BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	))))))	A.11-11-002

PHASE 1 OPENING BRIEF OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G)

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SUMMARY OF RECOMMENDATIONS

SoCalGas and SDG&E respectfully request that the Commission take the following actions with respect to their proposed Pipeline Safety Enhancement Plan:

RESPONSIBILITY FOR PHASE I COSTS

- Authorize SoCalGas and SDG&E to fully recover in customer rates the revenue requirements resulting from their Phase 1A capital and O&M expense forecasts, with no "disallowances" or "shareholder responsibility" for such expenses.
- Affirm the direction provided by the Commission in Ordering Paragraph No. 4 of D.11-06-017 that all in-service natural gas transmission pipelines in California will need to be pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c).
- Affirm that pre-1970 pipelines are required to be tested to modern standards, and modern standards means a 49 CFR 192 Subpart J pressure test, even when the utilities have a pressure test record that includes all elements required by the regulations in effect when the test was conducted.
- Decline to consider recordkeeping penalty proposals in Phase 1 of this proceeding.

PROPOSED PIPELINE SAFETY ENHANCEMENT PLAN

General Plan-Related Proposals

- Approve SoCalGas and SDG&E's proposed three-phased prioritization schedule and timeline for the entire PSEP.
- Affirm that SoCalGas and SDG&E may address segments out of rank-order to address operational constraints, permit delays, and/or project efficiencies.
- Approve SoCalGas and SDG&E's interim safety enhancement measures, which include: pressure reductions, more frequent ground patrols and leak surveys, and inline inspections using transverse field inspection technology.
- Affirm that execution of the approved PSEP 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 PSEP.

- Create a Commission plan, with the support of the natural gas utilities, to educate state, federal, and local agencies that will be called upon to provide environmental approvals of Plan projects, so that these projects may receive priority treatment in the permit application process.
- Request that applicable permitting agencies set aside personnel and consultant resources that can be funded by the natural gas utilities to focus on PSEP projects.
- Request that all environmental agencies develop or expeditiously approve pending applications for programmatic permits to ensure consistent permit conditions and mitigation requirements for PSEP projects.

Plan to Test or Replace Pipeline Segments

- Approve SoCalGas and SDG&E's proposed criteria for determining whether to test or replace pipeline segments:
    - Complete direct assessment using direct examination or replace pipeline segments that are less than 1,000 feet in length unless our cost benefit analysis indicates it would be more cost effective to pressure test.
    - Pressure test pipeline segments that are greater than 1,000 feet in length that can be removed from service for testing with manageable customer impacts (unless the segment was installed prior to 1946 and is unpiggable).
    - Replace pipeline segments that are greater than 1,000 feet in length that cannot be removed from service for testing with manageable customer impacts.
    - Replace all unpiggable pipeline segments installed prior to 1946.
- Authorize inline inspection of all piggable transmission pipelines in populated areas using transverse field inspection technology prior to pressure testing.
- Authorize replacement of the specific non-piggable portions of transmission pipeline segments that contain pre-1946 girth welds.
- Authorize removal of wrinkle bends in transmission pipeline segments operated in populated areas.

- Approve SoCalGas and SDG&E's proposed method for performing a test or replace cost benefit analysis during the engineering and design process.
- Affirm that SoCalGas and SDG&E may accelerate pipeline segments and/or include distribution pipeline segments within the scope of a test or replace project in Phase 1A when it is more operationally efficient or cost-effective to do so.
- Authorize SoCalGas and SDG&E to assemble an Engineering Advisory Board for the purpose of reviewing and commenting on test/replace and project scope/design (*e.g.*, accelerated mileage, capacity increases, and alternate routing) determinations.
- Decline to adopt SCGC's proposal to file an expedited application for each proposed replacement project.
- Direct Commission Staff to work with interested stakeholders to develop a standard for determining when a pressure reduction may be used as an alternative to pressure testing or replacement.

Valve Enhancement Plan

- Approve the ten-year valve enhancement schedule proposed by SoCalGas and SDG&E.
- Authorize installation of automatic shutoff and remote control valve capability to isolate all transmission pipeline segments greater than or equal to twenty inches in diameter that are located in populated areas at intervals of approximately eight miles or less.
- Authorize installation of automatic shutoff and remote control valve capability to isolate all transmission pipeline segments less than twenty inches in diameter if a pipeline is equal to or larger than twelve inches in diameter operating at 30% or more of Specified Minimum Yield Strength at approximately eight mile intervals.
- Authorize retrofitting of up to twenty pipeline segments meeting the above criteria that also cross a known geological threat with automatic shutoff and remote control valve capability at "Short Interval Spacing" (i.e., spacing between half a mile and one mile in length).
- Approve the prioritization of Valve Enhancement Plan work 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.

- Approve the installation of 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.
- Authorize the implementation of system modifications to prevent backflow of gas from supply lines feeding ruptured gas transmission lines.
- Approve the installation of meters at taps and pipeline interconnections to measure flow from transmission pipelines.
- Authorize expansion of the existing SCADA system to support enhanced system management.
- Approve expansion of the coverage area of private radio networks currently planned or employed by SoCalGas and SDG&E.
- Decline to order SoCalGas and SDG&E to operate enhanced shutoff valves in automatic shutoff mode, and instead, affirm that SoCalGas and SDG&E should exercise sound engineering judgment to determine the safe operation of enhanced valves.

Technology Enhancement Program

- Authorize the installation of fiber-optic sensing on all future pipeline installations twelve inches and greater in diameter.
- Authorize the installation of continuous methane monitors on all pipelines twelve inches and greater in diameter routed in Location Class 3 and 4 areas and High Consequence Areas.
- Approve the development of a Data Collection and Management System to interface with fiber optic and methane detection sensors to be installed under the Plan.

Enterprise Asset Management System

- Authorize the development of detailed architecture and design of an Enterprise Asset Management System.

PHASE 1A COST ESTIMATES

- Approve capital forecasts for Phase 1A of $1.2 billion for SoCalGas and $229 million for SDG&E and O&M forecasts for Phase 1A of $255 million for SoCalGas and $7 million for SDG&E.
- Approve pipeline replacement and pressure test contingencies used to develop the capital and O&M forecasts of 20% for projects in excess of $2 million and 30% for projects under $2 million.
- Approve the valve and technology enhancement contingency of 8%.
- Decline to adopt the contrary Phase 1A cost estimates proposed by various intervenors.

REVENUE REQUIREMENTS

Proposed Revenue Requirements

- Authorize SoCalGas and SDG&E to recover in customer rates the revenue requirements resulting from their Phase 1A capital and O&M expense forecasts. For the years 2011 through 2015, these proposed Phase 1A revenue requirements are $593 million for SoCalGas and $62 million for SDG&E.

Intervenor Proposals Relating to Revenue Requirements

- Decline to adopt TURN's proposal for AFUDC percentages of 2% for small PSEP jobs and 5% for larger ones.
- Decline to adopt SCGC's recommendation that non-destructive examination costs be entirely expensed.
- Reject TURN's recommendation that the Commission not allow SoCalGas and SDG&E to apply an Incentive Compensation Plan overhead loader to their PSEP-related O&M and capital costs for PSEP-related capital costs.
- Decline to adopt, or even consider in this proceeding, SCIP/Watson's proposal that the Commission adopt a one-way balancing account for SoCalGas and SDG&E TIMP costs.

RATEMAKING TREATMENT FOR RECOVERY OF PHASE 1A COSTS

SoCalGas and SDG&E Ratemaking Proposals

- Authorize SoCalGas and SDG&E to each establish interest-bearing PSEP Cost Recovery Accounts. These will be two-way balancing accounts that record the difference between the authorized revenue requirements collected by the utilities and the actual O&M and capital-related revenue requirements associated with implementation of the PSEP. SoCalGas and SDG&E would not be able to recover any costs above authorized until the Commission has approved the proposed increase.
- Authorize SoCalGas and SDG&E to each file an advice letter to implement the Commission's Phase 1 decision. These advice letters will include updated revenue requirements to reflect any decision-ordered changes to the PSEP, and to adjust the revenue requirements to take into account the timing of the approval.
- Authorize SoCalGas and SDG&E to incorporate updated PSEP revenue requirements into rates on January 1 each year via their annual regulatory account balance update filings until PSEP investments are fully recovered. SoCalGas and SDG&E would include in their annual regulatory account balance update filings the revenue requirement associated with the current-year forecasted year-end balance in their PSEP Cost Recovery Accounts, combined with the PSEP-related revenue requirement for the coming year.
- Authorize SoCalGas and SDG&E to recover in rates costs previously recorded in the utilities' PSEP Memorandum Accounts established pursuant to D.12-04-021, and to include such costs in the utilities' updated PSEP-related revenue requirements. This can be accomplished by the utilities transferring costs recorded in their PSEP Memorandum Accounts to the new PSEP Cost Recovery Accounts and then closing the PSEP Memorandum Accounts.
- Authorize SoCalGas and SDG&E to file expedited advice letters seeking Commission authorization of changes, either up or down, to the overall level of PSEP funding previously authorized by the Commission. These advice letters will include an explanation of the proposed changes, have a protest deadline of 10 days, and request Commission approval within 21 days. This expedited advice letter process would apply to all aspects of the

utilities' PSEP, including any elements adopted by the Commission after an initial Phase 1 decision in this proceeding.

- Authorize SoCalGas and SDG&E to provide the Commission and interested parties with an annual PSEP status report on or before March 31 each year.

Intervenor Ratemaking Proposals

- Decline to adopt DRA's and SCIP/Watson's recommendation for one-way balancing account treatment for PSEP costs.
- Decline to adopt SCGC's proposal that the Commission require SoCalGas and SDG&E to maintain expense and capital subaccounts within their PSEP Cost Recovery Accounts.
- Decline to adopt SCGC's proposal that the Commission not allow recovery of PSEP replacement project revenue requirements until the project is "used and useful."

ADDITIONAL INTERVENOR PROPOSALS

- Decline to adopt the SCIP/Watson proposal that SoCalGas and SDG&E be required to provide "customers operating critical energy infrastructure" with at least 6 months' notice of a PSEP-related curtailment.
- Decline to adopt the SCIP/Watson proposal for a local transmission interruption credit in the event that SoCalGas or SDG&E interrupts noncore customer service due to pipeline integrity work for which the customer has not received at least 30 days notice, or when SoCalGas or SDG&E fail to provide at least six months' notice of an impending curtailment to large noncore customers "operating critical energy infrastructure."
- Decline to adopt the SCIP/Watson proposal that SoCalGas and SDG&E provide reservation charge credits to firm G-BTS backbone transportation customers when their backbone transmission service is disrupted by pipeline safety work.
- Decline to adopt each of UWUA's proposed changes to the O&M practices of SoCalGas.
- Decline to adopt TURN's proposed treatment of royalties received by SoCalGas as a result of SoCalGas' royalty interest in robotic inspection technology developed by the research arm of the Northeast Gas Association (NYSEARCH).

PHASE 1B and PHASE 2

- Authorize SoCalGas and SDG&E to use their proposed prioritization and decision-making process for both Phase 1B and Phase 2.
- Authorize SoCalGas and SDG&E to seek recovery of Phase 1B costs and Phase 2 costs in either upcoming GRCs or via separate application.

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PHASE 1 OPENING BRIEF OF
SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND
SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G)

I. INTRODUCTION AND EXECUTIVE SUMMARY

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) are pleased to submit this Opening Brief in support of our proposed Pipeline Safety Enhancement Plan (PSEP or Plan). We share the Commission's resolve to take those actions necessary to avoid the recurrence of the San Bruno tragedy. Safety is, and has always been, paramount at SoCalGas and SDG&E, and our safe operating histories and cultures are a clear reflection of that.

Since September 9, 2010, our pipeline integrity engineers and supporting personnel have been focused on learning from San Bruno, re-assessing our existing pipeline integrity program and the status of our system, and identifying ways that we might further enhance our own system. Two years 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.

SoCalGas and SDG&E's proposed PSEP stems from Decision (D.) 11-06-017, which directed PG&E, SoCalGas, SDG&E and Southwest Gas to file by August 26, 2011, proposed implementation plans to pressure test or replace all transmission pipelines that do not have documentation of a pressure test or where the pressure test does not meet certain regulatory standards. Decision 11-06-017 further directed these natural gas pipeline operators to consider retrofitting pipelines to allow for inline inspections and enhanced shutoff valves as part of those plans. In the sections that follow, we demonstrate why the Commission should accept our proposed PSEP.

All of the work we propose to complete as part of our PSEP is designed to meet the higher safety and regulatory standards being established by the Commission, and to enhance the safety and reliability of our transmission system for the benefit of our customers. Accordingly, the costs of implementing the PSEP should be recovered from our customers through rates.

Some intervenors recommend that the Commission deviate from standard ratemaking processes and preclude SoCalGas and SDG&E from recovering the full costs of implementing the proposed Plan. In Section III, which follows the Background Section, we explain that these intervenor recommendations are not supported by the record and why their adoption would be punitive, unjustified and against public policy.

While intervenors characterize their recommendations as mere disallowances, the Commission should not be fooled by this labeling. What DRA, TURN and other intervenors recommend are proposed penalties. Intervenors' so-called "disallowances" are not premised on SoCalGas or SDG&E overspending on pipeline safety work or making expenditures that the

Commission does not approve of. There is no showing that the work to be done under PSEP is the result of any violation by SoCalGas or SDG&E of a Commission decision or order, or any other law or regulation. The Commission should not penalize SoCalGas and SDG&E based on speculation or a few missing records, particularly in light of our more than one hundred year old safe operating histories.

SoCalGas and SDG&E do not have a choice about pressure testing or replacing transmission pipelines that do not meet the Commission's new, more stringent standards. And despite what intervenors may say, ratepayers would still have to do the work required under the PSEP even if SoCalGas and SDG&E had a record of every pressure test ever performed. The simple fact of the matter is that any pressure test performed prior to 1970 does not meet the Commission's directive to have all in-service pipeline pressure tested to modern standards.

Our proposed plan to pressure test or replace pipelines that have not been pressure tested to modern standards is discussed in Section IV. There we describe our proposed three-phased prioritization process, which prioritizes pipeline segments in more populated areas ahead of pipeline segments located in less populated areas, prioritizes pipeline segments that do not have documentation of a pressure test to at least 1.25 times the pipeline's maximum allowable operating pressure (MAOP) ahead of pipeline segments that have such documentation, and rank orders pipeline segments based on an assessment of segment-specific risk factors.

In Section IV, we also describe our proposed processes for pressure testing or replacing pipeline segments to achieve the Commission's infrastructure modernization goals, and propose to form an Engineering Advisory Board to review and provide input into our test or replace determinations as we design and engineer each specific pressure test or replacement project. Our proposed plan for testing or replacing pipelines incorporates the use of inline inspections using advanced inline inspection technologies (transverse field inspection or TFI tools) as part of our testing or replacement process, and also includes a proposal to assess whether these advanced inline inspection tools can provide an equivalent means of assessing the integrity of in-service pipelines. We also propose to use non-destructive examination methods, such as radiography, ultrasonic inspection and magnetic particle testing, as an appropriate alternative to pressure testing short segments of pipe. Both of these potential alternatives to pressure testing could significantly reduce the costs and impacts that implementation of our PSEP may have to our customers if they are approved by the Commission.

Section IV also includes an overview of our proposed plan to augment SoCalGas and SDG&E's existing automatic shutoff valves (ASV) and remote controlled valves (RCV) for transmission pipelines routed through populated areas. Through our Valve Enhancement Plan, we propose to install ASV/RCV capability at approximate eight-mile-or-less intervals for all larger-diameter, higher-pressure, transmission pipeline segments. In addition, SoCalGas and SDG&E propose to retrofit up to twenty valves covering such pipeline segments that are also known to cross geological threats at spacing between half a mile and one mile in length. SoCalGas and SDG&E further propose to install supporting equipment and features (*e.g.*, metering stations), to provide enhanced information and control options to SoCalGas and SDG&E personnel to support more timely and informed management decisions in the event of a confirmed (or suspected) pipeline rupture.

In addition, we discuss our proposals to install fiber optic cable on all new pipelines, install gas detection monitors in pipeline rights-of-way near facilities that are high-occupancy and pose evacuation challenges, and install a Data Collection and Management System to interface with these assets. These proposed improvements seek to take advantage of this unique opportunity to retrofit our pipelines while they are either exposed for examination or testing, or are being replaced, to address the most common threat to pipelines—third party damage.

Finally, we discuss in Section IV our proposal to design an Enterprise Asset Management System. As prudent operators, SoCalGas and SDG&E have taken note of what is unfolding in the industry. Lessons learned from San Bruno and the subsequent investigative reports make it prudent to develop new Enterprise Asset Management System capabilities that go beyond current industry standards and regulatory compliance requirements. Our proposal is intended to develop and blueprint these proposed capabilities, requirements, and solutions for subsequent consideration by the Commission.

Section V provides our estimates for capital and Operations and Maintenance (O&M) direct costs for Phase 1A. SoCalGas and SDG&E developed cost estimates for both the work required under D.11-06-017 (Base Case) and additional safety enhancement elements we recommend as part of our Plan (Proposed Case). These cost estimates are based on reasonable assumptions and projections and, when combined with the risk-based allowances provided by contingencies, establish reasonable projections of SoCalGas and SDG&E's PSEP costs. In total, SoCalGas and SDG&E request that the Commission adopt the Phase 1A Proposed Case cost estimates of $1.2 billion for SoCalGas and $229 million for SDG&E for capital costs and $255 million for SoCalGas and $7 million for SDG&E for O&M costs.

In Section VI, SoCalGas and SDG&E offer two alternatives to pressure testing and replacement that could potentially reduce the costs and impacts to our customers of implementing the PSEP. The first proposal is to directly examine pipeline segments less than 1,000 feet in length using non-destructive examination methods (such as ultrasonic, radiographic and magnetic particle inspection techniques). The second proposal is for the Commission to consider the development and approval of rules that would allow for a reduction in the MAOP of a grandfathered pipeline 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.

Section VII presents our proposed revenue requirements based upon the direct costs described in Section V, and explains the methodology we used to develop these revenue requirements. For the years 2011 through 2015, these proposed Phase 1A revenue requirements are $593 million for SoCalGas and $62 million for SDG&E. In Section VII, we also address certain proposals by intervenors regarding the development of PSEP-related revenue requirements, and explain why these proposals should not be adopted by the Commission.

Section VIII describes our proposed PSEP-related regulatory accounting mechanisms, including the PSEP cost recovery account, rate recovery for forecasted and actual PSEP costs, our proposed expedited advice letter process for adjustments to authorized PSEP funding levels, and our proposed annual PSEP update report.

In Section IX, we discuss specific PSEP-related proposals from intervenors that should not be adopted by the Commission.

Finally, in Sections X and XI, SoCalGas and SDG&E describe Phase 1B and Phase 2 of the proposed PSEP, and clarify that we propose to seek authorization to recover the costs of implementing these later phases of our Plan in our 2016 general rate cases (GRC) or other appropriate proceedings.

II. BACKGROUND

At SoCalGas and SDG&E, the safety of our employees, customers and communities has been and will continue to be our highest priority. Our tradition of providing safe and reliable service spans the more than 140 and 131 years of our respective company histories.[1] Our safety philosophy is expressed in the following Commitment to Safety statement that our senior management team wholeheartedly endorses:

> ***[Our] longstanding commitment to safety focuses on three primary areas – employee safety, customer safety and public safety. This safety focus is embedded in what we do and is the foundation for who we are – from initial employee training, to the installation, operation and maintenance of our utility infrastructure, and to our commitment to provide safe and reliable service to our customers.[2]***

While we are proud of our safety and reliability achievements thus far, we know there is always room for improving the overall safety of our pipeline system and infrastructure. SoCalGas and SDG&E know that we cannot be complacent, that we can always do better by applying forward-looking safety strategies, and that we should challenge ourselves to be even more diligent in maintaining the safety of our natural gas system. Our aim is to continuously drive process improvements throughout our pipeline system and operations, to meet state and federal safety regulations, and to stay abreast of industry best practices.[3]

A. Procedural History

On September 9, 2010, a thirty-inch diameter natural gas transmission pipeline owned and operated by PG&E ruptured and caught fire in the city of San Bruno, California, causing the death of eight persons, injury to many others, as well as massive property damage.[4] Following this event, pipeline operators, federal and state legislators, federal and state regulators and

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[1] SoCalGas Natural Gas System Operator Safety Plan at 1, filed June 29, 2012 in R.11-02-019; SDG&E Natural Gas System Operator Safety Plan at 1, filed June 29, 2012 in R.11-02-019.

[2] SoCalGas Natural Gas System Operator Safety Plan at 1; SDG&E Natural Gas System Operator Safety Plan at 1 (quoting SoCalGas and SDG&E's Commitment to Safety statements).

[3] SoCalGas Natural Gas System Operator Safety Plan at 1; SDG&E Natural Gas System Operator Safety Plan at 1.

[4] *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* (Pipeline Safety Rulemaking), issued February 25, 2012, at 1.

concerned members of the public all focused on addressing the question – What can be done to prevent this from happening again?

On October 14, 2010, the Commission announced its formation of an Independent Review Panel of experts "for the purpose of conducting a comprehensive study and investigation of the September 9, 2010, explosion and fire along a [PG&E] natural gas transmission pipeline in San Bruno, CA. The investigation shall include a technical assessment of the events and their root causes, and recommendations for action by the Commission to best ensure such an accident is not repeated elsewhere."[5] The Independent Review Panel published its Report on the San Bruno Pipeline Rupture on June 9, 2011, offering numerous recommendations to PG&E, the Commission and other state authorities "to reduce the likelihood of future incidents."[6]

On January 3, 2011, the NTSB issued several safety recommendations in connection with its investigation of the natural gas pipeline rupture and fire that occurred in San Bruno on September 9, 2010. These NTSB safety recommendations focused on reviewing records to validate the safe operating pressure of pipeline segments in all Class 3 and Class 4 locations and high consequence areas in Class 1 and 2 locations (i.e., more populated areas) that were not strength tested after construction.[7]

The NTSB also issued an urgent safety recommendation to the Commission to "immediately inform California intrastate natural gas transmission operators of the circumstances leading up to and the consequences of the September 9, 2010, pipeline rupture in San Bruno, California, and the NTSB's urgent safety recommendations to Pacific Gas and Electric Company

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[5] Independent Review Panel Charter, available at http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/124860.htm.
[6] Report of the Independent Review Panel, Executive Summary, at 2 (available at http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm).
[7] *See generally*, NTSB Safety Recommendations P-10-001(Urgent) through P-10-007 (Urgent).

so that pipeline operators can proactively implement corrective measures as appropriate for their pipeline systems."[8]

The same day, Paul Clanon, Executive Director of the Commission, sent a letter to SoCalGas, Southwest Gas Corporation and SDG&E advising them of the Safety Recommendations to PG&E, and directing each to "pay particular attention to NTSB recommendations to PG&E titled P-10-2, P-10-3, and P-10-4."[9] The letter further directed each gas pipeline operator to report to the Executive Director by February 1, 2011, "detailing the steps [it] will take proactively to implement corrective actions as appropriate for [its] natural gas transmission pipeline systems located in California."[10]

On February 25, 2011, the Commission opened the Pipeline Safety Rulemaking a "forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[11]

B. SoCalGas and SDG&E's Work in Response to the National Transportation Safety Board's Safety Recommendations

On April 15, 2011, SoCalGas and SDG&E filed their *Report on Actions Taken in Response to* [*National Transportation Safety Board*] *Safety Recommendations* ("April 15

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[8] NTSB Safety Recommendation P-10-007 (Urgent), January 3, 2011. *See also* January 3, 2011 letter from the NTSB to Paul Clanon, Executive Director of the Commission, available at http://www3.ntsb.gov/recs/letters/2010/P-10-005-007.pdf.

[9] January 3, 2011 letter from Paul Clanon, Executive Director of the Commission to Michael Allman, President and Chief Executive Officer, SoCalGas, Jeffrey Shaw, Chief Executive Officer, Southwest Gas Company, and Jesse Knight, Jr., Chairman and Chief Executive Officer, SDG&E, available at http://www.cpuc.ca.gov/NR/rdonlyres/CE921E44-7596-4B04-B875-A0F521FF27A3/0/LettertoSoCalUtilities010311.PDF.

[10] January 3, 2011 letter from Paul Clanon, Executive Director of the Commission to Michael Allman, President and Chief Executive Officer, SoCalGas, Jeffrey Shaw, Chief Executive Officer, Southwest Gas Company, and Jesse Knight, Jr., Chairman and Chief Executive Officer, SDG&E, available at http://www.cpuc.ca.gov/NR/rdonlyres/CE921E44-7596-4B04-B875-A0F521FF27A3/0/LettertoSoCalUtilities010311.PDF.

[11] Order Instituting the Pipeline Safety Rulemaking at 1.

Report").[12] In the April 15 Report, SoCalGas and SDG&E described our process for reviewing the records for pipelines located in Class 3 and Class 4 locations and Class 1 and Class 2 HCAs (referred to as "Criteria Miles" in the Report), a process for classifying those pipelines in one of four categories for further review and action based on whether a pipeline segment had sufficient documentation of a pressure test to at least 1.25 times the pipeline's MAOP.[13] For those pipelines that did not have sufficient documentation of a 1.25 times MAOP post-construction pressure test (classified as Category 4 in the Report),[14] SoCalGas and SDG&E described a plan for further action.[15]

This Report, and the record review process described in the Report, were focused, not on demonstrating compliance with regulations, but rather, on evaluating pipelines based on sound engineering principles on an urgent basis to validate that those pipelines are operating within a sufficient margin of safety in light of information known about the San Bruno pipeline rupture.[16]

SoCalGas and SDG&E selected the 1.25 times MAOP threshold based upon industry analysis that indicates that this threshold provides a sufficient margin of safety immediately following a pressure test.[17]

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[12] SoCalGas and SDG&E filed the April 15 Report in Rulemaking 11-02-019 on April 15, 2011 and the April 15 Report was entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.
[13] April 15 Report at 6-11.
[14] Pipelines that had sufficient documentation of a pressure test using water as a medium were classified as Category 1. Pipelines that had sufficient documentation of a pressure test using a medium other than water were classified as Category 2. Where a pipeline's MAOP was reduced to a level below its historical operating pressure sufficient to validate a margin of safety of at least 1.25 times MAOP, the pipeline was categorized as Category 3. All remaining pipelines were categorized as Category 4 for further review and action. April 15 Report at 6-11. As explained by Mr. Schneider during hearings, documentation was not necessarily deemed "sufficient" if it complied with regulatory requirements. SoCalGas and SDG&E applied a more stringent standard in this post-San Bruno environment. *See* Tr. 402-17 (SoCalGas/SDG&E/Schneider).
[15] April 15 Report at 12-15.
[16] *See* Tr. 402-17 (SoCalGas/SDG&E/Schneider).
[17] April 15 Report at 7 (quoting *Final Report on Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, April 16, 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 at 17-18 ("One definition of a stable pipeline defect could be a defect that never threatens the integrity of a pipeline at any time during the useful life of the pipeline. Basically, such a defect would have one essential

SoCalGas and SDG&E also set forth proposed interim safety enhancement measures in the April 15 Report to address Category 4 pipelines until such time as we could take further action to validate the safety margin for those pipeline segments. Specifically, we began to patrol and leak survey each Category 4 pipeline segment on a bi-monthly basis and advised the Commission that we would lower the operating pressure on Category 4 pipelines where location-specific operational conditions allowed for immediate lowering of the operating pressure without jeopardizing reliability of service to our customers.[18]

C. The Commission's Decision Directing the Filing of Comprehensive Plans to Test or Replace Transmission Pipelines

On June 16, 2011, the Commission issued *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans*.[19] This decision directed PG&E, SoCalGas, SDG&E and Southwest Gas to file comprehensive implementation plans "to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested."[20] In this order, the Commission describes several key elements that were to be included in these plans: (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)

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characteristic: its failure stress level would always be higher than the maximum stress level (considering both hoop stress and longitudinal stress) experienced by the pipeline during its useful life. Therefore, it would never cause the pipeline to fail. . . . Any manufacturing defect or imperfection that survives a pre-service hydrostatic test to 1.25 times the MAOP is stable immediately after the test. The reason is that by virtue of having survived the test, it is too small to fail at the MAOP that is only 80% of the test pressure)). *See also* Tr. 417 (SoCalGas/SDG&E/Schneider).

[18] April 15 Report at 10-11.

[19] D.11-06-017.

[20] D.11-06-017 at 1.

or (d);[21] (3) the prioritization of pipeline segments in populated areas and segments with the highest risk; (4) an expeditious timeline; (5) retrofitting to allow for inline 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.[22]

SoCalGas and SDG&E, in response to these directives, developed our PSEP to comply with the Commission's eight directives in a way that enhances public safety, minimizes customer impacts, and maximizes cost effectiveness.[23]

1. The Proposed PSEP Enhances Public Safety

Consistent with our public safety objective, and the Commission's directives in D.11-06-017, the PSEP 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 inline inspection tools, other than replacing pipelines that cannot be retrofitted to accommodate inline inspection tools, there is little room for proposing further enhancement of our transmission system to allow for inline inspection. We do propose in our Plan, however, to take advantage of these prior investments and perform inline inspections of identified retrofitted

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[21] The exclusion of 49 CFR 192.619(c) means that California gas utilities may no longer rely on records of operating history to establish MAOP but must instead locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline. Ex. SCG-01 (Morrow) at 3.
[22] D.11-06-017 at 30-33.
[23] Ex. SCG-02 (Morrow) at 10.

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.[24]

The PSEP 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 will enable 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. 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 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.[25]

2. The Proposed PSEP Minimizes Customer Impacts

A third foundational element of our proposed plan is minimization of customer impacts. The implementation of our PSEP 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.

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[24] Ex. SCG-02 (Morrow) at 14.
[25] Ex. SCG-02 (Morrow) at 15.

Every element of the PSEP described below takes into account potential customer impacts and strives to minimize those impacts as much as possible.[26]

In general, our proposals are guided by existing policies to provide uninterrupted gas service to customers whenever possible. 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 PSEP.[27] We commit to work with our customers on the scheduling of the work and to do all that is reasonable to provide uninterrupted service.

3. The Proposed PSEP Maximizes the Cost Effectiveness of Investments in the SoCalGas and SDG&E Transmission System

Cost effectiveness is the final major guiding principle of our 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 developing 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.[28]

As discussed in the following Section, SoCalGas and SDG&E propose that PSEP costs be recovered from ratepayers as the costs are being incurred to adhere to new regulatory requirements; not past imprudence. While it is true that the PSEP cost estimates for this unprecedented and tightly scheduled work are not as detailed and complete as might be possible if Phase 1A of our PSEP were scheduled over the next decade rather than the next four years, the estimates were developed based on a thoughtful, rational process that relied upon considerable

[26] Ex. SCG-02 (Morrow) at 15.
[27] Ex. SCG-02 (Morrow) at 15-16.
[28] Ex. SCG-13 (Morrow) at 17.

expertise and experience, and these estimates provide a reasonable cost projection for the Commission to approve our Plan.[29]

III. RESPONSIBILITY FOR PHASE I COSTS

A. Applicable Evidentiary Standard and Burden of Proof

1. Evidentiary Standards

SoCalGas and SDG&E believe that the applicable evidentiary standards to be employed in this proceeding are set forth in Rule 13.6 of the Commission's Rules of Practice and Procedure.[30] SoCalGas and SDG&E are not arguing for different standards, and we are unaware of any arguments to that effect from other parties. Given that hearings have already taken place and we have an established Phase 1 record, SoCalGas and SDG&E do not think it would be appropriate for anyone to argue that a different set of evidentiary standards should now apply.

On October 12, 2012, ALJ Bushey issued a proposed decision in R.11-02-019 regarding the proposed pipeline safety plan of PG&E. On October 11, 2012, counsel for TURN requested, and was granted, a one-week extension of the briefing schedule "[t]o allow parties time to digest the PG&E PSEP proposed decision and to modify their opening briefs as they deem appropriate."[31] A proposed decision on PG&E's PSEP, however, is not valid precedent in this proceeding. A proposed decision issued by an administrative law judge (or even an assigned commissioner) is not a decision by the Commission, and has no legal effect until approved by a majority of Commissioners. As the Commission recently explained, "[a] proposed decision is not a decision of the Commission and has no binding legal effect…"[32]

[29] Ex. SCG-13 (Morrow) at 12.
[30] Rule 13.6 establishes the evidentiary rules to be used in Commission proceedings.
[31] October 11, 2012 e-mail from Thomas Long of TURN to Administrative Law Judge Long, copied to the service list for A.11-11-002.
[32] D.11-09-028, mimeo., at 3. *See also* PUC Section 311 ("Every finding, opinion, and order made in the proposed decision and approved or confirmed by the commission shall*, upon that approval or confirmation*, be the finding, opinion, and order of the commission." (Emphasis added.)).

In addition, it would be unfair to apply Commission orders and determinations regarding PG&E's pipeline plan to our PSEP. SoCalGas and SDG&E are not affiliated with PG&E. We have very different approaches to pipeline maintenance and testing, we have different safety histories, and we have developed our PSEP independently from PG&E's proposals. In addition, the evidence in this current Triennial Cost Allocation Proceeding (TCAP) is very different from the evidence presented in R.11-02-019 regarding PG&E's proposed pipeline safety plan.[33] The Commission needs to make its determination regarding SoCalGas and SDG&E's PSEP based upon the record in this current proceeding, and not the record presented, in our absence, by PG&E and interested intervenors in R.11-02-019.

2. General Burden of Proof in Ratesetting Proceedings

This is a ratesetting proceeding, and SoCalGas and SDG&E are the applicants.[34] Applicants in ratesetting proceedings have the burden of proof with respect to their rate increase proposals. As the Commission explained in the 2006 GRC of Southern California Edison Company (SCE):

> The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable: "no public utility shall change any rate ... except upon a showing before the Commission, and a finding by the Commission that the new rate is justified." As the applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application. Other parties do not have the burden of proving the unreasonableness of SCE's showing. As the applicant in this rate case, SCE has the burden of proving that each of its proposals is reasonable.[35]

[33] This fact is emphasized by ALJ Long striking, at TURN's request, portions of Mr. Rosenfeld's testimony on the grounds that it related to an argument made in R.11-02-019 but not in A.11-11-002. *See* Tr. at 283-91 (SCG/SDG&E/Rosenfeld).
[34] *Assigned Commissioner's Scoping Memo and Ruling* dated February 24, 2012, at 4 and 14. SoCalGas and SDG&E originally filed their PSEP in R.11-02-019. That rulemaking is also a ratesetting proceeding. *See* R.11-02-019, *Scoping Memo and Ruling of the Assigned Commissioner* dated June 16, 2011, at 6.
[35] D.09-03-025, mimeo., at 8 (citations omitted).

SoCalGas and SDG&E acknowledge that it is our burden to justify our PSEP-related proposals, and, as discussed below and in our testimony, we have met this burden. In evaluating our showing, the Commission should keep in mind that the genesis of our proposed PSEP is the Commission's directive in D.11-06-017 that each of the state's natural gas utilities propose comprehensive transmission pipeline pressure testing plans no later than August 26, 2011,[36] and that SoCalGas and SDG&E had limited time to put our proposals together.[37] Accordingly, it is crucial for the Commission to look at not just our initial cost estimates – estimates that may change once we begin the detailed engineering work for each PSEP segment – but also the detailed process and controls that we have proposed to enable us to move forward with this important safety-related work in a timely and cost-effective manner.

3. Burden of Proof for Penalty Recommendations

When an intervenor proposes a ratemaking disallowance, the intervenor has the burden of producing evidence in support of the proposed disallowance, but the ultimate burden of proof is never shifted from the utility to the challenging parties.[38] When an intervenor proposes a penalty, however, they have the burden of proving that the penalty is justified.[39] As discussed in more detail below, the Division of Ratepayer Advocates (DRA), Toward Utility Reform Network (TURN), and certain other intervenors contend that SoCalGas and SDG&E shareholders should be held responsible for a substantial share of PSEP costs, both through denial of rate recovery for PSEP-related expenses and capital expenditures, and through a lowered return on equity (ROE) for certain PSEP capital expenditures.[40] These intervenors

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[36] D.11-06-017, mimeo., at 31 (Ordering Paragraph No. 4).
[37] D.11-06-017 was issued on June 9, 2011, allowing SoCalGas and SDG&E a little over two months to prepare their proposal.
[38] D.87-12-067, mimeo., at 297 (Finding of Fact No. 3).
[39] D.87-12-067, mimeo., at 297-98; *see also* D.96-08-033, mimeo., at 19.
[40] DRA recommends that shareholders be responsible for $1.603 billion (96%) of Phase 1A direct costs, while TURN proposes that shareholders pay for $274 million of Phase 1A direct costs. As Mr. Morrow points out in his

characterize their recommendations as proposals for "shareholder responsibility" and "disallowances."[41] In reality, however, they are proposed penalties.

In R.11-02-019, the Commission mandated that SoCalGas and SDG&E meet new pipeline safety standards established by the Commission. This mandate is a new safety-related initiative by the Commission; it is not the result of any violation by SoCalGas or SDG&E of a Commission decision or order, or any other law or regulation. SoCalGas and SDG&E's proposed PSEP is a direct response to that directive from the Commission. SoCalGas and SDG&E do not have a choice about pressure testing or replacing transmission pipelines that do not meet the Commission's new, more stringent standards. Moreover, the proposals from intervenors for "disallowances" of such future expenditures are not premised upon SoCalGas or SDG&E overspending on pipeline safety work, or making expenditures that the Commission does not approve of – ultimately we will do as much or as little PSEP-related work as the Commission authorizes. Instead, the intervenor "shareholder responsibility" and "disallowance" recommendations for future PSEP expenditures are based upon the theory that utility shareholders should be financially punished whenever SoCalGas and SDG&E are unable to produce a pressure test record from the 1960s or earlier. As Dr. Montgomery explained during evidentiary hearings, under such circumstances intervenor proposals for "disallowances" of future PSEP-related expenses and capital expenditures are in fact a call for penalties:

> [T]he words that I used I think were to describe what the intervenors were requesting as a penalty in the form of a disallowance, which strikes me as being an accurate use of language to describe it.

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rebuttal testimony, even TURN's recommendation would constitute the largest penalty in Commission history. *See* Ex. SCG-13 (Morrow) at 5.

[41] *See, e.g.*, Ex. DRA-01 (Peck) at 1 ("Applicants' shareholders should be entirely responsible for all expenses associated with hydrostatic testing or associated replacements . . ..); Ex. TURN-01 (Long) at 2 ("A significant portion of the PSEP work results from the absence of pressure test records the utilities should possess; the costs of this testing and replacement work should be disallowed from rate recovery.").

> . . . [T]he Commission in its safety directive has instructed the gas utilities to put together a plan for substantial investment to improve the safety of their system, that the normal procedure of the Commission and my understanding of general economic principles of regulation would be that the utility is entitled to recovery of those costs, recovery of the costs of making new investments to meet new requirements, that it's entitled to recovery of those costs going forward and that including a rate of -- including a fair return on its investment. Anything . . . that takes away from that by disallowing costs that everyone agrees are necessary to accomplish that objective or to reduce the rate of return below the -- that which the Commission has found fair and reasonable for other incentives is a taking, and I would call a taking of that kind a penalty.[42]

Given the unique circumstances created by the Commission's new pipeline safety mandates in R.11-02-019, the burden of proof applicable to intervenors' proposals in this proceeding for "shareholder responsibility" and "disallowances" should be the same as the burden for penalty recommendations – i.e., the intervenors should have the burden of proving that their proposed penalties are justified.

4. Any Consideration of Recordkeeping Penalties for SoCalGas and SDG&E Should Take Place Outside of Phase 1, and in a Manner that Provides Due Process

SoCalGas and SDG&E have a strong safety record, and have been on the forefront of making their transmission systems piggable and embracing new safety-related technologies. We are proud of our tradition of providing safe and reliable service to our customers in a cost-effective manner, and we strongly believe that absolutely no penalty is warranted for any of our past transmission system activities – including our inability to produce certain 40+ year-old pressure test records from grandfathered pipelines. If, however, the Commission believes that the penalty proposals by intervenors in this proceeding are worthy of further consideration, we urge the Commission to consider the proposals outside of this docket, and to do so in a manner that provides the utilities with due process, consistent with established Commission policies and procedures, and based on ample record support.

[42] Tr. at 722-23 (SoCalGas/SDG&E/Montgomery).

