$0.00284	$0.00240
SDG&E Gas		
Monthly PSEP Surcharge ($/mo)		
Residential	$2.83	$2.38
Volumetric PSEP Surcharges ($/th)		
Core C&I	$0.03484	$0.02939
Natural Gas Vehicle	$0.01031	$0.00870
Noncore C&I - Distribution Level Service	$0.00978	$0.00825
Electric Generation-Distribution Level Service	$0.00437	$0.00369
Transmission Level Service	$0.00286	$0.00241

a) CARE Applicability for Low Income Customers and Illustrative PSEP Surcharge

We propose to apply the 20% rate discount to the PSEP Surcharge for those customers on the California Alternate Rate for Energy (CARE) rate schedule. The discounted amounts shall be included in the CARE program costs and recovered through the Public Purpose Program Surcharge rate. An example of the calculation of the PSEP Surcharge applicable to CARE participants is shown in Table X-11 for the year 2015. A summary of the CARE rate table through 2022, showing the PSEP Surcharges resulting from the proposed Pipeline Safety Enhancement Plan revenue requirements, is shown in Appendix G. As discussed above, upon approval of proposed Pipeline Safety Enhancement Plan, an advice letter will be filed to

80 Surcharges reflected are for 2015. See Appendix F for ten-year rate schedule.

implement the Commission's decision. The advice letter will include an update to the applicable Public Purpose Program Surcharge rate.

Table X-11[81]
CARE PSEP Surcharge and Discounted Amounts for Phase 1A

		Proposed Case	Base Case
	<u>SoCalGas</u>		
	Non-Care PSEP Surcharge $/mo	$2.82	$2.38
*	20% CARE Discount	($0.56)	($0.48)
=	CARE PSEP Surcharge $/mo	$2.26	$1.91
*	# CARE Participants	1,708,706	1,708,706
*	12 months	12	12
=	CARE Discount $ million/yr	$11.6	$9.8
	<u>SDG&E</u>		
	Non-Care PSEP Surcharge $/mo	$2.83	$2.38
*	20% CARE Discount	($0.57)	($0.48)
=	CARE PSEP Surcharge $/mo	$2.26	$1.91
*	# CARE Participants	203,547	203,547
*	12 months	12	12
=	CARE Discount $ million/yr	$1.4	$1.2

b) <u>Impact on Existing Public Purpose Program Surcharge Rate</u>

An example of the impact of the discounted amounts recovered through the Public Purpose Program Surcharge rate is shown in Table X-12 for 2015. Additionally, a summary rate table showing the impacts of the Pipeline Safety Enhancement Plan on the Public Purpose Program Surcharge rates through 2022 is shown in Appendix H.

81 Numbers may not add due to rounding. Impact reflected is for 2015. *See* Appendix G for ten-year rate schedule.

Table X-12[82]
Public Purpose Program Surcharge for Phase 1A

	Current Rates $/th	Proposed Case $/th	Base Case $/th
SoCalGas			
Residential	$0.07687	$0.07959	$0.07917
Core C&I	$0.06809	$0.07082	$0.07039
NGV	$0.03076	$0.03348	$0.03306
Noncore C&I	$0.03476	$0.03749	$0.03706
SDG&E			
Residential	$0.07560	$0.07854	$0.07808
Core C&I	$0.12037	$0.12332	$0.12286
NGV	$0.03193	$0.03487	$0.03441
Noncore C&I	$0.11412	$0.11707	$0.11661

c) Illustrative Residential Bill Impact and Non-Residential Rate Impacts

Combining the charges described above for the PSEP Surcharge with the Public Purpose Program Surcharge rate impact will result in the illustrative Residential monthly bills and Non-Residential class average volumetric rates shown in Table X-13. The Residential bills are based on system-wide average monthly usage for SoCalGas of 38 therms/month and SDG&E of 33 therms/month, using current transportation rates and core procurement rates. The Non-Residential rates are based on current class-average transportation rates, excluding Firm Access Rights charges and gas commodity. Table X-13 below shows the residential bill impact and the non-residential customer rate impact. Additionally, a summary rate table showing the consolidated impacts of the Pipeline Safety Enhancement Plan through 2022 is provided in Appendix I.

82 Impact reflected is for 2015. *See* Appendix H for ten-year rate schedule.

Table X-13[83]
Consolidated Rate Impacts for Phase 1A

	Current	Proposed Case		Base Case	
SoCalGas			% Change		% Change
Residential Avg Monthly Bill - $/mo	$39.08	$42.00	7.5%	$41.54	6.3%
Avg Monthly Bill w/out G-CP - $/mo	$21.98	$24.91	13.3%	$24.45	11.2%
Non-res Rates ($/th)					
Core C&I	$0.38341	$0.42097	9.8%	$0.41510	8.3%
NGV	$0.11969	$0.13272	10.9%	$0.13068	9.2%
Noncore C&I – Distribution	$0.10884	$0.12129	11.4%	$0.11934	9.7%
EG – Distribution	$0.03874	$0.04309	11.2%	$0.04241	9.5%
Transmission Level Service	$0.02517	$0.02801	11.3%	$0.02757	9.5%
SDG&E					
Residential Avg Monthly Bill - $/mo	$38.76	$41.68	7.5%	$41.23	6.4%
Avg Monthly Bill w/out G-CP - $/mo	$23.91	$26.84	12.2%	$26.38	10.3%
Non-res Rates ($/th)					
Core C&I	$0.36970	$0.40749	10.2%	$0.40158	8.6%
NGV	$0.11915	$0.13240	11.1%	$0.13033	9.4%
Noncore C&I – Distribution	$0.25462	$0.26735	5.0%	$0.26536	4.2%
EG – Distribution	$0.04229	$0.04667	10.3%	$0.04598	8.7%
Transmission Level Service	$0.02517	$0.02803	11.4%	$0.02758	9.6%

