BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

MOTION FOR OFFICIAL NOTICE IN SUPPORT OF RESPONSE OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) TO JOINT PETITION OF THE UTILITY REFORM NETWORK AND SOUTHERN CALIFORNIA GENERATION COALITION FOR MODIFICATION OF D.11-06-017

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May 11, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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MOTION FOR OFFICIAL NOTICE IN SUPPORT OF RESPONSE OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) TO JOINT PETITION OF THE UTILITY REFORM NETWORK AND SOUTHERN CALIFORNIA GENERATION COALITION FOR MODIFICATION OF D.11-06-017

Pursuant to Rules 11.1 and 13.9 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Respondents") hereby respectfully request official notice of the following documents attached to this motion.

1. Exhibit A, A.11-11-002, Amended Direct Testimony of Richard Morrow – Chapter 2 dated December 2, 2011;
2. Exhibit B, A.11-11-002, DRA Report on the Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company dated June 19, 2012;
3. Exhibit C, A.11-11-002,[1] Response to Data Request DRA-DAO-29 dated May 11, 2012;
4. Exhibit D, A.11-11-002,[2] Response to Data Request from SCGC-10 dated April 27, 2012;
5. Exhibit E, A.16-09-005, Southern California Generation Coalition Protest of the Southern California Gas Company and San Diego Gas & Electric Company Application to Recover Costs Recorded in the Pipeline Safety Reliability Memorandum Account, the Safety Enhancement Expense Balancing Accounts,

[1] Exhibit C was originally in R.11-02-019 but was transferred to A.11-11-002 by D.12-04-021.
[2] Exhibit D was originally in R.11-02-019 but was transferred to A.11-11-002 by D.12-04-021.

and the Safety Enhancement Capital Cost Balancing Accounts dated October 10, 2016; and

6. Exhibit F, A.17-10-007/17-10-008, Protest of The Utility Reform Network dated November 17, 2017.

According to Rule 13.9 of CPUC Rules of Practice and Procedure, "[o]fficial notice may be taken of such matters as may be judicially noticed by the courts of the State of California pursuant to Evidence Code section 450 et seq." Judicial notice may be taken of official acts of executive branch, "[r]ecords of . . . any court of this state," and "[f]acts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy." Cal. Evid. Code §§ 451, 452. In this case, Respondents do not seek to establish the truth of the matters asserted in the records, but rather that the statements in the records were made.

The documents attached to this motion are appropriate for official notice because they are records and documents from various proceedings before the Commission that concern the Pipeline Safety Enhancement Plan ("PSEP"). The petitioners in this proceeding, TURN and SCGC, were and/or are parties to the proceedings in which the documents were provided; thus, they will not be prejudiced.

Because the documents are relevant to this proceeding, and the petitioners will not be prejudiced, it is appropriate for the Commission to take official notice of the foregoing documents.

Respectfully submitted on behalf of SoCalGas and SDG&E,

By: *\/s\/ Avisha A. Patel*
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May 11, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

[PROPOSED] RULING

Pursuant to Rules 11.1 and 13.9 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Respondents") filed a Motion for Official Notice in Support of Response of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 M) to Joint Petition of The Utility Reform Network and Southern California Generation Coalition for Modification of D.11-06-017 ("Motion").

The Motion sets forth reasons for the Commission to take official notice of the documents proposed by Respondents. Therefore, it is ruled that the Commission shall take official notice of the following documents:

1. Exhibit A, A.11-11-002, Amended Direct Testimony of Richard Morrow – Chapter 2 dated December 2, 2011;
2. Exhibit B, A.11-11-002, DRA Report on the Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company dated June 19, 2012;
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[1] Exhibit C was originally in R.11-02-019 but was transferred to A.11-11-002 by D.12-04-021.
[2] Exhibit D was originally in R.11-02-019 but was transferred to A.11-11-002 by D.12-04-021.

5. Exhibit E, A.16-09-005, Southern California Generation Coalition Protest of the Southern California Gas Company and San Diego Gas & Electric Company Application to Recover Costs Recorded in the Pipeline Safety Reliability Memorandum Account, the Safety Enhancement Expense Balancing Accounts, and the Safety Enhancement Capital Cost Balancing Accounts dated October 10, 2016; and
6. Exhibit F, A.17-10-007/17-10-008, Protest of The Utility Reform Network dated November 17, 2017.

IT IS SO ORDERED.

Dated: ______________________ ____________________________________
Administrative Law Judge

EXHIBIT A

Application No: A.11-11-002
Exhibit No.: SCG-02
Date: December 2, 2011
Witness: Richard Morrow

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 (Filed November 1, 2011)

CHAPTER II

AMENDED DIRECT TESTIMONY OF

RICHARD MORROW

OVERVIEW OF THE PROPOSED SAFETY ENHANCEMENT PLAN

IN SUPPORT OF PROPOSED NATURAL GAS PIPELINE SAFETY ENHANCEMENT PLAN FOR

SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

December 2, 2011

II.