No penalty for alleged recordkeeping "failures" can be assessed based upon the existing record in this proceeding. As Mr. Schneider testified, our efforts to date have been focused on determining whether we have pressure test records that give us enough comfort to rely on for the purpose of prioritizing pipeline safety work.[43] We have not been reviewing past records with an eye towards determining whether we have records that, even though they do not give us sufficient comfort to place a segment lower in the testing/replacement queue, might arguably satisfy a past industry standard or Commission requirement. As Mr. Schneider explained about our review of pressure testing records:

> We weren't thinking about the code requirements. We were thinking strictly of, okay, what are we trying to learn about what happened at San Bruno, how do we identify these pipelines where we're going to take additional action.[44]

In response to the Commission's directive, SoCalGas and SDG&E focused on safety, not on potential cost responsibility arguments. Under these circumstances, it would be unreasonable and unfair -- and deny SoCalGas and SDG&E due process -- to make any penalty-related determinations based upon the very limited recordkeeping record to date.

To properly assess the need for, and fairness of, a potential recordkeeping penalty, the Commission would need to carefully examine the individual characteristics of the particular segment in question (*e.g.*, vintage, operating pressure, division or class location), the circumstances surrounding any missing records for that segment, and whether such missing records make any difference in the test/replace equation. If, for example, records from a 1956 pressure test would not matter because the records still would not satisfy Subpart J,[45] no penalty

[43] Tr. at 397-99 (SoCalGas/SDG&E/Schneider).
[44] *See* Tr. at 397-99 (SoCalGas/SDG&E/Schneider).
[45] D.11-06-017 requires all in-service natural gas transmission pipeline in California to have been pressure tested in accordance with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c). This exclusion means that California gas utilities may no longer rely on records of operating history to establish MAOP, but must instead locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline. Ex. SCG-01 (Morrow) at 3.

could possibly be warranted. In addition, the Commission should consider the proposed recordkeeping penalties in a forum that allows it to weigh proposed penalty against the purported infraction, and compare the proportionality of the two against past penalties levied by the Commission. SoCalGas and SDG&E believe that our inability to locate all possible historical testing records does not merit the imposition of penalties, especially in light of the number of pipeline segments we operate, the safe operations of SoCalGas and SDG&E as a whole (which, we believe, should take primacy over a test record when evaluating system safety), the technological changes over the past 80 years (which make accessing historical information both difficult and costly), the absence for many years of specific directives on recordkeeping by the Commission, and the fact that SoCalGas and SDG&E did not financially benefit from failing to keep every pressure test record for every one of our pipelines.[46]

Penalties and proposed penalties are serious business, particularly proposed penalties of the unprecedented magnitude recommended by intervenors. Penalties should not be a sideline in a proceeding that is focused on the forward-looking PSEP presented by SoCalGas and SDG&E in response to the Commission's new pipeline safety requirements and directives:

> The Commission said it wants a timely response. And this is either a good plan for moving forward and … should be accepted or it's a bad plan for moving forward and should be rejected. But neither of those has anything to do with whether there should be a penalty on something that happened 40 years ago.[47]

If a penalty for any specific alleged past recordkeeping "failure" is warranted -- and we strongly believe that it is not -- the penalty should be considered as part of another proceeding (or perhaps another phase of this proceeding) in which the parties proposing penalties have the

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[46] *See* Ex. SCG-14 (Montgomery) at 7.
[47] Tr. at 759 (SoCalGas/SDG&E/Montgomery).

burden of proof, and the focus of the proceeding is solely on the recordkeeping penalty recommendations. As explained by Dr. Montgomery:

> I think you should be accepting their Application because the Commission wants a timely response to approve the safety, and it's got to be done. If you believe that the penalty is appropriate for -- that a penalty today is appropriate for failures 30 or 40 years ago to maintain the records, then that's something separate. But it is entirely separate, I think, from a . . . plan to move forward now to improve safety and recover the costs of doing that.[48]

B. Transmission Pipeline Testing and Record-Keeping Requirements and Standards

1. Pressure Testing

Post-construction pressure testing is now a standard practice for commissioning a pipeline, but this was not always the case.[49] Current pressure test standards were not developed and implemented until the issuance of Part 192, 49 CFR Subpart J – recognized as the modern standard for pressure testing.[50] At various times prior to the issuance of modern standards, pressure testing requirements differed among individual pipeline operators, industry-developed standards, state regulations, and federal regulations.[51] In this proceeding, intervenors propose, to varying degrees, shareholder responsibility for PSEP pipelines installed from 1935 to the present. DRA is at the extreme, proposing shareholder responsibility for pipelines installed from 1935 forward, although even DRA does not propose shareholder responsibility for the cost of testing or replacing any pre-1935 pipe.[52]

a. Industry Standards (1935-1955)

The evolution of modern pipeline standards can be traced to the B31 Code for Pressure Piping, Standard B31.1, first published as a tentative standard by the American Standards

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48 Tr. at 758-59 (SoCalGas/SDG&E/Montgomery).
49 Ex. SCG-17 (Rosenfeld) at 9.
50 Ex. SCG-18 (Schneider) at 6.
51 Ex. SCG-17 (Rosenfeld) at 1.
52 Tr. at 1604, lines 10-21 (DRA/Peck).

Association (ASA), a predecessor to the American National Standards Institute, with sponsorship of the American Society of Mechanical Engineers (ASME).[53] This tentative standard covered the materials, design, and fabrication of piping systems with industry-specific sections for power piping, gas and air piping, oil piping, and district heating piping.[54]

The 1935 B31.1 standard defined two categories of pipe based on location. Division 1 piping was air or gas piping constructed within power plants, gas plants, or manufacturing plants, or within the boundaries of cities or villages.[55] Division 2 piping was constructed in compressor stations, installed cross-country, or outside boundaries of cities or villages.[56] The pressure test standards for these pipelines were further divided into post and pre-installation pressure testing.

For Division 1 piping, before installation, valves and fittings were to be "capable of withstanding a hydrostatic shell test" to designated pressures based on pressure rating classes similar to present-day pressure ratings for valves and flanged fittings.[57] The pipeline was to be "capable of meeting the hydrostatic test requirements" contained in listed pipe product specifications.[58] After installation, piping systems containing welded joints were to be "capable of withstanding a hydrostatic test" to 1.5 times the service pressure, with the test to be applied *where practical*.[59] If a test is performed, it was to be done in accordance with the 1935 B31.1 standards, which permitted preliminary air or gas testing to 100 psig to check for leaks.[60]

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[53] Ex. SCG-17 (Rosenfeld) at 5.
[54] Ex. SCG-17 (Rosenfeld) at 5.
[55] Ex. SCG-17 (Rosenfeld) at 11.
[56] Ex. SCG-17 (Rosenfeld) at 11.
[57] Ex. SCG-17 (Rosenfeld) at 11.
[58] Ex. SCG-17 (Rosenfeld) at 11.
[59] Ex. SCG-17 (Rosenfeld) at 11-12.
[60] Ex. SCG-17 (Rosenfeld) at 12.

For Division 2 piping, before installation, valves and fittings were to be "capable of withstanding a hydrostatic test pressure" to 1.5 times the rated maximum working pressure.[61] The pipe was to be subjected to and safely withstand a mill pressure test in accordance with the pipe product specification, but not in excess of 90% of the yield point or yield strength of the material.[62] There were no pressure test requirements post-installation.[63]

The language in the 1935 B31.1 standard was understood to mean that testing of the pipe after installation was discretionary for Division 1 piping, and not required for Division 2 piping.[64] In addition, the wording "capable of withstanding a pressure test" was a design criterion calling for a combination of specified material strength grade and wall thickness of sufficient capacity to sustain pressure of specified amounts without impairment of the serviceability due to material failure or gross distortion.[65] This is not the same as requiring that a pressure test actually be performed.[66] Most pipeline operators made this same interpretation until such time as testing became clearly stated in the 1955 edition.[67]

The ASA standards were revised between 1935 and 1955. The 1942 edition slightly revised post-installation testing guidelines.[68] As with the 1935 edition, however, the standards were interpreted as requiring that a piping system be specified to be strong enough to withstand a test without actually being required to undergo such a test.[69] Working pressure for Division 2

[61] Ex. SCG-17 (Rosenfeld) at 12. The working pressure was 80% of the pipe mill test pressure, or a percentage of the yield strength calculated as the seam joint efficiency factor divided by 1.4. Ex. SCG-17 (Rosenfeld) at 12.
[62] Ex. SCG-17 (Rosenfeld) at 12.
[63] Ex. SCG-17 (Rosenfeld) at 12.
[64] Ex. SCG-17 (Rosenfeld) at 12.
[65] Ex. SCG-17 (Rosenfeld) at 12.
[66] Ex. SCG-17 (Rosenfeld) at 12.
[67] Ex. SCG-17 (Rosenfeld) at 12 (citing Hough, F.A., "The New Gas Transmission and Distribution Piping Code" (ASA B31 Section 8), Series in 8 Parts, Gas Magazine, January through September 1955.)
[68] Ex. SCG-17 (Rosenfeld) at 12.
[69] Ex. SCG-17 (Rosenfeld) at 13.

piping was established similarly to the 1935 standard, meaning it was based on the mill test or an engineering calculation if there was no mill test.[70]

The 1951 B31.1 standard revised the wording concerning post-installation testing to read: "Where an internal fluid pressure test is made, it shall not exceed" 150% of the maximum allowable working pressure for Division 1 piping, and for Division 2 piping, 120% of or 50 psig greater than the maximum allowable working pressure whichever was greater.[71] The language still only required the *capability* to withstand certain test conditions, not the performance of an actual test.[72] If a test was actually performed using any fluid (liquid or gaseous), the maximum test level was limited, and no minimum test duration was prescribed other than that it be long enough to inspect joints and connections for leaks.[73]

b. Industry Standards (1955-1961)

The 1955 edition of the B31 standards were identified as B31.1.8 and represented a thorough rewrite and advancement in standards for natural gas transmission and distribution piping systems.[74] It incorporated a risk-informed design basis in the form of a location class scheme based on the number of dwellings intended for human occupancy near the pipeline, more guidance relevant to the design and installation of cross-country transmission pipelines and gas distribution systems, and new pressure testing guidelines.[75]

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[70] Ex. SCG-17 (Rosenfeld) at 13.
[71] Ex. SCG-17 (Rosenfeld) at 13.
[72] Ex. SCG-17 (Rosenfeld) at 13.
[73] While the duration of the pressure test, if performed, was not specified, the standards recommended that "where an actual internal pressure test is made" (recognizing that an "actual internal pressure test" might not be made), the test pressure be maintained long enough to inspect the joints and connections. This statement indicates that, where a test was made, its primary purpose was a leak test of flanged, threaded, or welded connections. SCG-17 (Rosenfeld) at 13.
[74] Ex. SCG-17 (Rosenfeld) at 6.
[75] Ex. SCG-17 (Rosenfeld) at 6. The 1955 standard introduced the concept of four location class factors based on density of land development adjacent to the pipeline, each with different maximum allowable operating stress levels, and different pressure test requirements following installation. The precise definitions of the classes in terms of house counts and the dimensions of the reference area were somewhat different than today, but the intended

Post-construction testing standards were developed and stated that all mains and services were to be tested, except tie-ins where individual test sections were eventually joined after testing.[76] This was the first time in the gas piping standard that testing after installation was clearly called for in the standards, but still no minimum test duration was specified.[77] Design requirement for the capability to withstand a pressure test stated that components were to be designed to withstand the system pressure test without failure, leakage, or impairment of their serviceability.[78]

Pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength (SMYS) "shall be given a field test to prove strength after construction and before being placed in operation."[79] Piping installed in Class 1 areas was to be tested with air or gas to 1.1 times the maximum operating pressure or hydrostatically tested to at least 1.1 times the maximum operating pressure; piping installed in Class 2 areas was to be tested with air to 1.25 times the maximum operating pressure or hydrostatically tested to at least 1.25 times the maximum operating pressure; and piping installed in Class 3 and 4 areas was to be hydrostatically tested to at least 1.4 times the maximum operating pressure.[80]

Other sections within the standard discussed additional pressure test considerations and allowed for air testing under certain circumstances. For instance, the B31.1.8 standards waived the hydrotest requirement for Class 3 and 4 pipelines if ground temperature at the time of the test was or might fall below 32 degrees Fahrenheit, or water of satisfactory quality was not available

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meanings of the classes were the same as today and the allowed operating stresses were also the same. Ex. SCG-17 (Rosenfeld) at 6.

[76] Ex. SCG-17 (Rosenfeld) at 14.
[77] Ex. SCG-17 (Rosenfeld) at 14.
[78] Ex. SCG-17 (Rosenfeld) at 14.
[79] Ex. SCG-17 (Rosenfeld) at 14.
[80] Ex. SCG-17 (Rosenfeld) at 14-15.

in sufficient quantity.[81] In that case, an air test to 1.1 times the maximum operating pressure could be performed and the test pressure ratio of 1.4 did not apply.[82] Other sections allowed for air testing of Class 3 and 4 pipelines provided certain hoop stress limits were observed; the pipe was not operated at more than 80% of the test pressure and the pipe had a seam joint efficiency factor of 1.00.[83] Pressure test standards in 1958 were published as B31.8, but contained the same pressure testing standards.[84]

c. General Order 112 (1961-1970)

The Commission enacted General Order (GO) 112 with an effective date of July 1, 1961, specifying minimum rules for the design, construction, operation, and maintenance of natural gas pipelines within the state.[85] General Order 112 incorporated substantial portions of the 1958 edition of B31.8, omitted portions in conflict with Commission requirements, and provided additional language where necessary to accomplish its goals as a utility regulator.[86] Among those changes were: (1) the pressure testing requirements were extended to pipe operating at hoop stresses of 20% SMYS or more (rather than 30% SMYS), (2) the test margin for Class 1 pipelines was increased to 1.25 (from 1.1), (3) the test margins for Class 3 and 4 pipelines was increased to 1.5 (from 1.4), and (4) the test pressure was required to be maintained until it was stabilized and for a period of not less than one hour (previously there had not been a duration requirement).[87] This last item appears to be the first reference to a minimum hold period.[88] In addition, GO 112 allowed the testing to be limited to 90% of the mill test pressure, not just a

[81] Ex. SCG-17 (Rosenfeld) at 15.
[82] Ex. SCG-17 (Rosenfeld) at 15.
[83] Ex. SCG-17 (Rosenfeld) at 15.
[84] Ex. SCG-17 (Rosenfeld) at 15.
[85] Ex. SCG-17 (Rosenfeld) at 6.
[86] Ex. SCG-17 (Rosenfeld) at 6-7.
[87] Ex. SCG-17 (Rosenfeld) at 17.
[88] Ex. SCG-17 (Rosenfeld) at 17.

threshold above MAOP based on Location Class.[89] Subsequent issuances of GO 112 in 1964 and 1968 incorporated significant portions of the then most-current edition of B31.8 until the Department of Transportation (DOT) first issued gas pipeline regulations in 1970.[90]

d. Title 192 of the Code of Federal Regulations – Post 1970

The first full set of Federal pipeline regulations was issued in 1970 and included Subpart J – Test Requirements, section 192.501 through section 192.517, which set forth requirements for pressure testing of pipelines after construction.[91] Subpart J specifies the maximum test pressures to prove strength by test medium (water, air, inert gas or natural gas), the test pressure that must be achieved, and the duration that test pressure must be held. These pressure testing requirements were incorporated into GO 112.[92]

Aside from limitations based on maximum hoop stress levels, maximum operating pressure was based on dividing the pressure test by a minimum specified factor, given in Subpart L – Operations, Clause 192.619(a)(2)(ii).[93] For pipe installed after November 11, 1970, test pressure ratios were 1.1, 1.25, and 1.5 in Classes 1, 2, and 3 or 4, respectively.[94] For pipe installed and tested prior to November 12, 1970, the test ratio for Classes 3 and 4 was 1.4, based on the requirements in the interim Federal standard between 1968 and 1970 which were the same as B31.8.[95] An important new requirement relative to those contained in preceding or contemporaneous editions of B31.8 or GO 112 was section 192.505(c), requiring maintenance of

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[89] Tr. at 389-391 (SoCalGas/SDG&E/Schneider).
[90] Ex. SCG-17 (Rosenfeld) at 7.
[91] Ex. SCG-17 (Rosenfeld) at 18.
[92] Ex. SCG-17 (Rosenfeld) at 7.
[93] Ex. SCG-17 (Rosenfeld) at 18.
[94] Ex. SCG-17 (Rosenfeld) at 18.
[95] Ex. SCG-17 (Rosenfeld) at 18.

the strength test pressure for at least eight hours.[96] In subsequent years, these requirements for testing after construction remained relatively static.[97]

2. Recordkeeping

Recordkeeping requirements, as they pertain to pressure testing, establishing the MAOP, and other elements of the design and construction of pipelines, have not always existed, and have evolved differently than the standards or requirements for pressure testing itself.[98] At various times, recordkeeping practices and requirements differed among individual pipeline operators, recognized industry-developed standards, state regulations, and federal regulations.[99] Until recent times, such requirements lacked substantial specificity and pipeline regulators have not emphasized recordkeeping practices outside of the specific provisions contained in the applicable regulations.[100] As such, pipeline regulators have long recognized there could be manufacturing, construction, and testing activities for which records may not have been created or retained.[101] As discussed below, this recognition was embodied in the allowance of "grandfathered pipelines" having MAOPs established by prior operation, rather than documented testing or calculations requiring original engineering documents.[102] Recognition that testing documentation may not be available is also evident in regulatory requirements for integrity threat identification and risk assessment in connection with integrity management plans.[103]

[96] Ex. SCG-17 (Rosenfeld) at 18.
[97] Ex. SCG-17 (Rosenfeld) at 18.
[98] Ex. SCG-17 (Rosenfeld) at 1.
[99] Ex. SCG-17 (Rosenfeld) at 1.
[100] Ex. SCG-17 (Rosenfeld) at 1.
[101] Ex. SCG-17 (Rosenfeld) at 1.
[102] Ex. SCG-17 (Rosenfeld) at 1.
[103] Ex. SCG-17 (Rosenfeld) at 2.

a. Industry Standards (1935-1955)

Recordkeeping requirements specified in engineering standards for gas pipelines prior to 1955 were few and focused on welding.[104] No retention period for these records was specified, and no other recordkeeping requirements were expressed.[105] Retention of technical documents was not addressed by the engineering standards of the day.[106]

b. Industry Standards (1955-1961)

The 1955 standards included pressure testing recordkeeping guidance and recommended maintaining records showing the type of fluid used for pressure testing and the test pressure of pipelines that operate at a hoop stress of 30% or more of SMYS.[107] The retention period for these records was the useful life of the facility.[108] These recordkeeping guidelines, however, were not stated under other sections giving separate pressure test requirements for pipe operating at less than 30% SMYS, but greater than 100 psig; leak test requirements for pipe operating at 100 psig or more; and leak test requirements for pipe operating at less than 100 psig.[109] Thus, an operator might reasonably not have retained records for tests performed in accordance with those paragraphs.[110] In addition, since the entire B31 standard was a voluntary standard and not a regulation, operators could simply choose not to follow the standard.[111]

c. General Order 112 (1961-1970)

General Order 112 of 1961 incorporated most of the 1958 B31.8 standard, with some added requirements to better meet the Commission's objectives for enforcement.[112] General

[104] Ex. SCG-17 (Rosenfeld) at 19.
[105] Ex. SCG-17 (Rosenfeld) at 19.
[106] Ex. SCG-17 (Rosenfeld) at 19.
[107] Ex. SCG-17 (Rosenfeld) at 20.
[108] Ex. SCG-17 (Rosenfeld) at 20.
[109] Ex. SCG-17 (Rosenfeld) at 20.
[110] Ex. SCG-17 (Rosenfeld) at 20.
[111] Ex. SCG-17 (Rosenfeld) at 21.
[112] Ex. SCG-17 (Rosenfeld) at 22.

Order 112 as it existed in the 1960s prescribed that a gas operator, with respect to pressure test records, retain a record that shows the type of fluid used and the test pressure achieved for pipelines operating at a hoop stress of 20% or more of SMYS.[113]

d. Title 192 of the Code of Federal Regulations (Post 1970)

Complete federal safety standards for natural gas pipelines were introduced in 1970. Although some technical content was based on the 1968 edition of B31.8, the provisions went well beyond B31.8 in terms of recordkeeping.[114] Many of these requirements exceeded those in effect in GO 112 at that time.[115] Relevant sections are briefly summarized below:

- Subpart J – Test Requirements: Section 192.517, a record is required of each test performed on pipelines operating above 30% SMYS or above 100 psig but below 30% SMYS.[116] The record must indicate the following 7 items: the names of the operator, the responsible employee, and the test company (if any); the test medium used; the test pressure; the test duration; pressure readings; elevation variations if they are significant; and leaks or failures. Such records must be retained for the useful life of the facility.[117]

- Subpart L – Operations: Section 192.619(a) sets forth criteria for establishing the MAOP, as the lowest of the design pressure of the weakest components or pipe based on specified attributes, the pressure obtained by dividing the post-construction test pressure by a specified factor, the highest actual operating pressure during 5 years preceding July 1, 1970, for furnace butt-welded pipe a pressure equal to 60% of the mill test pressure, for other pipe a pressure equal to 85% of the highest test pressure the pipe experienced in the field or pipe mill, or the maximum safe pressure determined in consideration of the condition and operating history of the pipeline.[118]

[113] Ex. SCG-18 (Schneider) at 9.
[114] Ex. SCG-17 (Rosenfeld) at 23.
[115] Ex. SCG-17 (Rosenfeld) at 23.
[116] Ex. SCG-17 (Rosenfeld) at 23-24.
[117] Ex. SCG-17 (Rosenfeld) at 23-24.
[118] Ex. SCG-17 (Rosenfeld) at 24.

The following table summarizes the strength testing and associated record keeping requirements of industry standards and regulatory requirements:[119]

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[119] Ex. SCG-18 (Schneider) at 9 (Figure DMS-2).

Summary Table of Post Construction Pressure Tests and Duration

Post Construction Strength Test Duration and Record Specification				
	Industry Standard		Regulatory Requirement	
N/S = Not Specified N/A = Not Applicable	Pre-1955	1955 - 1961	GO 112 1961 - 1970	GO 112 Post 1970 (49 CFR 192)
Strength Test Requirement and Duration when Specified				
30% and more of SMYS	N/A	Yes - N/S	Yes - 1 Hour	Yes - 8 Hour
20% SMYS up to 30% SMYS	N/A	Yes - N/S	Yes - 1 Hour	Yes - 1 Hour
100 psig to 20% SMYS*	N/A	Yes - N/S	Yes - N/S	Yes - 1 Hour

Documentation Requirements - 30% and more of SMYS				
Operator Information	No	No	No	Yes
Test Medium	No	Yes	Yes	Yes
Test Pressure	No	Yes	Yes	Yes
Test Duration	No	No	No	Yes
Record of Pressure Readings	No	No	No	Yes
Significant Elevation Changes	No	No	No	Yes
Disposition of Leaks and Failures	No	No	No	Yes

Documentation Requirements - 20% SMYS to < 30% SMYS				
Operator Information	No	No	No	Yes
Test Medium	No	No	Yes	Yes
Test Pressure	No	No	Yes	Yes
Test Duration	No	No	No	Yes
Record of Pressure Readings	No	No	No	Yes
Significant Elevation Changes	No	No	No	Yes
Disposition of Leaks and Failures	No	No	No	Yes

Documentation Requirements - 100 psig to < 20% SMYS*				
Operator Information	No	No	No	Yes
Test Medium	No	No	No	Yes
Test Pressure	No	No	No	Yes
Test Duration	No	No	No	Yes
Record of Pressure Readings	No	No	No	Yes
Significant Elevation Changes	No	No	No	Yes
Disposition of Leaks and Failures	No	No	No	Yes

* Some editions of the code refer to pressures in excess of 100 psig, while others including current code, refer to at or above 100 psig.

3. Grandfathered Pipelines

The term "grandfathered pipelines" refers to those pipelines for which the operating pressure was established on the basis of operating history rather than pressure testing in accordance with Subpart L.[120] In the original proposal for Part 192, no special consideration was given for piping installed prior to 1955 on the basis of very loose testing requirements, and for piping already operating at hoop stress levels greater than 72% SMYS.[121] The Federal Power Commission contacted the Office of Pipeline Safety pointing out that there were thousands of miles of pipeline already in service, installed in accordance with prevailing standards and practices, that could not continue operating at their then-current levels and comply with the proposed regulations.[122] The Federal Power Commission also stated that based on a review of the operating records of interstate pipelines, no improvement in safety would be gained by reducing the operating pressures of existing pipelines "which have been proven to be capable of withstanding present operating pressures through actual operation."[123] In response, the Office of Pipeline Safety inserted a "grandfather" clause to permit continued operation of pipelines at the highest operating pressure the pipeline had experienced in service during the five years preceding July 1, 1970 (even if the pipe had previously been subjected to a pressure test to qualify a higher MAOP but the pipe had not operated at that level during the specified five-year interval).[124]

General Order 112 had already set a regulatory precedent for the "grandfathering" of untested pipelines in California.[125] Under GO 112, gas pipelines placed in service after July 1, 1961 were required to be pressure tested, but those installed before this date were exempted from

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[120] Ex. SCG-17 (Rosenfeld) at 26.
[121] Ex. SCG-17 (Rosenfeld) at 26.
[122] Ex. SCG-17 (Rosenfeld) at 26.
[123] Ex. SCG-17 (Rosenfeld) at 26-27.
[124] Ex. SCG-17 (Rosenfeld) at 27.
[125] Ex. SCG-17 (Rosenfeld) at 27.

pressure test requirements.[126] Consistent with these California exemptions, the concept that new or evolving requirements concerning materials, design, construction, and the establishment of MAOP are not retroactive to existing facilities that are already in operation was recognized in the federal pipeline regulations from the outset.[127]

The practical significance of the "grandfather" clause was that it was not necessary for an existing pipeline already in service to have been pressure tested to the minimum specified ratio of the MAOP.[128] Instead, Section 192.619 offered four possible alternatives for establishing the MAOP that would not necessarily have required any documentation of a prior post-installation pressure test or, in some cases, other technical data about the pipe:

- Section 192.619(a)(1) recognized the design pressure of the weakest component in accordance with Subparts C and D. In this case the MAOP would be based on manufacturer's component pressure ratings or engineering calculations using specified material strength and wall thickness dimensions.[129]

- Section 192.619(a)(3) recognized the highest pressure to which the pipeline had been subjected during the five years preceding July 1, 1970.[130]

- Section 192.619(a)(4) recognized 85% of the highest test pressure to which the pipe had been subjected, either in the pipe mill or in the field. If no field test was documented, the mill test would govern. The operator could determine the pipe mill test pressure if he knew the pipe product specification and year of manufacture.[131]

- Section 192.619(a)(5) allowed the operator to determine the maximum safe pressure considering the history of the segment, known corrosion, and actual operating pressure. This might be used, for example, with an uncoated pipeline that had experienced general wall thinning due to corrosion.[132]

[126] Ex. SCG-17 (Rosenfeld) at 27.
[127] Ex. SCG-17 (Rosenfeld) at 27.
[128] Ex. SCG-17 (Rosenfeld) at 28.
[129] Ex. SCG-17 (Rosenfeld) at 28.
[130] Ex. SCG-17 (Rosenfeld) at 28.
[131] Ex. SCG-17 (Rosenfeld) at 28.
[132] Ex. SCG-17 (Rosenfeld) at 28.

None of the above methods for establishing the MAOP necessarily require a documented prior pressure test, meaning, since 1970, regulators have accepted that not all records need necessarily be present, or if present, need necessarily be complete or represent an unbroken chain of traceability.[133] In fact, the method permitted in (a)(3) requires knowing no information about the specified grade or wall thickness of the pipe.[134] These alternatives have been in Part 192 from 1970 to the present day.[135]

C. Cost Responsibility

SoCalGas and SDG&E have proposed an ambitious plan to implement the Commission's new requirements to further enhance the safety of our transmission pipeline system. Intervenors to this proceeding propose a variety of modifications to SoCalGas and SDG&E's plan, as it relates to cost responsibility:

- DRA proposes that SoCalGas and SDG&E be entirely responsible for all expenses associated with testing pipelines installed from 1935 to 1955 for which a record of pressure testing cannot be found.[136] If the Commission authorizes replacement rather than testing for pipelines installed between 1935 and 1955 for which a record of pressure testing cannot be found, the return on equity for those capital investments should be adjusted downwards by 200 basis points.[137]

- DRA and TURN propose that SoCalGas and SDG&E be entirely responsible for all expenses associated with testing or replacing pipelines installed from 1955 to 1961 for which a record of pressure testing cannot be found.[138]

[133] Ex. SCG-17 (Rosenfeld) at 28.
[134] Ex. SCG-17 (Rosenfeld) at 28.
[135] Ex. SCG-17 (Rosenfeld) at 28.
[136] Ex. DRA-01 (Peck) at 15-16.
[137] Ex. DRA-01 (Peck) at 16-18.
[138] Ex. DRA-01 (Peck) at 10-16; Ex. TURN-01(Long) at 14-18.

- DRA, TURN, SCGC, and SCIP propose that SoCalGas and SDG&E be entirely responsible for all expenses associated with testing or replacing pipelines installed post-1961 for which a record of pressure testing cannot be found.[139]

The costs requested by SoCalGas and SDG&E, however, are not the result of mismanagement or imprudence. Rather, they are a direct and necessary consequence of the new transmission safety requirements established by the Commission in D.11-06-017. There is no evidence that SoCalGas and SDG&E have operated their systems unsafely; quite the contrary, the evidence demonstrates that SoCalGas and SDG&E have made safety a top priority and have complied with past and existing laws and regulatory requirements relating to their transmission systems.

1. D.11-06-017 established new pipeline safety-related requirements for transmission pipelines and related records

In D.11-06-017 the Commission instituted new safety-related requirements which surpass existing state and federal pipeline regulations, and are a clear departure from the "grandfathering" of pre-1970 vintage pipelines under current federal regulations and previous state regulations. Specifically, regulations in place prior to Commission D.11-06-017 did not require SoCalGas and SDG&E to: (1) hydrotest to modern standards pipelines that were installed prior to 1970; or (2) validate the MAOP of all gas transmission pipelines through traceable, verifiable, and complete records. The Commission's new requirements will require SoCalGas and SDG&E to locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline.

Intervenors argue that D.11-06-017 has merely ordered the utilities to comply with pre-existing regulatory mandates.[140] Such arguments are rooted in what SoCalGas and SDG&E

[139] Ex. DRA-01 (Peck) at 10-16; Ex. TURN-01(Long) at 14-18; Ex. SCGC-01 (Yap) at 12-14; Ex. SCIP (Beach) at 19-20.

believe to be a clear misunderstanding of D.11-06-017's requirements.[141] The following discussion with DRA's Mr. Peck is illustrative:

> Q: Okay. I appreciate the clarification on DRA's position. Just so I've got it straight, and my frame of reference here is Decision 11-06-017 and in particular Ordering Paragraph 4 that directs the utilities to present plans, and I'm paraphrasing up to that point, 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). And as I understand it, this latter reference, 49 CFR 192.619(c), that's what's often referred to as the grandfathering provision.
>
> Now, it's DRA's position that if the utilities have conducted hydrotests in compliance with standards in place in earlier times, standards, you know, in place in 1962, even if those tests or the records that we retain don't comply with the standard referenced in Ordering Paragraph 4, it's DRA's contention that we don't have to do the work again?
>
> A: Certainly not for Phase 1, or in case of Sempra utilities, Phase 1A.
>
> Q: Well, if that interpretation isn't correct, if in fact the utilities are directed to pressure test to the Subpart J standards lines that we have tests and records that satisfy earlier standards, is it still DRA's recommendation that we shouldn't receive cost recovery for those particular lines?
>
> A: We don't believe they will need to be tested. If you can produce a record that reliably can show that the test was done and it was performed to the standards that were in place when the test was complete, they wouldn't be part of this plan.[142]

Other intervenors have a similar interpretation of the scope of the Commission's directives in D.11-06-017, arguing that compliance with pre-1970 regulations or industry standards would obviate the need to incur costs to pressure test or replace pipeline lacking documentation of a pressure test to Subpart J standards.[143]

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[140] Ex. SCG-13 (Morrow) at 6.
[141] Ex. SCG-13 (Morrow) at 6.
[142] Tr. at 1609-1610 (DRA/Peck).
[143] Ex. TURN-01 (Long) at 16; Ex. SCGC-01 (Yap) at 14; Ex. SCIP-01 (Beach) at 4.

Intervenors' interpretation of the Commission's directives in D.11-06-017 is fundamentally incorrect. In Ordering Paragraph No. 4 of that decision, the Commission explicitly stated as follows:

> No later than August 26, 2011, San Diego Gas & Electric Company, Southern California Gas Company, Southwest Gas Corporation and Pacific Gas and Electric Company must file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation 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)*. The Implementation Plan should 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. The schedule and cost detail for lower priority pipeline segments may be limited.[144]

Ordering Paragraph No. 4 requires all in-service natural gas transmission pipelines in California to have been pressure tested in accordance with 49 CFR 192.619, excluding subsection 49 CFR 192.619(c). This exclusion means that California gas utilities may no longer rely on records of operating history to establish MAOP, but must instead locate records of pressure testing in accordance with Subpart J standards or conduct such pressure tests or replace the pipeline. As the Commission stated in D.11-06-017, "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety."[145]

DRA and the other intervenors taking DRA's position argue that past pressure tests that do not meet Subpart J standards are still somehow grandfathered from this new Commission-ordered requirement. That view ignores the plain meaning of the words in Ordering Paragraph No. 4. Grandfathering of past pressure tests that do not meet Subpart J standards – the modern standards for safety – is either eliminated or it isn't, and the words in Ordering Paragraph No. 4 clearly say that it is. Intervenors' interpretation also runs contrary to the safety-oriented goals of

[144] D.11-06-017, mimeo., at 31 (Ordering Paragraph No. 4) (emphasis added).
[145] D.11-06-017, mimeo., at 18.

the Commission. Continued grandfathering of pre-Subpart J pressure tests would not maximize safety, a fact that even DRA acknowledges:

> Q: Well, testing to Subpart J standards might also maximize safety, wouldn't you agree?
>
> A: Obviously.[146]

As such, SoCalGas and SDG&E have designed their PSEP to comply with the Commission's directive in D.11-06-017 and maximize pipeline safety by pressure testing or replacing all pipeline segments which do not have a record of a pressure test to Subpart J standards.

2. SoCalGas and SDG&E's proposed pipeline safety enhancement plan is a direct response to new pipeline safety requirements, not the result of past imprudence

As stated, SoCalGas and SDG&E's PSEP was developed in response to the Commission's directive in D.11-06-017 that each of the state's natural gas utilities propose comprehensive transmission pipeline pressure testing plans so that all in-service transmission pipelines in California may be pressure tested to modern standards.[147] SoCalGas and SDG&E strongly support this initiative by the Commission. Safety is, and has always been, paramount at SoCalGas and SDG&E, and our safe operating history and safety-centric culture are clear reflections of that fact.

This consistent commitment to pipeline safety is exemplified by a number of SoCalGas and SDG&E safety-related endeavors. For example, in the mid-1980s, SoCalGas initiated a special pipeline replacement program focused on non-state of the art infrastructure that presented elevated risk to public safety.[148] When this program was completed in the mid-1990s, a follow-

[146] Tr. at 1612 (DRA/Peck).
[147] D.11-06-017, mimeo., at 31 (Ordering Paragraph No. 4).
[148] Ex. SCG-16 (Stewart) at 3.

on internal process called System Integrity Program was developed to further examine and screen older families of infrastructure.[149]

More recently, SoCalGas and SDG&E were at the forefront of implementing inline inspection and developed a prudent strategy and program based on extensive retrofitting of existing pipelines and internal inspection of its gas system using "smart-pigs." As presented in the SoCalGas and SDG&E Amended Pipeline Safety Enhancement Plan (Dec. 2, 2011) at 15, 833 miles (63%) of the total baseline assessment of pipeline segments in HCA were already completed through December 2010 using inline inspection with smart pigs.[150] This contrasts with the PG&E pipeline integrity plan that called for a total of 208 miles (20%) of HCA miles to be completed using inline inspection.[151]

Beyond SoCalGas and SDG&E's efforts to enhance system safety, we have also striven to comply with applicable laws and regulations. The Commission has, however, recognized the impossibility of reaching 100% compliance and found, in the context of compliance with its GOs: "It is impossible for a utility to keep…in full compliance with the safety GOs at all times, and, at any given time, there will be multiple violations on a utility's system."[152] A utility cannot attain perfection while keeping the goals of safe and reliable service and reasonable cost in balance. As the Commission has previously stated, "100% compliance . . . at all times is not realistic."[153] As it relates to the PSEP, the Commission has previously reviewed and approved of SoCalGas' efforts related to MAOP validation and pipeline pressure testing. When Part 192 was first implemented, SoCalGas filed Application No. 52296 seeking five additional months to

[149] Ex. SCG-16 (Stewart) at 3.
[150] Ex. SCG-16 (Stewart) at 3.
[151] Ex. SCG-16 (Stewart) at 3 (citing NTSB Accident Report – PG&E's Natural Gas Transmission Pipeline Rupture and Fire, NTSB/PAR-11/01, PB2011-916501 (Sept. 9, 2010) at 63.)
[152] D.04-04-065, mimeo., at 62 (Finding of Fact No. 10).
[153] D.04-04-065, mimeo., at 31.

comply with the new MAOP provisions. The Commission staff conducted an investigation and concluded: "there is no evidence that the system is being or will be operated in an unsafe manner…"[154]

On top of SoCalGas and SDG&E's documented commitment to safety, a review of the applicable standards and regulations confirms that the estimated costs of SoCalGas and SDG&E's PSEP are not the result of any previous utility imprudence.

a. SoCalGas and SDG&E were not required to pressure test or maintain records of pressure testing from 1935-1955

As noted above, DRA argues that SoCalGas and SDG&E shareholders should be entirely responsible for all costs associated with testing pipelines installed between 1935 and 1955 for which a reliable record of a pressure test cannot be found.[155] In addition, if the Commission authorizes replacement rather than testing for such pipelines, DRA argues that the return on equity for those capital investments should be adjusted downward by 200 basis points.[156] The basis for these recommendations is DRA's contention that SoCalGas and SDG&E should have adhered to voluntary pressure testing guidelines issued by the ASA from 1935 to 1955, and should have retained records indicating compliance with the ASA standards pursuant to GO 28. SoCalGas and SDG&E believe that DRA's position is flawed for at least three reasons.

First, the 1935 ASA and each of its successors were voluntary advisory guidelines; not requirements. Standards such as the ASA guidelines are created to provide technical guidance and promote uniformity in practices.[157] As discussed above, GO 112 and Part 192 acknowledged the lack of prior state and federal regulation in the area and made accommodations for existing pipelines by deciding that the regulations would only have limited retroactive application for

[154] D.79502, mimeo., at 6.
[155] Ex. DRA-01 (Peck) at 15-16.
[156] Ex. DRA-01 (Peck) at 16-18.
[157] Ex. SCG-17 (Rosenfeld) at 8.

existing pipelines.[158] As such, a utility does not need to have a documented pressure test on pre-1961 pipeline to be in compliance with GO 112 or the Code of Federal Regulations.[159]

Second, the 1935-1955 versions of the ASA only called for limited pressure testing. Post-installation hydrostatic testing was for a limited subsection of pipe (Division 1) and only "where practicable."[160] In addition, the pressure testing standards only called for pipe that was "capable of withstanding a pressure test."[161] This design criterion called for a combination of specified material strength grade and wall thickness to be strong enough to withstand a test, without actually being required to undergo such a test.[162] Regardless, the limited pressure testing guidelines that existed would not meet modern standards.

Third, even if hydrostatic pressure tests were conducted during this era, SoCalGas and SDG&E were not required to retain records of these tests, nor were they put on notice that a failure to retain such records would have potential negative consequences. As acknowledged by DRA,[163] the recommendation to keep any hydrostatic pressure test records did not appear in the ASA until 1955.[164] In fact, nothing contained in the ASA prior to 1955 required the operator to create (much less maintain) a record of a pressure test.[165] DRA alleges that GO 28 has required SoCalGas and SDG&E to indefinitely retain records associated with hydrostatic testing since its inception in 1912.[166] When GO 28 was implemented in 1912, however, it was implemented to promote the preservation of records "supporting each and every entry in the following general books" including the accounts payable ledger, accounts receivable ledger, general and auxiliary

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[158] Ex. SCG-17 (Rosenfeld) at 27.
[159] *See* Section III.B.
[160] *See* Section III.B.
[161] *See* Section III.B.
[162] See Section III.B.
[163] Ex. DRA-01 (Peck) at Attachment 1, page 11.
[164] *See* Section III.B.
[165] *See* Section III.B.
[166] Ex. DRA-01 (Peck) at 15-16.

ledgers, journals and cash books, annual reports and records pertaining to the "original cost," and "depreciation and replacement" of property, equipment and plant.[167] The only references to "equipment and plant" records are those "pertaining to depreciation and replacement."[168] Meaning, GO 28 is an accounting document preservation requirement. It assumes that the utility has created an accounting record and, once created, the accounting record comes within GO 28's preservation rules. Records related to pressure testing, however, are operational in nature and have never been considered accounting records.[169]

b. SoCalGas and SDG&E were not required to pressure test or maintain records of pressure testing from 1955-1961

TURN and DRA argue shareholders should be entirely responsible for all of the expenses associated with testing and replacing pipelines installed from 1955 to 1961 for which a reliable record of a pressure test cannot be found.[170] This position is based on their assertion that industry standards, released in 1955, effectively required SoCalGas and SDG&E to pressure test and create and retain records of the pressure test. This particular intervenor position is flawed for at least two reasons.