83 Impact reflected is for 2015. *See* Appendix I for ten-year rate schedule.

XI.

WITNESS QUALIFICATIONS

QUALIFICATIONS OF MICHAEL W. ALLMAN

My name is Michael W. Allman. I am President and Chief Executive Officer for Southern California Gas Company (SoCalGas). My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I received a Bachelor of Science degree in Chemical Engineering from Michigan State University and a Master of Business Administration degree from The University of Chicago Booth School of Business. I am a Certified Management Accountant and a Certified Internal Auditor.

I have been employed with SoCalGas since March 2010 in my current position as President and CEO responsible for SoCalGas, a regulated business unit and subsidiary of Sempra Energy. Prior to joining SoCalGas, I was President and CEO of Sempra Generation and in various leadership positions with Sempra Energy and its subsidiaries, including CFO of Sempra Global, President of Sempra Technology Ventures, Vice President of Corporate Planning and Development; and Vice President of Audit Services. Prior to joining Sempra Energy in 1998, I was responsible for marketing and delivering consulting projects for LEK/Alcar, a strategic and financial consulting-services firm. I am on the Board of Directors of the American Gas Association, Los Angeles World Affairs Council and the California Chamber of Commerce.

I have not testified previously before the California Public Utilities Commission.

QUALIFICATIONS OF DAVID M. BISI

My name is David M. Bisi. I am employed by Southern California Gas Company (SoCalGas) as the Gas Transmission Planning Department Manager. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I received a Bachelor of Science degree in Mechanical Engineering from the University of California at Irvine in 1989. I have been employed by SoCalGas since 1989, and have held positions within the Engineering, Customer Services, and Gas Operations departments. The majority of my employment with SoCalGas has been involved with the plan and design of the gas transmission pipeline and storage system.

I have held my current position since April 2002. My current responsibilities include the management of the Gas Transmission Planning Department responsible for the design and planning of SoCalGas and SDG&E's gas transmission and storage systems. As such, I am responsible for: ensuring that the transmission system meets the CPUC-mandated design standards for core and noncore firm service over a 25 year forecast period; recommending improvements and additions as necessary; monitoring the changing dynamics of the gas transmission system as new load centers develop and new supply receipt points are created; and alerting management when operating precautions or changes become necessary; performing short-term capacity analyses for customer service requests from the transmission system; evaluating system impacts from storage expansion projects and new product offerings to customers; and developing staff to maintain continuity and consistency in system planning.

I have previously testified before the Commission.

QUALIFICATIONS OF GARY G. LENART

My name is Gary G. Lenart. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by Southern California Gas Company (SoCalGas) as Natural Gas Rate Manager for SoCalGas and San Diego Gas and Electric Company (SDG&E).

I hold a Bachelor of Science degree in Business Finance and Computer Science from Bradley University in Peoria, Illinois and a Master of Business Administration from California State University at Northridge, California. I have been employed by SoCalGas since 1988, and have held positions of responsibilities as a General Ledger Accountant for Pacific Interstate Company (an interstate pipeline affiliate), a Financial Analyst for Pacific Enterprises Oil & Gas Company (an oil exploration and production affiliate), as an analyst in the Strategic Planning & Economic Analysis department, as the Financial Analyst for the New Product Development department, as a Market Advisor for the Customer Service & Information department, and as Principle Economic Analyst for the Regulatory Affairs department. I have been in my current position as Natural Gas Transportation Rates Manager since June, 2010.

As Manager of Gas Transportation Rates I am responsible for managing the gas transportation rates for both SoCalGas and for SDG&E. This includes allocating authorized revenue requirements to customer rate classes; and, developing the design of the rate for each class; and, managing the impact on customers' monthly bills.

I have previously testified before the Commission.

QUALIFICATIONS OF RICHARD M. MORROW

My name is Richard M. Morrow. I am the Vice President of Engineering & Operations Staff for Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E). My business address is 555 West Fifth Street, Los Angeles, California 90013-1011. I have been a vice president of SoCalGas since 1995 and of SDG&E since 2001.

I received a Bachelor of Science degree in Chemical Engineering from California State Polytechnic University and a Master of Chemical Engineering degree from the University of California at Davis. I am also a registered petroleum engineer in California. I have been employed by SoCalGas since 1974. I have held various positions for over the past 37 years with SoCalGas, including positions in Engineering, Transmission and Storage, Environmental Engineering, Gas Supply, Gas Acquisition, Gas Exploration, Gas Distribution and Customer Service.