OVERVIEW OF THE PROPOSED SAFETY ENHANCEMENT PLAN

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

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

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

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

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

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

[5] D.11-06-017, Ordering ¶ 2.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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14 *Id.*, Ordering ¶ 5.

15 *Id.*, Ordering ¶ 9.

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

2. <u>The Proposed Pipeline Safety Enhancement Plan Enhances Public Safety</u>

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

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

3. The Proposed Pipeline Safety Enhancement Plan Minimizes Customer Impacts

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

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

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

As a general guideline, notice for suspension of service to noncore customers, would be provided at least thirty days prior to any scheduled service outages required for implementation of the Pipeline Safety Enhancement Plan.

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

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

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

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

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

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

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

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

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

Because of the scope and complexity of work required to implement the Commission's directives, and to satisfy the Commission's prioritization requirements, we propose to implement our Pipeline Safety Enhancement Plan in two separate phases. Phase 1 covers the ten-year period from 2012 through 2021. This phase includes the pressure testing or replacement of those pipelines in Class 3 or 4 locations and Class 1 and 2 High Consequence Areas that do not have sufficient documentation of pressure testing to satisfy the Commission's directives. Phase 1 also includes the placement of additional remote control and automatic shut-off valves on the transmission system, and installation of technology enhancements to enhance our ability to

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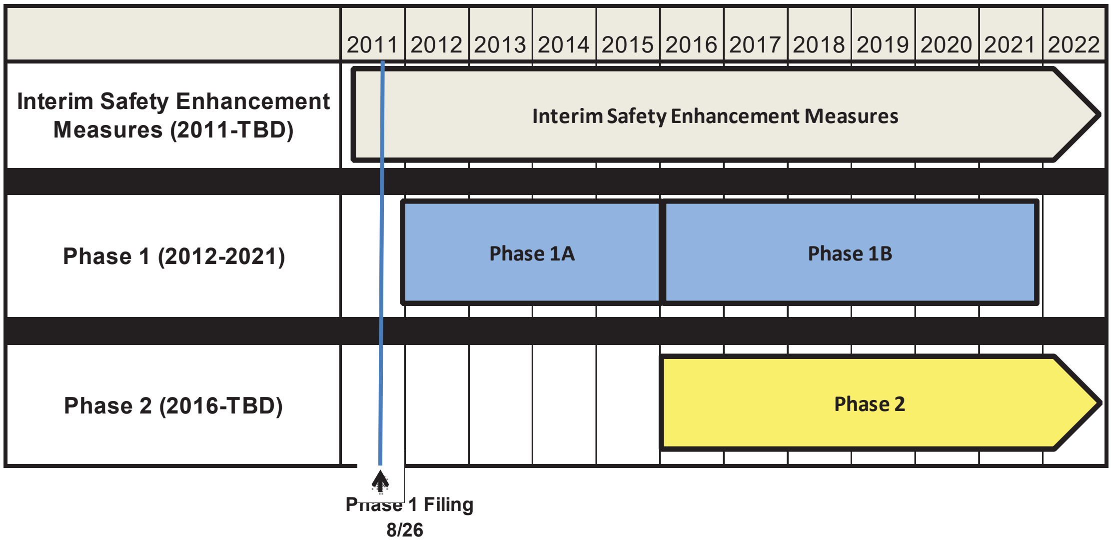
16 This figure includes approximately 377 miles of pre-1970 and 8 miles of post-1970 pipelines, as of June 24, 2011. This proposed Pipeline Safety Enhancement Plan does not include any costs for testing or replacing pipelines constructed post-1970.

monitor our transmission pipeline system. As discussed above, and in greater detail in Chapter IV, our Pipeline Safety Enhancement Plan includes a proposal to replace pre-1946 pipeline segments that were manufactured using non-state-of-the-art construction and fabrication methods. This proposal, which is also proposed to be implemented in Phase 1, addresses the Commission's stated goal of bringing all transmission pipelines in-service in California into compliance with modern standards, and the directive to consider retrofitting our pipelines to accommodate in-line inspection tools.

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

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

Figure II-1
Proposed Pipeline Safety Enhancement Plan Timeline



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

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

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

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

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

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

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

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

Therefore, we propose that the incremental costs of implementing these new safety standards be tracked separately from other pipeline system costs and allocated on an equal percent of margin basis.[17] Furthermore, we propose that these costs be identified as a surcharge in each customer's monthly bill. Recovery of these costs through a line-item surcharge will provide transparency to our customers regarding the purpose for these costs. SoCalGas and SDG&E estimate that by 2015, Phase 1A will result in a $2.89/month surcharge on residential bills for both SoCalGas and SDG&E.[18]

Today, a majority of transmission costs are allocated to large electric generators, manufacturers, refineries, and other large businesses that have very few employees—relative to the overall service territory population. The costs being ordered by the Commission, such as those associated with pressure testing, replacement of pipelines and automated valves, go beyond current Federal safety standards for pipelines. Industries and businesses will not realize significant improvements in transmission service from these safety-related investments; therefore, it would be inappropriate to allocate these costs to these large throughput non-core customers in the same manner that transmission costs are allocated today. Furthermore, such an approach would likely encourage most, if not all, of these customers to eventually seek service from FERC-

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

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

regulated transmission pipelines that are not required to recover the additional pipeline safety costs being ordered in this California proceeding.