First, industry standards are voluntary guidelines and there was no legal or regulatory requirement to pressure test pipelines installed from 1955 to 1961.[171] The lack of regulatory requirements prior to 1961 was acknowledged by the Code of Federal Regulations and GO 112 when both provided for limited retroactive application, and the ability to "grandfather" in older

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[167] GO 28, mimeo., at 1.
[168] Ex. SCG-13 (Morrow) at 7.
[169] Ex. SCG-13 (Morrow) at 7.
[170] Ex. DRA-01 (Peck) at 10-16; Ex. TURN-01 (Long) at 14-18 (recovery of testing and replacement costs should be denied for pipeline segments constructed after 1955.)
[171] *See* Section III.B.

pipelines.[172] As such, a utility does not need to have a documented pressure test on pre-1961 pipeline to be in compliance with GO 112 or the Code of Federal Regulations.[173]

Second, the pressure testing and record retention standards in place from 1955-1961 did not provide for pressure tests that would meet modern (i.e., Subpart J) standards. The standards in effect from 1955-1961 specified a post construction strength test for pipelines that operate at hoop stresses of 30% or more of SMYS. There was no minimum test duration specified and the test records that were required to be retained included only the test medium and the test pressure achieved.[174] For Subpart J, however, pipelines intended to operate at a hoop stress of 30% or more of its SMYS must have a pressure test which was held for a minimum of eight hours, unless the pipe is a fabricated unit or short segment where a post-installation test is impractical, in which case a pre-installation test of four hours is required.[175] The test duration for pipelines intended to operate at or above 100 psig but less than 30% of SMYS is one hour.[176] In addition, Subpart J requires pipelines with an MAOP at or above 100 psig to have a record of: (1) the operator's name, the name of the employee responsible for the test, and the name of any testing company used; (2) test medium used; (3) the test pressure achieved; (4) the duration of the test; (5) record of pressure readings; (6) significant elevation variations; and (7) the disposition of any leaks and failures during the test.[177] Tests and test records that would satisfy the 1955 pressure testing guidelines are insufficient to meet modern standards. Pursuant to Ordering Paragraph No. 4 of D.11-06-017, even if SoCalGas and SDG&E were to have full and complete documentation of their adherence to these voluntary guidelines for every pipeline segment

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[172] *See* Section III.B.
[173] *See* Section III.B.
[174] Ex. SCG-18 (Schneider) at 7.
[175] Ex. SCG-18 (Schneider) at 6.
[176] Ex. SCG-18 (Schneider) at 6.
[177] Ex. SCG-18 (Schneider) at 6-7.

installed between 1955 and July of 1961, they would still be required to replace or pressure test all those pipelines to modern standards.

c. SoCalGas and SDG&E were not required to maintain records of pressure testing from 1961-1970 that would meet modern standards

A number of intervenors argue that SoCalGas and SDG&E shareholders should be entirely responsible for all of the expenses associated with testing and replacing pipelines installed from 1961 to 1970 for which a reliable record of a pressure test cannot be found.[178] This position, however, ignores the significance of the Commission's directive in Ordering Paragraph No. 4, which requires all in-service natural gas transmission pipelines to have documented pressure tests in accordance with Subpart J standards or to conduct such pressure tests or replace the pipeline. Pressure tests conducted in accordance with GO 112 as it existed in the 1960s do not satisfy this new modern standard.

As discussed above, Subpart J specifies the maximum test pressures to prove strength by test medium (water, air, inert gas or natural gas), the test pressure that must be achieved, and the duration that test pressure must be held.[179] For pipelines intended to operate at a hoop stress of 30% or more of its SMYS, the pressure test must be held for a minimum of eight hours, unless the pipe is a fabricated unit or short segment where a post-installation test is impractical, in which case a pre-installation test of four hours is required.[180] The test duration for pipelines intended to operate at or above 100 psig but less than 30% of SMYS is one hour.[181] The threshold the pressure test must meet was an amount above the MAOP, with the amount varying

[178] Ex. DRA-01 (Peck) at 10-16; Ex. TURN-01 (Long) at 14-18 (recovery of testing and replacement costs should be denied for pipeline segments constructed after 1955); Ex. SCGC-01 (Yap) at 12-14 (recovery of testing and replacement costs should be denied for pipeline segments constructed after July 1, 1961); Ex. SCIP-01 (Beach) at 4 (same position as SCGC.)
[179] Ex. SCG-18 (Schneider) at 6.
[180] Ex. SCG-18 (Schneider) at 6.
[181] Ex. SCG-18 (Schneider) at 6.

depending on Location Class. In addition, for pipelines with an MAOP at or above 100 psig, a gas operator must retain a record of: (1) the operator's name, the name of the employee responsible for the test, and the name of any testing company used; (2) test medium used; (3) the test pressure achieved; (4) the duration of the test; (5) record of pressure readings; (6) significant elevation variations; and (7) the disposition of any leaks and failures during the test.[182]

On the other hand, GO 112 only prescribed that a gas operator retain a record that shows the type of fluid used for the test and the test pressure achieved for pipelines operating at a hoop stress of 20% or more of SMYS.[183] While GO 112 prescribed the permissible test fluids and minimum test pressures for pipelines to be operated at 100 psig and higher, it required test duration of at least one hour only for pipelines intended to operate at a hoop stress of 20% or more of SMYS.[184] As a result, pipelines tested under GO 112 that operate at a hoop stress of 30% or more of SMYS may not have been tested for eight hours, as required in the modern standard, and it is unlikely that records exist that meet the recordkeeping requirements of Subpart J.[185] Moreover, the test pressure threshold requirements found in GO 112 were not the same as those found in Subpart J, with the primary differences being that GO 112 allowed the testing to be limited to 90% of the mill test pressure, not just a threshold above MAOP based on Location Class. Meaning, Subpart J offers a significant increase in safety and, with or without GO 112 compliant records, SoCalGas and SDG&E would still be responsible for replacing or pressure testing 1961-1970 vintage lines to modern standards as required by D.11-06-017.

[182] Ex. SCG-18 (Schneider) at 6-7.
[183] Ex. SCG-18 (Schneider) at 7.
[184] Ex. SCG-18 (Schneider) at 7.
[185] Ex. SCG-18 (Schneider) at 7.

d. Post-1970 Regulations

SoCalGas and SDG&E have classified certain pipeline segments constructed after 1970 as Category 4 because we do not have sufficient documentation of a pressure test to 1.25 times MAOP.[186] However, based on information from inspections, maintenance and operational records, and company construction standards, we are confident these segments were installed in compliance with applicable code requirements.[187]

As of the end of 2011, this category included approximately 7 miles of pipeline -- 6 miles at SoCalGas, and 1 mile at SDG&E.[188] In order to achieve our safety objectives and comply with our regulatory responsibilities, SoCalGas and SDG&E are taking steps to either retest or replace these segments.[189] However, SoCalGas and SDG&E are not seeking cost recovery through our PSEP for this work.[190] Accordingly, there is no decision or directive needed from the Commission in this proceeding with respect to pipelines installed by SoCalGas and SDG&E after 1970.

3. All costs of complying with these new pipeline safety requirements should be paid for by ratepayers

In order to provide natural gas service to its customers, SoCalGas and SDG&E must operate our natural gas systems in accordance with applicable regulations and requirements, including the new standards established by the Commission D.11-06-017. Compliance with these new safety-related requirements is an unavoidable cost of providing utility service.

In exchange for providing utility service under regulated rates, long-standing regulatory policies provide that utilities are entitled to an opportunity to recover their operating costs, plus a

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[186] As discussed above, SoCalGas and SDG&E's initial review looked for at least a margin of safety of 1.25 times MAOP, but did not look to see whether all the requirements of Subpart J had been met. Tr. 397-99 (SoCalGas/SDG&E/Schneider); Tr. 407-409 (SoCalGas/SDG&E/Schneider).
[187] Ex. SCG-13 (Morrow) at 11.
[188] Ex. SCG-13 (Morrow) at 11.
[189] Ex. SCG-13 (Morrow) at 11.
[190] Ex. SCG-13 (Morrow) at 11.

reasonable return.[191] SoCalGas and SDG&E operate on the expectation that regulators will ensure ratepayers pay rates that are "just and reasonable" while shareholders will be entitled to recover the reasonable costs of operating the enterprise, including the return of their invested capital and the opportunity to earn a reasonable rate of return on that investment. The opportunity (but not a guarantee) for the utility to earn a reasonable rate of return has been a long-standing principle of utility regulation.[192] O&M costs and capital costs – however large they may be – are borne by ratepayers except to the extent they are proven to be unauthorized, unreasonable or imprudent.[193]

As discussed above, intervenor characterizations of PSEP costs as unreasonable or imprudently incurred are unfounded. Lack of strict compliance with voluntary industry standards and early versions of GO 112 is not evidence of an imprudent operator or imprudently incurred costs for several reasons. As stated, there were no state or federal requirements for pressure tests or retention of pressure testing records until the Commission issued GO 112 in 1961. In fact, in-service pressure testing was not clearly a part of voluntary industry standards until 1955.[194]

Intervenors' "disallowance" and "shareholder responsibility" arguments are also premised on the incorrect assumption that if SoCalGas and SDG&E can just locate pre-1970 pressure test records, the utilities will not be required to replace or pressure test their older pipelines in order to satisfy the new modern standards. As discussed above, this is simply not the case. In D.11-06-017, the Commission eliminated grandfathering for pre-1970 pipelines, requiring that all in-service transmission pipelines in California be pressure tested to Subpart J

[191] Ex. SCG-13 (Morrow) at 5.
[192] Ex. SCG-13 (Morrow) at 6.
[193] Ex. SCG-13 (Morrow) at 6.
[194] Ex. SCG-17 (Rosenfeld) at 14

standards. Accordingly, in-service transmission pipelines that have been pressure tested in accordance with voluntary industry standards and GO 112 requirements will in all likelihood need to be retested to Subpart J standards. As such, the costs that will be incurred by SoCalGas and SDG&E to implement their PSEP cannot be the result of past imprudence or recordkeeping "failures." Even perfect maintenance of pressure test records for the past half century, and even complete adherence to voluntary industry standards would not keep SoCalGas and SDG&E from having to incur new costs to bring their previously-grandfathered pre-1970 pipelines up to the Commission's new Subpart J testing requirement.

In addition, the cost responsibility arguments from intervenors fail to recognize how prudent gas system operators operate their transmission systems. Pressure test records are only one consideration and, in some instances, a pipeline's safety can be better assessed by an examination of the operator's operational and risk management history.[195] In fact, once the MAOP has been established using any one of the allowed methods, an operator is unlikely to revisit the issue except perhaps to address a change in class location or to uprate the pipe.[196] The Commission and federal regulators previously acknowledged this, allowing operators to remain in compliance by using alternative methods for calculating MAOP under the federal "grandfathering" rules. Thus, SoCalGas and SDG&E's failure to preserve some pressure testing records prior to any express regulatory requirement does not justify penalizing the company with the costs of newly ordered pressure tests pursuant to the PSEP.[197] Nor does the lack of old records warrant a penalty equal to *all* costs associated with new pipeline pressure testing and replacement,[198] which would have been required even if those old records had been retained.

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[195] Ex. SCG-15 (Tenley) at 7.
[196] Ex. SCG-17 (Rosenfeld) at 28-29.
[197] Ex. SCG-15 (Tenley) at 5.
[198] Ex. SCG-15 (Tenley) at 5-6.

Finally, the cost responsibility proposals from intervenors are utterly lacking in proportionality, and fail to recognize the difficulties inherent in keeping perfect records for many decades in a pre-electronic-storage era -- particularly records that the utilities did not know they could be penalized hundreds of millions of dollars, or even billions, for not maintaining. As explained by Dr. Montgomery in his prepared rebuttal:

> [T]he penalty is grossly disproportionate to the purported infraction. The inability to locate all possible historical testing records seems to be a clerical error rather than a fundamental misdeed, especially in light the pipeline segments at issue and the safe operations of SoCalGas and SDG&E as a whole (which should take primacy over a test record when evaluating system safety), the technological changes over the past 80 years (which make accessing historical information both difficult and costly), and the absence for many years of specific directives on recordkeeping by the regulator. Furthermore, it would be difficult to tally any gains that SoCalGas and SDG&E could have achieved by failing to keep records.[199]

Moreover, as Dr. Montgomery explained during hearings, less than perfect recordkeeping is not an unusual or extreme condition:

> I have spent a lot of time trying to get data from clients for various kind of work that I've done. And at first I was surprised and then I became used to the fact that they never have complete records on anything. Therefore, I did not find that the absence of some records in this case disturbed me as being a violation or inconsistency of anything.
>
> . . .
>
> . . . I did give some thought to whether there was a specific requirement in any of these standards for a particular kind of recordkeeping, and whether I thought that the absence of some records 40 years later was inconsistent with that.
>
> And my answer is it struck me as being within the kind of things that I found missing in the past that were perfectly innocent.
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> . . .
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> . . . I'm simply saying the missing records is something that I think it inevitably [is] going to happen.[200]

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[199] Ex. SCG-14 (Montgomery) at 7.
[200] Tr. at 727-28, 731-32 (SoCalGas/SDG&E/Montgomery).

Intervenor arguments for shareholder PSEP cost responsibility are unreasonable and unfair. As explained above, if pre-Subpart J pressure test records do not satisfy the Commission's new post-San Bruno pressure testing requirements, then there can be no basis for any sort of recordkeeping penalty against either SoCalGas or SDG&E. Moreover, even if intervenors are correct in their assertions that the Commission is still allowing grandfathering of pressure tests that do not meet Subpart J standards (and they are not correct), the financial "punishment" the intervenors would have the Commission mete out is wholly disproportionate to the gravity of alleged recordkeeping infractions by SoCalGas and SDG&E. Any Commission consideration of potential recordkeeping penalties against SoCalGas and SDG&E needs to consider proportionality and context, concepts wholly lacking from intervenors' cost responsibility proposals in this proceeding.

D. Requiring shareholders to pay for PSEP costs would be bad regulatory policy

1. Incentives matter

The stated goal of the Commission is to improve the safety of the natural gas transmission systems in the State of California in a cost-effective manner.[201] There is a tradeoff between the safety, reliability, and robustness of a natural gas system (often collectively referred to as "quality of service"), on the one hand, and on the other hand, its cost: each incremental improvement to the quality of service of the system entails additional materials and redundancies that increase its cost.[202] In addition, utilities such as SoCalGas and SDG&E have far greater knowledge of their systems, and the options for improving system safety, than the Commission. This asymmetry of information makes it necessary for the Commission to use incentives, rather

[201] D.11-06-017, mimeo., at 1.
[202] Ex. SCG-14 (Montgomery) at 2-3.

than command and control oversight, to strike a balance between the quality of service provided by utilities, and the cost which customers must pay for that service.[203]

To achieve its objective of improving safety in a cost-effective manner, the Commission's actions should cause SoCalGas and SDG&E to choose actions that achieve the desired behavior:

> [I]t's very important that the Commission provide incentives that align the utility's interest with the Commission's interest in having a cost effective system that achieves the safety goals.[204]

For the utilities, there must be a financial incentive to design and implement the desired safety improvements in a manner that avoids excessive cost: expected returns from carrying out the PSEP in a cost-effective manner should be greater than the expected returns from any other course of action.[205] A well-designed system of constraints and incentives will achieve the desired safety improvements at least cost to utility customers. In contrast, a poorly designed regulatory system, as discussed below, will create perverse incentives that neither achieves the goals of service quality nor delivers low cost to customers.

2. Intervenor cost responsibility proposals would create undesirable incentives

The intervenors' shareholder cost responsibility proposals would create two different but equally undesirable incentives for SoCalGas and SDG&E. For the pre-1970s pipelines that are at issue in this proceeding, the intervenors propose cost disallowance and a reduced rate of return in performing upgrades. SoCalGas and SDG&E will not take actions that would compromise the safety of their transmission systems, and we will always be cognizant of the potential customer impacts from PSEP-related work. But by disallowing PSEP costs and providing unfavorable

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[203] Ex. SCG-14 (Montgomery) at 3.
[204] Tr. at 696-97 (SoCalGas/SDG&E/Montgomery).
[205] Ex. SCG-14 (Montgomery) at 3-4.

rates of return for transmission pipeline capital improvements, the Commission would encourage minimum capital investment in these areas (so as to minimize the capital investments on which SoCalGas and SDG&E collect the subpar returns).[206] As explained by Dr. Montgomery, these decisions tend to be more costly in the long term.[207] Under the intervenors' proposals, SoCalGas and SDG&E's pre-1970 pipeline systems, then, are likely to be upgraded in a way that makes them more expensive to operate going forward.[208]

For all other pipeline-related expenditures, the impact of the intervenors' proposals is markedly different. The disproportionate penalty proposed by the intervenors for missing paperwork would create an incentive to maintain and operate the entire system going forward so as to avoid any chance of being judged guilty of a future violation.[209] This would involve redundancy in pipeline construction, testing, maintenance and recordkeeping in excess of a reasonable standard of economic efficiency. By holding SoCalGas and SDG&E retroactively to a new and higher standard, the intervenors' proposals would create an incentive for a more costly system that would be proof against unknown future changes in standards.[210] Dr. Montgomery refers to this behavior as "scrupulosity" -- expenditure of large amounts of resources to avoid every minor infraction in a particular category whose importance to the regulator is far less than the social cost of resources devoted to over-compliance.[211] Moreover, the penalties proposed by intervenors could have an effect beyond pipeline-related expenditures and recordkeeping. Imposition of a new standard, and imposition of large penalties for imperfect compliance, years

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[206] Ex. SCG-14 (Montgomery) at 9.
[207] Ex. SCG-14 (Montgomery) at 9 (referencing the switch from innovative generation technologies to more costly conventional ones following the hindsight reviews of the 1970s, and citing Lyon, T.P. (1995) "Regulatory Hindsight Review and Innovation by Electric Utilities," *Journal of Regulatory Economics*, 7:233-254).
[208] Ex. SCG-14 (Montgomery) at 10.
[209] Ex. SCG-14 (Montgomery) at 10.
[210] Ex. SCG-14 (Montgomery) at 10.
[211] Ex. SCG-14 (Montgomery) at 6.

after an activity takes place, would create uncertainty about what standards will be applied by the Commission in the future across the board.[212]

Regulatory opportunism is a term used to describe a situation in which a regulator leaves open the possibility that it will not allow utilities to recover the cost of sunk capital.[213] As noted by Dr. Montgomery, regulatory opportunism can have substantial negative effects:

> [T]he lack of regulatory credibility induces myopic behavior by the firm: a strong incentive to delay cost-reducing investment, or, if the firm does invest, it will favor a series of sequential investments over a single larger, cheaper investment…The prospect of regulatory opportunism means that the firm will not fully exploit economies of scale in investment.[214]

The cost responsibility proposals presented by intervenors encourage regulatory opportunism.

3. *Ex post* reasonableness review of PSEP expenditures and investments would also create undesirable incentives

DRA proposes that the Commission review SoCalGas and SDG&E's PSEP-related expenditures for reasonableness on an *ex post* basis – i.e., after the expenditures have been made. As with intervenors' other proposals to require utility shareholders to shoulder the financial burden of PSEP-related costs, DRA's proposal for *ex post* reasonableness reviews would create undesirable incentives. In particular, conducting such reviews *ex post* would create a perception of regulatory opportunism, and would be economically inefficient.[215]

Traditionally, details over the quality of service delivered and cost recovery are resolved in GRCs. *Ex-post* reviews, sometimes called reasonableness or prudency reviews, are a mechanism designed to assess whether past expenditures were made appropriately. However, the temptation to critique past decisions with 20-20 hindsight tends to create a skewed view of

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212 Ex. SCG-14 (Montgomery) at 8.
213 Ex. SCG-14 (Montgomery) at 14.
214 Ex. SCG-14 (Montgomery) at 14 (citing Guthrie, G., (2006) "Regulating Infrastructure: The Impact on Risk and Investment," *Journal of Economic Literature*, V. 44, December, pp. 925-972.
215 Ex. SCG-14 (Montgomery) at 14.

what constitutes "reasonable" or "appropriate."[216] In much the same way that punishing a stock trader for incorrectly predicting the peak price of a stock does not produce a better trading strategy, using *ex post* reviews to judge reasonableness sets an unfair burden of foresight on the utility.[217]

Similar to disallowance of future costs, *ex post* reviews create an incentive for inefficient expenditure on the part of the utility. Rather than devoting resources to implementing an approved plan, the utility will focus on documenting the justification for each expenditure, and when forced to invest, will choose less-efficient systems with low capital costs (but possibly higher operating costs) to hedge the risk that they will not be able to recover the full capital cost of the investment.[218] Utilities will also be less willing to take risks on new technologies, even if they offer possibilities of achieving other social objectives for technology improvement and lowered environmental impact. The phrase "nobody ever lost his job for choosing IBM" characterizes this behavior.[219]

If there were just one simple, low-cost way to design systems for the safe and reliable operation of a complicated natural gas transmission and distribution system, perhaps such a regime would be harmless. In reality, the types of investment incentivized by *ex post* reviews tend to be more expensive to operate, less innovative, and therefore more costly to ratepayers in the long run.[220] The experience of electric utilities in the 1970s provides support for this point. After having much of their sunk investment disallowed, and facing *ex post* reasonableness

[216] Ex. SCG-14 (Montgomery) at 15.
[217] Ex. SCG-14 (Montgomery) at 15.
[218] Ex. SCG-14 (Montgomery) at 15.
[219] Ex. SCG-14 (Montgomery) at 15.
[220] Ex. SCG-14 (Montgomery) at 15.

reviews going forward, many utilities became extremely risk averse and inefficient in their investments, raising the cost to ratepayers without providing an improvement in service.[221]

4. Intervenor cost responsibility proposals would increase future costs and rates

The Commission's goal in this proceeding is to improve safety through a cost-effective program of pipeline testing and replacement. The intervenors' shareholder cost responsibility proposals would work against the Commission's goal in two ways: First, the retroactive regulatory change and cost disallowance would distort incentives and result in potential unintended consequences for safety improvement, as just discussed. The second effect would be an unambiguous cost increase for SoCalGas and SDG&E customers.[222]

The intervenors' proposals amount to an arbitrary and disproportionate penalty, which would adversely affect the willingness of shareholders to invest in future infrastructure programs, ultimately increasing the cost of financing for new investment.[223] Moreover, this appearance of a new risk of regulatory opportunism would not be limited to just the SoCalGas and SDG&E PSEP. Unless the Commission could reverse the altered perception, a longer-term cost of the intervenors' proposals would be the added cost of *all* new investment by the utilities.[224] As a result, the intervenors' proposals would create a qualitative change in the regulatory regime, with potentially severe implications for future utility investment decisions in all areas.[225] As Dr. Montgomery explained, "A penalty in the form of disallowance of future costs is an example of a misguided penalty."[226]

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[221] Ex. SCG-14 (Montgomery) at 15-16 (citing Lyon (1995) and Guthrie (2006)).
[222] Ex. SCG-14 (Montgomery) at 16.
[223] Ex. SCG-14 (Montgomery) at 16.
[224] Ex. SCG-14 (Montgomery) at 16.
[225] Ex. SCG-14 (Montgomery) at 16.
[226] Ex. SCG-14 (Montgomery) at 6.

If a regulator imposes penalties that are proportional to the offence, that create incentives for desirable behavior, and that are consistent with the expectation of shareholders about regulatory behavior, a utility's share price and cost of capital should not be affected by such penalties.[227] This neutrality will disappear, however, if regulators penalize past actions in ways that create an expectation among shareholders that future investments are subject to the risk of having partial cost recovery or a lower return imposed on them.[228]

> I believe that in retrospect the Commission discovers that a utility did something that it should not have done, and that is in violation of the Commission's standards, orders, or whatever else, it is appropriate to assess penalties. But I do not think that making those penalties a disallowance of future costs of future investment provides the kind of alignment of incentives that the Commission wants to have. So that one can penalize a utility effective [sic] and severely without doing so in a way that grossly distorts their incentives going forward.[229]

The economic link between risk and rate of return is well established. Simply put, it is necessary to offer higher returns to compensate investors for an investment with additional risk. Investors will see higher risks associated with new capital investment projects in California, because the intervenors' proposals would assure them a lower rate of return.[230] As a result, the borrowing costs for the utilities, and the rates borne by ratepayers, will rise. Overall, the economic consequences of adopting the intervenors' proposals would be higher rates due to: (i) increased expenditures to avoid excessive penalties; (ii) incentives to choose less than optimal capital expenditures for pre-1970 pipeline replacements and upgrades; (iii) incentives to build in redundant levels of safety in future capital projects and O&M expenditures; and (iv) increased cost of capital due to a lower rate of return on the utilities' capital investments.[231]

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[227] Ex. SCG-14 (Montgomery) at 17.
[228] Ex. SCG-14 (Montgomery) at 17.
[229] Tr. at 738 (SoCalGas/SDG&E/Montgomery).
[230] Ex. SCG-14 (Montgomery) at 17.
[231] Ex. SCG-14 (Montgomery) at 18.

5. Full cost recovery of PSEP expenditures and investments is crucial

Failure to provide for full recovery of PSEP costs can bias SoCalGas and SDG&E decisions in three ways:

- By encouraging the utilities to design and implement improvements to avoid unrecoverable expenditures rather than to minimize the total cost of the changes;
- By creating an incentive for the utilities to overspend on future safety-related activities to avoid disproportionate penalties; and,
- By changing the risk assessments of future investors in a manner that will depress share prices and raise the cost of financing future investments of all types.[232]

Because utility investments in infrastructure are costly and irreversible, an assurance of future cost recovery is necessary prior to undertaking investment. Stable policies regarding cost recovery and standards of service are critical to maintaining shareholders' assessments of the risks of investing in the utilities in question.[233] Although many jurisdictions are evolving from traditional cost of service regulation to performance-based regulation, both forms of regulation include several key components:

- No retrospective ratemaking – costs that were determined to be prudent at the time incurred are not to be disallowed with benefit of hindsight. Expenditures to meet new requirements are not disallowed because they could have been made earlier.
- The reasonableness of capital investment plans to assure adequacy and cost-minimization is reviewed and approved in advance of commitment and not revisited later.
- Costs of meeting new regulatory requirements (environmental regulations, renewable energy standards, social expenditures, tax increases) are borne by ratepayers not shareholders.

[232] Ex. SCG-14 (Montgomery) at 4.
[233] Ex. SCG-14 (Montgomery) at 12-13.

- Automatic pass-through of costs that are known to change unpredictably (fuel cost adjustment), possibly with incentive mechanisms to motivate risk management and hedging.
- Any penalties or damages borne by shareholders take the form of a fixed payment not a reduced rate of return or disallowance of a category of future costs.[234]

Ratepayers benefit from application of these principles because they reduce some of the risks of long-term investment by eliminating the possibility of unexpected alterations of the rules of cost-recovery, while at the same time they motivate utility management to make cost-effective decisions about the design of investments and the operation of the system.[235]

Rulings from other jurisdictions and previous rulings by the Commission have acknowledged that in a cost-of-service system the best results are achieved if the future incentives of the utility are aligned with customer priorities by providing for full recovery of all reasonable costs. For example, the Maryland Public Utility Commission recently completed a review of the reliability of electric service by Potomac Electric Power Company (PEPCO).[236] The Maryland Commission balanced the need for punishment due to past inadequacy of service quality with the need for prudent forward-looking incentives for service improvement. After finding clearly supported evidence of inadequate investment and poor management in the past, but with an eye towards aligning the incentives of the utility, they assessed a lump-sum penalty and imposed reporting requirements, but did not fundamentally alter the cost-recovery mechanisms of the utility.

In 2005, the Michigan Public Service Commission, "concerned that [the gas utility Michigan Consolidated] have the financial ability to meet these new safety and training-related

[234] Ex. SCG-14 (Montgomery) at 13-14.
[235] Ex. SCG-14 (Montgomery) at 14.
[236] Order No. 84564, Case No. 9240, In the Matter of an Investigation in the Reliability and Quality of Electric Distribution Service of Potomac Electric Power Company, Maryland Public Service Commission, 12/21/2011.

costs," allowed cost recovery for additional unplanned expenses associated with pipeline safety in meeting the Federal Pipeline Safety Improvement Act (FPSIA) of 2002, while also improving oversight by using additional reporting requirements.[237] Similarly, the Indiana Utility Regulatory Commission, recognizing that the utility [Indiana Gas Company] "is now incurring and will continue to incur incremental compliance expenses" due to the new safety standards imposed by FPSIA, authorized an expansion of the utility rate cap and provision for future recovery of deferred costs.[238] Both of these rulings, along with precedent on cost recovery of integrity management expenses from FERC, were noted in the Independent Review Panel Report on the San Bruno pipeline explosion.[239]

In addition, many judicial rulings have endorsed the principle that utilities be allowed sufficient revenue to cover costs and earn a risk-adjusted rate of return. The U.S. Supreme Court in the *Bluefield* case notes (in affirming that rates must be sufficient to yield a reasonable return): "This is so well settled by numerous decisions of this Court that citation of the cases is scarcely necessary."[240] The Commission determines reasonable operating costs that utilities incur "*to maintain their systems in accordance with the Commission's safety and reliability standards and industry best practices.*"[241] It follows that when the Commission's safety and reliability standards tighten, additional cost recovery should be approved. Recent rulings by the Commission have validated the idea that financial incentives encourage future utility priorities

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[237] *Michigan Consolidated Gas Co.*, Opinion and Order Granting Rate Relief, Case No. U-13898 at 74-76 (Apr. 28, 2005).

[238] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43967.

[239] June 9, 2011: Independent Review Panel Report on San Bruno Pipeline Explosion, Appendix Q: "Public Policies in the State of California: Ratemaking Regulatory Regime" http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm

[240] *Bluefield Water Works & Improvement Company v. Public Service Commission* (1923) 262 U.S. 679; and previous precedent in *Smyth v. Ames* (1898) 169 U.S. 466, 467 and 547, *Willcox v. Consolidated Gas Co.* (1909) 212 U.S. 19, 41 and 52, *Minnesota Rate Cases* (1913) 230 U.S. 352, 434; and *Federal Power Commission v. Hope Natural Gas Co.* (1944) 320 U.S. 591.

[241] California Public Utilities Commission, Electric & Gas Utility Cost Report; Public Utilities Code Section 747 Report to the Governor and Legislature at 30 (Apr. 2011).

(in the context of energy efficiency rather than pipeline safety):

> We are of the opinion that subjecting the IOUs to penalties or substantially reduced incentives based on factors they could not reasonably be expected to anticipate or effectively respond to will do little to motivate them to aggressively pursue energy efficiency, and may undermine the interests of the people of the state of California in placing energy efficiency on a par with "steel-in-the-ground" supply-side resources. By adopting this approach, we ensure the mechanism remains effective in aligning utility and ratepayer interests with respect to the resource priorities of the state.[242]

The Commission echoed Congress in recognizing the need to provide financial incentives in order to encourage utility priorities: "Rates charged . . . shall be such that the utility is encouraged to make investments in, and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution."[243] The objectives of the Commission for transmission system safety improvements will be best achieved by allowing for full PSEP cost recovery, rather than imposition of disallowances or lowered returns on PSEP capital expenditures:

> [I]n order to align the incentives for the development and implementation of the PSEP and meeting the California Commission's heightened concern about safety, the Commission should continue doing exactly what it's done in the past, which is treat the additional expenditures that are required and the development of the plan for building out the safety enhancements and making those billion dollar plus investments, treat them exactly the same way as they treat every other activity that Southern California Gas and San Diego Gas & Electric engage in, which is do not apply discriminatory -- do not apply discriminatory rates of return on those particular investments; don't disallow some of the costs as a penalty for past actions; treat it as the Commission normally would in terms of stating its expectations for what the quality of service will be and of reviewing in its standard way how SoCalGas goes about doing it.[244]

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[242] D.10-12-049, mimeo., at 7.
[243] Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776, Oct. 24, 1992.
[244] Tr. at 700-701 (SoCalGas/SDG&E/Montgomery).

E. Requiring Shareholders to Pay PSEP Costs Would Violate the Takings Clauses of the U.S. and California Constitutions

Both the United States and California Constitutions prohibit a government taking of private property without just compensation.[245] In the context of public utilities, it is well settled that these constitutional safeguards bar the regulator from setting rates for the use of utility property that are so unjust as to be confiscatory.[246] There are many court and Commission decisions that recognize the *concept* of this kind of regulatory taking. But they typically conclude no such *showing* has been made because the cost recovery allowed -- while less and perhaps far less than the complaining utility requested -- is not so low constitute a taking. That standard has been variously described not only as "confiscatory," but also "unjust and unreasonable," causing "deep financial hardship," or "'the functional equivalent of an 'ouster.'"[247]

Determining if these conditions are met may be difficult in many cases, but it is obvious when it comes to the various intervenor recommendations in this proceeding. While some are less draconian than others, all of them urge the Commission to require SoCalGas and SDG&E to conduct certain tests and install new pipelines yet *receive no compensation whatsoever* for that work or property.[248] A rate order implementing such recommendations would surely violate the

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[245] U.S. Const., Amend. V and XIV; Cal. Const. Art. I, Sec. 19. Although there are some differences in the wording of these two documents, and some decisions that have concluded that the California Constitution offers more protection to the property owner, this brief follows the practice of the Commission in its takings decisions which do not distinguish between the two. *See*, *e.g.*, Application of Calaveras Telephone Co. et al, D 10-10-036, 2010 Cal PUC LEXIS 47, *8 n. 4.

[246] *Duquesne Light Co. v. Barasch* (1989) 488 U.S. 299, 307; quoting *Covington & Lexington Turnpike Road Co. v. Sandford* (1896) 164 U.S. 578, 597.

[247] *Bluefield Waterworks & Improvement Co. v. W. Va. Pub. Serv. Comm.* (1923) 262 U.S. 679, 690; *20th Century Insurance v. Garamendi* (1994) 8 Cal. 4th 216, 296; OIR Re Local Exchange Service and OII Re Competition for Local Exchange Service, D. 97-04-090, 1997 Cal. PUC LEXIS 363 *32 citing *Yee v. Escondido* (1992) 503 U.S. 519, 522.

[248] DRA also recommends that if the Commission requires the replacement of pipelines installed between 1935 because of a lack of previous test records, then the return on equity for those costs should be reduced by 200 basis points from the ROE otherwise authorized for capital investments for these utilities. This would also be an explicit denial of a portion of compensation that the Commission has otherwise determined to be at a reasonable level.

Commission's own guidelines on this subject as well as state and federal constitutional standards.[249]

IV. REASONABLENESS OF SOCALGAS AND SDG&E'S PHASE 1A RECOMMENDATIONS

A. Decision-Making Process

1. The Commission Should Approve SoCalGas and SDG&E's Proposed Three-Phased Prioritization Process

Consistent with the Commission's directive in Ordering Paragraph No. 4 of D.11-06-017 to "start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas [i.e., Criteria Miles],[250] with pipeline segments in other locations given lower priority for pressure testing," SoCalGas and SDG&E's proposed plan to test or replace pipeline segments prioritizes pipeline segments in these more populated areas first, with the less populated areas being addressed at a later stage. The Plan is divided into three phases. [251]

In Phase 1A, all Criteria Mile pipeline segments that do not have sufficient documentation to validate a post-construction pressure test of at least 1.25 times the pipeline's MAOP are scheduled to be addressed.[252] These segments were previously classified as Category 4 in SoCalGas and SDG&E's April 15 Report and represent the highest priority work. Consistent with our objective to maximize the cost effectiveness of our investments, the length of the segment to be tested or replaced may be increased to include adjoining pipeline that is in

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[249] "Under *Hope* [*Federal Power Comm. v. Hope Natural Gas Co* (1994) 320 U.S. 591], so long as our determinations fall within a 'zone of reasonableness,' courts must defer to the *balancing* of consumer and investor interests arrived at by the Commission." Application of Calaveras Telephone Co. supra, 2010 PUC LEXIS at *10-11 (emphasis added). There is no balance in the intervenors' proposals. "A taking is unconstitutional only if the property owner does not receive just compensation." OIR on Competition for Local Exchange Service and OII Re Competition for Local Exchange Service, D. 00-03-055, 2000 Cal. PUC LEXIS 228, *12. For many of SoCalGas' and SDG&E's transmission pipelines, the intervenors' proposals would provide *no compensation* at all.

[250] In their proposed Pipeline Safety Enhancement Plan, SoCalGas and SDG&E continue to use the term "Criteria Miles" to refer to the subset of their transmission pipelines that are located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, and build upon the records review and pipeline categorization work described in the April 15 Report to prioritize pipeline segments within the Plan.

[251] Ex. SCG-04 (Schneider) at 50.

[252] Ex. SCG-04 (Schneider) at 50-51.

more sparsely populated areas due to operational necessity and project efficiency.[253] As discussed in greater detail in Section IV.C below, these adjoining segments are, in essence, "accelerated" into Phase 1A for purposes of developing the estimated costs of implementing the proposed plan, even though the segments would otherwise be addressed in a later phase according to our proposed prioritization process.[254] SoCalGas and SDG&E are seeking approval of Phase 1A, including our proposed prioritization process, test or replace decision-making process and cost recovery. Phase 1A is anticipated to span four years from the date the Commission issues a final decision approving our Plan.

In Phase 1B, SoCalGas and SDG&E propose to 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.[255] Also in Phase 1B, SoCalGas and SDG&E propose to replace any non-piggable transmission pipeline segments installed prior to 1946 that remain in their transmission system after the completion of Phase 1A work, to mitigate historic construction and fabrication methods (*e.g.*, oxy-acetylene girth welds) that were commonly utilized prior to 1946.[256] While SoCalGas and SDG&E do not seek approval of the costs of implementing Phase 1B at this time, SoCalGas and SDG&E do seek approval of their proposed prioritization and decision-making process, costs for inline inspecting Line 1600 using TFI technology as an interim safety enhancement measure during Phase 1A, as well as costs for designing and pre-engineering a replacement line for Line 1600. SoCalGas and SDG&E propose to seek authorization from the Commission to recover Phase 1B costs either in a future GRC or other appropriate proceeding at a later date.

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[253] Ex. SCG-04 (Schneider) at 50-51.
[254] Ex. SCG-04 (Schneider) at 50-51.
[255] Ex. SCG-04 (Schneider) at 51.
[256] Ex. SCG-04 (Schneider) at 51.

Phase 2 is expected to run in parallel with and extend past the completion of Phase 1B.[257] In this final phase, SoCalGas and SDG&E propose to address all remaining transmission pipeline segments that do not have sufficient documentation to validate post-construction pressure tests to 1.25 times the pipeline's MAOP (i.e., Category 3 and 4 pipelines located in less populated areas that have not yet been addressed) and all other remaining transmission pipelines that have not been strength tested to modern standards. 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.[258] While SoCalGas and SDG&E do not seek approval of the costs of implementing Phase 2 at this time, SoCalGas and SDG&E do seek approval of the proposed prioritization and decision-making process described below.[259]

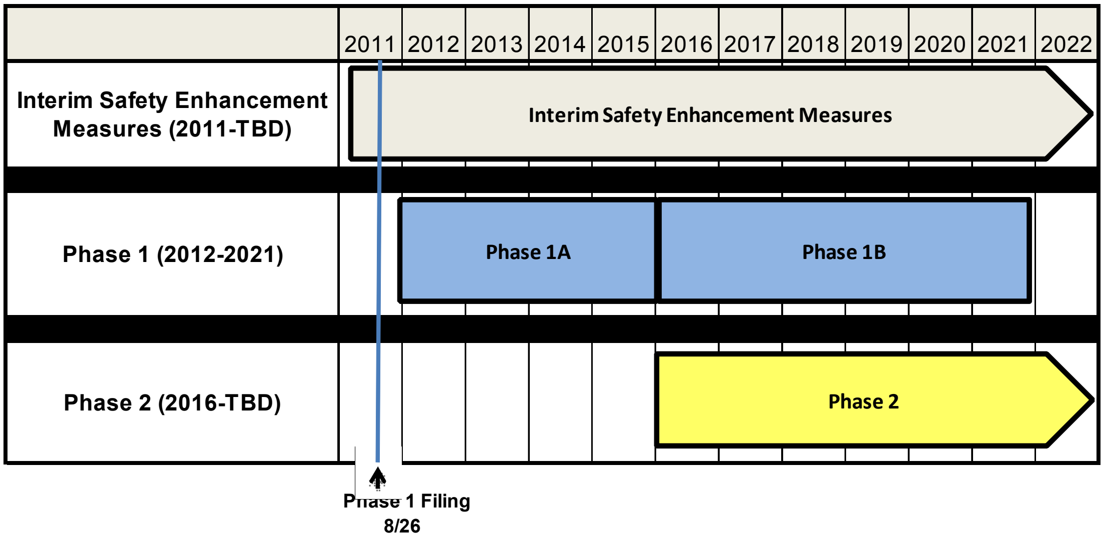
This phasing process was depicted in our direct testimony in the following figure, based upon issuance of a decision approving our Plan in the first quarter of 2012:

[257] Ex. SCG-04 (Schneider) at 51.