I am responsible for the SoCalGas and SDG&E transmission and distribution pipeline integrity programs, gas engineering, measurement, transmission system planning, gas storage and pipeline capacity programs, project development and construction, and account management for our largest energy users including electric generators and wholesale customers. My organization is also responsible for developing and overseeing the gas standards and operating policies pertaining to distribution, transmission and customer service field operations.

I have previously testified before the Commission.

QUALIFICATIONS OF JOSEPH M. RIVERA

My name is Joseph M. Rivera and I am currently the Director of Gas Engineering for SoCalGas and SDG&E. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I hold a Bachelor of Science degree in Civil Engineering from California State Polytechnic University, Pomona, and have completed the Executive Program at the University of Michigan Business School. I have broad background in engineering and natural gas pipeline operations with 36 years of experience with SoCalGas and one year with Sempra Energy Utility Ventures. I have held a number of key managerial positions with increasing responsibility in Engineering, Distribution Operations, and Transmission Operations. In recent years, I have held the positions of Vice President of Operations (with Sempra Energy Utility Ventures), Director of Procurement and Logistics and General Manager of Mountain View Region. Throughout my career, I have been responsible for various areas related to the design, construction, operation and maintenance of transmission and distribution system facilities.

As the Director of Gas Engineering, I am responsible for providing centralized gas infrastructure engineering and technical services to support utility operations. To accomplish this responsibility, I manage an organization of approximately 300 employees. I have held this position since January 2000.

I have previously testified before the Commission.

QUALIFICATIONS OF DOUGLAS M. SCHNEIDER

My name is Douglas M. Schneider. I am employed by Southern California Gas Company (SoCalGas) as the Director of Pipeline Integrity. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I graduated from Rutgers University in 1988 with a Bachelor of Arts degree in Chemistry and from California State University Fullerton in 1993 with a Master of Business Administration degree. I am also a Registered Professional Engineer in California and have over 20 years of industry experience related to pipeline safety and corrosion control.

I was first employed by SoCalGas as an Engineer from 1991 to 1997, and returned to SoCalGas in 2001. From 1997 to 2001, I was employed as Vice President of Sales and Marketing with Rohrback Cosasco Systems, a manufacturer of corrosion control instrumentation and related systems based in Santa Fe Springs, CA.

In my current position, my responsibilities include overseeing the transmission and distribution pipeline integrity programs and other activities related to pipeline safety for SoCalGas and San Diego Gas and Electric Company. My previous experience includes positions of increasing responsibility including Engineering Design Manager, Technical services Manager, Special Projects Manager and Pipeline Integrity Manager.

I have not previously testified before the California Public Utilities Commission.

QUALIFICATIONS OF CHERYL A. SHEPHERD

My name is Cheryl A. Shepherd. I am employed by Southern California Gas Company (SoCalGas) as the Director of Financial Analysis and Assistant Treasurer. My business address is 555 W. Fifth Street, Los Angeles, California, 90013.

I received a Bachelor of Science degree in Economics from the University of California at Los Angeles, where my area of emphasis was accounting and finance.

I have been in my current position since December, 2010. In my current position my responsibilities include overseeing the strategic and financial analysis in support of new investment opportunities, the development and analysis of ratebase, and implementation of revenue requirements, regulatory accounts, and cost recovery strategies for SoCalGas.

I have been employed by SCG in various positions and responsibilities since 1981. My experience is in numerous areas including Cost Accounting, Treasury, Financial Planning, Market Services, Human Resources, Accounting Operations, Real Estate, and Customer Operations.

I have previously testified before the California Public Utilities Commission.

Appendix A
Table of Acronyms

Acronym	Definition
ASV	Automatic Shutoff Valve
Bcf	Billion Cubic Feet
CAISO	California Independent System Operator
CARE	California Alternate Rate for Energy
CDFG	California Department of Fish and Game
CEQA	California Environmental Quality Act
COF	Consequence of Failure
EAMS	Enterprise Asset Management System
EPAM	Equal Percent of Authorized Margin
GIS	Geographical Information System
GO	General Order
HCA	High Consequence Area
ILI	In-Line Inspection
LOF	Likelihood of Failure
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic Flux Leakage
MinOP	Minimum Operating Pressure
MMcfd	Million Cubic Feet Per Day
NDE	Non-Destructive Examination
NGV	Natural Gas Vehicle
NTSB	National Transportation Safety Board
O&M	Operating and Maintenance
PG&E	Pacific Gas and Electric Company
PG&E/GTN	Pacific Gas and Electric Company/Gas Transmission Northwest

Acronym	Definition
PPPS	Public Purpose Program Surcharge
PSEP	Pipeline Safety Enhancement Plan
PSEP PMO	Pipeline Safety Enhancement Plan Project Management Organization
RCV	Remote Control Valve
SCADA	Supervisory Control and Data Acquisition
SMYS	Specified Minimum Yield Strength
SoCalGas	Southern California Gas Company
SPEC Services	System Planning Engineering and Consulting Services
TFI	Transverse Field Inspection
TIMP	Transmission Integrity Management Program

Appendix B[84]