[258] Ex. SCG-04 (Schneider) at 51. As discussed in Section IV.D below, in some circumstances, Phase 2 pipeline segments adjacent to Phase 1 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.

[259] Ex. SCG-04 (Schneider) at 51. SoCalGas and SDG&E also seek the flexibility to propose alternative assessment methods using advanced inspection methods and emerging technologies, 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. Ex. SCG-04 (Schneider) at 51.

Figure 1



The total miles to be address in each phase are set out in Exhibit 34-R. Exhibit 34-R also delineates the miles by vintage and, for Phase 1A and 1B, breaks down the mileage according to the categorization process SoCalGas and SDG&E used to prepare the April 15 Report.

Thus far, no parties have raised objections to this phased schedule and it should be approved by the Commission as a reasonable implementation of the directives in D.11-06-017.

2. The Commission Can Help Mitigate Some Execution Challenges That May Increase Costs and/or Delay Implementation

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."[260] 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

[260] Ex. SCG-02 (Morrow) at 28 (quoting D.11-06-017 at 31, Ordering Paragraph 5).

California DOT, California State Lands Commission, Federal Aviation Administration, 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.[261] 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.[262] SoCalGas and SDG&E recommend that the Commission take four specific actions in order to mitigate these execution challenges.

First, to minimize the potential for construction permitting delays and challenges, the Commission should expressly state in its decision approving our Plan that execution of the PSEP 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 PSEP, while affirming that California natural gas pipeline operators are required to obtain all necessary non-preempted permits prior to commencing construction.[263]

Second, 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 PSEP 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

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[261] Ex. SCG-02 (Morrow) at 23.
[262] Ex. SCG-02 (Morrow) at 26.
[263] Ex. SCG-02 (Morrow) at 26.

with the natural gas utilities in developing and conducting outreach and education efforts to communicate the purpose and need for timely execution of their safety enhancement plans.[264]

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. The natural gas utilities will rely on agencies to process their permits in a timely and responsive manner. Recent experience indicates that resource constraints and these agencies are likely to pose a significant challenge to timely execution of the PSEP. 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.[265]

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

[264] Ex. SCG-02 (Morrow) at 26-27.
[265] Ex. SCG-02 (Morrow) at 27.

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.[266]

No intervenors oppose these proposals by SoCalGas and SDG&E. Indeed, "DRA supports [SoCalGas and SDG&E's] general request for CPUC assistance with permitting issues. Specifically, DRA recommends that the CPUC work with the State Water Resources Control Board to establish a statewide permit, or to educate the Regional WQCBs about the public benefit of hydrotesting, and to guide and coordinate the regional water board permit processes."[267]

3. Proposed Sub-Prioritization Process

The SoCalGas and SDG&E Plan includes a proposed sub-prioritization process that complies with the Commission's directives to develop a "priority-ranked schedule for pressure testing pipeline not previously so tested"[268] and to test or replace segments with the highest risk first.[269] Under this proposed sub-prioritization process, after priorities have been broadly established for all lines as described in the phased approach above, detailed planning will be conducted to rank order pipeline segments 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[270] for each pipeline segment divided by its long

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[266] Ex. SCG-02 (Morrow) at 27-28.
[267] Ex. DRA-03 (Roberts) at 30.
[268] D.11-06-017 at 32, Ordering Paragraph No. 7.
[269] D.11-06-017 at 32, Ordering Paragraph No. 9.
[270] 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 effect on population density. Ex. SCG-04 (Schneider) at 63.

seam factor. Long seam factors will be applied to raise the score for certain pipeline segments, as specified in 49 CFR 192.113.[271] This approach is consistent with pipeline risk principles.[272]

When segments have the same score, the pipeline segment that operates at a higher percentage of the SMYS at MAOP will be given a higher priority.[273]

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.[274]

DRA claims that this "sub-prioritization methodology does not account for pipeline location, risk assessments from Transmission Integrity Management Program (TIMP), or maintenance data in ranking pipeline for MAOP validation"[275] and recommends that these elements be incorporated into SoCalGas and SDG&E's proposed sub-prioritization process.[276] This recommendation ignores that SoCalGas and SDG&E's phasing process already accounts for pipeline location, and follows specific direction from the Commission in Ordering Paragraph No. 4.

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271 Ex. SCG-04 (Schneider) at 63.

272 Ex. SCG-04 (Schneider) at 62. 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 are sub-ranked for scheduling purposes primarily based on the consequence of failure of each segment. Ex. SCG-04 (Schneider) at 62-63.

273 Ex. SCG-04 (Schneider) at 63.

274 Ex. SCG-04 (Schneider) at 63.

275 Ex. DRA-01 (Peck) at 3.

276 Ex. DRA-02 (Phan) at 83 (" . . . Sempra should consider ranking pipeline segments in descending order of class location from Class 3 to Class 1, decreasing PIR's and percentage of High Consequence Area (HCA) pipe within each project. Sempra should consider the date of the last assessment in sub-prioritization as well. All other factors being equal, a pipeline that is more problematic or shows a higher level of risks, based on the TIMP risk assessments, should be given higher priority than a pipeline that was assessed and was ranked with a lower level of risks.").

The primary objective of the SoCalGas and SDG&E proposed sub-prioritization process is to rank pipelines with a higher potential risk for rupture in populated areas ahead of pipelines with a lower risk for rupture in populated areas.[277]

Sub-ranking pipelines by potential impact radius, as proposed by SoCalGas and SDG&E, serves as an effective proxy for the accounting of all factors contributing to stress level and, therefore, rupture risk. Potential impact radius correlates closely to stress level as the two factors share in common both diameter and pressure, and potential impact radius proportionately reflects the increased exposure to rupture risk to people by accounting for the areas of impact as opposed to stress level alone (i.e., potential impact radius avoids the pitfalls of prioritizing a small but highly stressed pipeline with a small impact area over a medium or low stress pipeline with a much greater area of impact). In turn, division of the potential impact radius by the long seam factor serves to up-rank pipelines with longitudinal seam factors less than 1.0, and thus provide for the initiation of those projects sooner than if only the potential impact radius were used. Stress level is directly proportional to increased rupture risk, and is used as the final prioritization factor to account for increased likelihood of pipe failure as opposed to the consequences of a failure.[278]

It is for these reasons that potential impact radius, seam type, and stress level have the greatest effect on the pressure-carrying capacity of the long seam, and should remain as the main factors for ranking the testing or replacement of pipelines that are in populated areas and do not have sufficient demonstration of a 1.25 times MAOP safety margin.[279]

DRA also recommends that TIMP and maintenance information be used as part of the prioritization criteria. SoCalGas and SDG&E's TIMP, and by extension, general maintenance

[277] Ex. SCG-04 (Schneider) at 63.
[278] Ex. SCG-18 (Schneider) at 14-15.
[279] Ex. SCG-18 (Schneider) at 15.

practices, are separate and distinct from this proposed Plan. The objective of this Plan is to validate the integrity of long seams through pressure testing, addressing more heavily populated areas prior to lesser populated areas. DRA's recommendation to add corrosion control and other data into the prioritization process would dilute focus away from higher priority long seams and does not meet the objective of prioritizing pipelines with the greatest potential consequences from long seam failure above those with lesser potential consequences.[280] It would also frustrate and delay the implementation of the Plan, conflicting with the Commission's directive to implement the plan "as soon as practicable."[281]

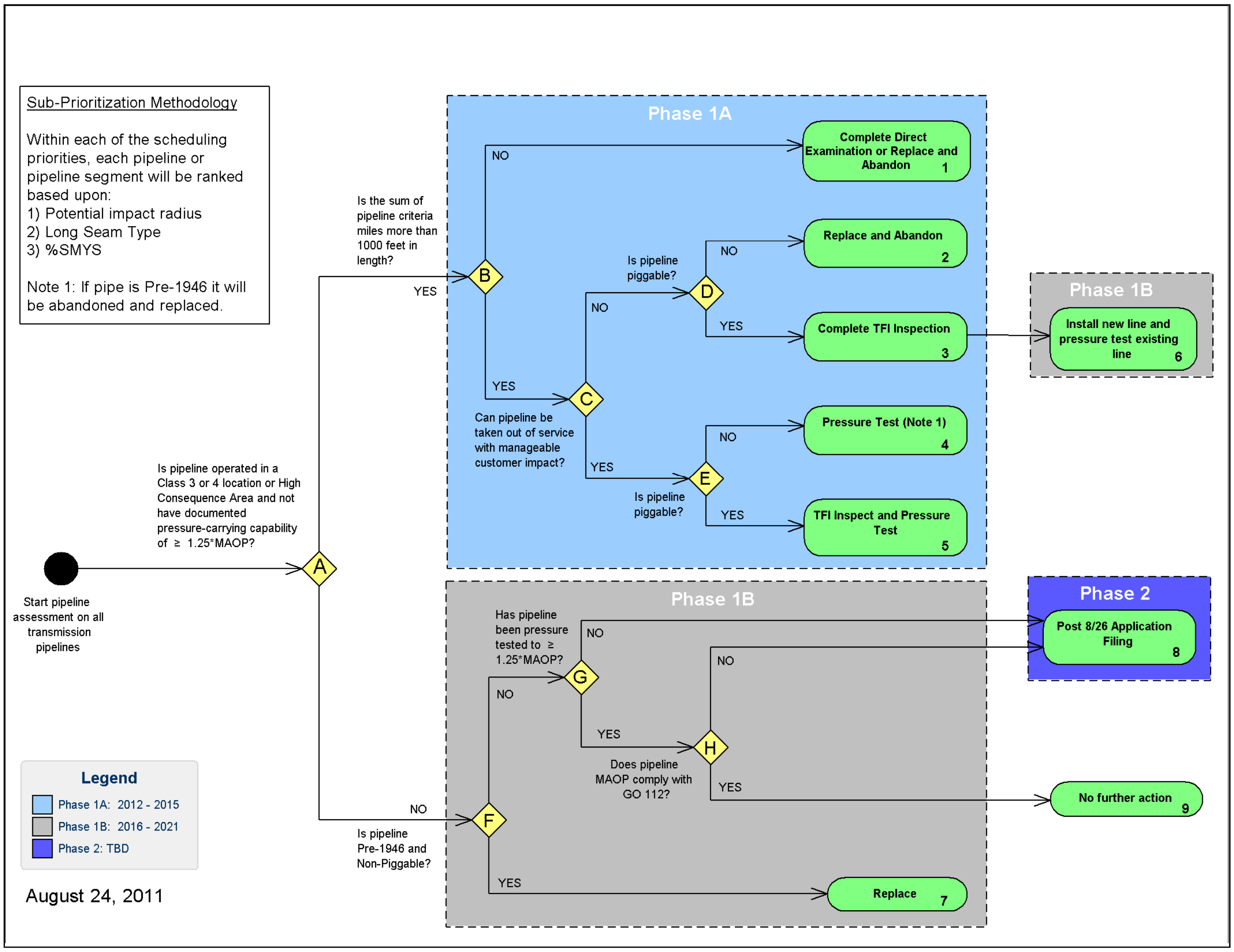
4. Criteria for Determining Whether to Test or Replace Pipeline Segments

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 without significantly impacting customers.[282] As discussed below, SoCalGas and SDG&E propose to (1) perform a complete inspection of a pipeline segment using non-destructive examination methods on pipeline segments that are less than 1,000 feet in length; (2) pressure test those pipeline segments greater than 1,000 feet in length where we can manage the impacts that such testing would have on our customers; and (3) replace those pipeline segments that are greater than 1,000 feet in length that cannot be taken out service for pressure testing.

This decision-making process is illustrated in the figure below.

[280] Ex. SCG-18 (Schneider) at 15.
[281] D.11-06-017 at 31, Ordering Paragraph No. 5.
[282] Ex. SCG-04 (Schneider) at 52.

Figure 2
Pipeline Safety Enhancement Plan Test/Replace Decision Tree



The number of pipeline miles to be addressed at each decision point is set out in Exhibit 33-R.

a. Pipeline Segments Less Than 1,000 Feet in Length

SoCalGas and SDG&E propose to perform a complete inspection of a pipeline segment using non-destructive examination methods on pipeline segments that are less than 1,000 feet in length, rather than pressure testing or replacing these pipeline segments.[283]

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[283] Ex. SCG-04 (Schneider) at 54.

If the Commission does not approve this proposed alternative to pressure testing, which is discussed in greater detail in Section VI, SoCalGas and SDG&E propose to replace and abandon these short segments. This is because 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 for short segments of pipe.[284] Therefore, it will typically be more cost effective to abandon and replace pipeline segments that are 1,000 feet or less in length rather than perform a pressure test.[285] In addition, these short segments are usually off takes that feed a regulator station and therefore, the longer customer impact timeframes associated with hydrotests would likely be unacceptable.[286] In such circumstances, replacement is likely to be the more cost-effective approach. Moreover, installation of the new segment can usually be performed while 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.[287]

While we believe that it will be more cost effective to replace these short segments, SoCalGas and SDG&E will consider all costs associated with pressure testing, including managing customer impacts (through CNG, LNG, installing temporary bypasses, etc.) during the detailed design and engineering process. Those costs will be compared with the costs of replacing the old pipeline with a new one. Other engineering factors will also be considered depending on the situation of each unique pipeline.[288] SoCalGas and SDG&E will only move

[284] Ex. SCG-04 (Schneider) at 53.
[285] Ex. SCG-04 (Schneider) at 53.
[286] Ex. SCG-20 (Phillips) at 11.
[287] Ex. SCG-04 (Schneider) at 53.
[288] Ex. SCG-20 (Phillips) at 10-11.

forward with replacement of these shorter segments of pipeline if this cost benefit analysis indicates that it is more cost effective to do so.[289]

DRA asks the Commission to reject this element of the SoCalGas and SDG&E decision-making process as having "no basis" and "unsupported."[290] Contrary to DRA's contentions, however, there is ample evidence in the record to support this assumption. First, as explained in SoCalGas and SDG&E's testimony, for short segments of pipeline "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."[291] Second, while it is true that SoCalGas and SDG&E have not yet performed a formal cost benefit analysis for each segment of pipeline to be addressed under the proposed Plan, DRA acknowledges that this preliminary determination was based on the engineering judgment of SoCalGas and SDG&E's subject matter experts.[292] These subject matter experts have years of experience designing and maintaining complicated interconnected piping systems that contain numerous off takes to customers,[293] a fact that is inexplicably dismissed by DRA.

Moreover, as explained by SoCalGas and SDG&E in their testimony, "installation of the new segment can usually be performed while existing service is maintained to customers, thereby avoiding service disruptions that may otherwise occur during pressure testing."[294] DRA's recommendation appears to give little or no regard to the impracticality of testing very small pipeline segments or to customers being without gas service for extended periods of time. For example, DRA is silent about the significant difference in time that customers will be

[289] Ex. SCG-20 (Phillips) at 10-11. *See also* Tr. at 1079-82, 1116-17 (SoCalGas/SDG&E/Phillips).
[290] Ex. DRA-02 (Phan) at 45.
[291] Ex. SCG-04 (Schneider) at 53.
[292] Ex. DRA-02 (Phan) at 45 (quoting a data request response from SoCalGas and SDG&E that states that "[t]his determination was based on engineering judgment.")
[293] Ex. SCG-20 (Phillips) at 5.
[294] Ex. SCG-04 (Schneider) at 53.

without service for pressure testing when compared to replacement. Unlike replacing a pipeline segment, pressure testing an in-service pipeline can cause service outages anywhere from two to several weeks. In addition, while there is little variability in the length of time it takes to tie in a replacement line to the existing system (less than one day to two days), there can be significant variability of how long customers will be without service for pressure testing. Small leaks to outright failures can occur, taking anywhere from a day to weeks to repair. There may also be problems removing hydrotest water from the pipeline segment. SoCalGas and SDG&E's Plan takes these realities into consideration, whereas DRA's proposal does not.[295]

DRA's argument appears to be based on a fundamental misunderstanding of the SoCalGas and SDG&E proposal. While DRA claims that SoCalGas and SDG&E are seeking approval of "the more costly option,"[296] this is not the case. SoCalGas and SDG&E seek authorization to replace and abandon these shorter pipeline segments if, after the design and engineering process is completed, it is determined that replacement is the less costly option. If in particular instances it would be more cost-effective to pressure test these shorter segments, SoCalGas and SDG&E will do so.[297] In implementing their PSEP, SoCalGas and SDG&E are requesting that we be provided the flexibility to apply prudent engineering judgment to determine the most cost-effective, logical and operationally feasible approach to bring pipelines up to the new safety standards being set by the Commission.

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[295] Ex. SCG-20 (Phillips) at 7. *See also* Hearing Transcript, Vol. 6 (Phillips) at 1081 ("So there's a number of costs we have to look into when we evaluate a pipeline. If we're going to evaluate it, test it, rather than replace it, modifications we have to make to the pipeline to make it available to hydrostatically test. We haven't designed the system to be filled with water and taken out of the system for six weeks. We haven't designed the system that way in the 80 years we've been designing the system. We have to look at the cost to that.")
[296] Ex. DRA-02 (Phan) at 46.
[297] Ex. SCG-20 (Phillips) at 10-11. See Section IV.B.4.c below for a description of the cost benefit analysis to be performed by SoCalGas and SDG&E during the design and engineering process.

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 two to six weeks to complete pressure testing. Those pipelines that can be taken out of service with manageable customer impacts are identified for pressure testing in Phase 1A.[298] If, however, the pipeline was installed prior to 1946 and is unpiggable, as explained in Section IV.B.4.d below, the pipeline will be considered for replacement.

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

As explained above, where removal from service for pressure testing is expected to be feasible, the pipeline segments are identified for pressure testing. Where service disruption is not likely to be feasible, the pipelines are either identified for abandonment or for pressure testing once new replacement pipelines have been installed to maintain service to customers.[299]

Construction and installation of a 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.[300]

i. SoCalGas and SDG&E Propose to Comprehensively Assess Engineering Factors, Customer Impacts, Costs and Benefits Prior to Making a Final Test or Replace Determination

DRA, TURN and SCGC object to the SoCalGas and SDG&E decision-making process on the grounds that the criteria for determining whether to replace a pipeline segment is not

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[298] Ex. SCG-04 (Schneider) at 55.
[299] Ex. SCG-04 (Schneider) at 55.
[300] Ex. SCG-04 (Schneider) at 59.

clearly defined in the Plan.[301] At the heart of their testimony, DRA, TURN and SCGC would prefer for SoCalGas and SDG&E to pressure test, rather than replace, pipelines no matter what the condition or age of the pipeline, because they believe that it is the lower-cost option.

DRA states in its testimony that SoCalGas and SDG&E's determination to test or replace a pipeline is "too vague and subjective to be relied on by the Commission," and recommends that all pipeline segments be pressure tested.[302] DRA is wrong. SoCalGas and SDG&E relied on the judgment of our subject matter experts, based on years of experience and system knowledge, to determine which segments of pipe should be tested and which segments should be replaced.[303] And while SoCalGas and SDG&E agree that additional engineering analysis will be needed, that is no basis to conclude that all pipeline segments should be pressure tested, as argued by DRA.

Based on our considerable expertise and judgment, during our preliminary assessment, we determined that over half of our Phase 1A miles could be pressure tested with manageable customer impacts. The decision to place a pipeline in the replacement category was based on a measured review of the difficulty or impracticality of taking a line out of service. This judgment was made by SoCalGas and SDG&E personnel with years of experience designing and maintaining complicated interconnected piping systems that contain numerous off takes to customers.[304]

In their recommendations for pressure testing of pipelines that SoCalGas and SDG&E propose to replace, intervenors give little or no regard to the impracticality of testing certain lines or to customers being without gas service for extended periods of time. For example, they are

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[301] *See* Ex. DRA-02 (Phan) at 47-53; Ex. TURN-01 (Long) at 3-5; Ex. SCGC-01 (Yap) at 9-10.
[302] Ex. DRA-02 (Phan) at 48; TURN similarly states that "[i]t is hard to fathom how the Commission can reasonably be expected to pass judgment on the reasonableness of the utilities' proposals and the associated costs when the utilities are not yet in a position to explain how they intend to make the decisions underlying those proposals." Ex. TURN-01 (Long) at 4.
[303] Ex. SCG-20 (Phillips) at 5.
[304] Ex. SCG-20 (Phillips) at 5.

silent about the significant difference in time that customers will be without service for pressure testing when compared to replacement. Unlike replacing a pipeline segment, pressure testing an in-service pipeline can cause service outages anywhere from two to several weeks.[305] In addition, while there is little variability in the length of time it takes to tie in a replacement line to the existing system (less than one day to two days), there can be significant variability as to how long customers will be without service for pressure testing. Small leaks to outright failures can occur, taking anywhere from a day to weeks to repair. There may also be problems removing hydrotest water from the pipeline. SoCalGas and SDG&E took these realities into consideration when evaluating customer impacts.[306] These intervenors, on the other hand, fail to recognize the impracticality of testing some lines, the burden that testing imposes on customers when they have no service for extended periods of time, and the improvement in quality of the pipeline asset that will result from the approach proposed by SoCalGas and SDG&E.[307]

<u>Impracticality of Testing Some Lines</u>

Many pipelines simply cannot reasonably accommodate pressure testing because of their configuration and the number of taps off the lines that are used to feed customers. Such pipelines are typically referred to as "distribution supply lines." As the name implies, these lines are used to supply many customers. While they are operated at greater than 20% specified minimum yield strength, and therefore are transmission lines under DOT regulations, they – unlike the larger transmission lines used to carry gas long distances – have many interconnections and take off points. A consequence of the multiple take off points for these

[305] Ex. SCG-20 (Phillips) at 7.
[306] Ex. SCG-20 (Phillips) at 7.
[307] Ex. SCG-20 (Phillips) at 2.

distribution supply lines is that it is much more complicated to feed the many customers with alternate means.[308]

Distribution supply lines are also typically comprised of more than one pipe diameter (*e.g.*, eight-inch, ten-inch and twelve-inch). This is a legacy of their age and changes that were implemented over the life of the pipeline (*e.g.*, replacements of pipe sections in an active corrosion zone, the widening of a freeway or road that necessitated the relocation of the line, or a new substructure crossing the line transversely). These lines also contain many features (reduced-sized valves, pressure control fittings, etc.) that need to be removed prior to testing. Different sizes of pipe make executing a pressure test with water very difficult or impossible. This is because "pigging" is needed in the pressure test process, first in order to remove any air that would otherwise create an air void and influence the test reading, and then to remove water that can otherwise lead to internal corrosion or reach a customer's meter, causing an outage. The pig device is used to separate liquid from gas and is usually an inflatable neoprene ball or dense foam device. These pigs are able to accommodate one or possibly two pipeline diameters. Accordingly, pipelines with multiple diameters would require multiple hydrotests, increasing costs and creating execution challenges.[309]

Potential Impacts to Customers

DRA, TURN and SCGC highlight the relative difference in the unit cost of pressure testing versus replacement activities as an important reason to either reject or discourage inclusion of pipe replacement within the scope of Phase 1A.[310] Simply applying a pressure test

[308] Ex. SCG-20 (Phillips) at 5-6.
[309] Ex. SCG-20 (Phillips) at 6.
[310] *See*, *e.g.*, Ex. DRA-02 (Phan) at 49 ("Given the Sempra estimate for replacement at seven times higher than for pressure testing, there is a disincentive for Sempra to pursue an action that is lower in costs."); Ex. TURN-01 (Long) at 10 ("The Commission's decision at this stage of the proceeding should . . . limit its consideration of projects to those that are relatively lower cost, that is, pressure testing rather than pipeline replacement."); Ex. SCGC-01 (Yap) at 11 ("[T]he Commission should direct the Applicants to pursue pipeline replacement as a last resort. . . . The

unit cost to a project mileage, however, can result in the omission of potentially significant project costs to manage customer impacts and disregards the opportunity to lower future costs and risks by improving the quality of the pipeline asset.[311]

SoCalGas and SDG&E's estimated costs for pressure testing do not include costs for managing customer impacts, as the pipeline segments selected for pressure testing are assumed to not require extraordinary efforts to maintain service to customers during pipeline outages.[312] While TURN presumes that the "vast differential in the per-unit costs associated with the two options makes pressure testing the less financially consequential of the two,"[313] it is certainly feasible that the costs to manage customer impacts will be significant and cost prohibitive. Pressure test costs are expected to be higher than those that appear to have been assumed by intervenors. Indeed, PG&E's experience has shown costs to be higher than originally planned.[314]

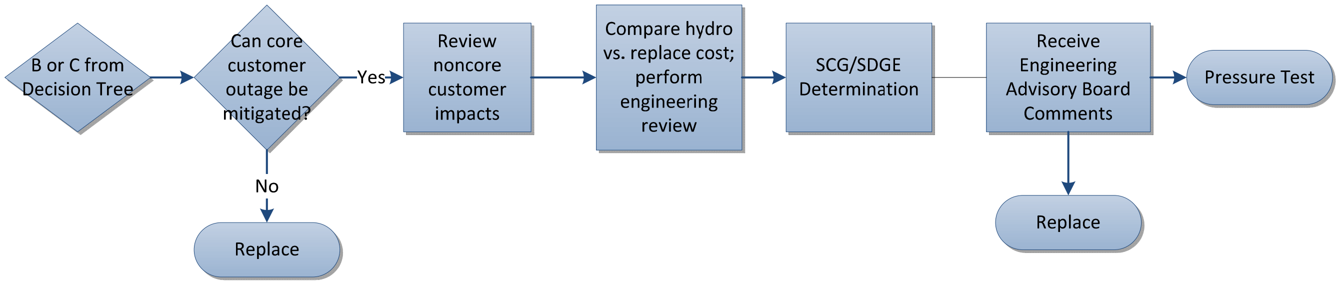
Proposed Replacement Decision Tree

SoCalGas and SDG&E performed considerable work to determine which segments of pipeline should be tested and which segments need to be replaced. But SoCalGas and SDG&E recognize that more work still needs to be done. Accordingly, we developed the following Replacement Decision Tree, shown in Figure 3 below, to assist in the decisions to be made under SoCalGas and SDG&E's original decision tree shown in Figure 2 above.[315]

Commission should adopt a procedure for the Phase 1A period that would subject each proposal to replace a pipeline with a rigorous review of the justifications of that decision.").

311 Ex. SCG-20 (Phillips) at 9.
312 Ex. SCG-20 (Phillips) at 10.
313 Ex. TURN-01 (Long) at 11.
314 Ex. SCG-20 (Phillips) at 10. *See also* Tr. at 1081-82 (SoCalGas/SDG&E/Phillips).
315 Ex. SCG-04 (Schneider) at 58-59.

Figure 3 – Replacement Decision Tree



This Replacement Decision Tree should reassure the Commission that the appropriate factors that meet all the Commission objectives will be considered when assessing the determination of whether to pressure test or replace the lines.[316]

The Replacement Decision Tree is based on the following principles: (1) SoCalGas and SDG&E will not interrupt service to its core customers in order to pressure test a pipeline; (2) SoCalGas and SDG&E will work with noncore customers to determine if an extended outage is possible; (3) SoCalGas and SDG&E will, where necessary, temporarily interrupt noncore customers as provided for in their tariffs; (4) SoCalGas and SDG&E will work with noncore customers to plan, where possible, service interruptions during schedule maintenance, down time or off peak seasons; and (5) SoCalGas and SDG&E will consider cost and engineering factors, along with the improvement of the pipeline asset.[317]

The evaluation process will begin with a determination of whether taking a pipeline out of service for pressure testing would result in the loss of gas service to customers. If service would be interrupted, alternatives to maintaining service to customers during pipeline outages will be evaluated. As part of the planning for the pressure test, SoCalGas and SDG&E will determine whether there is a viable alternative method of providing gas service to impacted core

[316] Ex. SCG-20 (Phillips) at 8.
[317] Ex. SCG-20 (Phillips) at 8-9.

customers (i.e. compressed natural gas, liquefied natural gas, temporary bypass, etc.). If there is not, a replacement line will be installed and the original asset will be abandoned or pressure tested once the new pipeline is in service.[318]

SoCalGas and SDG&E will make every effort to minimize impacts to customers by working with them to determine if an extended outage is acceptable or if the outage can be planned around the customer's scheduled maintenance, down time or during off-peak seasons.[319]

The following is an example that illustrates the project execution aspects and challenges and the type of analysis that will be considered in the pressure test versus replace process. Line 32-21, depicted in Figure 4 below, runs mostly in city streets in the Pasadena area. The primary line was installed in the late 1940s and early 1950s.[320]

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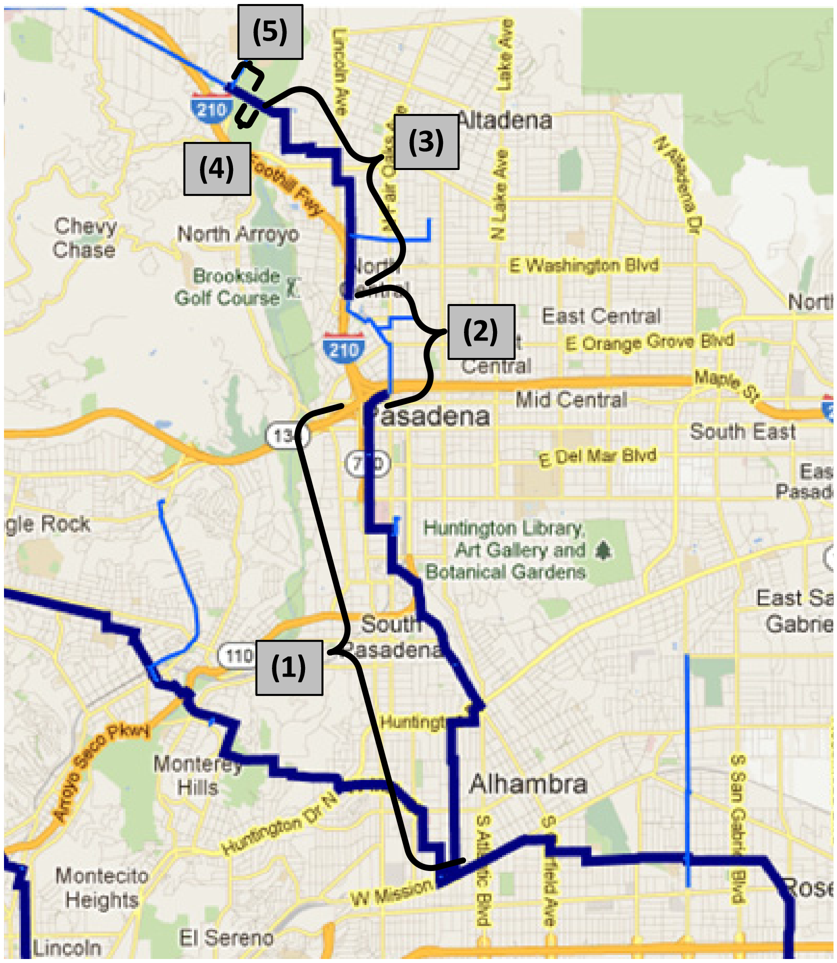
[318] Ex. SCG-20 (Phillips) at 9.
[319] Ex. SCG-02 (Morrow) at 15-16.
[320] Ex. SCG-20 (Phillips) at 12.

Figure 4



For most of the line segments that make up this pipeline there are no records of a pressure test, thus rendering them Category 4.[321] The following describes the sections identified in Figure 4:

(1) Entirely Category 4 Criteria mileage except for a twenty-foot segment at the beginning of the line that meets the DOT definition of a distribution line. The pipe segments were installed in the late 1940s and early 1950s. This section contains twelve-inch, sixteen-inch, and twenty-inch pipe and changes from one to another seven times. Hydrotesting

[321] Ex. SCG-20 (Phillips) at 12.

may well require a minimum of seven different test segments, and possibly more, to avoid customer impacts.

(2) Primarily contains a pipe relocation done in the early 1970s due to a freeway widening effort. These pipe segments are identified as Category 1 in the Plan. This section is comprised of two different pipe diameters. This section also contains a small amount of pipe meeting the definition of a DOT distribution line, and also is comprised of two different pipe diameters.

(3) Entirely Category 4 Criteria mileage installed originally in the late 1940s. There is one diameter change over this section from twenty inches to twelve inches, which precludes hydrotesting the entire section with a single test.

(4) Short section of Category 4 non-Criteria mileage. This is a Class 1 area where the pipeline crosses the Arroyo Grande (north of the Rose Bowl). Under DRA's proposal, this section would not qualify for accelerated treatment in Phase 1A, thus creating the need to re-visit this pipeline in a later Phase of the Plan. (The inclusion of Accelerated pipeline segments in the Base Case is discussed in more detail in Section IV.C.1.b below.)

(5) Short section of Category 4 Criteria mileage installed originally in the late 1940s.[322]

This example is provided to highlight the issues that SoCalGas and SDG&E would factor into a final cost estimate for pressure testing. First, customer impacts would be assessed. If necessary, costs to provide alternate means of service during the time that each section was out of service would be calculated. Next, the number of test sections would be determined. Under DRA's proposal to only pressure test Category 4 Criteria pipe in Phase 1A, there would be up to ten separate pressure test sections, with the possibility of more if elevation changes or mitigation

[322] Ex. SCG-20 (Phillips) at 13.

of customer impacts requires further segmenting of the pressure test. Costs to prepare each of the ten pressure test sections would be calculated. The pipeline would then have to be revisited (contractors re-mobilized, permits applied for again, customers possibly impacted a second time) in Phase 2 for one additional pressure test.[323]

Further engineering review would take into consideration the age and condition of the more-than-55-year-old-pipe that would still remain in the system.[324]

After all factors are gathered, SoCalGas and SDG&E engineers will propose replacement or pressure testing. It may be that certain sections of a pipeline will be planned for replacement and other sections planned for hydrotesting. The proposed action will then be offered to an Engineering Advisory Board for input.[325] Review of the SoCalGas and SDG&E test-or-replace decision-making process by this Board is described below and in Section IV.B.4.

<u>Benefits of Replacement</u>

There are cases where a new line is superior in integrity to an older hydrotested line. Therefore, SoCalGas and SDG&E disagree with SCGC's statement that "[p]ressure-testing pipelines and replacing pipelines are equally effective in assuring customers that pipelines are safe." As explained above in Section IV.A, pressure testing does little to prove the integrity of legacy girth welds and other construction threats. New lines can also be made piggable, enhancing future ability to assess the line's integrity.

Moreover, as prudent operators, SoCalGas and SDG&E may identify situations in which spending incremental dollars to replace a pipe segment today will pre-empt asking for further funds in a future regulatory proceeding to make a line piggable, add capacity, or replace sections of a pipeline that qualifies for replacement due to leakage history. New lines can have structural

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[323] Ex. SCG-20 (Phillips) at 13-14.
[324] Ex. SCG-20 (Phillips) at 14.
[325] Ex. SCG-20 (Phillips) at 14.

advantages compared to earlier vintage lines that improve the overall quality and life of the pipeline asset. Accordingly, SoCalGas and SDG&E include within their Replacement Decision Tree a process that will compare the costs of pressure testing against the costs of replacing an old pipeline if pressure testing appears feasible.[326]

During the detailed engineering process, SoCalGas and SDG&E will consider all costs associated with pressure testing, including managing customer impacts (through compressed natural gas, liquefied natural gas, temporary bypass, etc.). Those costs will be compared with the costs of replacing the old pipeline with a new one. Other engineering factors will also be considered depending on the situation of each unique pipeline. Examples include relocation of the pipeline if it is known that it will need to be moved in the future, and burying the pipeline deeper to reduce the possibility of outside damage.[327]

ii. SoCalGas and SDG&E Propose to Form an Engineering Advisory Board to Review Complex Test or Replace Determinations

The Replacement Decision Tree described above still allows for considerable flexibility, which is necessary at the beginning stage of PSEP implementation.[328] Accordingly, SoCalGas and SDG&E propose to create an Engineering Advisory Board, discussed in greater detailed in Section IV.C below, to review test-versus-replace decisions until sufficient experience has been gained to allow for the creation of a more systematic approach. Such an advisory board will avoid the cumbersome and time consuming process recommended by SCGC, which would require SoCalGas and SDG&E to file separate expedited applications for each and every proposed replacement project.[329]

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[326] Ex. SCG-20 (Phillips) at 10.
[327] Ex. SCG-20 (Phillips) at 10-11.
[328] Ex. SCG-20 (Phillips) at 14. See Section IV.D.1.b below for a discussion of accelerated miles.
[329] Ex. SCGC-01 (Yap) at 12.

iii. Pipeline Segments that Cannot be Addressed Within the Phase 1A Timeframe will be Addressed in Phase 1B

SoCalGas and SDG&E may not be able to address all Phase 1A pipeline segments during the Phase 1A timeframe 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.[330]

iv. If Piggable, Phase 1A Pipeline Segments that Cannot be Addressed Within the Phase 1A Timeframe Will be Inline Inspected as an Interim Safety Measure

For Category 4 pipelines in populated areas that cannot be addressed in Phase 1A, SoCalGas and SDG&E propose to perform inline inspections using the TFI tool (this tool, as explained by Mr. Haines, is oriented to examine the long seam of a pipeline)[331] to the extent that pipeline has already been retrofitted to allow for inline inspection, or that can be readily converted for doing so.[332] Inline inspection using TFI technology will provide interim validation of the pipeline's integrity until the pressure test can be performed or a replacement pipe can be put in.[333]

d. Unpiggable Pipeline Segments Installed Prior to 1946 Will be Replaced

As part of our ongoing TIMP, SoCalGas and SDG&E have already identified, retrofitted and inline inspected all pre-1946 transmission pipelines that were constructed using acceptable

[330] Ex. SCG-04 (Schneider) at 58.
[331] Ex. SCG-19 (Haines) at 9-16.
[332] Ex. SCG-04 (Schneider) at 58.
[333] Ex. SCG-04 (Schneider) at 58.

welding techniques and are operationally suited to inline inspection.[334] Since these lines can accommodate modern inspection technologies (smart pigs), and the capability of these technologies continues to expand, these lines have been identified for pressure testing as part of our proposed decision-making process.[335] The remaining pre-1946 pipeline segments in the SoCalGas and SDG&E system are not suited for inline inspection, likely have non-state-of-the-art welds, and would require significant investment for retrofitting to accommodate inline inspection tools.[336] Those pre-1946 transmission lines that have not been retrofitted and cannot accommodate inline inspection tools have been identified for replacement in order to meet the Commission directive to retrofit pipelines to allow for inline inspection tools as well as enhance transmission pipeline safety in a cost-effective manner.[337]

Pre-1946 pipelines were built using non-state-of-the-art construction methods (*e.g.*, oxy-acetylene welds that are inherently brittle), were not designed to be hydrotested post construction, and are relatively more likely to develop leaks on girth welds or experience other failures at elevated test pressures that will be costly to locate and repair.[338] The same elevated risk of failure is also true for these pipelines with regard to the possible presence of non-state-of-the-art system additions, modifications and repairs that may not be suited for the elevated test pressures. These factors add a higher degree of uncertainty during a pressure test compared to pipelines that have been inline inspected or were constructed at a later date.[339]

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.,

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[334] Ex. SCG-04 (Schneider) at 60.
[335] Ex. SCG-18 (Schneider) at 27.
[336] Ex. SCG-04 (Schneider) at 60.
[337] Ex. SCG-04 (Schneider) at 28.
[338] Ex SCG-18 (Schneider) at 28.
[339] Ex SCG-18 (Schneider) at 28.

girth weld defects, wrinkle bends and acetylene girth welds) are somewhat unique, in that the stability of construction defects cannot be fully assessed through the performance of a pressure test.[340] As explained in a 2007 report prepared for the United States DOT:

> 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.[341]
>
> 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.[342]
>
> 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.[343]
>
> 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

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[340] Ex. SCG-04 (Schneider) at 42. **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. **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. Ex SCG-04 (Schneider) at 42.

[341] Ex SCG-04 (Schneider) at 42-43 (quoting *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 (Keifner Manufacturing and Construction Defect Report) at 2).

[342] Ex SCG-04 (Schneider) at 43 (quoting Keifner Manufacturing and Construction Defect Report at 9).

[343] Ex SCG-04 (Schneider) at 43 (quoting Keifner Manufacturing and Construction Defect Report at 10).

> pipeline has been subjected to an adequate pre-service hydrostatic test or a pressure increase would not seem to make much difference.[344]

Replacement of these aged pipelines will further drive down the risk associated with those remaining and otherwise stable flaws.[345]

DRA asks the Commission to reject this element of the SoCalGas and SDG&E decision-making process, and argues that SoCalGas and SDG&E should pressure test rather than replace these aging segments and continue to indefinitely assess and manage the risks associated with these more than 66 year old non-piggable pipelines:

> SoCalGas has been assessing the risks and managing the risks of these pipelines as part of the on-going management of the transmission pipeline system. SoCalGas should continue to manage the Pre-1946 pipelines and address the issues with these pipelines accordingly. The management of these pipelines should not be included for ratepayer funding as part of the Pipeline Safety Enhancement proceeding. This is above and beyond the scope of D.11-06-017.[346]

DRA's recommendation that these aged lines be pressure tested rather than replaced is short-sighted and fails to recognize that while a remote possibility exists that pressure testing may reveal flaws that are on the verge of failure, it is well-established in the industry that the circumferential orientation and size of typical girth weld flaws is such that they are relatively insensitive to the effects of pressure testing. Performing only a pressure test on these non-piggable, non-state-of-the-art-constructed pipelines will thus leave a population of potential flaws in service that may be considered stable, yet remain prone to future failure during earth movement events.[347]

While DRA claims that replacement of these more than 66 year old non-piggable pipelines is beyond the scope of D.11-06-017, SoCalGas and SDG&E believe that failure to

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344 Ex SCG-04 (Schneider) at 43 (quoting Keifner Manufacturing and Construction Defect Report at 11).
345 Ex SCG-18 (Schneider) at 28-29.
346 Ex. DRA-02 (Phan) at 33.
347 Ex. SCG-18 (Schneider) at 28.

replace these pipeline segments would be inconsistent with the stated objectives of the Commission in D.11-06-17. Specifically, failure to replace these segments would be inconsistent with the Commission's statements that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety,"[348] and that "[a]t the completion of the implementation period, all California natural gas transmission pipeline segments must be. . . where warranted, capable of accommodating in-line inspection devices."[349]

5. Criteria for Retrofitting Pipelines with Improved Shutoff Valves

The San Bruno pipeline rupture and fire focused considerable attention at both the state and federal level on protocols for pipeline isolation in the event of a pipeline rupture.[350] In D.11-02-019, the Commission directed all California pipeline operators to consider retrofitting pipelines, where appropriate, with "improved shut off valves."[351] In response to this directive, and in light of concerns raised by the pipeline rupture in San Bruno, SoCalGas and SDG&E offer a proposed Valve Enhancement Plan as part of the PSEP to accelerate our ability to isolate and minimize escaping gas volumes in the event of a pipeline rupture and enhance the swiftness of their response.[352]

SoCalGas and SDG&E's proposed Valve Enhancement Plan focuses on pipelines routed through populated areas that are operated at a hoop stress of 20% or more of SMYS and augments SoCalGas and SDG&E's existing automatic shutoff and remote controlled valves.[353] The work proposed in the Valve Enhancement Plan will be prioritized based on five criteria: (1)

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[348] D.11-06-017 at 18.
[349] D.11-06-017 at 19.
[350] Ex. SCG-05 (Rivera) at 67.
[351] D.11-06-017 at 32, Ordering Paragraph No. 8.
[352] Ex. SCG-05 (Rivera) at 74.
[353] Ex. SCG-05 (Rivera) at 78.

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).[354]

In developing our Valve Enhancement Plan, SoCalGas and SDG&E considered the amount of time it would take to isolate pipeline segments located in populated areas, challenges associated with the deployment of automatic shutoff valves and remote controlled valves in populated areas, and measures to limit potential backflow of gas into damaged pipelines.[355] Our decision-making criteria for the Valve Enhancement Plan are illustrated in the following figure.

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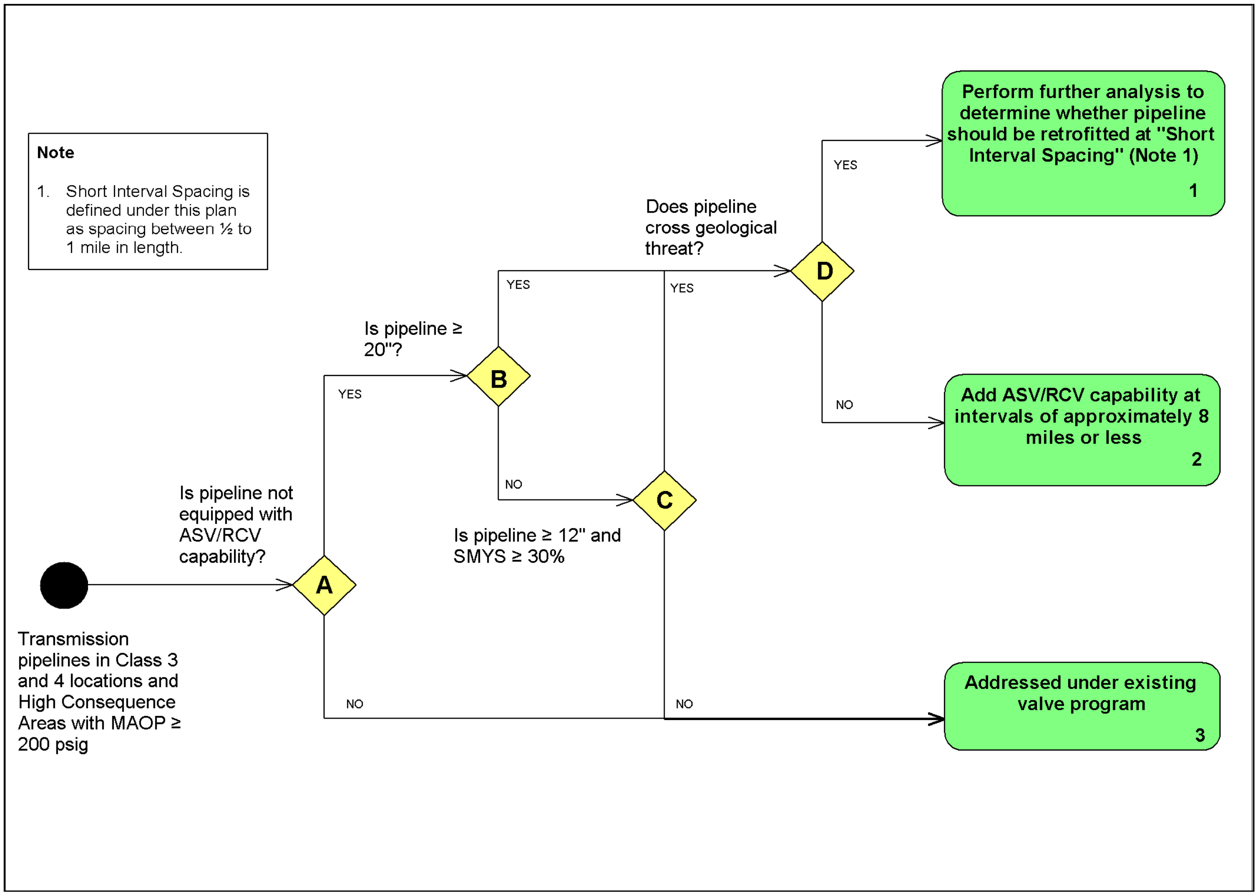
[354] Ex. SCG-05 (Rivera) 84.

[355] As explained below in Section IV.C.3.b, backflow occurs when a ruptured pipeline section has more than one supply point and/or receipt point within the section to be isolated, which is typically the case in more populated areas. *See* Ex. SCG-05 (Rivera) at 76.

Figure 5

Evaluation Process for Transmission Pipeline Valve Safety Optimization[356]



The decision-making process developed by SoCalGas and SDG&E for the Valve Enhancement Plan distinguishes between those pipelines routed through Class 3 and 4 locations and high consequence areas that are greater than or equal to twenty inches in diameter and those that are less than that diameter. First, SoCalGas and SDG&E propose to install ASV/RCV capability on all such transmission pipeline segments greater than or equal to twenty inches in diameter that operate at or above 200 psig at intervals of approximately eight miles or less.[357] This eight-mile spacing is based on current regulations that already require shutoff valves (but

[356] Ex. SCG-05 (Rivera) at 81.
[357] Ex. SCG-05 (Rivera) at 78-79.

not necessarily ASVs or RCVs) to be placed at increments of eight miles or less in populated areas.[358] This leveraging of existing valve spacing provides for cost and operational efficiencies.

Second, for pipeline segments less than twenty inches in diameter, SoCalGas and SDG&E propose to install ASV and RCV capability at approximately eight mile intervals if a pipeline is equal to or larger than twelve inches in diameter, operates at or above 200 psig and has an associated SMYS value of 30% or greater.[359]

Third, pipelines meeting the above criteria that also cross a known geological threat, such as an earthquake fault, landslide area or washout area, have been identified for further analysis to determine whether the pipeline segment should be retrofitted at "Short Interval Spacing" (i.e., spacing between half a mile and one mile in length). SoCalGas and SDG&E propose to install ASV and RCV capability at Short Interval Spacing on no more than twenty pipeline segments. These twenty segments are selected based upon the specific circumstances of the geological threat identified, the diameter of the pipeline and the potential impact radius.[360]

The Commission's Consumer Protection and Safety Division (CPSD) reviewed SoCalGas and SDG&E's valve enhancement proposal and determined that the SoCalGas and SDG&E Valve Enhancement Plan is based upon sound decision-making criteria. In its Technical Report on the SoCalGas and SDG&E PSEP, CPSD states:

> CPSD believes the Companies have used a sound approach towards determining where automated valves should be installed, in order to reduce the consequences of a major pipeline breach. This approach appropriately considers pipeline diameter, the operating stress of the line, and geological threats as part of the determination process.[361]

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[358] Ex. SCG-05 (Rivera) at 77.
[359] Ex. SCG-05 (Rivera) at 79.
[360] Ex. SCG-05 (Rivera) at 79.
[361] *Technical Report of the Consumer Protection and Safety Division Regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan* at 13, filed January 27, 2012 in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.

DRA and TURN propose to dilute the SoCalGas and SDG&E Valve Enhancement Plan in order to reduce costs. DRA proposes "a more gradual upgrading of existing manual valves to ASVs/RCVs, ASVs to RCVs, and the installation of new valves," arguing that this approach "will give the utilities and the Commission time to gain more cost, operation and installation experience to determine if the Sempra upgrade plan is ' . . . necessary for the protection of the public.'"[362] TURN recommends that the Commission "direct both CPSD and Sempra to report back on their efforts to work together to . . . reduce the number of RCVs installed to increase the potential cost effectiveness of Sempra's PSEP without sacrificing safety."[363]

Both DRA and TURN recommend modifying SoCalGas and SDG&E's Valve Enhancement Plan from eight-mile spacing to sixteen-mile spacing.[364] DRA and TURN's proposals should not be adopted. Placing valves at sixteen-mile intervals in many instances will not provide for complete isolation of many pipeline sections located in Location Class 3 and 4 and high consequence areas or may not result in less isolation valves when compared to an eight-mile isolation plan. As explained by SoCalGas and SDG&E in their testimony, pipelines in many populated areas are configured such that they are effectively a grid matrix of pipelines connected every five to eight miles. Thus, attempting to properly install automatic shutoff valves and remote control valves at sixteen-mile sections will end up looking almost exactly like an eight-mile isolation plan in terms of valve count.[365]

The proposal to trade reduced automatic shutoff valve activation time for an expanded time required to evacuate gas from a longer stretch of pipeline in the event of a rupture, also fails

[362] Ex. DRA-03 (Lee) at 3-4.
[363] Ex. TURN-02 (Marcus) at 11. While TURN attempts to characterize this finding as a "proposal" by CPSD, there is no language in the Technical Report to indicate that this is CPSD's preferred approach.
[364] *See* Ex. DRA-03 (Lee) at 9; Ex. TURN-02 (Marcus) at 10-11.
[365] Ex. SCG-23 (Rivera) at 7.

to adequately consider instances where an automatic shutoff valve may not enhance isolation at all or lead to customer loss of service due to false closures.[366]

TURN and DRA choose to ignore or highly discount potential customer impacts, despite SoCalGas and SDG&E having provided the intervenors with evidence of false closures and the risks associated with the same. The risk of false closure in a networked system is a serious matter that must be carefully assessed.[367] SoCalGas and SDG&E must manage the risk and consequences of outages on our system, and prevent such outages where possible.[368]

TURN attempts to discount SoCalGas and SDG&E's false closure concerns by casually suggesting that SoCalGas and SDG&E's experiences with valves installed and operated for decades are irrelevant because SoCalGas and SDG&E have not documented situations where wide-scale customer loss has accompanied an automatic shutoff valve closure. Indeed, despite being provided with data regarding false closures on the SoCalGas and SDG&E system, TURN concludes the false closure risk is not a legitimate concern, because we lack a documentation trail of numerous unplanned or unexplained valve closures that resulted in wide-scale customer loss.[369]

The lack of service interruptions stems from SoCalGas and SDG&E's intensive and thoughtful efforts, as a prudent operator, to design and deploy its automatic shutoff valves to avoid negative consequences. Moreover, SoCalGas and SDG&E's previous automatic shutoff valve deployments have been limited to regions outside of complex piping areas like the Los Angeles Basin.

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[366] Ex. SCG-23 (Rivera) at 4.
[367] *See* SCG-05 (Rivera) at 74-75 (describing the challenges associated with deployment of ASVs and RCVs and noting those challenges are also described in the *Report of the Independent Review Panel San Bruno Explosion*, prepared for the Commission by Jacobs Consultancy, June 8, 2011, at 13 and *ASVs and RCVs on Natural Gas Transmission Pipelines*, AGA Transmission and Distribution Engineering Committee, March 25, 2011).
[368] Ex. SCG-23 (Rivera) at 5.
[369] Ex. SCG-23 (Rivera) at 5.

Expansion of our pipeline isolation success into areas where the stakes and risk associated with false closures are higher requires different thinking and analyses. To assume that a valve isolation plan for a Location Class 3 or 4 high consequence area can be structured based on extrapolating a successful Location Class 1 valve isolation plan ignores the complexity of the system.[370]

Finally, DRA's proposal to extend the timeline for implementation of the Valve Implementation Plan is not consistent with the Commission's directive in D.11-06-017 that the plan "should reflect a timeline for completion that is as soon as practicable,"[371] and furthermore, would preclude the Valve Enhancement Plan from achieving the objective set forth in Public Utilities Code section 957(a)(3) to "ensure that remote and automatic shutoff valves are installed as quickly as is reasonably possible."

Accordingly, SoCalGas and SDG&E urge the Commission to adopt our proposed Valve Enhancement Plan criteria.

B. Review of Decisions (Expedited Application Docket, Advisory Panel, etc.)

SoCalGas and SDG&E seek Commission approval of their proposed PSEP and further propose that the Commission review their compliance with the Plan through four processes described below: (1) an implementation advice letter, which will include updated revenue requirements and timing to reflect any Commission-ordered changes to the Plan; (2) annual reports to the Commission that will provide the Commission with a detailed update on the status of our Plan implementation work; (3) an expedited advice letter process to request approval for any adjustments to the overall level of PSEP funding requirements previously approved; and (4) an Engineering Advisory Board.

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370 Ex. SCG-23 (Rivera) at 5-6.
371 D.11-06-017 at 31, Ordering Paragraph No. 5.

The approach recommended by SoCalGas and SDG&E is consistent with the approach adopted by the Georgia Public Services Commission for review of Atlanta Gas Light Company's pipeline replacement and infrastructure enhancement programs. Under that regulatory approach, Georgia Power and Light is required to file quarterly and annual filings on its progress implementing its Plan, including all costs incurred as part of the Plan. [372] These quarterly and annual filings are comparable to the annual filings proposed by SoCalGas and SDG&E. Georgia Power and Light is not required to submit separate applications for each replacement project in its plan.

As discussed below, all of these processes are designed to provide the Commission with ongoing and frequent opportunities to review SoCalGas and SDG&E's implementation of the plan and costs incurred without hindering the ability of SoCalGas and SDG&E to comply with the Commission's directive to implement the plan "as soon as practicable."[373]

1. Implementation Advice Letter Filing

Upon approval of the Plan, SoCalGas and SDG&E each propose to file an advice letter to implement the Commission's decision. These advice letters will include updated revenue requirements and timing to reflect any decision-ordered changes to the Plan. This will allow SoCalGas and SDG&E to reflect any delays and incorporate the surcharge into rates, should approval of the Plan occur after January 1, 2012.[374] See Section VIII below for further discussion of this proposed advice letter filing process.

[372] *See Order of the Georgia Public Utilities Commission Adopting Stipulation*, filed October 13, 2009, Docket Nos. 8516 & 29950, at 3. SoCalGas and SDG&E request that the Commission take official notice of this decision of the Georgia Public Utilities Commission pursuant to Rule 13.9 of the Commission's Rules of Practice and Procedure and California Evidence Code sections 450 and 452.
[373] *See Order of the Georgia Public Utilities Commission Adopting Stipulation*, filed October 13, 2009, Docket Nos. 8516 & 29950, at 3.
[374] Ex. SCG-10 (Reyes) at 126.

2. Annual PSEP Update Report

Beginning in 2013, SoCalGas and SDG&E propose to provide an annual status report to the Commission on or before March 31 each year to provide the Commission and the public with an opportunity to review SoCalGas and SDG&E's progress in implementing the Plan and to evaluate the costs incurred and projected to be incurred the following year. This proposal is discussed in greater detail in Section VII below.

3. Expedited Advice Letter Filings

SoCalGas and SDG&E further propose to file expedited advice letters to request approval for any adjustments, either up or down, to the overall level of PSEP funding requirements previously approved.[375] This proposal is discussed in greater detail in Section VIII below.

4. Consultation with Engineering Review Board

SoCalGas and SDG&E also propose the formation of an Engineering Advisory Board to provide an extra level of comfort that certain engineering decisions—that is, to test or replace a pipeline segment or include accelerated miles in a project— are sound.[376] It would also provide input to SoCalGas and SDG&E's test/replace/accelerate criteria, as those criteria are updated to reflect the experience gained over time.[377] The Board's function will be reviewed annually as to its appropriate level of involvement.[378]

SoCalGas and SDG&E expect that the Board will be more active at the beginning as each segment is reviewed with a tapering off of the number of decisions to be reviewed as information

[375] Ex. SCG-10 (Reyes) at 127.
[376] Ex. SCG-20 (Phillips) at 14.
[377] Ex. SCG-20 (Phillips) at 15.
[378] Ex. SCG-20 (Phillips) at 15.

is gained over time.[379] And it is anticipated that the Board can be disbanded in connection with SoCalGas and SDG&E's next GRC decision.[380]

The Board, as envisioned by SoCalGas and SDG&E prior to the commencement of evidentiary hearings, would be a four member board made up of a company representative, a representative of the Commission's Consumer Protection and Safety Division, a representative of the Commission's Energy Division, and an outside pipeline integrity expert to be mutually agreed upon by the first three.[381]

During hearings, Administrative Law Judge Long questioned whether this Board could be comprised of independent outside experts, as opposed to members of the Commission's staff.[382] SoCalGas and SDG&E support such an approach so long as the Board members have sufficient expertise in pipeline engineering and operations.[383]

5. Intervenor Proposals for Commission Review Would Be Unduly Cumbersome and Should Not Be Adopted

DRA opposes the processes for reviewing PSEP-related expenditures on the grounds that there would be no after-the-fact reasonableness review of the expenditures, and because SoCalGas and SDG&E's proposal for an expedited advice letter process to review potential adjustments to approved PSEP funding levels does not provide interested parties with enough time to review the proposed changes.[384] In a similar vein, SCIP/Watson recommends that SoCalGas and SDG&E be required to obtain Commission authorization through a Tier 3 advice letter if the costs or scope of Phase 1A work increases beyond what the Commission has authorized, or if SoCalGas and SDG&E cannot complete the Phase 1A scope within the time or

[379] Ex. SCG-20 (Phillips) at 15. *See also*, Tr. at 1101 (SoCalGas/SDG&E/Phillips).
[380] Ex. SCG-20 (Phillips) at 15.
[381] Ex. SCG-20 (Phillips) at 15.
[382] Tr. at 1244-50 (SoCalGas/SDG&E/Phillips).
[383] Tr. at 1245 (SoCalGas/SDG&E/Phillips).
[384] Ex. DRA-05 (Sabino) at 2-3.

budget authorized.[385] TURN expresses similar concerns about SoCalGas and SDG&E's proposed process for cost recovery,[386] and SCGC proposes that SoCalGas and SDG&E be required to file an individual expedited application for each proposed pipeline replacement to ensure that pipelines are replaced only if truly necessary.[387]

None of the intervenors' competing suggestions for Commission review are appropriate. The SoCalGas and SDG&E proposal incorporates more efficient processes for reviewing their implementation of the Plan, given the limited resources of the Commission and the utilities. As explained in Section III.D above, there should be no need for after-the-fact reasonableness review of the costs recorded in the cost recovery accounts or for expedited applications for pipeline replacement projects so long as the costs incurred have been approved by the Commission. SoCalGas and SDG&E will review Plan costs that are recorded in their cost recovery accounts so that these costs are truly incremental and not otherwise recovered in base transportation rates or subject to any other Commission-approved balancing account mechanism.

The proposed expedited advice letter requesting Commission approval for changes to the overall funding level adopted in this proceeding provides parties with the opportunity to provide input to the Commission. While SoCalGas and SDG&E acknowledge that the time period to comment is short, the expedited review process is necessary, given the short time frame in which the work will be done. Parties will also be informed about our ongoing implementation of the PSEP through the annual report. As indicated in direct testimony, the annual status report will provide the Commission and other parties information on any work completed during the

[385] Ex. SCIP-01 (Beach) at 17-18.
[386] Ex. TURN-01 (Long) at 7.
[387] Ex. SCGC-01 (Yap) at 10-12.

previous year, work planned for the upcoming year, discussion of progress made to date and confirmation of the utilities Commission-approved annual PSEP budget.[388]

The proposal by SCGC for an individual expedited application for each proposed pipeline replacement is ill-advised and unworkable. SoCalGas and SDG&E's proposed Plan encompasses hundreds of potential pipeline replacements. Adding hundreds of new applications to the Commission's already burdened docket would severely strain the resources of the Commission and the utilities (not to mention intervenors), and would have a detrimental effect on all of the Commission's other work given the expedited nature of the new proceedings. Moreover, even if the new applications were expedited, the time required for each application (i.e., data/testimony presentation, hearings, briefs, proposed decision, comments, and final decision) would undoubtedly delay Phase 1 work well beyond the timeframes proposed in the Plan.[389]

In support of this proposal, SCGC points to the Expedited Application Docket (EAD) procedure adopted by the Commission in the 1990s for discounted contracts to avoid bypass as a model for their new pipeline replacement expedited applications.[390] But the EAD docket dealt with dozens of proposed contracts, not hundreds of construction projects that are complex in scope. SCGC's proposal appears to be a thinly veiled procedural attempt to force SoCalGas and SDG&E into testing rather than replacing pipelines whenever possible. To achieve the Commission's safety enhancement objectives in an orderly and cost effective manner, test or replace decisions should be made in accordance with the criteria and consultation process proposed by SoCalGas and SDG&E. SoCalGas, SDG&E, and their customers should not be

[388] Ex. SCG-26 (Reyes) at 6.
[389] Ex. SCG-26 (Reyes) at 7.
[390] Ex. SCGC-01 (Yap) at 12.

forced into pressure testing when it does not make sense just because of the time it would take to get a proposed replacement project approved.[391]

The Engineering Advisory Board proposal is superior to the process suggested by SCGC. Requiring SoCalGas and SDG&E to submit an application (even if expedited) for every replace or test decision will create an unnecessarily bureaucratic and cumbersome layer, slowing down progress on an already ambitious schedule, and ultimately preventing pipeline segments from being addressed "as soon as practicable."[392]

C. Base Case

For comparison purposes, SoCalGas and SDG&E developed two separate cost estimates in support of their proposed Plan, a Base Case and a Proposed Case. The Proposed Case 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. The Base Case, on the other hand, represents the minimum amount of work that could be completed to implement the ordering paragraphs of D.11-06-017, and does not include additional safety enhancing and cost-saving proposals that SoCalGas and SDG&E developed for Commission consideration.

The Base Case is comprised of three major components: (1) a plan to test or replace pipeline segments that lack sufficient documentation of a pressure test; (2) interim safety enhancement measures; and (3) a valve enhancement plan. Each of these components, and comments on those proposals by intervenors, are discussed separately in this section.

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[391] Ex. SCG-26 (Reyes) at 7.
[392] Ex. SCG-20 (Phillips) at 16 (quoting D.11-06-017 at 31, Ordering Paragraph No. 5).

1. Plan to Test or Replace Pipeline Segments

Base Case costs reflect the costs of implementing the decision-making criteria set forth above in Section IV. The Base Case incorporates the use of inline inspection prior to pressure testing segments that have already been retrofitted to accommodate inline inspection technology and recognizes that in some cases, lower priority and/or distribution pipeline segments should be addressed along with high priority transmission pipeline segments for operational and economic reasons.

a. Inline Inspection of Pipeline Segments Using Transverse Field Inspection Technology Prior to Pressure Testing

Prior to pressure testing, SoCalGas and SDG&E propose to inline inspect all pipelines that have already been retrofitted to accommodate inline inspection technology using transverse field inspection (TFI) tools, where it is feasible to do so without delaying pressure testing of the pipeline.[393]

These inspections can occur in parallel with the preparation for pressure testing. During mobilization for the pressure test, knowledge obtained though inline 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, inline 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.[394]

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393 Ex. SCG-04 (Schneider) at 56, as clarified in *Comments of SoCalGas and SDG&E on Technical Report of the Consumer Protection and Safety Division* at 13, filed January 27, 2012 in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012 (clarifying that SoCalGas and SDG&E do not propose to delay pressure test work).
394 Ex. SCG-04 (Schneider) at 57.

Fortunately, much of the SoCalGas and SDG&E transmission system has already been retrofitted to accommodate inline inspection tools, which allows for ready access to these pipelines to perform an inline inspection.

The information gained during these pressure tests can also be used to validate the TFI inline inspection tool as an equivalent alternative to a pressure test. SoCalGas and SDG&E propose to analyze and compare the results of pressure testing with the results of inline inspections in Phase 1, in order to determine whether 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.[395]

DRA argues that this aspect of the SoCalGas and SDG&E test or replace plan should be rejected as duplicative, based upon an inaccurate presumption that these pipelines would have been recently inline inspected under the utilities' ongoing TIMP.[396] DRA's rejection of the proposal is based upon the incorrect belief that previous inspections using standard axial magnetic flux leakage (MFL) technology adequately assessed the stability of pipeline long seams.[397] DRA appears to not understand the differences between MFL and TFI technologies, or the fact that the SoCalGas and SDG&E proposal is strictly for the incremental forecast costs of using the TFI tool, and that the costs associated with using the standard MFL tool are not included in the Plan, as these costs were included in the GRC filing.[398]

DRA also appears to misunderstand that the TIMP-related inspections performed to date have primarily used axially oriented MFL tools that are not sensitive to the long seam condition.

[395] Ex. SCG-04 (Schneider) at 57.
[396] Ex. DRA-02 (Phan) at 67.
[397] Ex. DRA-02 (Phan) at 67.
[398] Ex. SCG-18 (Schneider) at 31.

While the MFL tools may detect gross volumetric flaws in the long seam, this technology is not sensitive to axially oriented narrow flaws associated with seam issues.[399]

The physics of TFI tools, in contrast, are far more sensitive to targeted evaluation of the long seams to inspect for the same manufacturing flaws that are the focus of the PSEP, and are identified as stable under TIMP. This difference in inspection ability is clearly defined in the TIMP, and referenced in ASME B318.S, where assessment methods must be specifically tailored to the threats under evaluation.[400]

Further, TFI inspections have not been a requirement of the SoCalGas and SDG&E TIMP assessments to date, and thus use of this specific inspection technology is not redundant with the inspections using MFL tools that have been done so far. The assertion that duplication with TIMP should be the basis for rejecting our proposed use of TFI ignores the Workpapers supporting our PSEP and the numerous responses provided to DRA covering this very topic. In our Workpapers submitted in support of the PSEP, SoCalGas explains:

> SoCalGas currently operates approximately 170 miles of transmission pipeline segments located in Class 3 and 4 locations or High Consequence Areas that lack sufficient documentation of a pressure test 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 schedule to occur over the next five years. During the re-assessment, ***in addition to*** running the MFL tool, a [TFI] tool will also be utilized to allow for evaluation of the condition of the long seam as well. . . . The ***incremental cost*** to run a TFI tool through the pipeline is estimated at $200,000/run.[401]

[399] Ex. SCG-18 (Schneider) at 31.
[400] Ex. SCG-18 (Schneider) at 31-32.
[401] Ex. SCG-32 Amended Workpapers for SoCalGas and SDG&E in Support of PSEP, at WP-IX-1-38 (emphasis added).

In one data request response, when asked why SoCalGas and SDG&E are requesting funds in the PSEP to perform reassessments that are part of the TIMP, these issues were made clear in the following response:

> SoCalGas and SDG&E are not requesting any funding to perform activities already planned as part of TIMP. The proposed TFI inspections are incremental to TIMP-related activities. There are no pipelines for which a TFI tool run would supplant IMP activities, and TFI inspections were not contemplated as part of our most recent General Rate Case Applications. Please see section IV.B.2.c on page 49 of our Testimony, and additionally refer to pages 11-13 in our February 24, 2012 Comments on the Technical Report of the Consumer Protection and Safety Division for a complete description of our proposed use of incremental TFI inspections as part of the plan to satisfy the Commission's directives in Decision 11-06-017.[402]

It makes sense to leverage the investment made in these pipelines and gather additional long seam data using TFI technology that is above and beyond what is required by TIMP regulations and what was requested in the last GRC. Removal of critically-sized flaws on the long seam prior to the pressure test is in the best interest of all parties. The Commission should support the use of TFI as a cost-effective measure not only to prevent failures during pressure testing, but to also identify and permanently remove flaws that are of a critical size and further improve the safety of the transmission system.[403]

SoCalGas and SDG&E's proposed TFI assessments are also in keeping with the guiding principle of long-term cost effectiveness for our customers. Cost avoidance associated with pressure test failure disruptions, and the potential long-term benefit of cost savings in Phase 2 if TFI (and our proposed use of non-destructive evaluation) is adopted as an acceptable equivalent

[402] Ex. SCG-18 (Schneider) at 32 (quoting Data Request Response DRA-DAO-21-01).
[403] Ex. SCG-18 (Schneider) at 3.

to pressure testing, are the basis for this proposed approach. DRA should recognize and support the opportunity to achieve the significant cost savings potential on behalf of ratepayers.[404]

Furthermore, section 696, which was recently added to the California Public Utilities Code, requires that expenses for the TIMP be placed in a balancing account.[405] All costs associated with TIMP will therefore be subject to this balancing account requirement, and Plan costs will be subject to the rules the Commission determines during this proceeding. If our proposed ratemaking approach in Section VIII is approved, expenses will be accounted for in the appropriate balancing account (PSEP or TIMP), and will be included in one or the other, not both.[406]

b. Accelerated Miles

The Commission directives to SoCalGas and SDG&E were to develop plans that "should provide for testing or replacing all [segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test] as soon as practicable"[407] and that address "all natural gas transmission pipeline…even low priority segments,"[408] all the while "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[409] As such, SoCalGas and SDG&E have proposed including some lower priority

[404] Ex. SCG-18 (Schneider) at 33. A much more detailed discussion of the benefits and limitations of these assessment methods is provided in Ex. SCG-19 (Haines).
[405] Ex. SCG-18 (Schneider) at 32. California Public Utilities Code section 696 provides: "In any ratemaking proceeding in which the commission authorizes a gas corporation to recover expenses for the gas corporation's transmission pipeline integrity management program established pursuant to Subpart O (commencing with Section 192.901) of Part 192 of Title 49 of the United States Code or related capital expenditures for the maintenance and repair of transmission pipelines, the commission shall require the gas corporation to establish and maintain a balancing account for the recovery of those expenses. Any unspent moneys in the balancing account in the form of an accumulated account balance at the end of each rate case cycle, plus interest, shall be returned to ratepayers through a true-up filing. Nothing in this section is intended to interfere with the commission's discretion to establish a two-way balancing account."
[406] Ex. SCG-18 (Schneider) at 32.
[407] D.11-06-017, mimeo., at 19.
[408] D.11-06-017, mimeo., at 20.
[409] D.11-06-017, mimeo., at 22.

transmission segments or portions of transmission segments in Phase 1A in order to achieve overall project and program efficiency and cost effectiveness.[410]

SoCalGas and SDG&E propose accelerating some Phase 2 segment (or segments) located between two Phase 1A segments or immediately adjacent to a Phase 1A segment into the Phase 1A if including the Phase 2 segment(s) would be more efficient and cost effective.[411] In many cases, the length of the segment to be tested or replaced may be increased to include adjoining pipeline that is in more sparsely populated areas due to operational necessity and project efficiency.[412] These adjoining segments which would otherwise be addressed in Phase 2, were included within the scope of Phase 1 to maximize the cost effectiveness and minimize customer impact during execution of the proposed PSEP.[413] The SoCalGas and SDG&E proposal to accelerate some segments based on logistics and efficiency is common sense.

CPSD has acknowledged the reasonableness of accelerating miles, opining that doing so can potentially "provide operational as well as cost efficiency in project implementation, improve overall reliability and safety, reduce public inconvenience, and, perhaps lower risk of employee injuries associated with multiple projects."[414] CPSD, however, stresses that replacing or testing high priority mileage needs to drive the scope of Phase 1 projects.[415] SoCalGas and SDG&E agree and have only proposed the inclusion of accelerated mileage when doing so would enhance operational and program efficiencies.[416]

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[410] Ex. SCG-20 (Phillips) at 4.
[411] Ex. SCG-20 (Phillips) at 18.
[412] Ex. SCG-04 (Schneider) at 52.
[413] Ex. SCG-09R (Rivera) at 108; Ex. SCG-09R (Rivera) at 109.
[414] *Technical Report of the Consumer Protection and Safety Division Regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan* at 11-12, filed January 27, 2012 in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.
[415] *Technical Report of the Consumer Protection and Safety Division Regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan* at 12, filed January 27, 2012 in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.
[416] Ex. SCG-20 (Phillips) at 4.

Since submitting the PSEP, SoCalGas and SDG&E have studied in greater detail a select number of projects with accelerated mileage in the Phase 1A scope. Five projects (two pressure tests and three replacements) in the PSEP filing were examined to understand the effect on total cost of deferring the accelerated mileage portion of the as-filed Phase 1A scope to Phase 2.[417] Projects were chosen with differing characteristics in order to see if the outcome of the study varied based on any specific project characteristics.[418] SoCalGas and SDG&E selected the segments to be accelerated based on expertise and engineering judgments by subject matter experts who are knowledgeable about SoCalGas and SDG&E's system and represents intent to achieve the overarching goals of the PSEP.[419] In addition, SoCalGas and SDG&E assumed all accelerated miles would need to be addressed in Phase 2 and utilized a cost estimate methodology consistent with that presented in the filing and workpapers.[420] For the replacement projects, by deferring the accelerated mileage to Phase 2, the overall direct cost for the as-filed scope of work is estimated to increase by approximately 3.5 – 8.0%.[421] For the pressure test projects, the increase in overall direct cost resulting from the deferral of accelerated mileage to Phase 2 is estimated to be higher, in the range of 30 - 200%.[422] As such, analysis of proposed accelerations confirms the potential for SoCalGas and SDG&E's proposal to enhance project and cost efficiency.

Finally, as discussed in section IV.B, if the Commission agrees with SoCalGas and SDG&E's proposal to create an advisory board, this board will review and provide input on accelerated mileage decisions.[423]

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[417] Ex. SCGC-01 (Yap), Att. I (Response SCGC-10.4.1) at 253-254.
[418] Ex. DRA-31 (Response DRA-DBP-TCAP-PSEP-4) at 6.
[419] Ex. SCG-20 (Phillips) at 17.
[420] Ex. SCG-20 (Phillips) at 18-19.
[421] Ex. SCG-20 (Phillips) at 19.
[422] Ex. SCG-20 (Phillips) at 19.
[423] Ex. SCG-20 (Phillips) at 15.

c. Distribution Segments

SoCalGas and SDG&E have included in the PSEP some portions of pipeline defined as "distribution" per federal regulations.[424] The length of the distribution pipe included in the Plan account for approximately 4.3% of the Phase 1A scope for pressure test and replacement, totals approximately 28 miles, and is generally interspersed among the transmission lines included in the Plan.[425] These segments are included because of the anticipated cost and operational efficiencies gained by incorporating them into the scope rather than executing a project around them.[426]

The distribution pipe included in the PSEP is generally located adjacent to or in between transmission lines that are scheduled to be replaced or tested in Phase 1A. Because the distribution segments are interrelated with the Phase 1A transmission segments, it is more practical to continue to include these distribution segments within the scope of proposed Phase 1A work.[427] For example, replacement may require a new route and abandonment of all pipe between the start and stop location, including distribution segments. In other cases, the replacement may require starting before, or stopping after, the Phase 1A identified station start and stop points to a more practical and cost-effective point to connect to existing pipeline.[428] Similarly, a pressure test of an entire continuous length of pipeline could prove more cost effective than the performance of multiple pressure tests to exclude small portions of a pipeline classified as distribution.[429]

[424] Ex. SCG-12 (Schneider/Buczkowski) at 1.
[425] Ex. SCG-12 (Schneider/Buczkowski) at 2.
[426] Ex. SCG-20 (Phillips) at 22.
[427] Ex. SCG-12 (Schneider/Buczkowski) at 2.
[428] Ex. SCG-12 (Schneider/Buczkowski) at 2.
[429] Ex. SCG-12 (Schneider/Buczkowski) at 2.

SoCalGas and SDG&E anticipate that this proposal will increase cost and project efficiencies similar to the accelerated mileage proposal discussed above. Upon completion of detailed engineering, design, and execution planning, SoCalGas and SDG&E will determine if and where including distribution pipeline segments within the scope of work is projected to be more cost effective than excluding it.[430]

d. Capacity Increases/Pipeline Standardization

In their testimony, DRA singled out three pipelines from the SoCalGas and SDG&E Plan that they contend are actually designed to increase capacity rather than address the Commission's safety objectives.[431] In rebuttal testimony, SoCalGas and SDG&E demonstrate that these three pipelines—Line 41-6000-2, SL 38-959, and SL 38-539—are identified for replacement because they satisfy the criteria for replacement under our proposed test or replace decision-making process, and any resulting capacity increases are the result of both prudent system planning and an effort to minimize costs for our customers. [432]

In the case of Line 41-6000-2, SoCalGas and SDG&E propose an alternative to replacing Line 41-6000-2 in-kind, that not only will provide 100 MMcfd of additional capacity to our Imperial Valley pipeline system[433] but also cost $15 million less to install than an in-kind replacement.[434]

Regarding SL 38-959 and SL 38-593, both pipelines operate in areas of growing demand or low operating pressures, and it is only a matter of time before both need to be replaced with larger diameter pipeline to meet our customer demand and service obligations.[435] It makes sense

[430] Ex. SCG-12 (Schneider/Buczkowski) at 4.
[431] *See* Ex. DRA-02 (Phan) at 50-53.
[432] Ex. SCG-22 (Bisi) at 1-4.
[433] Tr. at 1439-40 (SoCalGas/SDG&E/Bisi).
[434] Tr. at 1428-29 (SoCalGas/SDG&E/Bisi).
[435] Ex. SCG-22 (Bisi) at 4.

to upsize the replacement pipeline now, while they are being replaced for safety purposes, rather than to wait and have our customers incur additional expenses later to replace them again as part of our ongoing pressure betterment program.[436]

By focusing solely on the short-term costs of implementing these projects, DRA fails to recognize that these projects are designed to reduce costs for our customers. The Commission should reject DRA's shortsighted approach in favor of the cost-saving approach offered by SoCalGas and SDG&E.