Proposed Case Pipeline Safety Enhancement Plan Direct Costs

(In Millions of Dollars)

SoCalGas												
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
Pipeline Replacement												
Capital	$0	$90	$243	$243	$243	$0	$0	$0	$0	$0	$0	$818
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Pressure Testing												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$36	$49	$49	$49	$0	$0	$0	$0	$0	$0	$183
In-Line-Inspection												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$12	$15	$15	$15	$0	$0	$0	$0	$0	$0	$58
Remote Control & Automatic Shutoff Valves												
Capital	$0	$26	$28	$33	$33	$32	$32	$29	$29	$29	$29	$301
O&M	$0	$0	$0	$1	$1	$1	$2	$2	$2	$2	$2	$14
Mitigation of Pre-1946 Construction Methods												
Capital	$0	$29	$57	$57	$57	$167	$167	$167	$128	$128	$128	$1,084
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Technology Enhancements												
Capital	$0	$15	$17	$7	$6	$2	$3	$3	$2	$2	$2	$57
O&M	$0	$0	$0	$1	$1	$1	$1	$1	$1	$1	$1	$7
Enterprise Asset Management System												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6
Interim Safety Enhancement Measures												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$6	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11
Implementation Costs												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
Total												
Capital	$0	$160	$345	$340	$339	$201	$201	$199	$158	$158	$159	$2,260
O&M	$6	$59	$65	$66	$66	$2	$3	$3	$3	$3	$3	$279

[84] Numbers may not add up due to rounding.

Appendix B (Cont'd)[85]

Proposed Case Pipeline Safety Enhancement Plan Direct Costs

(In Millions of Dollars)

SDG&E												
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
Pipeline Replacement												
Capital	$0	$23	$58	$58	$58	$106	$106	$106	$0	$0	$0	$515
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Pressure Testing												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0	$0	$11
In-Line-Inspection												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$0	$0	$4	$0	$0	$0	$0	$0	$0	$0	$4
Remote Control and Automatic Shutoff Valves												
Capital	$0	$5	$6	$7	$7	$6	$6	$6	$6	$6	$6	$61
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3
Mitigation of Pre-1946 Construction Methods												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Technology Enhancements												
Capital	$0	$2	$2	$1	$1	$0	$0	$0	$0	$0	$0	$8
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
Enterprise Asset Management System												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
Interim Safety Enhancement Measures												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2
Implementation Costs												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
Total												
Capital	$0	$30	$67	$66	$66	$112	$112	$112	$6	$6	$6	$583
O&M	$1	$1	$0	$5	$0	$0	$0	$0	$11	$0	$0	$20

85 Numbers may not add up due to rounding.

Appendix C[86]
Base Case Direct Costs
(In Millions of Dollars)

SoCalGas												
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
Pipeline Replacement												
Capital	$0	$90	$243	$243	$243	$0	$0	$0	$0	$0	$0	$818
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Pressure Testing												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$36	$49	$49	$49	$0	$0	$0	$0	$0	$0	$183
In-Line-Inspection												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$12	$15	$15	$15	$0	$0	$0	$0	$0	$0	$58
Remote Control & Automatic Shutoff Valves												
Capital	$0	$26	$28	$33	$33	$32	$32	$29	$29	$29	$29	$301
O&M	$0	$0	$0	$1	$1	$1	$2	$2	$2	$2	$2	$14
Interim Safety Enhancement Measures												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$6	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11
Implementation Costs												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
Total												
Capital	$0	$116	$271	$276	$276	$32	$32	$29	$29	$29	$29	$1,119
O&M	$6	$53	$65	$65	$65	$1	$2	$2	$2	$2	$2	$265

86 Numbers may not add up due to rounding.

Appendix C (Cont'd)[87]

Base Case Direct Costs

(In Millions of Dollars)

SDG&E												
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total**
Pipeline Replacement												
Capital	$0	$23	$58	$58	$58	$106	$106	$106	$0	$0	$0	$515
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Pressure Testing												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0	$0	$11
In-Line-Inspection												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$0	$0	$4	$0	$0	$0	$0	$0	$0	$0	$4
Remote Control & Automatic Shutoff Valves												
Capital	$0	$5	$6	$7	$7	$6	$6	$6	$6	$6	$6	$61
O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3
Interim Safety Enhancement Measures												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2
Implementation Costs												
Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
Total												
Capital	$0	$28	$64	$65	$65	$112	$112	$112	$6	$6	$6	$575
O&M	$1	$1	$0	$5	$0	$0	$0	$0	$10	$0	$0	$19

87 Numbers may not add up due to rounding.

Appendix D

Pressure Testing Cost Estimating Methodology and Assumptions

The following methodology and assumptions were used to prepare the cost estimates for performing pressure testing of existing pipelines:

1. Total pipeline testing length was obtained from pipeline stationing used in tabulating Category 4 pipeline segments.

2. Pipeline data, such as pipeline diameter and operating pressure, were provided to SPEC Services by SoCalGas and SDG&E.

3. Based on SPEC Services review of pipeline stationing, the total number of hydrotest sections was determined. For cost and efficiency reasons, some hydrotest sections include multiple individual pipeline segments requiring pressure testing. As a result, pipeline segments not requiring pressure testing, which bridge the required segments together, are included in the hydrotest section.

4. The elevation profile for each pipeline was assumed to be flat for reasons of simplicity. Understanding that additional hydrotest sections could be required for some pipelines with significant elevation change, provisions were included in the cost estimates to allow for additional hydrotest sections, if necessary.

5. For each hydrotest section it was assumed that SoCalGas will launch a pig from an existing launcher station. At the point the pig passes a mainline block valve upstream of a hydrotest segment, the block valve will be closed and a nitrogen truck will be connected downstream of the valve. The nitrogen will be used to continue to push the pig and purge the pipeline. At this point the valve will be closed and the nitrogen flow shut off and disconnected. This will leave the hydrotest section full of nitrogen and isolated between two mainline block valves. It was assumed existing valve spacing is 4 miles for nitrogen purging purposes.

6. The isolated pipeline will be purged of nitrogen from an existing vent or from a new tap. At points upstream and downstream of the hydrotest section the line will be cut and a temporary launcher and receiver will be installed.

7. Estimate assumes on-site water supply will be available for purchase at one end of the pipeline segment. Water from source will be diverted into an on-site vacuum truck connected to a temporary launcher. Once the pipeline is full of water and static, pumps

will be used to bring pressure up to desired test limit. Test pressure will be held for 8 hours. Estimate includes cost of third party witness.

8. Estimate assumes Baker Tanks (500 BBL capacity) will be positioned at the end of each hydrotest section to collect water after each hydrotest. For each Baker Tank there will be a dedicated vacuum truck collecting water for disposal. Estimate assumes that the maximum quantity of Baker Tanks for any hydrotest segment will be 10. This quantity of tanks assumes dewatering and disposal can occur simultaneously at a comparable rate. Water disposal location was assumed to allow for ten round trips per day for each vacuum truck. Estimate assumes a 1-hour round trip return, contaminated water, and a disposal fee.

9. For each hydrotest segment, it was assumed that multiple swab pigs will be sent through each hydrotest segment followed by compressed air for drying of the pipeline. Once the segments have been dried, tie-ins will be performed returning the pipeline back to operation.

10. Miscellaneous materials include air compressors, pigs, valves, fittings, disposables, etc.

11. Labor includes test technicians, welders, helpers, pipe fitter, etc. for setting the test heads and required equipment such as pumps, tanks, meters, filters, etc.

12. Costs are based on databases and recent construction estimates and/or bid data from projects SPEC Services has been involved. Labor rates are applicable through 2011 and do not include escalation.

13. Material costs were supplied by local material vendors. Material prices are based on current quotations and do not include escalation.

14. A “day” is defined as eight hours.

15. Estimate assumes the disposal of contaminated test water through Baker Tanks with filtration and testing at an approved location.

16. Estimate includes rental rate for a 1,200 GPM pump for filling the line.

17. Estimate includes all labor, materials, and equipment for one eight-person crew, working eight hours per day for estimated duration. The duration includes mobilization, set-up, hydrotest work, clean-up and purging of pipeline.

18. Construction management activities are based on total construction duration with contractor.

19. This estimate is based on preliminary engineering only and includes several assumptions. As a result, the estimate includes a 20% or 30% contingency depending on total estimated cost. Once detailed engineering and design are completed a revised estimate can be generated to reflect the actual scope of project and associated permit conditions.

Appendix E
Pipeline Replacement Estimate Assumptions

The following methodology and assumptions were used to prepare cost estimates for pipeline replacements:

1. Total pipeline length was provided to SPEC Services by SoCalGas and SDG&E.
2. Pipeline data, such as pipeline diameter and operating pressure, were provided to SPEC Services by SoCalGas and SDG&E.
3. GIS maps of each pipeline were studied to identify the location and type of construction applicable for each relocation area.
4. Construction types were assumed and applied to individual projects, as follows:

   Type 1 – **Rural**: Pipeline installations within Rural include no paving, minimum 36-inch cover depth, native backfill, minimum 30-foot wide workspace, limited existing substructures along alignment, no traffic control, no environmental restrictions and unrestricted work hours.*

   Type 2 – **Secondary Roadway**: Pipeline installations within Secondary Roadway include asphalt paving, minimum 48-inch cover depth, native backfill, minimum two-lane workspace, medium-density substructures, limited traffic control, no environmental restrictions, and normal working hours.*

   Type 3 – **Primary Roadway**: Pipeline installations within Primary Roadway include asphalt/concrete paving, minimum 48-inch cover, slurry backfill, minimum two-lane workspace, high-density substructures, heavy traffic control, no environmental restrictions, and restricted working hours (9:00 am to 3:30 pm).*

   Type 4 – **Auger Bore**: Installations within Auger Bore include bore/receiving pit excavation (15-foot maximum depth), auger bore equipment rental, and casing stringing/welding.**

   Type 5 – Horizontal Directional Drilling: Installations within Horizontal Directional Drilling include rig equipment rental, 2,000-foot maximum drill length, and pipe stringing/welding.**

Type 6 – Special Circumstances (*e.g.*, bridge crossing, etc.)