2. Interim Safety Enhancement Measures

Decision 11-06-017 requires that each utility's Plan "include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions… and other such measures that will enhance public safety."[437] To meet the directives of D.11-06-017, SoCalGas and SDG&E's Plan includes the following interim safety enhancement measures: (1) pressure reductions; (2) more frequent ground patrols and leakage surveys; and (3) inline inspections using TFI technology.

a. SoCalGas and SDG&E's Proposed Pressure Reductions Should be Approved

SoCalGas and SDG&E propose to reduce the MAOP of some pipelines identified for testing or replacement to provide an enhanced safety margin on an interim basis.[438] In determining when and where to make such pressure reductions, SoCalGas and SDG&E will consider both service and safety impacts so as to enhance safety, but do so without impacting capacity requirements or service reliability.[439] In addition, as discussed in greater detail in SoCalGas and SDG&E's alternative proposals, pressure reductions may ultimately prove to be

[436] Ex. SCG-22 (Bisi) at 4.
[437] D.11-06-017, mimeo, at 31.
[438] Ex. SCG-04 (Schneider) at 65; Tr. at 512, line 22-24 (SoCalGas/SDG&E/Schneider).
[439] Ex. SCG-04 (Schneider) at 65.

an alternative to pressure testing or replacement, providing equivalent safety benefits at reduced costs.[440] SoCalGas' proposed pressure reductions should be approved as they are prudent interim safety enhancement measures and potentially cost reductive.

b. SoCalGas and SDG&E's Proposed Ground Patrols and Leak Surveys Should be Approved

SoCalGas and SDG&E propose bi-monthly ground patrols and leak surveys for pipelines that do not have sufficient documentation of pressure testing.[441] Ground patrols and leak surveys are normally conducted on a schedule that ranges from one to four times annually depending upon the code requirements.[442] The surveys and patrols utilize both technology and human capital to detect leaking gas and enhance public safety. During leak surveys, SoCalGas and SDG&E utilize a variety of instruments such as infrared gas indicators, optical methane detectors, and barhole surveys to survey transmission lines and check for leaks.[443] Ground patrols are a 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 indication 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.[444] Both ground patrols and leak surveys are used to detect and report early signs of leakage for follow-up investigation and are important efforts to detect potential threats and enhance safety. Currently, ground patrols and leak surveys of pipelines that do not have sufficient documentation of pressure testing have been occurring bi-monthly,[445] and, if

[440] Ex. SCG-04 (Schneider) at 60.
[441] Ex. SCG-04 (Schneider) at 64.
[442] Ex. SCG-04 (Schneider) at 65.
[443] Ex. SCG-04 (Schneider) at 64.
[444] Ex. SCG-04 (Schneider) at 64.
[445] Ex. SCG-04 (Schneider) at 65.

approved, will continue until the testing or abandonment of the pipe has been completed.[446] SoCalGas and SDG&E's proposed bi-monthly ground patrols and leak surveys should be approved as appropriate O&M efforts to enhance pipeline safety during implementation of the PSEP.

c. SoCalGas and SDG&E's Proposed In-Line Inspections Should be Approved

SoCalGas and SDG&E propose to inline inspect piggable pipelines that cannot be pressure tested or replaced in the near term in order to assess the integrity of the long seam using TFI technology. By doing so, SoCalGas and SDG&E can gather additional information on their pipelines[447] and provide interim validation of the pipeline's integrity until pressure tests can be performed.[448] SoCalGas and SDG&E's proposed inline inspections should be approved as appropriate safety enhancement measures.

3. Valve Enhancement Plan

As ordered by the Commission, SoCalGas and SDG&E reviewed their current pipeline isolation capabilities and offer a proposed Valve Enhancement Plan to accelerate their ability to isolate and limit escaping gas volumes in the event of a pipeline rupture and enhance the swiftness of their response.[449] The decision-making criteria supporting these proposed valve enhancements are discussed above in Section IV.A.5. When the installation of all valve work under this proposed Valve Enhancement Plan is complete, SoCalGas and SDG&E will have segmented 1,866 miles of pipe with 306 new automatic shutoff or remote control-equipped isolation sections at nominal six-mile intervals. This pipeline work will provide rapid isolation

[446] Ex. SCG-04 (Schneider) at 64.
[447] Tr. at 448 (SoCalGas/SDG&E/Schneider).
[448] Ex. SCG-04 (Schneider) at 66.
[449] Ex. SCG-05 (Rivera) at 74.

for 1,226 net miles of pipeline in Class 3 locations and High Consequence Areas.[450] Table 1 below summarizes the scope of work to be completed in Phase 1 under our proposed Valve Enhancement Plan.[451]

Table 2
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

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 to/from transmission pipelines; (4) expand their existing Supervisory Control and Data Acquisition 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.[452]

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[450] Ex. SCG-05 (Rivera) at 80.
[451] Ex. SCG-05 (Rivera) at 81.
[452] Ex. SCG-05 (Rivera) at 81.

The importance of these companion enhancement elements was recognized by CPSD in its Technical Report on SoCalGas and SDG&E's proposed Plan:

> The additional enhancement measures related to automated valves, as proposed by the Companies, would improve current performance and CPSD recommends that the CPUC allow the Companies to proceed with their proposal to install telemetry facilities and backflow prevention devices at all locations as planned. CPSD believes these readings are crucial because they allow for pin-pointing failure locations and will assist in first response efforts to any failure events.[453]

As recognized by CPSD, SoCalGas and SDG&E proposed these key elements to deliver on achieving a shortened-response time for gas flow shutoff in the case of a pipeline rupture.[454]

a. The Commission Should Authorize the 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 remote control and automatic shutoff) 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

[453] *Technical Report of the Consumer Protection and Safety Division Regarding the SoCalGas and SDG&E Pipeline Safety Enhancement Plan* at 16, filed January 27, 2012 in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.
[454] Ex. SCG-23 (Rivera) at 12.

operators with twenty additional real-time flow measurement reference points along transmission pipelines to support pipeline system management.[455]

No parties have raised objections to the element of the Valve Enhancement Plan and the Commission should approve this proposed enhancement to current valve operation.

b. The Commission Should Approve SoCalGas and SDG&E's Proposed 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.[456]

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) remote control valves 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

[455] Ex. SCG-05 (Rivera) at 82.
[456] Ex. SCG-05 (Rivera) at 82.

highest-cost solution, which is best employed at connection points where a transmission mainline valve is being upgraded with automatic shutoff/remote control valve controls and communications.[457]

DRA dismisses the backflow prevention devices as being distribution-type assets. SoCalGas and SDG&E believe this to be a shortsighted and dangerous conclusion. Simply stated, in the event of a rupture, without backflow prevention devices to prevent backflow, natural gas would continue to flow into a ruptured segment. Indeed, were two mainline remote control/automatic shutoff valves to be activated, there would be sufficient backflow to inhibit emergency response until manual closure(s) could be executed, defeating the purpose of the investments made with the remote control/automatic shutoff valves. For example, a review of the August 2000 Carlsbad incident demonstrates how isolation can be delayed because of failure to address backflow. There, gas flowed back into the ruptured segment and was noted as the reason why a ruptured pipeline segment was not fully isolated once the main line valves were closed.[458]

In short, DRA's cost saving recommendation is technically unsound, unsafe, and will not allow us to isolate our pipelines in our stated timeline or at all in some instances.[459]

c. The Commission Should Approve the 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

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457 Ex. SCG-05 (Rivera) at 82-83.
458 Ex. SCG-23 (Rivera) at 12 (citing NTSB/PAR-03/01, PB2003-916501, Pipeline Accident Report, Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000, at 8).
459 Ex. SCG-05 (Rivera) at 13.

various sections of transmission line.[460] No parties have raised objections to the inclusion of this equipment to support the proposed Valve Enhancement Plan and this element of the Plan should be adopted.

d. The Commission Should Authorize the Expansion of the Existing SCADA System to Support Enhanced System Management

SoCalGas and SDG&E propose to provide for automatic shutoff/remote control valve 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 Supervisory Control and Data Acquisition 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.[461]

This proposal is consistent with the recommendations of the Commission's Independent Review Panel that PG&E:

> Conduct a study of SCADA needs to achieve enhanced gas transmission system knowledge that would enable improved shutdown capabilities in the event of a future pipeline rupture. Study to include: (1) the visibility of the transmission operations to system operators, (2) the ability of automation to sense line breaks, (3) the ability to model failure events; and (4) the capability to transmit schematic and real-time information to pipeline field personnel.[462]

[460] Ex. SCG-05 (Rivera) at 83.
[461] Ex. SCG-05 (Rivera) at 83.
[462] Independent Review Panel Report on San Bruno Pipeline Explosion at 78, Rec. 5.5.3.2., filed June 9, 2011, in R.11-02-019 and entered into the record of A.11-11-002 by *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* on April 17, 2012.

And further recommendation that "[w]hen study of SCADA needs is completed (described in Recommendation 5.5.3.2), establish a multi-year program to make implement [sic] the results of the study."[463]

e. The Commission Should Allow SoCalGas and SDG&E to Expand the Coverage Area of Private Radio Networks

SoCalGas and SDG&E propose to expand the coverage area of private radio networks currently planned or employed to achieve 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.[464]

DRA urges the rejection of SoCalGas and SDG&E's proposal to install this critical companion technology without any technical discussion, arguing that radio communication devices appear to be distribution-type assets.[465] The technical implication of DRA's removal of these devices from the Plan just results in a weakened communication system that can result in slowed response time and increased risk. Communication devices are an essential element of the Valve Enhancement Plan and to limit the communication capability of the plan can result in ineffective rupture response.[466] Accordingly, SoCalGas and SDG&E urge the Commission to authorize these proposed private radio network enhancements.

[463] Independent Review Panel Report on San Bruno Pipeline Explosion at 78, Rec. 5.5.3.3.
[464] Ex. SCG-05 (Rivera) at 83.
[465] Ex. DRA-03 (Lee) at 12.
[466] Ex. SCG-23 (Rivera) at 13.

D. Proposed Case

SoCalGas and SDG&E seek approval of their Proposed Case PSEP, which includes all of the elements included in the Base Case plus a plan to replace pipeline segments that contain pre-1946 construction and fabrication techniques, a plan to replace wrinkle bends, 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 so that all pipeline-related documentation is integrated and readily available. In this section, these three additional safety enhancing elements are discussed in greater detail.

1. Removal of Pre-1946 Girth Welds and Wrinkle Bends

As explained above in Section IV.A.3, the pressure testing required under D.11-06-017 will validate long seam stability, but may not necessarily address other known stable threats. Construction defects (such as girth weld defects, wrinkle bends and oxy-acetylene girth welds), are somewhat unique, in that their stability cannot be fully assessed through the performance of a pressure test or inline inspection.[467] 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. Therefore, the PSEP includes provisions for removal of historic girth welds and surgical removal of wrinkle bends as part of the preparation for a pressure test while the pipeline is out of service.[468] Once the historic 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.[469]

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[467] Ex. SCG-04 (Schneider) at 42.
[468] Ex. SCG-04 (Schneider) at 55-56.
[469] Ex. SCG-04 (Schneider) at 55.

While the pipeline rupture in San Bruno primarily placed focus on the need for post-construction pressure tests to validate the integrity and stability of a pipeline's long seam, the stability of all manufacturing and construction threats, including wrinkle bends, are receiving greater scrutiny. Indeed, current pipeline integrity regulations focus on the issue of defect stability as the trigger to determine the appropriate integrity assessment methods related to both manufacturing and construction defects.[470]

In addition, significant girth weld flaws were observed during the NTSB failure investigation. Vintage welds of similar quality pose a potential risk during any earth movement event, even if currently recognized as stable under normal operating conditions. The same risk applies to wrinkle bends or other field fabricated construction threats that are subject to permanent ground displacement.[471]

Execution of the Plan provides a particularly opportune time for mitigation of these construction and fabrication methods in high consequence areas and urbanized environments where access and logistics continue to narrow such windows of opportunity. Once the historic 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

[470] Ex. SCG-18 (Schneider) at 25.
[471] Ex. SCG-18 (Schneider) at 25(citing Pipeline Accident Report, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, National Transportation Safety Board, at 43).

and a lower likelihood of disruption to customers that may have otherwise resulted from pressure test failures.[472]

DRA recommends that the Commission reject this element of the SoCalGas and SDG&E Plan and direct that wrinkle bends be addressed only through the TIMP. DRA's proposal is short-sighted, fails to improve the safety of the transmission system in a cost-effective manner, and fails to recognize two important factors, namely: (1) that TIMP activities apply primarily to pipelines within high consequence areas, and that the scope of the Commission's decision extends well beyond these high consequence areas to all transmission pipeline; and (2) that construction-related threats such as wrinkle bends are typically considered stable under TIMPs, yet may still fail during a widespread destabilizing event such as an earthquake or continuous heavy rainstorm episodes.[473]

The Commission has stated it is resolute in its commitment to improve the safety of natural gas transmission pipelines.[474] The outages associated with pressure tests under the Plan provide an ideal window of opportunity to cost-effectively remove wrinkle bends with minimal additional disruption to service and enhance the safety of the transmission system.[475] If the proposal for removal of these wrinkle features is not approved as part of the PSEP, SoCalGas and SDG&E urge the Commission to consider the possibility of selected mitigation of a higher risk subset of wrinkle bends present on affected pipelines. A selective approach, while not as comprehensive as full mitigation of the threat, will at least result in a targeted reduction in the

[472] Ex. SCG-04 (Schneider) at 56.
[473] Ex. SCG-18 (Schneider) at 24.
[474] D.11-06-017 at 16-17.
[475] Ex. SCG-18 (Schneider) at 25.

overall risk associated with these features while taking advantage of the planned outage for pressure testing.[476]

2. Technology Plan

SoCalGas and SDG&E 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.[477] 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. 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.[478]

This proposed work includes:

- Installation of fiber-optic sensing on all future pipeline installations twelve inches and greater in diameter to detect when near-vicinity activity may pose a risk to the integrity of a pipeline.
- Installation of approximately 2,000 continuous methane monitors to be retrofitted on all pipelines twenty inches and greater in diameter routed in Location Class 3 and 4 areas and HCAs.

[476] Ex. SCG-18 (Schneider) at 27.
[477] Ex. SCG-06 (Rivera) at 85.
[478] Ex. SCG-06 (Rivera) at 85.

- Development of a Data Collection and Management System to interface with the above assets.[479]

These proposed improvements address the most common threat to pipelines, third party damage, along with a number of other pipeline risk factors.[480]

a. 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.[481]

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

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[479] Ex. SCG-23 (Rivera) at 15.
[480] Ex. SCG-23 (Rivera) at 15.
[481] Ex. SCG-06 (Rivera) at 85-86.

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 PSEP. 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 PSEP, will also be fitted with fiber optic sensing in the future.[482]

b. Proposal to Install Methane Detection Monitors

The safety of the SoCalGas and 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 and pose evacuation challenges, particularly where those facilities are located within 220 yards[483] 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 2,000 general locations that fit this proposed criterion for installing methane detection devices.[484]

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

[482] Ex. SCG-06 (Rivera) at 86. 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. Ex. SCG-06 (Rivera) at 86, n. 58.
[483] This 220-yard figure is based on class location distances set forth in 49 CFR 192.5. Ex. SCG-06 (Rivera) at 87.
[484] Ex. SCG-06 (Rivera) at 86-87.

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.[485]

c. 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 will serve both SoCalGas and SDG&E and will serve several functions. First, the data collection and management system 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 data collection and management system will receive alarm information initiated by any fiber optic or methane detection monitor with a latency of less than two minutes. Third, the data collection and management system will report alarms to appropriate dispatch personnel for review, call-out and resolution, as required. Fourth, the data collection and management system will track alarm acknowledgement and status. Fifth, the data collection and management system will provide permanent storage of all events with appropriate time and date stamping of events. Sixth, the data collection and management system will provide system-wide viewing of current alarm information to help field and operations personnel reconcile fiber optic and methane detection monitor information with Supervisory Control and Data Acquisition and other field observations during an emergency situation. Seventh, the data collection and management system will accommodate future expansion to 10,000 monitoring points and multiple sensor types, including remote Cathodic Protection, acoustic monitoring and pressure alarm. Finally, the data collection and management system will provide for export/routing of

[485] Ex. SCG-06 (Rivera) at 87.

information to support near real-time graphical viewing presentation of alarms on SoCalGas and SDG&E mapping products and provide connectivity with automated customer notification systems. [486]

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 Supervisory Control and Data Acquisition back-up capability and polling of latent pipeline information will provide adequate coverage for all Pipeline Infrastructure Monitoring sensors to be polled.[487]

d. Intervenor Objections to the Technology Plan are Shortsighted and Unfounded.

DRA and TURN have reviewed and rejected the SoCalGas and SDG&E Technology Plan, arguing that the Technology Plan goes beyond the Commission's intended scope and is unnecessary because SoCalGas and SDG&E operate safe pipelines under their current processes and programs. In addition, UWUA recommends rejection of our Technology Plan, arguing that the benefits associated with implementing the Technology Plan can be secured by expanding existing O&M programs via increases to the utility workforce.[488] As discussed in this Section, the arguments raised by these intervenors are shortsighted.

i. The Technology Plan is Within the Scope of the Plan

DRA argues that the entirety of SoCalGas and SDG&E's Technology Plan should be dismissed as outside the scope of the Commission's Order.[489] This argument is inconsistent with

[486] Ex. SCG-06 (Rivera) at 87-88.
[487] Ex. SCG-06 (Rivera) at 88-89.
[488] Ex. SCG-23 (Rivera) at 15.
[489] *See* Ex. DRA-02 (Phan) at 36-37.

the Commission's stated safety enhancement objectives in Rulemaking 11-02-019 and should be rejected.

In Rulemaking 11-02-019, the Commission describes its goal of establishing rules and policies that "accord safety of gas utility operations the highest level of significance" and expressly states that gas utilities must "recognize that mere compliance is not enough."[490] The Commission further explained:

> Due to aging utility infrastructure, we are interested in assessing whether we may be missing other natural gas pipeline safety issues or other catastrophic risks that are currently unidentified. In short, we pose the questions: 'what else is out there?' and 'what can we do to prevent another tragedy from unexpected sources?'. . . .
>
> We are also keenly interested in improving our regulation of the far more common threat to natural gas transmission and distribution system safety – accidental damage during unrelated but nearby excavation, often referred to as a "dig in."[491]

In D.11-06-017, the Commission affirmed its commitment to improving the safety of California's natural gas transmission pipelines:

> We are resolute in our commitment to improve the safety of natural gas transmission pipelines. In this context, it is absolutely essential that our regulated utilities display the highest level of candor and honesty. We understand that the issues at hand implicate substantial expenses and capital investments, and that the optimum means to address these safety issues may be subject to reasonable debate. To perform our Constitutional and statutory duties, we must have forthright and timely explanation of these issues, as well as comprehensive analysis of the advantages and disadvantages of potential actions.[492]

The SoCalGas and SDG&E Technology Plan responds to these stated objectives of the Commission by describing additional safety enhancement measures that can be undertaken to further enhance the SoCalGas and SDG&E system.

[490] Order Instituting Pipeline Safety Rulemaking at 9-10.
[491] Order Instituting Pipeline Safety Rulemaking at 10.
[492] D.11-06-017 at 16-17.

ii. Intervenor Arguments That There is No Need For Improvement Undermine the Commission's Stated Objectives

DRA concludes that because SoCalGas and SDG&E have operated, and continue to operate, safe pipelines, they should not pursue improvement as proffered in the Technology Plan.[493] While SoCalGas and SDG&E appreciate DRA's acknowledgement of their safe operating history, they disagree with DRA's assumption that prior success should preclude the implementation of strategic and tactical programs aimed at continuous pipeline safety improvements. The spirit of the Rulemaking, as expressed in the language quoted above, was for successful pipeline companies to look for ways to further enhance the safety of their systems. The Commission particularly expressed a desire to address potential dig-ins on natural gas pipelines.[494]

Toward this objective, SoCalGas and SDG&E's Technology Plan is designed to provide more precise and timely information to our operations personnel and enhance our personnel's ability to pre-empt problems associated with third parties who may not share SoCalGas and SDG&E's commitment to, or focus on, safety. Third parties account for about 60% of all pipeline ruptures based on industry statistics, can expose SoCalGas and SDG&E's pipelines to immediate threats, and can sow the seeds of latent pipeline problems which may not show for several years. Early detection of such activity on large high pressure pipelines in populated areas is prudent and precisely what our Technology Plan addresses.[495]

UWUA recommends rejection of the SoCalGas and SDG&E Technology Plan on an erroneous assertion that expanding existing leak survey and patrol programs can serve the same

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[493] Ex. DRA-02 (Phan) at 35.
[494] Ex. SCG-23 (Rivera) at 16.
[495] Ex. SCG-23 (Rivera) at 16. (citing Reported Damages by Cause, for California Gas Transmission, 2002-2011, PHMSA's Significant Incident filed June 11, 2012).

purpose.[496] While UWUA's recommendations are discussed in detail Section IX.D below, the proposed Technology Plan is intended to augment pipeline surveillance and leak monitoring beyond the capability of personnel walking the pipeline rights-of-way, not replace existing programs. Indeed, SoCalGas and SDG&E will not abandon current pipeline assessment survey processes that incorporate "boots on the ground." To assert that we can simply expand existing programs to achieve the same results as the Technology Plan, however, is without foundation. For example, to try and provide continuous leak survey along our pipelines, comparable to our methane sensor plan (in near-real-time at 2,000 locations), would require a field force of approximately 10,000 added workers equipped with gas detection monitors. Such an approach would not be economically practical.[497]

TURN makes note that the fiber and/or methane detection will not be accompanied by reduction in monitoring activities and related costs associated with SoCalGas and SDG&E's current practices.[498] TURN is accurate in its interpretation that there is no offsetting reduction in existing leak survey activities associated with this proposed work. This is because the Technology Plan is designed to augment, not replace, existing patrol and survey activities.[499]

iii. The Proposed Technology Enhancements are Forward-Looking and Not Limited to PSEP Work

TURN and DRA both inaccurately describe SoCalGas and SDG&E's fiber optic enhancement proposal as being limited to a small portion of the SoCalGas and SDG&E transmission pipeline system.[500] Furthermore, DRA opines that SoCalGas and SDG&E, if it can

[496] Ex. UWUA-01 (Wood) at 10.
[497] Ex. SCG-23 (Rivera) at 17.
[498] Ex. TURN-02 (Marcus) at 27.
[499] Ex. SCG-23 (Rivera) at 20.
[500] Ex. DRA-02 (Phan) at 33; Ex. TURN-02 (Marcus) at 26.

justify its proposed technology enhancements, should seek funding via the next GRC, and not as part of the PSEP.[501]

Contrary to these characterizations, SoCalGas and SDG&E's proposed installation of fiber optic monitoring is intended to reflect a new technology standard to apply to new or replaced high pressure pipelines with specific risk characteristic. This includes both pipeline work performed under the PSEP and future work which might be performed under normal GRC funded programs. While the scope of funding requested in this Technology Plan is for the base monitoring system and for pipelines replaced under PSEP-approved projects, future pipeline work can and will be integrated into the proposed monitoring system.[502]

iv. The Commission Should Not Miss the Opportunity to Cost-Effectively Implement Technology Enhancements Pending Further Cost-Benefit Analysis and Justification

TURN and DRA suggest SoCalGas and SDG&E defer its Technology Plan because SoCalGas and SDG&E have not provided sufficient justification or cost-benefit analyses.[503]

SoCalGas and SDG&E's cost estimates for the proposed technology work are bottom-up estimates with accuracy of plus or minus 10% where the field equipment is concerned and plus or minus 20% where the Data Collection and Management System is concerned. These are not gross or "dubious" estimates as suggested by TURN. The Workpapers supporting these estimates provide detailed cost estimates based on discussions with vendors, secured equipment costs, and on our own internal history in routing pipelines through Location Class 3 and 4 high consequence areas.[504]

[501] Ex. DRA-02 (Phan) at 37.
[502] Ex. SCG-23 (Rivera) at 18.
[503] Ex. DRA-02 (Phan) at 36; Ex. TURN-02 (Marcus) at 26.
[504] Ex. SCG-23 (Rivera) at 18-19.

As for the benefits, the record in this proceeding reflects that for less than 6% of the construction cost for associated new pipeline, SoCalGas and SDG&E can equip pipelines with technologies that will help identify right-of-way intrusions and gas leakage in near real time. SoCalGas and SDG&E have presented sufficient information to substantiate that pipelines are subject to damage from third parties, and that these damages can result in either immediate and/or latent pipeline integrity issues. The inclusion of this technology responds to the Commission's Rulemaking and will cost-effectively enable SoCalGas and SDG&E to better monitor rights-of-way impacts or other events resulting in gas leakage.[505]

v. The Technology Plan is Not Designed to Generate Revenues for Non-Tariffed Products and Services

TURN expresses concern that SoCalGas and SDG&E might use fiber installation to support Non-Tariffed Products and Services revenue stream via the leasing of "dark fiber" – using bandwidth and communication paths intended for pipeline monitoring for third party commercial communication exploits.[506] This concern is baseless. The application of fiber optics is intended only to allow SoCalGas and SDG&E to identify a condition and activity before it turns into an emergency. These fiber optic cables are to be installed with the express purpose of being disturbed or damaged by right-of-way intrusions. Accordingly, SoCalGas and SDG&E have no such designs for added revenue from our Technology Plan, and simply aim to monitor our pipelines and rights-of-way for the reasons cited.[507]

3. 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

[505] Ex. SCG-23 (Rivera) at 19.
[506] Ex. TURN-02 (Marcus) at 26.
[507] Ex. SCG-23 (Rivera) at 19.

pipeline records "readily available."[508] 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 and SDG&E natural gas transmission pipeline system are currently 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.[509] 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 GRC Applications.[510]

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.[511]

DRA contends that SoCalGas and SDG&E's proposed Enterprise Asset Management System Blueprint project should be rejected because it goes beyond the scope and objectives of the Commission's decision and we have not demonstrated that our current record management

[508] D.11-06-017 at 19.
[509] Ex. SCG-07 (Rivera) at 90.
[510] Ex. SCG-07 (Rivera) at 94.
[511] Ex. SCG-07 (Rivera) at 93.

systems are inadequate.[512] On the other hand, TURN contends that SoCalGas and SDG&E have failed to demonstrate that our existing systems are adequate and that the Enterprise Asset Management System is not remedial in nature.[513] These contentions by DRA and TURN are unfounded.

DRA's argument that the Commission should reject SoCalGas and SDG&E's Enterprise Asset Management System Blueprint as beyond the scope of D.11-06-017 is without merit. The Commission has expressed that mere compliance with regulations is insufficient and directs California's pipeline operators to provide more information to the Commission regarding their transmission pipeline systems going forward.[514]

Moreover, as prudent operators, SoCalGas and SDG&E have taken note of what is unfolding in the industry. Lessons learned from San Bruno and the subsequent investigative reports make it prudent to develop new Enterprise Asset Management System capabilities that go beyond current industry standards and regulatory compliance requirements.[515]

The Enterprise Asset Management System Blueprint solution is not an activity designed to remediate inadequate governance, processes, and systems, or bring systems up to standards that should already have been met relating to accessibility of data and data governance, as implied by TURN. To the contrary, SoCalGas and SDG&E's current processes and systems meet regulatory requirements and applicable industry standards.[516] Indeed, DRA, in its criticism of SoCalGas and SDG&E's proposal, asserts the adequacy of the current systems.[517]

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[512] Ex. DRA-02 (Phan) at 38, 41.
[513] Ex. TURN-01 (Long) at 24.
[514] Order Instituting Pipeline Safety Rulemaking at 9-10.
[515] Ex. SCG-23 (Rivera) at 22.
[516] Ex. SCG-23 (Rivera) at 24.
[517] *See* Ex. DRA-02 (Phan) at 39-41.

The Enterprise Asset Management System is intended to respond to the increased level of pipeline design, permitting and construction activities that will take place over the course of the next ten years in order to pressure test or replace pipelines covered by D.11-06-017. Analyzing existing processes and technologies to verify that they will stand up to this significantly larger-than-normal volume of work and number of contractors, and identifying appropriate system enhancements, is the prudent course of action contemplated as part of the Enterprise Asset Management System Blueprint activity.[518]

V. REASONABLENESS OF COST ESTIMATES

On June 16, 2011, the Commission ordered California's natural gas transmission pipeline operators to prepare and submit their PSEP.[519] The California gas utilities were ordered to file their pipeline safety enhancement plans no later than August 26, 2011[520] and include "best available expense and capital cost projections."[521] As such, SoCalGas and SDG&E had approximately two months to develop a comprehensive pipeline safety enhancement plan and establish reasonable cost projections and timelines.[522]

SoCalGas and SDG&E developed cost estimates for both the work required under D.11-06-017 (Base Case) and additional safety enhancement elements (Proposed Case). The Base Case includes costs associated with testing or replacing pipeline segments that do not have sufficient documentation of pressure testing to at least 1.25 MAOP, proposed interim safety enhancement measures, a Valve Enhancement Plan, and costs to modify SoCalGas and SDG&E's billing system. The Proposed Case includes additional costs for the replacement of pipeline segments to mitigate pre-1946 construction and manufacturing methods, replacement of

[518] Ex. SCG-23 (Rivera) at 24-25.
[519] D.11-06-017, mimeo., at 19.
[520] D.11-06-017, mimeo., at 20.
[521] D.11-06-017, mimeo., at 22.
[522] Ex. SCG-21 (Buczkowski) at 1.

wrinkle bends, technology enhancements, and the development of an Enterprise Asset Management System. The PSEP cost estimates associated with the Base and Proposed Case were developed based on reasonable assumptions and projections, and establish preliminary cost estimates following industry practices.[523] These estimates, when combined with the risk-based allowances provided by contingencies, establish reasonable projections of SoCalGas and SDG&E's PSEP costs.[524] In total, SoCalGas and SDG&E request that the Commission adopt the Phase 1A proposed case cost estimates of $1.2 billion for SoCalGas and $229 million for SDG&E for capital costs[525] and $255 million for SoCalGas and $7 million for SDG&E for O&M costs.[526]

A. Pipeline Replacement and Testing Estimates

SoCalGas and SDG&E's estimates reflect early planning efforts for PSEP projects and the historical experience of SoCalGas, SDG&E, and System Planning Engineering and Consulting Services (SPEC Services) – the consultant hired to assist in developing estimates.[527] Through these efforts, SoCalGas and SDG&E have developed pipeline replacement and testing cost estimates that are "between a Class 4 and a Class 5" in the guidelines developed by the Association for the Advancement of Cost Engineering (AACE).[528] The AACE estimate class system describes, among other attributes, the characteristics, end usages, and expected accuracies of cost estimates as they range from high level to fully detailed.[529] Commonly, an estimate in the

[523] Ex. SCG-21 (Buczkowski) at 3.
[524] Ex. SCG-21 (Buczkowski) at 2.
[525] Ex. SCG-09-R (Rivera) at 103.
[526] Ex. SCG-09-R (Rivera) at 104.
[527] DRA-38 (DRA-PZS-TCAP-PSEP-14) at 2.
[528]Tr. 582, line 12 (SoCalGas/SDG&E/Buczkowski).
[529] Ex. SCG-21 (Buczkowski) at 3.

Class 5 to Class 4 stage of development will be used to establish funding authorizations and preliminary program budgets.[530] As stated by Mr. Buczkowski:

> I've characterized our estimate as estimate between class four and class five, just to make that clarification.
>
> And one of the factors that AACE stipulates is the [usage] of the estimate. So I think to answer your question can a class-four -- class-four or five estimate be used to establish a budget that could be approved by the Commission, my answer is yes.[531]

SoCalGas and SDG&E recognize that cost estimates will necessarily require refinements and updates as more information is compiled and projects are further defined.[532] Further analysis, project definition, and updating of the PSEP cost estimates will be performed during the engineering, design, and execution planning phase of each project.[533] This will ensure that decisions made based on estimated costs, particularly the decision to pressure test or replace, will be based on a greater level of project definition than currently exists.[534] However, by establishing a cost projection based on current estimates and associated contingencies, SoCalGas and SDG&E have provided the Commission the basis to approve PSEP cost estimates and allow the PSEP program to move forward.[535]

1. Pipeline Replacement Cost Estimates

Both the Base Case and Proposed Case require SoCalGas and SDG&E to replace transmission pipeline segments located in Class 3 and 4 locations or high consequence areas.[536] As discussed above, the pipeline replacement cost estimates assume replacement of not only

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530 DRA-38 (DRA-PZS-TCAP-PSEP-14) at 2.
531 Tr. at 1036 (SoCalGas/SDG&E/Buczkowski).
532 Ex. SCG-21 (Buczkowski) at 2.
533 Ex. SCG-21 (Buczkowski) at 2.
534 Ex. SCG-21 (Buczkowski) at 2.
535 Ex. SCG-21 (Buczkowski) at 4; Tr. at 582 (SoCalGas/SDG&E/Buczkowski); Tr. at 1036 (SoCalGas/SDG&E/Buczkowski).
536 Ex. SCG-09-R (Rivera) at 109.

these segments, but also "accelerated miles"[537] and a small number of distribution segments to facilitate continuity in construction.[538] In total, 348 miles of pipeline will be replaced in Phase 1 at an estimated cost of $1,332 million.[539]

Replacement cost estimates were developed based on proposed replacement mileage, pipeline system data, such as operating pressure and diameter, and GIS Maps of each pipeline segment to identify the location and type of construction applicable for each relocation area.[540] Based on this data, SPEC Services developed estimates using recent construction estimate and bid data, material prices based on supplier quotes, and labor costs based on historical data and quotes provided by local construction contractors.[541] A subset of pipeline replacement cost estimates, the replacement of pre-1946 pipeline segments, was estimated using a cost matrix provided by SPEC Services.[542] This matrix combined pipeline diameter with replacement length to arrive at a replacement cost per foot.[543] Finally, the PSEP also includes cost estimates to replace wrinkle bends based on historically observed repair costs.[544] The PSEP cost estimates were developed using reasonable assumptions and best available information to develop projections of pipelines replacement costs.

2. Pressure Testing Cost Estimates

Both the Base Case and Proposed Case PSEP includes cost estimates for SoCalGas and SDG&E to pressure test transmission pipeline segments located in Class 3 and 4 locations or high consequence areas.[545] As discussed above, the pressure testing cost estimates assume

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[537] Ex. SCG-09-R (Rivera) at 109.
[538] Ex. SCG-12 (Schneider/Buczkowski) at 1.
[539] Ex. SCG-09-R (Rivera) at 109.
[540] Ex. SCG-09-R (Rivera) at 110.
[541] Ex. SCG-09-R (Rivera) at Appendix E.
[542] Ex. SCG-09-R (Rivera) at 116.
[543] Ex. SCG-09-R (Rivera) at 116.
[544] Ex. SCG-09-R (Rivera) at 116.
[545] Ex. SCG-09-R (Rivera) at 108.

replacement of not only these segments, but also "accelerated miles"[546] and a small number of distribution segments to facilitate continuity in construction.[547] In total, 407 miles of transmission pipeline will be pressure tested in Phase 1 at a cost of $193 million.[548]

Pressure testing cost estimates were developed based on proposed pressure test mileage, pipeline system data, such as pipeline diameter and operating pressure, and estimating factors including segment size, pipeline profile, water supply, equipment, personnel, and materials.[549] Additionally, SPEC Services developed numerous pressure testing assumptions related to the filling, transportation, unloading of water via truck,[550] and the disposal of effluent water.[551] Based on these assumptions, SPEC Services then reviewed recent construction estimate and bid data and procured vendor and supplier quotes to arrive at the pressure testing cost estimates.[552] These estimates were then reviewed and approved by SoCalGas and SDG&E's construction and project managers who regularly engage in related work.[553]

In addition, SoCalGas and SDG&E developed an allowance for post-pressure test repairs to remedy leaks or ruptures caused by pressure tests taking SoCalGas and SDG&E's system to pressure levels not achieved under normal operations.[554] The propriety of the estimate factors, assumptions, and associated contingencies has since found support in the pressure testing costs experienced by PG&E in their PSEP.[555]

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[546] Ex. SCG-09-R (Rivera) at 108.
[547] Ex. SCG-12 (Schneider/Buczkowski) at 1.
[548] Ex. SCG-09-R (Rivera) at 108.
[549] Ex. SCG-09-R (Rivera) at 109.
[550] Ex. SCG-21 (Buczkowski) at 7.
[551] Ex. SCG-21 (Buczkowski) at 8.
[552] Ex. SCG-09-R (Rivera) at Appendix D.
[553] Tr. at 844 (SoCalGas/SDG&E/Buczkowski); Tr. at 868 (SoCalGas/SDG&E/Buczkowski).
[554] Ex. SCG-21 (Buczkowski) at 8.
[555] Tr. at 847 (SoCalGas/SDG&E/Buczkowski); Tr. at 1060 (SoCalGas/SDG&E/Buczkowski); Ex. SCG-20 (Phillips) at 10; Ex. SCG-21 (Buczkowski) at 7.

B. Valve Enhancement Plan Cost Estimates

SoCalGas and SDG&E propose to enhance 561 valve locations and install companion equipment to allow their operators to better view system operations and better manage valve closures, ruptures and other extraordinary events.[556] In total, the valve and companion equipment installations will cost $315 million for SoCalGas and $63 million for SDG&E.[557]

Estimated capital and O&M costs for proposed valve installations and upgrades were developed based on estimates from contractor(s) providing consulting estimates for the proposed valve work and a review of recorded costs for historical and current valve and control system installations and replacements of similar size and complexity.[558] 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.[559] The valve cost estimates are composed of the following factors: material cost of valve; material cost of actuator; material cost of power, controls and telemetry; material cost for pipes; material cost for other in-directs such as lost gas, fees, and permits; contract labor performed by a third-party contractor; and utility labor performed by SoCalGas.[560] The utility and contractor labor costs consist of estimates for valve installation, actuator mounting, and power, controls and telemetry installation.[561] These estimates are further impacted by the size of the pipe and location of the valve.[562] The final cost estimates were developed by averaging the cost estimates derived independently from SoCalGas and the third-party contractor.[563]

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[556] Ex. SCG-09-R (Rivera) at 112-113.
[557] Ex. SCG-09-R (Rivera) at 113.
[558] Ex. SCG-09-R (Rivera) at 114.
[559] Ex. SCG-09-R (Rivera) at 114.
[560] Ex. SCG-32 (Workpapers) at WP-IX-2--27 of 116.
[561] Ex. SCG-32 (Workpapers) at WP-IX-2--27 of 116.
[562] Ex. SCG-32 (Workpapers) at WP-IX-2--27 of 116.
[563] Ex. SCG-32 (Workpapers) at WP-IX-2--27 of 116.

The accuracy of SoCalGas and SDG&E's valve estimates is supported by SoCalGas and SDG&E's recent valve installations. In response to a data request, SoCalGas and SDG&E provided the recorded and expected final costs for multiple valve installations,[564] many of which reflect the scope of work to be performed as part of SoCalGas and SDG&E's PSEP.[565] The average recorded cost for these installations was $1.201 million per site; consistent with the $1.171 million average costs forecasted for the PSEP and well within the 8% contingency discussed below.[566] The reason for the accuracy of the valve estimates is explained by Mr. Rivera: "…the point we tried to get across is that the costs were developed on work that we do day in and day out. It's based on historical cost estimates. It's based on work that we're actually doing at this point in time. The work that we're doing in our TIMP project is identical to the work that we propose to do on PSEP."[567] As such, the valve enhancement cost estimates were developed based on historical costs and work that is currently in process.

C. Interim Safety Cost Estimates

SoCalGas and SDG&E have implemented interim safety enhancement measures for those pipeline segments that do not have sufficient documentation of pressure testing to at least 1.25 MAOP.[568] Specifically, SoCalGas and SDG&E propose to continue their increased frequency of ground patrols and leakage surveys to bi-monthly, implement pressure reductions where feasible, and perform inline inspections using the TFI inline inspection tool.[569] In total, SoCalGas and SDG&E estimate incurring $12 million for the proposed interim safety enhancement measures.[570]

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[564] Ex. DRA-34 (Data Request DRA-KCL-TCAP-PSEP-05) at pages 4-5.
[565] Ex. SCG-23 (Rivera) at 9.
[566] Ex. SCG-23 (Rivera) at 9.
[567] Tr. at 1284 (SoCalGas/SDG&E/Rivera).
[568] Ex. SCG-09-R (Rivera) at 111.
[569] Ex. SCG-09-R (Rivera) at 111-112.
[570] Ex. SCG-09-R (Rivera) at 112.