Type 7 – Night Work on Primary Roadway (30% more than Type 3): Installations within Night Work on Primary Roadway include asphalt/concrete paving, minimum 48-inch cover depth, slurry backfill, minimum two-lane workspace, high-density substructures, heavy traffic control, no environmental restrictions, and restricted working hours (10:00 pm to 5:00 am).*

* General construction labor rates include all activities associated with pipe installation, including but not limited to: trench excavation, pipe stringing/welding, pipe lowering/fitting, backfill/compaction, hydrotesting, pipeline cleaning, and surface restoration.

** Specialty construction labor rates include sub-contracting equipment, pit excavation, pipe/casing stringing, welding, and backfill/compaction associated with auger bore and HDD.

5. The construction cost per foot of pipeline replacement is based on recent construction estimates and/or bid data from projects SPEC Services has been involved.
6. Material costs were obtained through acquiring quotes from suppliers. Material prices are based on current quotations and do not include escalation.
7. The estimates prepared include the following assumptions/clarifications:

   a) Estimates do not currently include cost or time for the following items: contaminated soil handling/disposal, asbestos abatement, right-of-way acquisition, construction permits and environmental permits. Costs for these items will be added on a case by case basis.

   b) Miscellaneous materials include: shrink sleeves, test stations, small fittings, disposables, etc.

   c) Construction labor costs are based on SPEC Service's project database, and input provided by local construction contractors. Labor rates are applicable for construction through 2011 and do not include escalation.

e) Analogous and parametric estimating techniques were used to prepare the project cost estimates.

f) Estimates assume production rates based on construction type, inspection by SoCalGas or SDG&E, radiographic inspection, construction staking and as-built surveying. The following production rates (one day is 8 hrs.) were applied:

Type 1 – 1,500 feet/day

Type 2 – 500 feet/day

Type 3 – 300 feet/day

Type 4 – 100 feet/day

Type 5 – 100 feet/day

g) Construction is assumed to have a minimum duration of ten days for each pipeline replacement, regardless of length.

h) Valve costs include: actuator (gas and electric), ASV/RCV capability, vault, and conduit from valve to control panel.

i) Tie-in crew rates (including welders, helpers, pipe-fitters, etc.) were based on pipeline outside diameter involved in tie-in:

- Pipe diameters less than 12" have a crew rate of $25,000
- Pipe diameters greater than 12" and less than 24" have a crew rate of $35,000
- Pipe diameters greater than 24" have a crew rate of $60,000

j) SoCalGas and SDG&E labor /inspection percentages include the following internal SoCalGas or SDG&E costs: inspection, engineering, project management and overhead.

k) This estimate is based on preliminary engineering only and includes several assumptions

l) Radiographic Inspection and Construction Stake As-Built Survey are assumed to have minimum base periods of two days.

Appendix F
Illustrative PSEP Surcharge for Phase 1

Proposed Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SoCalGas												
Monthly PSEP Surcharges ($/mo)												
Residential	0.00	0.67	1.07	2.11	2.82	2.83	3.36	3.86	4.50	4.58	4.82	5.01
Volumetric PSEP Surcharges ($/th)												
Core Commercial & Industrial	0.000	0.008	0.013	0.026	0.035	0.035	0.041	0.048	0.055	0.057	0.060	0.062
Gas Air Conditioning	0.000	0.002	0.004	0.007	0.010	0.010	0.012	0.013	0.016	0.016	0.017	0.017
Gas Engine	0.000	0.003	0.005	0.009	0.013	0.013	0.015	0.017	0.020	0.021	0.022	0.023
Natural Gas Vehicle	0.000	0.002	0.004	0.008	0.010	0.010	0.012	0.014	0.016	0.017	0.018	0.018
Noncore C&I - Distribution	0.000	0.002	0.004	0.007	0.010	0.010	0.012	0.013	0.015	0.016	0.017	0.017
Electric Generation - Distribution	0.000	0.001	0.002	0.003	0.004	0.004	0.005	0.006	0.007	0.007	0.007	0.008
Enhanced Oil Recovery - Distribution	0.000	0.001	0.002	0.003	0.004	0.004	0.005	0.006	0.007	0.007	0.007	0.008
Transmission Level Service	0.000	0.001	0.001	0.002	0.003	0.003	0.003	0.004	0.005	0.005	0.005	0.005
SDG&E												
Monthly PSEP Surcharges ($/mo)												
Residential	0.00	0.67	1.08	2.11	2.83	2.83	3.36	3.87	4.50	4.58	4.83	5.01
Volumetric PSEP Surcharges ($/th)												
Core Commercial & Industrial	0.000	0.008	0.013	0.026	0.035	0.035	0.041	0.048	0.055	0.057	0.060	0.062
Natural Gas Vehicle	0.000	0.002	0.004	0.008	0.010	0.010	0.012	0.014	0.016	0.017	0.018	0.018
Noncore C&I - Distribution	0.000	0.002	0.004	0.007	0.010	0.010	0.012	0.013	0.016	0.016	0.017	0.017
Electric Generation - Distribution	0.000	0.001	0.002	0.003	0.004	0.004	0.005	0.006	0.007	0.007	0.007	0.008
Transmission Level Service	0.000	0.001	0.001	0.002	0.003	0.003	0.003	0.004	0.005	0.005	0.005	0.005

Base Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SoCalGas												
Monthly PSEP Surcharges ($/mo)												
Residential	0.00	0.68	1.03	1.76	2.38	2.28	2.48	2.70	3.04	2.88	2.87	2.82
Volumetric PSEP Surcharges ($/th)												
Core Commercial & Industrial	0.000	0.008	0.013	0.022	0.029	0.028	0.031	0.033	0.038	0.036	0.035	0.035
Gas Air Conditioning	0.000	0.002	0.004	0.006	0.008	0.008	0.009	0.009	0.011	0.010	0.010	0.010
Gas Engine	0.000	0.003	0.005	0.008	0.011	0.010	0.011	0.012	0.014	0.013	0.013	0.013
Natural Gas Vehicle	0.000	0.002	0.004	0.006	0.009	0.008	0.009	0.010	0.011	0.011	0.010	0.010
Noncore C&I - Distribution	0.000	0.002	0.004	0.006	0.008	0.008	0.009	0.009	0.010	0.010	0.010	0.010
Electric Generation - Distribution	0.000	0.001	0.002	0.003	0.004	0.004	0.004	0.004	0.005	0.004	0.004	0.004
Enhanced Oil Recovery - Distribution	0.000	0.001	0.002	0.003	0.004	0.004	0.004	0.004	0.005	0.004	0.004	0.004
Transmission Level Service	0.000	0.001	0.001	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003
SDG&E												
Monthly PSEP Surcharges ($/mo)												
Residential	0.00	0.68	1.03	1.76	2.38	2.28	2.48	2.70	3.05	2.88	2.88	2.82
Volumetric PSEP Surcharges ($/th)												
Core Commercial & Industrial	0.000	0.008	0.013	0.022	0.029	0.028	0.031	0.033	0.038	0.036	0.035	0.035
Natural Gas Vehicle	0.000	0.002	0.004	0.006	0.009	0.008	0.009	0.010	0.011	0.011	0.010	0.010
Noncore C&I - Distribution	0.000	0.002	0.004	0.006	0.008	0.008	0.009	0.009	0.011	0.010	0.010	0.010
Electric Generation - Distribution	0.000	0.001	0.002	0.003	0.004	0.004	0.004	0.004	0.005	0.004	0.004	0.004
Transmission Level Service	0.000	0.001	0.001	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003	0.003

Appendix G
Illustrative PSEP Surcharge for CARE Participants for Phase 1

Proposed Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Monthly CARE PSEP Surcharges												
SoCalGas - Residential $/mo	0.00	0.53	0.86	1.68	2.26	2.26	2.69	3.09	3.60	3.66	3.86	4.00
SDG&E - Residential $/mo	0.00	0.53	0.86	1.69	2.26	2.26	2.69	3.09	3.60	3.67	3.86	4.01

Base Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Monthly CARE PSEP Surcharges												
SoCalGas - Residential $/mo	0.00	0.55	0.82	1.41	1.91	1.82	1.99	2.16	2.43	2.30	2.30	2.25
SDG&E - Residential $/mo	0.00	0.55	0.82	1.41	1.91	1.83	1.99	2.16	2.44	2.31	2.30	2.26

Appendix H
Illustrative Public Purpose Program Surcharge Rates for Phase 1

Proposed Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SoCalGas - $/th												
Residential	0.077	0.078	0.078	0.079	0.080	0.080	0.080	0.081	0.081	0.081	0.082	0.082
Core Commercial & Industrial	0.068	0.069	0.069	0.070	0.071	0.071	0.071	0.072	0.072	0.073	0.073	0.073
Natural Gas Vehicle	0.031	0.031	0.032	0.033	0.033	0.033	0.034	0.034	0.035	0.035	0.035	0.036
Noncore C&I	0.035	0.035	0.036	0.037	0.037	0.037	0.038	0.038	0.039	0.039	0.039	0.040
SDG&E - $/th												
Residential	0.076	0.076	0.077	0.078	0.079	0.079	0.079	0.080	0.080	0.080	0.081	0.081
Core Commercial & Industrial	0.120	0.121	0.121	0.123	0.123	0.123	0.124	0.124	0.125	0.125	0.125	0.126
Natural Gas Vehicle	0.032	0.033	0.033	0.034	0.035	0.035	0.035	0.036	0.037	0.037	0.037	0.037
Noncore C&I	0.114	0.115	0.115	0.116	0.117	0.117	0.118	0.118	0.119	0.119	0.119	0.119

Base Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SoCalGas - $/th												
Residential	0.077	0.078	0.078	0.079	0.079	0.079	0.079	0.079	0.080	0.080	0.080	0.080
Core Commercial & Industrial	0.068	0.069	0.069	0.070	0.070	0.070	0.070	0.071	0.071	0.071	0.071	0.071
Natural Gas Vehicle	0.031	0.031	0.032	0.032	0.033	0.033	0.033	0.033	0.034	0.034	0.034	0.033
Noncore C&I	0.035	0.035	0.036	0.036	0.037	0.037	0.037	0.037	0.038	0.038	0.038	0.037
SDG&E - $/th												
Residential	0.076	0.076	0.077	0.077	0.078	0.078	0.078	0.078	0.079	0.079	0.079	0.079
Core Commercial & Industrial	0.120	0.121	0.121	0.122	0.123	0.123	0.123	0.123	0.124	0.123	0.123	0.123
Natural Gas Vehicle	0.032	0.033	0.033	0.034	0.034	0.034	0.035	0.035	0.035	0.035	0.035	0.035
Noncore C&I	0.114	0.115	0.115	0.116	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.117