Incremental costs have been incurred and tracked since February 2011, as a result of increased efforts beyond the existing pipeline integrity management program.[571] These costs include employee overtime pay to implement the additional leak surveys and pipeline patrols, incremental costs associated with the installation of pressure control equipment to facilitate the lowering of pressure on some segments, and costs incurred to run a TFI tool with associated excavation and validation.[572] The estimates are based on historical costs observed on prior company projects.[573]

D. Cost Estimates 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 proposed pipeline safety enhancement plan surcharge.[574] 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.[575] Prior efforts to change and enhance the billing systems of SoCalGas and SDG&E were considered in formulating this cost estimate and support the reasonableness of the cost estimate.[576]

E. Technology Enhancement Estimates

SoCalGas and SDG&E have propose installing fiber optic cabling, methane detection monitors, and a computer-based remote monitoring system to collect and manage information and alarms from the proposed sensor technologies.[577] Estimates for the technology enhancement proposals include capital costs to acquire the assets and O&M costs to install, operate, and

[571] Ex. SCG-09-R (Rivera) at 112.
[572] Ex. SCG-09-R (Rivera) at 111-112.
[573] Ex. SCG-09-R (Rivera) at 111.
[574] Ex. SCG-09-R (Rivera) at 115.
[575] Ex. SCG-09-R (Rivera) at 115.
[576] Ex. SCG-09-R (Rivera) at 115.
[577] Ex. SCG-09-R (Rivera) at 116.

manage the assets.[578] In total, technology costs will include $65 million in capital costs and $8 million in O&M costs.[579]

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 costs based on vendor installation requirements.[580] A review of historical excavation costs provides concrete historical cost examples for excavation in the pipeline right of way; the primary fiber optic cost driver.[581]

Next, estimated capital costs for methane detection monitors were developed based on unit cost information provided by methane detection system vendors, historical utility costs for communication systems of similar size and complexity, and construction costs based on vendor installation requirements and experience with installing monitoring equipment.[582]

Finally, estimates for the computer-based remote monitoring system to interface with the above assets are based on detailed estimates provided by IT program managers who have developed comparable systems.[583]

These detailed cost estimates are based on discussions with vendors, secured equipment costs, historical cost examples, and on our own internal history in routing pipelines through location Class 3 and 4 high consequence areas.[584] As such, the technology cost estimates are not

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[578] Ex. SCG-09-R (Rivera) at 116.
[579] Ex. SCG-09-R (Rivera) at 117.
[580] Ex. SCG-09-R (Rivera) at 116.
[581] Tr. at 1296 (SoCalGas/SDG&E/Rivera).
[582] Ex. SCG-09-R (Rivera) at 117.
[583] Ex. SCG-32 (Workpapers) at WP-IX-3--34 of 39.
[584] Ex. SCG-23 (Rivera) at 18-19.

preliminary estimates, but defined cost estimates based on current unit cost information and historical cost examples.[585]

F. Enterprise Asset Management System Cost Estimates

In determining the cost estimates for the Enterprise Asset Management System, SoCalGas and SDG&E's considered the system's requirements and the cost and scale of similar projects.[586] Based on an understanding of the system's intended scope and use, coupled with a review of costs incurred for similar systems, SoCalGas and SDG&E estimate O&M costs of approximately $6.5 million in 2012 to develop a blueprint for a comprehensive enterprise asset management system.[587] 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.[588]

Enterprise Asset Management System cost estimates include labor and non-labor costs necessary to develop an Enterprise Asset Management System technical blueprint, establish an organization to manage the Enterprise Asset Management System, develop an Enterprise Asset Management System process and policy blueprint, and develop processes for data capture of new construction going forward.[589] Costs are based on rates used in prior company software development projects and include standard expenses and a 20% contingency.[590]

G. Contingency Estimates

A contingency is an essential element of any estimate and provides a risk-based allowance for unforeseeable elements and reflects the current stage of project definition and project risk profile to allow the estimator to establish a reasonable estimate amount for the

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[585] Tr. at 1286-1287 (SoCalGas/SDG&E/Rivera).
[586] Ex. SCG-09-R (Rivera) at 117.
[587] Ex. SCG-09-R (Rivera) at 117.
[588] Ex. SCG-09-R (Rivera) at 117.
[589] Ex. SCG-32 (Workpapers) at WP-IX-5-1.
[590] Ex. SCG-32 (Workpapers) at WP-IX-5-1.

ultimate project delivery.[591] In past decisions the Commission has stated that a proper contingency should be based on a risk analysis of the specific project.[592] Thus, the value of the contingency amount is dependent on the risk profile(s) of the project components and the status of project definition at the time of the estimate.[593]

SoCalGas and SDG&E developed their contingencies as intended to cover "costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope."[594] Consistent with this goal, SoCalGas and SDG&E's different contingency estimates reflect the specific risk profile of the different proposals and are consistent with prior Commission directives and common industry practice.

1. PSEP Contingency

For the pipeline replacement and pressure test projects proposed in the PSEP, SoCalGas and SDG&E have proposed two contingency amounts depending on the size of the individual project. First, for projects in excess of $2 million dollars, SoCalGas and SDG&E propose a 20% contingency.[595] For projects under $2 million dollars, SoCalGas and SDG&E propose a contingency of 30%.[596] In order to calculate these contingencies, SoCalGas retained SPEC Services to determine a contingency to account for uncertainty associated with project scope.[597]

SPEC Services initial contingency was 30% and intended to account for uncertainties related to both fixed costs (*e.g.*, environmental permitting and right-of-way acquisition) and variable costs (*e.g.*, materials and construction labor).[598] It was determined, however, because fixed costs tend to decrease on a per foot basis and there is indication that material and

[591] Ex. SCG-21 (Buczkowski) at 11.
[592] D.09-03-026, mimeo., at 88.
[593] Ex. SCG-21 (Buczkowski) at 11.
[594] Ex. SCG-21 (Buczkowski) at 10.
[595] Ex. DRA-32 (Data Request DRA-DAO-01) at 7
[596] Ex. DRA-32 (Data Request DRA-DAO-01) at 7
[597] Ex. DRA-32 (Data Request DRA-DAO-01) at 7.
[598] Ex. DRA-32 (Data Request DRA-DAO-01) at 7.

construction labor costs will decrease as the size of the project increases due to competitive pricing and the desire of suppliers to reduce profit volume, the contingency could be reduced to 20% once the project reached $2 million.[599] This reduction was not meant to imply that there is less uncertainty associated with the project, but rather that there is an expectation that a reduction in cost per foot pricing and project size pricing reductions would offset the level of contingency required.[600]

Currently, the PSEP is comprised of multiple projects at very early phases of project definition and, necessarily, includes a variety of assumptions and risks.[601] For example, environmental permitting was not addressed in the estimates, and an assumption was made that all pressure test segments have a flat elevation profile.[602] For the pipe replacement estimates, replacements were assumed to be done in the existing rights-of-way, and no additional costs were included for alternate pipe routings likely resulting in increased pipe quantities and construction man-hours nor right-of-way acquisition.[603] As explained by Mr. Buczkowski:

> The contingency is part of a project scope to account for uncertainties within defined project scope.
>
> Because of the amount of time that we had to define the project scope, the level of definition isn't there to support a lower contingency. The contingency we put in is appropriate for the scope definition as well as the risks that we looked at.[604]

As such, the 20 and 30 percent contingency estimates are directly related to the project scope, level of definition, and high risk profile associated with the PSEP.[605]

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599 Ex. DRA-32 (Data Request DRA-DAO-01) at 7.
600 Ex. DRA-32 (Data Request DRA-DAO-01) at 7.
601 Ex. SCG-21 (Buczkowski) at 14.
602 Ex. SCG-21 (Buczkowski) at 14.
603 Ex. SCG-21 (Buczkowski) at 14.
604 Tr. at 594 (SoCalGas/SDG&E/Buczkowski).
605 Ex. SCG-32 (Workpapers); Tr. at 594 (SoCalGas/SDG&E/Buczkowski).

2. Valve and Technology Enhancement Plan Contingency

As discussed above, the cost estimates and scope of work to be performed on the Valve Enhancement Plan and technology enhancements were developed based on historical costs, current unit cost information, and supported by work that is currently in process. As the contingency is a reflection of the current stage of project definition and project risk profile, the contingencies requested for the Valve Enhancement Plan and technology enhancement are 8%.[606] This lower contingency is a result of greater certainty in valve and technology cost estimates and the lower risk profile associated with the Valve Enhancement Plan and technology enhancements.[607]

VI. ALTERNATIVES TO REPLACEMENT OR PRESSURE TESTING

A. Non-Destructive Direct Assessment of Pipelines Less Than 1,000 Feet in Length

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 methods (such as ultrasonic, radiographic and magnetic particle inspection techniques).[608] 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.[609]

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

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[606] Ex. SCG-32 (Workpapers) at WP-IX-2--27 of 116.
[607] Tr. at 1284-1287 (SoCalGas/SDG&E/Rivera).
[608] Approval of this proposal may require amendment of Public Utilities Code section 958, which codifies the pressure testing requirements contained in D.11-06-017.
[609] Ex. SCG-04 (Schneider) at 54.

typically more direct, reliable, and provide a higher level of anomaly discrimination when compared to pressure testing or inline 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 inline 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.[610]

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.[611]

SCGC supports this proposed cost-saving alternative to pressure testing, stating:

> Applicants are making a cost-effective proposal that ensures the same level of safety as pressure testing while reducing the direct costs by approximately $5-15 million. The Commission should adopt the Applicants' proposal to use NDE techniques to establish the safety of short lengths of pipe.[612]

[610] Ex. SCG-04 (Schneider) at 54.
[611] Ex. SCG-04 (Schneider) at 54-55.
[612] Ex. SCGC-01 (Yap) at 15.

DRA, on the other hand, "takes issues with the alternative proposal to use NDE methods on these short segments because at this time NDE methods have not been officially recognized as achieving the same standard of safety as hydrostatic testing."[613] Because DRA did not cite to any authority for its assertion that non-destructive examination has not been "officially recognized" as achieving the same standard of safety as hydrostatic testing, it is difficult to discern the basis for this assertion. In fact, the record in this proceeding, as briefed above, reflects that non-destructive examination techniques are recognized as providing an equivalent level of safety as hydrostatic testing. Indeed, Dr. Harvey H. Haines, an outside expert on pipeline integrity assessment methods retained by SoCalGas and SDG&E, testified that "[i]f measurements from certified personnel are taken and recorded then non-destructive examination could serve as the sole assessment technique for short segments where the entire pipe can be excavated for examination, or is already above ground."[614]

B. Future Consideration of Potential Rules to Allow an In-Service Pressure Test to Serve as an Alternative to Replacement

In their proposed PSEP, SoCalGas and SDG&E request that the Commission consider the development and approval of rules that would allow for 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. SoCalGas and SDG&E do not seek adoption of such rules at this time, but rather, ask the Commission to establish a stakeholder process of considering and developing such rules in Rulemaking 11-02-019.

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

[613] Ex. DRA-02 (Phan) at 45.
[614] Ex. SCG-19 (Haines) at 15.

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.[615]

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 PSEP 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 Rulemaking 11-02-019.[616]

VII. REVENUE REQUIREMENTS

A. Proposed Revenue Requirements

1. Authorization Requested

SoCalGas and SDG&E have requested authorization to recover in customer rates the revenue requirements resulting from our Phase 1A capital and O&M expense forecasts. For the years 2011 through 2015, these proposed Phase 1A revenue requirements are $593 million for

[615] Ex. SCG-04 (Schneider) at 59.
[616] Ex. SCG-04 (Schneider) at 60.

SoCalGas and $62 million for SDG&E.[617] SoCalGas and SDG&E propose that PSEP funding requests for later years be dealt with in the utilities' GRCs, or other applicable proceedings.[618]

2. Development of PSEP-Related Revenue Requirements

SoCalGas' and SDG&E's estimated PSEP-related revenue requirements are derived from the forecasted incremental capital costs and O&M costs described above and in the utilities' testimony.[619] Those costs are direct costs only, and do not include overhead, escalation, or certain other expenditures necessary to support PSEP-related investments.[620] To develop their proposed revenue requirements, SoCalGas and SDG&E first adjusted the direct cost forecasts to include applicable overhead loaders and escalation.[621] These "loaded and escalated" costs were then used to develop forecasted revenue requirements, which 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.[622]

In developing their PSEP-related revenue requirements, SoCalGas and SDG&E assumed that all capital costs, including allowance for funds used for construction (AFUDC), are recovered through depreciation over the book life of the assets, and that O&M is recovered in the period it is spent.[623] The SoCalGas revenue requirement calculation reflects the current authorized rate of return of 8.68% based on 10.82% return on equity.[624] The SDG&E revenue requirement calculation reflects the current authorized rate of return of 8.40% based on 11.10% return on equity.[625]

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[617] Ex. SCG-10 (Reyes) at 121.
[618] Ex. SCG-10 (Reyes) at 121.
[619] Ex. SCG-10 (Reyes) at 121.
[620] Ex. SCG-10 (Reyes) at 121-22.
[621] Ex. SCG-10 (Reyes) at 122-23.
[622] Ex. SCG-10 (Reyes) at 123.
[623] Ex. SCG-10 (Reyes) at 123.
[624] Ex. SCG-10 (Reyes) at 123.
[625] Ex. SCG-10 (Reyes) at 123.

3. Overhead Loaders

Overhead costs are costs that indirectly support the business operations of SoCalGas and SDG&E, and the utilities allocate these costs to particular projects through the use of overhead loading rates.[626] SoCalGas and SDG&E applied overhead rates to each PSEP direct cost input according to its classification as company labor, contract labor, purchased services, and materials.[627] The overhead rates used by SoCalGas and SDG&E are set forth is Table X-1 to Mr. Reyes' direct testimony.[628]

SoCalGas' and SDG&E's accounting systems apply over 20 different classes of overhead rates to various combinations of company labor, contract labor, purchased services, and materials; however, many of these costs are already fully recovered in base utility rates and therefore not applicable to our PSEP proposal, which is prepared on an incremental basis.[629] Only eight overhead loaders have been identified as being applicable to PSEP-related expenditures – (1) payroll tax; (2) vacation and sick time; (3) benefits (non-balanced only); (4) workers' compensation; (5) public liability / property damage; (6) incentive compensation plan; (7) purchased services and materials; and (8) administrative and general.[630] Each of these loaders is incremental because it represents an overhead cost that will proportionately increase as a result of PSEP work.[631]

This approach to overheads (i.e., only applying truly incremental loaders), is consistent with the approach used by SoCalGas and SDG&E for their recent Commission-authorized AMI projects.[632] SoCalGas and SDG&E have used 2010 costs to develop the estimated overhead

[626] Ex. SCG-26 (Reyes) at 11.
[627] Ex. SCG-10 (Reyes) at 122.
[628] *See* Ex. SCG-10 (Reyes) at 122.
[629] Ex. SCG-26 (Reyes) at 11-12.
[630] Ex. SCG-26 (Reyes) at 12.
[631] Ex. SCG-26 (Reyes) at 12.
[632] Ex. SCG-26 (Reyes) at 12.

rates set forth in Mr. Reyes' direct testimony.[633] However, the utilities intend to use actual overhead rates each year to calculate our actual PSEP-related revenue requirements.[634]

4. Escalation

SoCalGas and SDG&E have also escalated their forecasted PSEP direct costs to approximate expected inflation, as the direct costs are in 2011 dollars. The range of the annual escalation factors used by the utilities is set forth in Table X-2 of Mr. Reyes' direct testimony.[635] The actual annual escalation factors used by the utilities vary from year to year, and are provided in our supporting workpapers.[636]

5. Proposed Case Revenue Requirements

The loaded and escalated costs for SoCalGas and SDG&E's proposed case are set forth in Table X-4 of Mr. Reyes' direct testimony, and the revenue requirements developed from those loaded and escalated costs are set forth in Table X-5 to Mr. Reyes' direct testimony.[637] For convenience, both of these tables are reproduced below.

Loaded and Escalated Costs Summary for Proposed PSEP
(In Millions of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	180.35	393.06	398.46	408.69	251.01	256.66	259.44	213.16	219.19	225.66	2,806
SoCalGas - O&M	6.15	63.90	71.45	74.86	77.27	3.25	4.20	4.47	4.64	4.92	5.21	320
Total SoCalGas	**6.15**	**244.25**	**464.51**	**473.32**	**485.96**	**254.26**	**260.86**	**263.91**	**217.80**	**224.11**	**230.88**	**3,126**
SDG&E - Capital	-	33.29	73.86	75.39	76.98	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**	**34.50**	**74.17**	**81.02**	**77.67**	**132.29**	**135.45**	**139.24**	**21.38**	**8.91**	**9.16**	**715**

633 Ex. SCG-10 (Reyes) at 122.
634 Ex. SCG-10 (Reyes) at 122.
635 *See* Ex. SCG-10 (Reyes) at 123.
636 *See* Ex. SCG-32 (Workpapers) at *WP-X-1-9.*
637 Ex. SCG-10 (Reyes) at 124.

Revenue Requirement Summary for Proposed PSEP
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
SoCalGas	6.37	57.74	100.25	182.30	246.69	233.86	266.22	296.43	325.76	350.35	375.80	396.54	6580.50	9,419
SDG&E	0.92	0.35	5.18	24.53	30.73	44.14	64.42	83.68	116.81	100.31	98.76	96.03	1762.63	2,428

6. Base Case Revenue Requirements

The loaded and escalated costs for SoCalGas and SDG&E's base case are set forth in Table X-7 of Mr. Reyes' direct testimony, and the revenue requirements developed from those loaded and escalated costs are set forth in Table X-8 to Mr. Reyes' direct testimony.[638] For convenience, both of these tables are reproduced below.

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	-	131.22	308.92	324.32	333.59	41.84	41.90	39.69	39.75	41.18	43.01	1,345
SoCalGas - O&M	6.15	56.67	70.92	73.61	75.96	1.98	2.86	3.07	3.17	3.38	3.61	301
Total SoCalGas	**6.15**	**187.89**	**379.84**	**397.92**	**409.55**	**43.82**	**44.76**	**42.76**	**42.92**	**44.56**	**46.62**	**1,647**
SDG&E - Capital	-	30.90	71.11	74.28	76.08	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**	**31.60**	**71.34**	**79.74**	**76.59**	**131.86**	**134.81**	**138.62**	**20.90**	**8.41**	**8.65**	**703**

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	58.68	95.57	150.69	205.43	182.49	181.85	183.46	183.85	184.41	185.18	182.37	2730.90	4,531
Total SDG&E	0.92	0.98	5.27	22.31	28.56	41.91	62.37	82.16	115.83	99.32	97.74	95.21	1749.35	2,402

[638] Ex. SCG-10 (Reyes) at 125.

B. Intervenor Proposals Relating to Revenue Requirements

1. TURN's Proposal for Lower AFUDC Percentages

TURN points out that the SPEC Services' direct cost estimates do not include AFUDC, and, because AFUDC is part of standard utility ratemaking, TURN proposes that "there should be a small upward adjustment of the capital costs contained in any adopted capital costs figures based on Sempra's cost estimates on the order of 2% for small jobs and 5% for larger ones."[639] SoCalGas and SDG&E agree with TURN that AFUDC is a standard part of utility ratemaking, and that PSEP-related capital costs should be adjusted upward to reflect AFUDC. We disagree, however, with TURN's proposed AFUDC percentages.

The AFUDC mechanism is designed to compensate utility investors for the delayed recovery of their investment due to long construction periods.[640] Although SPEC Services did not include AFUDC in any of its estimates, SoCalGas and SDG&E did in fact incorporate AFUDC into our capital cost revenue requirement calculations, as part of depreciation expense over the book life of the assets.[641] SoCalGas and SDG&E used their authorized rates of return (ROR) of 8.68% and 8.40%, respectively, to calculate forecasted AFUDC.[642] Authorized ROR is an appropriate approximation for the historic recorded AFUDC rates for SoCalGas and SDG&E.[643] SoCalGas' and SDG&E's use of ROR for AFUDC in our PSEP proposal is consistent with the methodology used in calculating the capital forecast and associated revenue requirement approved in the past GRCs and recently filed incremental projects such as SoCalGas' and SDG&E's Advanced Metering Infrastructure applications.[644] In addition,

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[639] Ex. TURN-02 (Marcus) at 8.
[640] Ex. SCG-26 (Reyes) at 10.
[641] Ex. SCG-10 (Reyes) at 123.
[642] Ex. SCG-26 (Reyes) at 10.
[643] Ex. SCG-26 (Reyes) at 10.
[644] Ex. SCG-26 (Reyes) at 10.

SoCalGas' and SDG&E's use of authorized ROR for AFUDC approximates actual AFUDC, which is derived in accordance with the formula prescribed in the Code of Federal Regulations.[645]

2. SCGC's Recommendation that Non-Destructive Examination Costs be Entirely Expensed

SCGC agrees that the Commission should adopt SoCalGas and SDG&E's proposal to use NDE techniques instead of pressure testing or replacement to establish the safety of short lengths of pipeline.[646] However, SCGC's witness also makes the following recommendation with respect to the treatment of non-destructive examination (NDE) costs: "Given the small size of these projects with most of the activities being associated with verifying the integrity of the existing pipelines, I recommend that the NDE costs be entirely expensed."[647]

SoCalGas and SDG&E appreciate SCGC's support for our proposal to use NDE techniques to establish the safety of small segments of pipeline. As discussed above, these methods have proven to be a direct, reliable, and cost-effective approach to detecting potential anomalies in short pipeline segments. We part ways, however, over SCGC's recommendation that SoCalGas and SDG&E be required to expense all of the costs of such examinations. SoCalGas and SDG&E should be authorized to expense or capitalize NDE costs in accordance with our existing capitalization policies.[648] These are the same policies that SoCalGas and

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[645] Ex. SCG-26 (Reyes) at 10. *See* 18 C.F.R. Section 201.3.17 (2012). Per the referenced CFR, AFUDC is one of the standard components of construction costs.

[646] Ex. SCGC-01 (Yap) at 14-15. As explained in our direct testimony NDE uses a variety of inspection methods – radiography, ultrasonic inspection, and magnetic particle inspection – to determine if a pipeline is sound. NDE techniques are manual methods that are economical only for shorter lengths of pipeline. *See* Ex. SCG-04 (Schneider) at 54-55.

[647] Ex. SCGC-01 (Yap) at 14-15.

[648] Ex. SCG-26 (Reyes) at 11.

SDG&E have used to present capital and O&M forecasts and associated revenue requirements approved in our past GRCs.[649]

Many costs associated with NDE may in fact be expensed rather than capitalized.[650] But the appropriate treatment of such costs needs to be made on the basis of a rational policy that takes into the account the nature of the expenditure, the length of time that customers will benefit from the expenditure, etc. SoCalGas and SDG&E cannot simply decree that an expenditure that is traditionally capitalized (such as a replacement pipeline segment) can be expensed because we want it to be. Neither the fact that the NDE projects would be "small in size," nor the fact that the activities would be "associated with verifying the integrity of the existing pipelines," changes the fundamental nature of the activities, or justifies a departure from our well-established capitalization policies.

3. TURN's Proposal for No Incentive Compensation Plan Loader

TURN recommends that the Commission reject SoCalGas and SDG&E's proposal to apply an Incentive Compensation Plan (ICP) overhead loader to their PSEP-related O&M and capital costs. According to TURN:

> In general, incentive compensation plans are used by utilities to attract, motivate and retain a high-performing workforce. Incentive compensation plans are often structured to reward management and employees for meeting specific financial goals that contribute to the shareholders' bottom line. While these types of incentive compensation plans may or may not be in the ratepayers' interests in the normal course of business (typically the issue arises in a general rate case proceeding), in the case of the current pipeline safety enhancement plan, TURN believes the ICP loader is clearly not in the ratepayers' best interests.
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> . . .

[649] Ex. SCG-26 (Reyes) at 11. The capitalization policies themselves are Ex. SCG-35.
[650] As explained by Mr. Reyes, "Generally they're expensed but there are certain situations where they can be capitalized as well." Tr. at 1589 (SoCalGas/SDG&E/Reyes).

> In addition, as shown in the accompanying testimony of Mr. Long, some portions of the PSEP cost request are the result of past management mistakes such as failing to adequately document and maintain historic records of pipeline tests and inspections. Under these circumstances, it would be poor public policy to additionally reward Sempra management with this overhead loader for its incentive compensation plan.[651]

SoCalGas and SDG&E agree with TURN that incentive compensation plans are used by utilities to attract, motivate, and retain a high-performing workforce – that is the purpose of ICP at SoCalGas and SDG&E, and it is an important component of our total compensation program. SoCalGas and SDG&E do not, however, agree that providing incentive compensation to employees working on PSEP is somehow "not in the ratepayers' best interests." Particularly with the aggressive schedule of PSEP, it is important to attract and retain well-qualified employees at both utilities, and ICP is an important element of that process.[652] It would not make sense for SoCalGas and SDG&E to offer incentive compensation to their other employees, but not to employees working on pipeline safety. Such a two-tiered compensation structure at the utilities would make it more difficult to hire qualified personnel for PSEP-related positions – a big potential problem given that we need to do a great deal of PSEP-related hiring in the near future in a very competitive hiring environment.[653] Moreover, such a structure would effectively punish existing employees working on safety-related tasks, and provide a strong incentive for well-qualified employees, both new and old, to gravitate to other positions within the utilities that carry the potential for incentive compensation. Pipeline safety needs to be our top priority and it needs to be properly incentivized to attract the high-caliber workforce that is required. PSEP-related positions should not be a disfavored "backwater" at the utilities.

[651] Ex. TURN-02 (Marcus) at 8-9.
[652] Ex. SCG-26 (Reyes) at 13.
[653] As SoCalGas and SDG&E have explained: "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. Ex. SCG-02 (Morrow) at 24.

SoCalGas and SDG&E also strongly disagree with TURN's underlying assumption that "it would be poor public policy to additionally reward Sempra management with this overhead loader" for past "mistakes." As discussed at length above and in our testimony, the SoCalGas and SDG&E PSEP is not an effort to have customers pay for past utility "mistakes." Our pipeline systems already meet or exceed the standards that existed prior to the Commission's new safety requirements. Instead, the PSEP is a direct and necessary response to new Commission directives and policies designed to provide additional pipeline safety.

The Commission has previously authorized utility GRC budget requests that include incentive compensation programs.[654] Consistent with current utility practice and past guidance from the Commission, ICP should be provided to employees at SoCalGas and SDG&E working on pipeline safety. TURN's recommendation to the contrary is not reasonable. The Legislature has decreed that it is the policy of the state that the Commission and each gas corporation place safety of the public and gas corporation employees as the top priority.[655] The Commission has made new pipeline safety standards an imperative. Current and prospective employees should be *encouraged* to focus their energy and talents on pipeline safety, not deliberately financially *discouraged* from doing this honorable and important work.

Finally, if the Commission does not agree with TURN's proposal for no incentive compensation loader for pipeline safety work, TURN recommends that the Commission order SoCalGas and SDG&E to adjust recorded labor and management costs by whatever incentive compensation plan loader percentages are finally adopted in the two utilities' 2012 GRCs.[656] SoCalGas and SDG&E do not take issue with this particular proposal. This is an action that we

[654] *See, e.g.*, D.08-07-046 (SoCalGas and SDG&E 2008 GRC) (note that the "Incentive Compensation" discussion at p. 22 of the original D.08-07-046 was deleted per D.09-06-052, but the approved budgets were not changed); *see also* D.06-05-016, mimeo., at 124 and 128 (SCE 2006 GRC) (citing D.04-07-022).
[655] Public Utilities Code Section 963(b)(3).
[656] Ex. TURN-02 (Marcus) at 9.

would take with or without TURN's recommendation since we propose to use our effective ICP loaders for PSEP-related work.

4. SCIP/Watson Recommendation for a One-Way TIMP Balancing Account

SCIP/Watson proposes that the Commission adopt a one-way balancing account for SoCalGas and SDG&E TIMP costs. According to the summary portion of SCIP/Watson's testimony, "[t]his is necessary in order to ensure that the costs for a particular pipeline safety project are not recovered twice, once through the PSEP and again through the TIMP."[657] In the substantive portion of its testimony, however, SCIP/Watson offers a different rationale for one-way TIMP balancing accounts:

> A one-way balancing account will ensure that, in the event that SoCalGas or SDG&E underspend their TIMP budget (perhaps because their focus is on implementing the PSEP, or if a PSEP project duplicates a TIMP project), the unspent safety-related funds will be returned to ratepayers rather than enhancing shareholder returns. At the same time, this process will require the utilities to adhere to approved budgets.[658]

Neither rationale offers a reasonable basis for the Commission to establish one-way balancing accounts for SoCalGas' and SDG&E's TIMP expenditures.

First, SCIP/Watson's proposal for a one-way TIMP balancing account is not appropriate for this PSEP-related proceeding. The utilities' existing TIMP programs and related regulatory accounting mechanisms are not before the Commission in this TCAP. Instead, consistent with the direction from the Legislature embodied in Public Utilities Code Section 969,[659] SoCalGas and SDG&E have proposed two-way TIMP balancing accounts in their current GRC

[657] Ex. SCIP-01 (Beach) at 3.
[658] Ex. SCIP-01 (Beach) at 15.
[659] This provision requires balancing accounts for TIMP-related expenditures, and provides that: "Nothing in this section is intended to interfere with the commission's discretion to establish a two-way balancing account."

proceedings, and DRA, TURN, and UCAN have proposed one-way TIMP balancing accounts.[660] The Commission should not entertain a TIMP-related balancing account proposal in this proceeding, especially since proposals for TIMP balancing accounts are already being considered by the Commission in another pending proceeding. As Mr. Reyes has explained, "TIMP costs were addressed in SoCalGas' and SDG&E's 2012 GRC applications, and will likely be addressed in future GRC applications. If SCIP/Watson or Mr. Beach wish to make recommendations with respect to TIMP costs in our future GRC proceedings, they are certainly free to do so."[661]

In addition, as explained by Mr. Schneider, TIMP and PSEP are distinct programs that do not overlap each other.[662] As such, there is no need to adopt a new accounting mechanism to prevent overlap between the two programs. Plus, SCIP/Watson offers no support for its contention that a one-way TIMP balancing account would somehow prevent double recovery of pipeline safety expenditures. Any potential risk of double recovery of safety program expenditures is the result of the utilities having more than one safety program. The *type* of balancing account adopted for each program does not affect that risk. Accordingly, SCIP/Watson's argument in the summary portion of its testimony for one-way TIMP balancing accounts, rather than the two-way TIMP balancing accounts proposed by SoCalGas and SDG&E in their pending GRCs, does not make sense.

Finally, SCIP/Watson's assertion that a one-way TIMP balancing account will ensure that "unspent safety-related funds will be returned to ratepayers rather than enhancing shareholder returns" is also lacking in logic. The two-way TIMP balancing accounts proposed by SoCalGas and SDG&E would accomplish the same purpose.

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[660] *See* A.10-12-005/A.10-12-006, April 12, 2012 Opening Brief of SoCalGas and SDG&E at 182-83.
[661] Ex. SCG-26 (Reyes) at 3.
[662] Ex. SCG-18 (Schneider) at 31.

VIII. RATEMAKING TREATMENT FOR RECOVERY OF PHASE 1A COSTS

A. PSEP Cost Recovery Accounts

SoCalGas and SDG&E propose to each establish interest-bearing PSEP Cost Recovery Accounts. These will be two-way balancing accounts that record the difference between the authorized revenue requirements collected by the utilities and the actual O&M and capital-related revenue requirements associated with implementation of the PSEP.[663]

DRA and SCIP/Watson recommend one-way balancing account treatment for PSEP costs, rather than the two-way balancing account treatment proposed by SoCalGas and SDG&E.[664] SoCalGas and SDG&E do not agree. One-way balancing account treatment could potentially impact progress on the plan, and result in SoCalGas and SDG&E shareholders bearing the cost of necessary PSEP safety-related expenditures in excess of an authorized budget/cost cap approved by the Commission. This would not be fair, or consistent with the Commission's safety-related objectives. The latter issue was discussed in the Report of the Independent Review Panel, which found that "one-way balancing accounts create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no less or more than authorized for a given activity."[665] The report also concludes that "it is not clear whether one-way balancing account associated with a federally mandated integrity management program improves the incentive for prudent utility decision-making regarding safety."[666]

There will be no potential harm to customers that would result from adoption of two-way balancing accounts for PSEP-related expenditures. As explained by Mr. Reyes, the utilities are proposing that their two-way balancing accounts have a cap, and that SoCalGas and SDG&E

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[663] Ex. SCG-10 (Reyes) at 127.
[664] Ex. DRA-02 (Phan) at 25; Ex. SCIP-01 (Beach) at 3.
[665] Report of the Independent Review Panel – San Bruno Explosion issued on June 8, 2011, Section 7.2 at page 109.
[666] Report of the Independent Review Panel – San Bruno Explosion issued on June 8, 2011, Section 7.3 at page 110.

will not be able to recover PSEP-related costs in excess of the cap without further Commission authorization.[667] Accordingly, the only real difference between the two-way treatment proposed by the utilities and the one-way approach advocated by DRA and SCIP/Watson is that under our proposed approach we could continue recording expenditures in excess of the cap for potential future recovery after Commission authorization, and under the intervenors' proposal we would be barred from seeking future recovery of expenditures in excess of the cap by the rule against retroactive ratemaking.

SoCalGas and SDG&E should not be put in the position of having to choose between reasonable and necessary pipeline-related expenditures that exceed PSEP budgets and a shareholder penalty for undertaking necessary safety-related improvements. The Legislature has unambiguously determined that "[i]t is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority."[668] Two-way balancing of PSEP costs achieves this objective. One-way balancing of PSEP costs would not.

In addition, SCGC proposes that the Commission require SoCalGas and SDG&E to maintain subaccounts within their PSEP Cost Recovery Accounts to show expense activities separately from the revenue requirements associated with capitalized projects.[669] As explained by Mr. Reyes, however, such subaccounts would serve no purpose. SoCalGas' and SDG&E's financial systems already distinguish between O&M and capital expenditures so that we can properly capture these costs within the accounts, and we maintain records that enable us, and any Commission auditor, to distinguish between these two categories of costs.[670]

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[667] *See* Tr. at 1495-98 (SoCalGas/SDG&E/Reyes).
[668] Public Utilities Code Section 963(b)(3).
[669] Ex. SCGC-01 (Yap) at 30.
[670] *See* Tr. at 1514-15 (SoCalGas/SDG&E/Reyes).

B. Rate Recovery of Authorized Phase 1A Costs

As noted above, SoCalGas and SDG&E have requested authorization to recover in customer rates proposed Phase 1A revenue requirements are $593 million for SoCalGas and $62 million for SDG&E for the years 2011 through 2015. Because PSEP-related rates were not in place in 2011 and 2012, however, any PSEP-related rate recovery as a result of a Phase 1 decision will begin in 2013 at the earliest.[671] Upon approval of the PSEP, SoCalGas and SDG&E each propose to file an advice letter to implement the Commission's decision. These advice letters will include updated revenue requirements to reflect any decision-ordered changes to the PSEP, and to adjust the revenue requirements to take into account the timing of the approval (i.e., that the approval is taking place in 2013 rather than in 2011 or 2012).[672] PSEP-related costs incurred by SoCalGas and SDG&E prior to a Phase 1 decision in this proceeding are being recorded in the utilities' PSEP memorandum accounts. As discussed below, SoCalGas and SDG&E are seeking to incorporate those costs in our post-decision revenue requirements.

SoCalGas and SDG&E propose to incorporate updated PSEP revenue requirements into rates on January 1 each year until PSEP investments are fully recovered.[673] Specifically, SoCalGas and SDG&E would include in their annual regulatory account balance update filings, (1) the revenue requirement associated with the current-year forecasted year-end balance in their PSEP Cost Recovery Accounts, combined with (2) the PSEP-related revenue requirement for the coming year.[674] Any residual balance in the PSEP Cost Recovery Accounts would be amortized in rates at the completion of the PSEP.[675]

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[671] SoCalGas and SDG&E have submitted a motion for interim rate recovery of costs recorded in the PSEP memorandum account. If the Commission grants this motion, such interim recovery could begin earlier than 2013.
[672] Ex. SCG-10 (Reyes) at 126.
[673] Ex. SCG-10 (Reyes) at 126.
[674] Ex. SCG-10 (Reyes) at 126.
[675] Ex. SCG-10 (Reyes) at 126.

SCGC argues that the Commission should not allow recovery of replacement project revenue requirements until the project is "used and useful."[676] SoCalGas and SDG&E disagree. The Commission regularly authorizes utilities to recover revenues associated with capital projects on a forecast basis, before the projects are considered "used and useful."[677] In fact, our proposed collection of forecasted PSEP capital revenue requirements is similar to the way various other incremental projects have been funded, for example, SoCalGas' Advanced Meter Infrastructure (AMI) and SDG&E's AMI projects, SDG&E's Cuyamaca Peak Energy Plant, and SDG&E's Solar Energy Project.[678] Funding for PSEP costs prior to the time that PSEP assets are considered "used and useful" is also consistent with the Commission's direction that SoCalGas and SDG&E, to the extent possible, not create large PSEP-related undercollections that could have a significant rate impact to customers.[679]

C. Rate Recovery of Costs Recorded in PSEP Memorandum Accounts

As noted above, upon approval of the PSEP, SoCalGas and SDG&E propose to file an implementation advice filing that will incorporate any Commission-ordered changes to the PSEP and include updated revenue requirements. SoCalGas and SDG&E propose that the Commission authorize the utilities to recover in rates costs previously recorded in the utilities' PSEP Memorandum Accounts, and to include such costs in the utilities' updated revenue requirements.[680] This could be accomplished by the utilities transferring costs recorded in their PSEP Memorandum Accounts to the new PSEP Cost Recovery Accounts and then closing the PSEP Memorandum Accounts.

[676] Ex. SCGC-01 (Yap) at 28-29.
[677] Ex. SCG-26 (Reyes) at 4.
[678] Ex. SCG-26 (Reyes) at 4.
[679] Ex. SCG-26 (Reyes) at 4.
[680] Ex. SCG-10 (Reyes) at 127.

In D.12-04-021, the Commission authorized SoCalGas and SDG&E to establish these Memorandum Accounts and to record certain PSEP-related costs in the accounts for potential future recovery in rates.[681] Costs eligible for potential recovery include testing/replacement work ("Attachment A" costs), and costs related to records review and interim safety measures ("Attachment B" costs).[682] In D.12-04-021, the Commission explained that the recoverability of costs recorded in the utilities' PSEP Memorandum Accounts will be considered in this current TCAP: "[t]he Commission will consider whether such properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement at a later time in the Triennial Cost Allocation Proceeding."[683]

The PSEP-related costs recorded in the utilities' PSEP Memorandum Accounts are simply Phase 1A costs that the utilities needed to incur prior to a Phase 1 decision in this proceeding. They should be authorized for recovery in this proceeding along with all of our proposed Phase 1A costs. In fact, the rationale for recovery of these particular costs is particularly strong because the particular projects and related costs were spelled out in detail in the utilities' January 13, 2012 comments, and SoCalGas and SDG&E have only been doing the limited work deemed necessary to keep their PSEP reasonably on track while our PSEP is evaluated by the Commission. Moreover, as explained in the utilities' comments, the Phase 1A

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[681] *See* D.12-04-021, mimeo., at 7-9.

[682] D.12-04-021, mimeo., at 7 and 8. Note that the referenced attachments are attachments to comments submitted by SoCalGas and SDG&E on January 13, 2012, in R. 11-02-019, supporting the transfer of the PSEP to this TCAP and providing further detail on the utilities' proposed memorandum accounts.