Appendix I
Consolidated Impact of Pipeline Safety Enhancement Plan Phase 1

Proposed Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SoCalGas												
Residential Avg Monthly Bill - $/mo (1)	39.08	39.77	40.19	41.26	42.00	42.01	42.56	43.08	43.74	43.82	44.07	44.26
Non-res Rates ($/th) (2)												
Core Commercial & Industrial	0.383	0.392	0.398	0.411	0.421	0.421	0.428	0.435	0.443	0.444	0.448	0.450
Natural Gas Vehicle	0.120	0.123	0.125	0.129	0.133	0.133	0.135	0.138	0.140	0.141	0.142	0.143
Noncore C&I - Distribution	0.109	0.112	0.114	0.118	0.121	0.121	0.124	0.126	0.129	0.129	0.130	0.131
Electric Generation - Distribution	0.039	0.040	0.040	0.042	0.043	0.043	0.044	0.045	0.046	0.046	0.046	0.046
Transmission Level Service	0.025	0.026	0.026	0.027	0.028	0.028	0.029	0.029	0.030	0.030	0.030	0.030
SDG&E												
Residential Avg Monthly Bill - $/mo (1)	38.76	39.45	39.87	40.94	41.68	41.69	42.24	42.76	43.41	43.50	43.75	43.94
Non-res Rates ($/th) (2)												
Core Commercial & Industrial	0.370	0.379	0.384	0.398	0.407	0.408	0.415	0.421	0.430	0.431	0.434	0.437
Natural Gas Vehicle	0.119	0.122	0.124	0.129	0.132	0.132	0.135	0.137	0.140	0.141	0.142	0.143
Noncore C&I - Distribution	0.255	0.258	0.259	0.264	0.267	0.267	0.270	0.272	0.275	0.275	0.276	0.277
Electric Generation - Distribution	0.042	0.043	0.044	0.046	0.047	0.047	0.047	0.048	0.049	0.049	0.050	0.050
Transmission Level Service	0.025	0.026	0.026	0.027	0.028	0.028	0.029	0.029	0.030	0.030	0.030	0.030

(1) Residential Average Monthly Bill includes transportation rates, commodity charges, commission fees, PSEP surcharge, and PPPS rates.
(2) Non-res Rates are current class-average transportation rate plus volumetric PSEP surcharge and PPPS rates.

Base Case

		Phase 1A				Phase 1A & 1B						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SoCalGas												
Residential Avg Monthly Bill - $/mo (1)	39.08	39.78	40.14	40.90	41.54	41.44	41.65	41.87	42.23	42.06	42.05	42.00
Non-res Rates ($/th) (2)												
Core Commercial & Industrial	0.383	0.392	0.397	0.407	0.415	0.414	0.416	0.419	0.424	0.422	0.422	0.421
Natural Gas Vehicle	0.120	0.123	0.124	0.128	0.131	0.130	0.131	0.132	0.134	0.133	0.133	0.133
Noncore C&I - Distribution	0.109	0.112	0.113	0.117	0.119	0.119	0.120	0.121	0.122	0.122	0.122	0.121
Electric Generation - Distribution	0.039	0.040	0.040	0.041	0.042	0.042	0.043	0.043	0.043	0.043	0.043	0.043
Transmission Level Service	0.025	0.026	0.026	0.027	0.028	0.027	0.028	0.028	0.028	0.028	0.028	0.028
SDG&E												
Residential Avg Monthly Bill - $/mo (1)	38.76	39.47	39.82	40.58	41.23	41.12	41.33	41.55	41.91	41.74	41.73	41.68
Non-res Rates ($/th) (2)												
Core Commercial & Industrial	0.370	0.379	0.383	0.393	0.402	0.400	0.403	0.406	0.410	0.408	0.408	0.407
Natural Gas Vehicle	0.119	0.122	0.124	0.127	0.130	0.130	0.131	0.132	0.133	0.133	0.133	0.132
Noncore C&I - Distribution	0.255	0.258	0.259	0.263	0.265	0.265	0.266	0.267	0.268	0.268	0.268	0.267
Electric Generation - Distribution	0.042	0.043	0.044	0.045	0.046	0.046	0.046	0.046	0.047	0.047	0.047	0.047
Transmission Level Service	0.025	0.026	0.026	0.027	0.028	0.027	0.028	0.028	0.028	0.028	0.028	0.028

(1) Residential Average Monthly Bill includes transportation rates, commodity charges, commission fees, PSEP surcharge, and PPPS rates.
(2) Non-res Rates are current class-average transportation rate plus volumetric PSEP surcharge and PPPS rates.