[683] D.12-04-021, mimeo., at 7. Note that this particular statement is in the paragraph of D.12-04-021 referencing Attachment A costs. However, SoCalGas and SDG&E believe that it is a reasonable inference that the statement also applies (or at least should apply) to the Attachment B costs discussed in the following paragraph on page 8 of D.12-04-021.

work that we have been doing during this interim period is confined to base case work, and does not include any work from our proposed case that would not also be part of our base case.[684]

D. Expedited Advice Letter for Proposed Adjustments to PSEP Funding

As discussed above, even if SoCalGas and SDG&E receive two-way balancing account treatment for PSEP costs, the utilities propose that they not be able to recover any costs above authorized until the Commission has approved the proposed increase. SoCalGas and SDG&E would file expedited advice letters seeking Commission authorization of changes, either up or down, to the overall level of PSEP funding previously authorized by the Commission.[685] These advice letters will include an explanation of the proposed changes, have a protest deadline of 10 days, and request Commission approval within 21 days.[686] Under our proposal, this expedited advice letter process would apply to all aspects of the utilities' PSEP, including any elements adopted by the Commission after an initial Phase 1 decision in this proceeding.[687]

SoCalGas and SDG&E believe this proposed expedited advice letter process represents a reasonable compromise between the desire of intervenors and the Commission for information and the desire of the utilities to pursue PSEP-related work in a timely manner. The Commission has utilized an expedited advice letter approval process in the past,[688] and SoCalGas and SDG&E believe this is another instance where such a process can work.

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[684] *See* January 13, 2012 Comments of SoCalGas and SDG&E in Response to Assigned Commissioner's Rulings and Supplement to Request to Memorandum Account in R.11-02-019, at 7 (fn. No. 15).
[685] Ex. SCG-10 (Reyes) at 127.
[686] Ex. SCG-10 (Reyes) at 127; Tr. at 1554 (SoCalGas/SDG&E/Reyes).
[687] Ex. SCG-10 (Reyes) at 127.
[688] *See,* D.04-09-022, mimeo., at 26 and 84 (preapproval of certain PG&E, SoCalGas, and SDG&E interstate pipeline capacity commitments via a 21-day expedited capacity advice letter process that includes 10 days for parties to file protests).

E. Annual PSEP Update Report

SoCalGas and SDG&E propose that they provide the Commission and interested parties with an annual PSEP status report on or before March 31 each year.[689] This report would provide at least the following information:

- Work completed during the previous year (scope and cost);
- Work planned for the upcoming year (scope and cost);
- A discussion of progress made to date; and
- Confirmation of our Commission-approved annual PSEP budget.[690]

The annual hazardous substance mechanism reports submitted by the state's utilities natural gas and electric utilities to the Commission pursuant to D.94-05-020 can serve as a starting point for this new annual PSEP report.[691] However, SoCalGas and SDG&E propose that their annual PSEP reports include substantial additional detail not found in the annual hazwaste reports.[692]

SoCalGas and SDG&E believe that these annual reports will provide transparency regarding our ongoing PSEP work, and help keep the Commission and interested parties informed of our progress until our next PSEP-related application or other PSEP-related filing (*e.g.*, our next GRC application). No party appears to have expressed any opposition to this particular proposal.

IX. ADDITIONAL INTERVENOR PROPOSALS

A. Proposed Notice Requirement

SCIP/Watson proposes that SoCalGas and SDG&E be required to provide "customers operating critical energy infrastructure" with at least 6 months' notice of a PSEP-related curtailment in order "to allow the safe wind down of operations."[693] SCIP/Watson does not

[689] Ex. SCG-10 (Reyes) at 127.
[690] Ex. SCG-10 (Reyes) at 127.
[691] Tr. at 1504 (SoCalGas/SDG&E/Reyes). *See also* D.94-05-020, mimeo., at p. 14 of Attachment A.
[692] Tr. at 1505 (SoCalGas/SDG&E/Reyes).
[693] Ex. SCIP-01 (Beach) at 4.

provide a proposed definition of who would qualify as a "customer operating critical energy infrastructure," but apparently this proposal would at least apply to refineries and large electric generators.[694]

SoCalGas and SDG&E are committed to giving our customers as much notice as reasonably possible regarding upcoming PSEP-related service interruptions, but we respectfully disagree with this particular recommendation from SCIP/Watson. As discussed above, the minimization of customer impacts is one of the foundational elements of our proposed PSEP, and one of the primary factors in our test/replace decision tree. Moreover, the utilities have committed to work with our customers on the scheduling of PSEP work, and to do all that is reasonable to provide uninterrupted service.[695] Customer account managers will work with customers as projects are planned, and we will plan our PSEP activities around customer schedules whenever possible.[696] Additionally, we will consult with the California Independent System Operator (CAISO) in advance of planned outages that could affect electric generator availability, and make every attempt to schedule the outages during lower demand shoulder months.[697]

SoCalGas and SDG&E agree that it would be ideal to give customers operating critical energy infrastructure the six months' notice that SCIP/Watson has proposed. However, the ambitious schedule proposed for the PSEP may not always allow for such extensive notification. With the amount of projects that need to be executed in Phase 1A, after allowing for detailed engineering, design, and execution planning, there may not be sufficient time to afford six-month

[694] *See* Ex. SCIP-01 (Beach) at 22.
[695] Ex. SCG-02 (Morrow) at 15.
[696] Ex. SCG-02 (Morrow) at 16.
[697] Ex. SCG-02 (Morrow) at 16.

notice before field work and any ensuing customer outages need to commence.[698] Plus, given that generators are used to dealing with substantial day-to-day and even hour-by-hour fluctuations in the need for electricity and ancillary services, SoCalGas and SDG&E do not believe that of our electric generation customers would actually need 6 months' notice in order to "to allow the safe wind down of operations."[699]

Given all of these circumstances, and given the fact that SoCalGas and SDG&E will be in close contact with CAISO regarding any impending PSEP-related work that could impact the electric grid, the SCIP/Watson proposal for six months' mandatory notice of a PSEP-related curtailment to "customers operating critical energy infrastructure" is not reasonable and not necessary. That said, SoCalGas and SDG&E recognize the importance of providing reliable service to our customers, and we will work to provide as much notice as feasible to impacted noncore customers should an interruption be necessary.[700]

B. Local Transmission Interruption Credit Proposal

SCIP/Watson proposes a local transmission interruption credit (LTIC) of $2.50/dth funded 100% by shareholders (annual combined SoCalGas and SDG&E shareholder exposure capped at $25 million/year) in the event that noncore customer service is interrupted due to pipeline integrity work (either PSEP or TIMP) for which the customer has not received at least 30 days notice.[701] This LTIC would also apply to complete curtailments of service to large noncore customers "operating critical energy infrastructure" when the utility has not provided at

[698] Ex. SCG-20 (Phillips) at 16-17.
[699] SoCalGas and SDG&E also believe that that it may also be problematical, though not impossible, to determine which of our customers "operate critical energy infrastructure." For example, do all of our electric generation customers fall within this definition, or just generators above a certain size, or just generators who have been designated by CAISO as necessary for grid stability?
[700] Ex. SCG-20 (Phillips) at 17.
[701] Ex. SCIP-01 (Beach) at 26.

least six months' notice of the complete curtailment.[702] According to SCIP/Watson, the amount of this credit was chosen: "to provide SoCalGas and SDG&E with a consequential incentive and to recognize that unexpected reductions in natural gas service can result in significant additional costs to a noncore customer's operations."[703]

SoCalGas and SDG&E strongly oppose this proposal, on the grounds that it would be unfair and potentially counterproductive to the safety-related objectives of the utilities, the Commission, and the state.[704] SDG&E and SoCalGas will endeavor to give affected customers at least 30 days notice of upcoming pipeline-related work that will affect their service, but we should not be financially penalized if we are unable to provide this much notice. If a pipeline-related safety issue arises that needs to be dealt with more quickly than 30 days hence, SoCalGas and SDG&E should be permitted to do the work without financial penalty, and we should not be put in the position of having to decide whether to put off safety-related work to avoid a financial penalty.[705] Likewise, the Commission should not establish a policy for SoCalGas, SDG&E, or any other utility that gives the utility a strong financial incentive to put off necessary safety-related work.[706]

The utilities understand that, all other things being equal, more notice of an impending curtailment would generally be appreciated by our customers. But that has always been the case, and SoCalGas and SDG&E already have Commission-authorized tariff provisions that clearly and unequivocally establish the relationship between the utilities and their noncore customers with respect to repairs and maintenance work. These tariffs (Rule 30 – Transportation of

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702 Ex. SCIP-01 (Beach) at 26.
703 Ex. SCIP-01 (Beach) at 26.
704 As the Legislature recently explained in Public Utilities Code Section 963(b)(3), "It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority."
705 Ex. SCG-25 (Watson) at 4.
706 Ex. SCG-25 (Watson) at 4.

Customer-Owned Gas) provide that the utilities have the right, *without liability*, “to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation.”[707] These long-established tariff provisions also provide to that “[w]hen doing so, the Utility will try to cause a minimum of inconvenience to the customer. Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity.”[708] Given these existing tariff provisions allowing the utilities to interrupt service without liability for operational and maintenance reasons, SoCalGas and SDG&E noncore customers cannot reasonably assert that they had an expectation of uninterrupted service under all circumstances.

SDG&E does have a Service Interruption Credit (SIC) provision which provides that SDG&E may be required to provide a credit of $0.25/therm if SDG&E interrupts service to conduct non-emergency scheduled maintenance without providing at least 30 days prior written notice of the scheduled interruption.[709] But this existing provision allows for one service interruption of up to 72 hours per customer every 10 years without SIC liability, it does not apply to curtailments resulting from unforeseen events or conditions outside of SDG&E’s control, and SDG&E’s maximum potential SIC obligation in any calendar year is $5 million.[710] The fact that SCIP/Watson is proposing a potential annual LTIC shareholder penalty that is 500% greater than SDG&E’s existing potential SIC obligation, and the fact that the LTIC would have none of the more nuanced and balanced provisions contained in SDG&E’s existing SIC, demonstrates that

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[707] SoCalGas Rule 30(E)(2); SDG&E Rule 30(E)(2).

[708] SoCalGas Rule 30(E)(2); SDG&E Rule 30(E)(2). Note that SDG&E’s Rule 30 tariff refers to the “Utility System Operator” rather than the “Utility” in this particular sentence, but otherwise the wording is identical.

[709] *See* SDG&E Rule 14(O)(2). SoCalGas used to have a similar SIC provision, but that provision ended in 2003. *See* SoCalGas Rule 23(K) (the provision only applied during the “ten-year period beginning on the implementation date of the CPUC's Capacity Brokering Rules.”).

[710] SDG&E Rule 14(O).

the SCIP/Watson proposal is unreasonable, and designed to potentially financially punish SoCalGas and SDG&E for doing pipeline safety work mandated by the Commission.

Additionally, since hydrotesting a pipeline would take the line out of service for a much longer time than replacing it, the SCIP/Watson LTIC proposal could provide SoCalGas and SDG&E with a perverse incentive to replace pipe in order to minimize the length of time the line is out of service.[711] The test-versus-replace decisions of SoCalGas and SDG&E should be made in accordance with the criteria and consultation process proposed by SoCalGas and SDG&E. These decisions should not be influenced by the existence of a crediting mechanism that would give SoCalGas and SDG&E an artificial incentive to replace lines rather than pressure test.

C. BTS Reservation Charge Credit Proposal

SCIP/Watson also proposes that SoCalGas and SDG&E provide reservation charge credits to firm Schedule G-BTS backbone transportation customers when their backbone transmission service is disrupted by pipeline safety work.[712] According to SCIP/Watson, "Consistent with PG&E's circumstances to date, such BTS reservation credits should be funded 50% by Sempra shareholders. Otherwise, the utilities will have no financial incentive to minimize such unscheduled disruptions in service, and the burden of funding such credits would fall entirely on other ratepayers."[713] SCIP/Watson goes on to explain that PG&E has been providing firm backbone transportation customers with similar credits since June of 2011, and under the Gas Accord V revenue-sharing structure, such credits are funded 50% by PG&E shareholders.[714]

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[711] Ex. SCG-25 (Watson) at 5. *See also* Tr. at 827 (SoCalGas/SDG&E/Watson) ("Mr. Beach's proposal gives us a perverse shareholder incentive to just replace the line so that customers are not interrupted rather than risk violating some notice period requirement.").
[712] Ex. SCIP-01 (Beach) at 4-5 and 23.
[713] Ex. SCIP-01 (Beach) at 23.
[714] Ex. SCIP-01 (Beach) at 23.

SoCalGas and SDG&E also strongly disagree with this second crediting proposal from SCIP/Watson. This proposal would undermine the basic premise of the firm access rights (FAR) decisions that Sempra shareholders would not be at-risk for the provision of backbone transmission services.[715] Applying the 50/50 sharing mechanism of the negotiated PG&E Gas Accord to SoCalGas and SDG&E for any element of backbone transmission costs, including disruptions caused by maintenance for pipeline safety enhancement, is not reasonable or fair. As SCE accurately explains in its rebuttal testimony opposing the SCIP/Watson crediting proposal:

> PG&E's situation is very different from SoCalGas'. Specifically, I would note that for historical reasons, PG&E is at risk for backbone transportation service whereas SoCalGas is not. Therefore, PG&E can make a profit or a loss on the sales of backbone service. However, SoCalGas has always been revenue neutral with respect to BTS (previously FAR) service. Mr. Beach's proposal would eliminate SoCalGas' revenue neutrality and change the fundamental character of the BTS accounting.[716]

In D.09-11-006 (SoCalGas and SDG&E Phase 2 BCAP decision), the Commission adopted a settlement between SoCalGas, SDG&E, and almost all of the interested parties in that proceeding (including Watson and the Indicated Producers).[717] The settlement provides that SoCalGas and SDG&E shall not be at risk for throughput during the term of the settlement.[718] In adopting this particular portion of the Phase 2 settlement, the Commission specifically determined that it would be reasonable and in the public interest to not place SoCalGas and SDG&E at risk for throughput:

> Section II.B.3.A. of the Settlement Agreement provides that SDG&E and SoCalGas shall not be at risk for throughput during the term of the Settlement Agreement. The agreement not to place SDG&E and SoCalGas at risk for any variation between the forecasted and actual throughput during the settlement

[715] Ex. SCG-25 (Watson) at 2 (citing D.06-12-031, mimeo., at 139 and 142 (Conclusion of Law No. 9 and Ordering Paragraph No. 6); D.11-04-032, mimeo., at 81 and 84 (Ordering Paragraph Nos. 2 and 14)).
[716] SCE-02 (Alexander) at 12.
[717] Mr. Beach signed the settlement on behalf of Watson and the California Cogeneration Council. D.09-11-006, mimeo., at p. 18 of Appendix A (settlement). The Indicated Producers are also a signatory to the settlement.
[718] The term of this Phase 2 settlement runs through the effective date that rates are established in this current TCAP proceeding. See D.09-11-006, mimeo., at p. 2 of Appendix A (settlement).

> term represents a recognition that the balancing account protection is important to foster the Commission's energy efficiency goals of reducing gas usage while providing an incentive for the utilities to promote energy conservation. Accordingly, the agreement not to place SDG&E and SoCalGas at risk for gas throughput is reasonable and in the public interest, and should be adopted.[719]

SCIP/Watson's BTS credit proposal would place SoCalGas and SDG&E at risk for noncore throughput, and upset the balance created by the Commission in D.09-11-006. The Commission should not change its existing policy with respect to throughput responsibility on the SoCalGas and SDG&E systems without careful examination of all of the potential consequences. The record in Phase 1 is clearly not adequate to make such an important sea change in regulatory policy.

SoCalGas and SDG&E could provide backbone reservation charge credits under the current 100% balancing regime, but such credits would simply have to be recovered as backbone cost increases in future periods from all firm backbone transmission rights holders – potentially including those who originally received the "credits."[720] Put another way, if a firm BTS customer has their service disrupted by pipeline safety work and chooses not to use firm alternate rights, then the revenue loss is simply charged to other backbone users.[721] Such an approach would be counterproductive and administratively cumbersome. Credits are not currently provided to backbone rights holders when other maintenance events occur, including pipeline integrity work.[722] SoCalGas and SDG&E should not be required to provide BTS credits for the first time for maintenance events specifically related to new Commission-mandated pipeline safety requirements.

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[719] D.09-11-006, mimeo., at 43.
[720] Ex. SCG-25 (Watson) at 2-3.
[721] Tr. at 840 (SoCalGas/SDG&E/Watson).
[722] Ex. SCG-25 (Watson) at 3.

A minority of noncore customers currently holds long-term backbone capacity that could be negatively affected by SoCalGas' and SDG&E's planned pipeline work.[723] Moreover, customers could easily avoid paying for firm backbone capacity that could be interrupted by PSEP work by simply not purchasing capacity at any receipt point that would be affected.[724] In addition, SoCalGas provides its firm backbone shippers with substantial flexibility that should further limit any potential negative consequences to firm transmission rights holders from PSEP-related work. If maintenance affects a particular receipt point, firm rights holders have the ability to move their firm capacity to different receipt point that is not affected, to the extent capacity is available at the requested receipt point.[725] Given that SoCalGas currently has a limited number of firm capacity holders at any of its receipt points, this would be a reasonable option for firm rights holders temporarily affected by PSEP work.

As with its LTIC proposal, the SCIP/Watson BTS reservation charge credit proposal would provide SoCalGas and SDG&E with an incentive to replace pipe rather than pressure test: "Mr. Beach's proposal gives us a perverse shareholder incentive to just replace the line so that customers are not interrupted rather than risk violating some notice period requirement."[726] Our test-versus-replace decisions should not be subject to the influence of a crediting mechanism that would give SoCalGas and SDG&E an artificial incentive to replace lines rather than pressure test.

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[723] Ex. SCG-25 (Watson) at 3.
[724] Ex. SCG-25 (Watson) at 3.
[725] Ex. SCG-25 (Watson) at 3.
[726] Tr. at 827 (SoCalGas/SDG&E/Watson). *See also* SCGC's rebuttal testimony ("Requiring the shareholders to bear 50 percent of the cost of the [BTS reservation charge] credits would however provide an incentive for the Applicants to avoid pressure testing and to pursue much more costly replacements.") (Ex. SCGC-02 (Yap) at 3); SCE's rebuttal testimony ("requiring SoCalGas and SDG&E shareholders to pay 50% of the credit could be interpreted as a signal from the Commission that minimizing customer outages is more important than minimizing customer costs since outages will normally be shorter when pipelines are replaced than when they are hydrotested.") (SCE-02 (Alexander) at 12-13.).

Additionally, in the recent Firm Access Rights (FAR) update proceeding (A.10-03-028), the Commission rejected the concept of FAR credits.[727] Parties to that proceeding (including Watson) presented a joint recommendation proposing that: "No reservation charge credits will be issued." The Commission adopted this particular aspect of the joint recommendation, explaining that there are good reasons for not providing credits:

> We reject the proposal to establish reservation charge credits because such credits may encourage shippers to purchase excess incremental short-term FARs in order to enlarge their share of windowed FARs. The availability of reservation charge credits could encourage shippers to purchase excess incremental short-term FARs to increase their share of any windowed FARs, thereby exacerbating capacity constraints and increasing scheduling uncertainty.
>
> . . . Rejecting the reservation charge credit proposal resolves concerns that shippers might modify their nominating practices in order to receive credits, and concerns that shippers who do not receive such credits will unfairly subsidize shippers that do.[728]

These same concerns potentially apply to PSEP-related testing and replacement work. For each of the reasons discussed above, the Commission should decline to adopt the SCIP/Watson BTS crediting proposal.

D. UWUA O&M Proposals

1. UWUA's O&M Proposals Should Not be Considered in this Proceeding

The subject of Phase 1 of this TCAP is SoCalGas and SDG&E's proposed PSEP. UWUA, however, has proposed permanent changes to the O&M practices of SoCalGas.[729] Although SoCalGas and SDG&E's PSEP does include increased O&M activities as interim safety measures, UWUA's proposal to have the Commission implement new, permanent

[727] FARs and BTS rights are the same thing; the name was changed as the concept evolved.
[728] D.11-04-032, mimeo., at 48-49.
[729] Ex. UWUA-02 (Downs) at 3.

increased levels of O&M activities should not be considered in this TCAP, but rather addressed on a statewide basis as it deals with issues of statewide concern.

UWUA's proposed implementation of changes to SoCalGas' O&M requirements would necessitate changes to GO 112 and create different requirements and regulations for California's pipeline operators. The Commission, however, has stated its intent to review and implement statewide modifications to the O&M requirements in R.11-02-019, and this is the appropriate venue for UWUA to raise its proposed O&M changes.[730] In a comparable proceeding, Rulemaking 08-11-005, the Commission considered and adopted regulations to reduce the fire hazards associated with overhead power-line facilities and aerial communication facilities in close proximity to power lines. Therein, the Commission noted that statewide application of rules and regulations was preferable to enhance safety and ensure consistency.[731] A similar rationale should guide the Commission here and require UWUA's proposed permanent changes to be reviewed at a statewide level and adopted or rejected after input by all interested parties.

As such, in order to maintain consistency, UWUA's proposed changes to O&M requirements should be addressed on a statewide basis and, if appropriate, adopted statewide to conform to the Commission's stated objective of consolidating the adoption of new safety regulations for all natural gas transmission and distribution systems in California.[732] To adopt UWUA's proposed changes, and implement new O&M requirement only for SoCalGas, would require the Commission to impose and enforce one set of regulations for SoCalGas and a

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[730] R.11-02-019, mimeo., at 4.

[731] D.09-08-029, mimeo., at 48 (Finding of Fact 22) ("Statewide application of these revisions is preferable to limiting the application to 'Extreme and Very High Fire Threat Zones' in Southern California to ensure consistency and due to the public safety hazards associated with pole overloading.")

[732] *Scoping Memo and Ruling of the Assigned Commissioner*, mimeo., at 4, filed June 16, 2011 in Rulemaking 11-02-019, entered into the record of Application 11-11-002 by April 17, 2012 *Administrative Law Judge's Ruling Admitting Specific Documents into the Record* ("The primary objectives of this proceeding are to consolidate and coordinate efforts to adopt new safety and reliability regulations for natural gas transmission and distribution systems in California, obtain public input, and propose rule and policy changes as necessary.")

different set of regulations for other utilities. The resultant investigative and enforcement requirements would necessitate inconsistent application of rules and regulations; in stark contrast to previous Commission policy and current efforts to consolidate and coordinate pipeline safety rules and regulations.

2. UWUA's O&M Proposals Would Not Cost Effectively Enhance Pipeline Safety

a. Locate and Mark

UWUA proposes requiring SoCalGas to mark transmission pipe with line-of-sight visible markers and initiate bi-weekly marker checks.[733] UWUA's proposal, however, is unnecessary as SoCalGas has in place comprehensive locate and mark efforts that meet or exceed all applicable locate and mark laws and regulations.[734]

SoCalGas currently requires line of sight markers,[735] and engages in bi-monthly patrols and frequent work in the right of way where employees are instructed to engage in marker inspections, replacements, and repairs.[736] In addition, SoCalGas has proposed in this proceeding the installation of fiber optic right-of-way monitors which would provide continuous monitoring where installed and instantaneously identify intrusions into the pipeline right-of-way.[737]

As such, UWUA proposals are unnecessary and fail to cost effectively enhance pipeline safety. First, UWUA's proposal regarding line of sight markers is unnecessary, as SoCalGas already requires line of sight markers.[738] Next, the benefits from increasing required marker checks to twenty-four times is insignificant and not cost effective as SoCalGas already engages in six patrols per year, has implemented policy to require employees to inspect, replace, and

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[733] Ex. UWUA-02 (Downs) at 4.
[734] Ex. SCG-24 (Dagg) at 3.
[735] Tr. at 777 (SoCalGas/SDG&E/Dagg).
[736] Ex. SCG-24 (Dagg) at 3-4; Ex. SCG-04 (Schneider) at 64.
[737] See Section IV; Ex. SCG-04 (Rivera) at 85.
[738] Tr. at 777 (SoCalGas/SDG&E/Dagg).

repair markers during any work in the right of way, and there is no indication that these efforts are insufficient.

b. Inspections and Patrols

UWUA proposes bi-weekly, by foot or vehicle, patrols of each pipeline segment and facility, without the use of aerial patrols.[739] UWUA's proposal, however, is costly, unnecessary, and would eliminate proven inspection and patrol tools.

SoCalGas currently engages in bi-monthly patrols on pipelines subject to its PSEP.[740] In addition, SoCalGas employees are trained to conduct informal observation of pipeline conditions during normal pipeline operation and maintenance activities.[741] Consistent with the code of federal regulations,[742] SoCalGas does utilize a helicopter to patrol one line which is difficult to access by foot or vehicle,[743] and a fixed wing aircraft to *supplement* ground patrols.[744] Finally, SoCalGas has proposed in this proceeding the installation of methane detection monitors which would provide real-time pipeline right-of-way gas detection near facilities that are high-occupancy and pose evacuation challenges.[745]

SoCalGas' current inspection and patrol policy meets or exceeds all applicable regulations and has proven effective. SoCalGas has implemented successful ground patrol policy and supplemented these efforts by leveraging the benefits of aerial patrol. The effectiveness of SoCalGas' current efforts was acknowledged by CPSD who even opined: "it appears to CPSD that patrols could be performed on a semi-annual frequency, unless the

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[739] Ex. UWUA-02 (Downs) at 6.
[740] Ex. SCG-04 (Schneider) at 64.
[741] Ex. SCG-24 (Dagg) at 5.
[742] 49 CFR 192.705.
[743] Ex. SCG-24 (Dagg) at 6-7.
[744] Ex. SCG-24 (Dagg) at 7.
[745] *See* Section IV.D.2.B; Ex. SCG-06 (Rivera) at 86-87.

transmission line is located where quarterly patrols are required by code."[746] As such, there is no basis for the Commission to adopt UWUA's proposal to increase ground patrols and eliminate aerial patrols.

c. Leak Surveys and Repairs

UWUA proposes that at least once a year the entire system should be walked by employees with an instrument or gas sensing device to identify specific leak locations.[747] When a leak is discovered, UWUA states that it should be repaired as soon as possible.[748] UWUA's proposal, however, would not cost effectively enhance safety and is unnecessary as SoCalGas has in place leak survey and repair policy which already meets or exceeds applicable regulations.

SoCalGas currently engages in bi-monthly leak surveys on pipelines subject to its PSEP,[749] requires annual leak surveys on all other transmission lines,[750] utilizes leak detection equipment for many section of pipe,[751] uses truck mounted leak detection equipment,[752] is currently in the testing stages of employing aerial leak sensor technology to supplement leak surveys,[753] and, as discussed above, has proposed the installation of methane detection monitors to provide real-time pipeline right-of-way gas detection.[754]

SoCalGas agrees, however, that leaks need to be repaired quickly, and has endeavored to address all leaks quickly and effectively. Evidencing the effectiveness of these repair efforts, UWUA has provided no evidence to challenge the effectiveness of SoCalGas' current procedures

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[746] *Technical Report of the Consumer Protection and Safety Division Regarding Southern California Gas Company and San Diego Gas and Electric Company Pipeline Safety Enhancement Plan*, mimeo., at 23, filed in Rulemaking 11-02-019, entered into the record of Application 11-11-002 by April 17, 2012 *Administrative Law Judge's Ruling Admitting Specific Documents into the Record*.
[747] Ex. UWUA-02 (Downs) at 7.
[748] Ex. UWUA-02 (Downs) at 7.
[749] Ex. SCG-04 (Schneider) at 64.
[750] Ex. SCG-24 (Dagg) at 8.
[751] Ex. SCG-24 (Dagg) at 8.
[752] Ex. SCG-24 (Dagg) at 8.
[753] Ex. SCG-24 (Dagg) at 8.
[754] *See* Section IV.

other than unsubstantiated allegations that leaks may go "unrepaired for months."[755] When asked for instances of leaks going unrepaired for months UWUA, however, was unable to provide any examples.[756]

UWUA's proposal should be rejected as inferior to SoCalGas current safety measures. First, UWUA's proposed leak survey schedule is less aggressive than SoCalGas' safety measures on pipelines subject to its PSEP (where SoCalGas proposes the implementation of six annual surveys)[757] and the same as SoCalGas' safety measures on other pipelines.[758] In addition, SoCalGas does utilize truck mounted and handheld leak detection technology to supplement leak survey efforts when possible.[759] Finally, SoCalGas' repair policy requires "When a hazardous leak is found on a transmission line, SoCalGas initiates immediate and continuous action until the situation is made safe and the immediate threat is eliminated."[760] As such, SoCalGas has in place effective leak survey and repair policy and efforts.

d. Cathodic Protection

UWUA proposes that cathodic protection on all transmission lines should be checked and corrected at least eight times per year.[761] UWUA's proposal, however, is unnecessary and would not cost effectively enhance safety.

SoCalGas currently inspects its cathodic protection rectifiers at least six times each calendar year in accordance with federal regulations[762] and is nearing completion of a project to install cellular communication devices on all Transmission Department rectifiers to allow employees to check rectifier status online and create a notification system to inform SoCalGas

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[755] Ex. UWUA-02 (Downs) at 8.
[756] Ex. SCG-24 (Dagg) at 9, fn 2.
[757] Ex. SCG-04 (Schneider) at 65.
[758] Ex. SCG-24 (Dagg) at 8-9.
[759] Ex. SCG-24 (Dagg) at 8-9.
[760] Ex. SCG-24 (Dagg) at 8-9.
[761] Ex. UWUA-02 (Downs) at 8.
[762] Ex. SCG-24 (Dagg) at 9.

should an issue be detected with rectifier operation.[763] While the 6 in-person rectifier checks will still be carried out, this system will allow SoCalGas to provide continuous monitoring of rectifier operation and collect and analyze rectifier data outputs; allowing for enhanced monitoring of cathodic protection effectiveness.[764]

SoCalGas' current six in-person rectifier checks have proven effective. SoCalGas has found its current policy effective and UWUA has offered no evidence to support how an increase from six to eight times per year would incrementally enhance safety, while it is readily apparent that the proposal would increase costs.

e. Valve Maintenance

UWUA proposes that all valves should be inspected and maintained at least quarterly and suggests that if, during scheduled maintenance, a valve is found in need of additional repair, the maintenance work order should remain open until all issues are resolved.[765] UWUA's proposal, however, is unnecessary and would not cost effectively enhance safety.

Currently, SoCalGas inspects its valves annually in accordance with the requirements of the federal regulations[766] and, additionally, views all pipeline activities as an opportunity to engage in valve monitoring, inspection, and maintenance.[767] SoCalGas policy requires that when a valve is found inoperable SoCalGas must take prompt remedial action to correct the valve or designate an alternative valve.[768] SoCalGas has found this maintenance and repair policy to be appropriate and effective in maintaining valve function and promoting system safety.[769]

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[763] Ex. SCG-24 (Dagg) at 10.
[764] Ex. SCG-24 (Dagg) at 10.
[765] Ex. UWUA-02 (Downs) at 9.
[766] Ex. SCG-24 (Dagg) at 11.
[767] Ex. SCG-24 (Dagg) at 11.
[768] Ex. SCG-24 (Dagg) at 11.
[769] Ex. SCG-24 (Dagg) at 11.

SoCalGas' current efforts and policy have proven effective in maintaining and repairing valves and UWUA has offered no evidence or rationale as why their proposal is necessary, how their proposal would enhance system safety, or examples and evidence of issues or problems with SoCalGas' current policy. UWUA witness Robin Downs states: "The objective is to assure that all valves, whether automatic, remote controlled or manual in fact operate as anticipated, without delay or obstruction."[770] SoCalGas agrees, and current policy effectively promotes this objective.

E. Treatment of Robotics Royalties

Although it has not received any payments to date, SoCalGas has a small royalty interest in robotic inspection technology developed by the research arm of the Northeast Gas Association (NYSEARCH).[771] SoCalGas and SDG&E hope to use this technology during the PSEP implementation period to inspect unpiggable pipeline segments without having to shut down the segments.

TURN strongly endorses our efforts to help develop this robotic inspection technology.[772] However, echoing similar arguments made by TURN in SoCalGas' recent GRC (A.10-12-006), TURN recommends that 100% of royalties received by SoCalGas be applied to offset PSEP costs.[773] According to TURN, these revenue offsets should apply to *all* royalty payments from NYSEARCH, and not just royalty payments that result from SoCalGas' and SDG&E's use of the technology.[774]

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[770] Ex. UWUA-02 (Downs) at 9.
[771] Ex. SCG-26 (Reyes) at 8-9. This interest is 12.3%. *See* Ex. TURN-02 (Marcus) at 22 (citing SoCalGas' and SDG&E's response to TURN DR 1-3).
[772] Ex. TURN-02 (Marcus) at 22.
[773] Ex. TURN-02 (Marcus) at 22-23.
[774] Ex. TURN-02 (Marcus) at 23.

SoCalGas and SDG&E disagree with TURN's proposed approach to robotics royalties. SoCalGas recommends that, consistent with the past treatment of other projects such as SoCalGas' investment in Plug Power, Inc., royalties from NYSEARCH should be credited 100% to customers until all customer investments in the project have been repaid.[775] Any additional royalties would then be shared 60/40 between customers and shareholders, pursuant to the existing Commission-authorized approach for handling royalties received by SoCalGas from research projects.[776]

This proposed approach to robotics royalties will ensure that customers are first reimbursed for their financial support of this particular RD&D project, while still providing a strong incentive for utilities to participate in projects that can lead to commercially viable results, and giving customers a substantial potential upside for providing the funding for such projects. Conversely, TURN's approach would provide utilities with no possible upside for participating in RD&D projects, and no financial incentive to spend time and energy developing new tools such as NYSEARCH's robotic inspection technology.

The Commission has already established how SoCalGas should treat royalties from RD&D investments. Other than potentially clarifying that royalties from NYSEARCH should be credited 100% to customers until all customer investments in the project have been repaid,[777] there is no reason to change the established treatment of royalties for this particular successful investment. As TURN admits, SoCalGas' RD&D efforts with respect to robotic inspection technology is "an example of research, development and demonstration projects that have a

[775] Ex. SCG-26 (Reyes) at 9. Note that this proposed treatment for robotics royalties would require a limited change to SoCalGas' existing tariffs. Currently, any royalties from this project would be shared 60/40 between ratepayers and shareholders. *See* SoCalGas' Preliminary Statement, Part VI., Memorandum Accounts, Research Royalty Memorandum Account (RRMA) ("Pursuant to D.08-07-046, TY 2008 GRC, revenues associated with projects commencing on and after January 1, 2008 are subject to a revenue sharing mechanism which allocates 60% of revenues to ratepayers and the remaining 40% to shareholders.").
[776] Ex. SCG-26 (Reyes) at 9.
[777] SoCalGas is planning on simply voluntarily treating NYSEARCH royalties in this manner.

strong potential to provide ratepayer benefits by lowering operating costs."[778] SoCalGas and other utilities should be encouraged to enter into such projects, not discouraged by having the potential for sharing eliminated when and if a research project actually becomes commercially viable.

X. 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 the Decision Tree - Figure 2). In addition, in Phase 1B, SoCalGas and SDG&E propose to abandon and replace all pre-1946 non-piggable transmission pipelines segments remaining in the system after the completion of Phase 1A.[779] The justification for this proposed work is discussed in Section IV.A.3.d above.

SoCalGas and SDG&E are not seeking approval of the costs of implementing Phase 1B at this time. However, SoCalGas and SDG&E do seek approval of the proposed prioritization and decision-making process described in Section IV.A above for all phases of their proposed Plan. In addition, Phase 1A includes costs to pre-engineer a replacement line for Line 1600, and costs to inline inspect the existing Line 1600 using TFI technology as an interim safety enhancement measure. SoCalGas and SDG&E propose to file a request for authority to recover Phase 1B costs either in their 2016 GRC or via a separate application.

A. Line 1600

Although additional Phase 1A pipelines may ultimately move to Phase 1B if implementation challenges preclude those pipelines from being addressed in the near term, at this

[778] Ex. TURN-02 (Marcus) at 22.
[779] Ex. SCG-04 (Schneider) at 60.

time, Line 1600 is the only pipeline identified as falling within the scope of Phase 1B. Under the proposed decision-making and implementation process described in Section IV above, SoCalGas and SDG&E propose to construct a replacement line for Line 1600 in Phase 1B to enable them to pressure test the existing line 1600, and to inline inspect the existing Line 1600 using TFI technology in Phase 1A as an interim safety enhancement measure. As stated above, SoCalGas and SDG&E are not seeking approval of the costs to construct a replacement line for Line 1600 at this time.

Both DRA and SCGC recommend that the work related to the pressure testing of Line 1600 be addressed in Phase 1B[780] and are also critical of the SoCalGas and SDG&E plan to construct a 36-inch diameter pipeline to replace Line 1600.[781]

The plan of SoCalGas and SDG&E for pressure testing Line 1600 is already a predominately Phase 1B project.[782] While some of the pipeline meets the criteria for replacement in Phase 1A, the need to construct a replacement pipeline before removing Line 1600 from service for testing pushes this project into the Phase 1B timeframe.[783] In order to complete the construction of this pipeline project within the Phase 1B timeframe, however, SoCalGas and SDG&E must begin the pre-engineering work now.[784] Accordingly, we seek recovery of those costs in Phase 1A.

B. Replacement of Non-Piggable Pipelines Installed Prior to 1946

In Phase 1B, SoCalGas and SDG&E propose to replace all remaining non-piggable pipelines, regardless of location, installed prior to 1946. As explained in Section IV.A.3.d

[780] Ex. DRA-02 (Phan) at 80; Ex. SCGC-01 (Yap) at 17. In addition, DRA recommends that the costs related to the inline inspection of Line 1600 be removed from Phase 1A. Ex. DRA-02 (Phan) at 81. The reasons why inspection of Line 1600 using a TFI tool is an appropriate Phase 1A cost are addressed above in Sections IV.A.4.c and IV.C.2.c.
[781] Ex. DRA-02 (Phan) at 81; Ex. SCGC-01 (Yap) at 20.
[782] Ex. SCG-22 (Bisi) at 5.
[783] Ex. SCG-22 (Bisi) at 7-8.
[784] Ex. SCG-22 (Bisi) at 6.

above, SoCalGas and SDG&E have already identified, retrofitted and inline inspected all pre-1946 transmission pipelines that were constructed using acceptable welding techniques and are operationally suited to inline inspection. The remaining pre-1946 segments in the SoCalGas and SDG&E system are not suited for inline inspection, likely have non-state-of-the-art welds, and would require significant investment for retrofitting to accommodate inline 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 of these remaining pre-1946 non-piggable pipelines as part of Phase 1B.[785] Justification for this element of the SoCalGas and SDG&E PSEP is discussed above in Section IV.A.3.d. As stated below in Section XI, this work can take place concurrently with Phase 2 work.

XI. PHASE 2

Consistent with Ordering Paragraphs Nos. 4 and 5 of D.11-06-017, SoCalGas and SDG&E prioritized pipelines located in Class 3 and Class 4 locations and Class 1 and Class 2 High Consequence Areas ahead of pipelines in less populated areas,[786] and further prioritized pipelines based on whether those pipelines had sufficient documentation of a stress test to at least 1.25 times the pipeline's MAOP.[787]

In Phases 1A and 1B, described in Section IV.A.1 above, SoCalGas and SDG&E propose to address all transmission pipelines operated in Class 3 and Class 4 locations and Class 1 and

[785] Ex. SCG-04 (Schneider) at 60.
[786] *See* D.11-06-017 at 31, Ordering Paragraph No. 4 ("The Implementation Plan should 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.").
[787] D.11-06-017 at 32, Ordering Paragraph No. 9 ("Segments with the highest risk . . . must be tested or replaced first.").

Class 2 High Consequence Areas that do not have sufficient documentation of a pressure test to at least 1.25 times the pipeline's MAOP. 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 times the pipeline's MAOP (i.e., those located in less populated areas) and all other remaining transmission pipelines that have not been strength tested in accordance with the Commission's direction (i.e., those that were pressure tested prior to adoption of Subpart J) will be addressed.

SoCalGas and SDG&E are not currently seeking authorization to recover the costs associated with implementation of Phase 2 of their proposed Plan. Rather, SoCalGas and SDG&E seek approval of the prioritization and decision-making process described in Section IV.A.1 above.

If the Commission approves the proposed alternatives to replacement or pressure testing set forth above in Section VI, and if such alternative methods appear to provide a more cost-effective means of achieving the Commission's safety objectives, SoCalGas and SDG&E plan to seek Commission approval to utilize such alternatives for Phase 2. Similarly, if SoCalGas and SDG&E's proposal to perform inline inspections of piggable pipelines using TFI technology prior to pressure testing (described above in Section IV.C.1) is approved, and if the resulting data confirms that inline inspection of a pipeline using TFI technology is equivalent or superior to pressure testing, SoCalGas and SDG&E will propose to utilize this assessment method in Phase 2.

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XII. CONCLUSION

For the reasons set forth above, in their Amended PSEP, and in their testimony, SoCalGas and SDG&E respectfully request that the Commission adopt each of the proposals submitted by SoCalGas and SDG&E in this proceeding, reject each of the contrary proposals by intervenors, and adopt each of the proposed recommendations set forth at the beginning of this brief.

Dated this 19th day of October 2012, in Los Angeles, California.

Respectfully submitted,

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