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

1. <u>General Construction Permitting Challenges</u>

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

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

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

2. <u>Availability of Materials and Qualified Personnel</u>

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

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

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

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

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

4. Proposals for Commission Alleviation of Implementation Challenges

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

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

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

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

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

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

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

EXHIBIT B

Docket:	:	A.11-11-002
Exhibit Number	:	DRA-2
Commissioner	:	Florio
ALJ	:	Long
Witness	:	Phan

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company

Pipeline Safety Enhancement Plan

San Francisco, California
June 19, 2012

TABLE OF CONTENTS

PIPELINE SAFETY ENHANCEMENT PLAN

I. INTRODUCTION

Commission Decision (D.) 11-06-017, issued on June 16, 2011, ordered "…all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested. The Implementation Plans may include alternatives that demonstrably achieve the same standard of safety but must include a prioritized schedule based on risk assessment and maintaining service reliability as well as cost estimates with proposed ratemaking."[1]

In response to this directive, Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") collectively referred to as Sempra, submitted testimony in support of its proposed natural gas pipeline safety enhancement plan ("the Plan"). Sempra's proposal includes plans, in multiple phases, to pressure test or replace all pipeline segments for both SoCalGas and for SDG&E that Sempra says do not have sufficient documentation to validate a post-construction pressure test of at least 1.25*Maximum Allowable Operating Pressure("MAOP").

For the first phase of the Plan, Phase 1A, Sempra seeks Commission authorization to recover a total of $1.7 billion in capital expenditures and Operation & Maintenance ("O&M") expenses to implement its Pipeline Safety Enhancement Plan.[2] Of this total, Sempra seeks $1.4 billion in capital expenditures and $262 million in O&M expenses for the years 2012-2015 for both utilities. Sempra also

[1] D. 11-06-017. p.1.

[2] Amended Testimony, page 5.

seeks $7 million in O&M expenses to implement its interim safety plan scheduled for 2011.[3]

Sempra requests the following:

1. Authorization to recover costs incurred to date, and to be incurred up to the time the Commission issues a decision approving Sempra's Plan, for the review of transmission pipeline transmission pipeline records and for implementation of its interim safety enhancement measures. Sempra forecasts $7 million for the interim safety plan.
2. Approval of Sempra's direct Capital forecasts for implementation of the Plan during the time period of 2012 through 2015 of approximately $1.2 billion for SoCalGas and $229 million for SDG&E, and direct Operation and Maintenance ("O&M") forecasts for implementation of the Plan during the time period of 2012 through 2015 of approximately $255 million for SoCalGas and $7 million for SDG&E.[4]
3. Approval of the revenue requirements resulting from Sempra's Capital and O&M forecasts for the years 2011 through 2015.
4. Authorization to include a request to approve the Capital and O&M forecasts and resulting revenue requirements for subsequent years of the Plan in Sempra's respective General Rate Cases or other appropriate proceedings.
5. Approval to track the costs of implementing Sempra's Plan separately from other pipeline system costs and to allocate those costs to its customers using the Equal Percent of Authorized Margin ("EPAM") method.

[3] Ibid.

[4] Amended Testimony, p. 5.

6. Approval to identify the costs of implementing its Plan as a separate item, a "PSEP Surcharge," on its customers' bills.
7. Approval to submit an annual status report to the Commission by March 31 of each year, beginning in 2013 that includes (a) information on work completed during the previous year; (b) work planned for the upcoming year; (c) discussion of progress made; and (d) confirmation of the Commission's approved annual budget for the Plan.

Sempra's Plan has minimal if any engineering analysis and contains proposals for system enhancement well beyond the scope of Decision 11-06-017. DRA reviewed Sempra's Plan, and conducted discovery to determine the reasonableness of Sempra's proposed work plans. DRA concludes that Sempra's Plan is overly ambitious and lacks adequate support. DRA recommends that the Commission authorize funding for the hydrostatic testing of the Category 4 pipelines only. DRA's recommendation results in a lower level of funding compared to Sempra's proposal.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends that the Commission:

- address in its decision in this case the pipeline segments Sempra identified for MAOP validation in Phase 1A only. Pipelines Sempra identified to be pressure tested or replaced in Phase 1B and Phase 2 should be addressed in the next Sempra General Rate Case ("GRC"). The Commission will have actual cost data for the pipeline projects after the completion of Phase 1A, and will better be able to assess the reasonableness of pipeline work planned for the later phases.
- reject Sempra's proposal to "enhance" its system beyond the measures required under D.11-06-017. Sempra calls its "enhanced" proposal the Proposed Case, and requests additional ratepayer funding for projects such as fiber optic and

methane detection, which are above and beyond the requirements of D.11-06-017.

- adopt what Sempra calls the Base Case, with some modifications. In its Base Case, Sempra requests funding to pressure test or replace pipelines without MAOP validation.
- authorize the funding necessary for Sempra to perform pressure tests on the Category 4 National Transportation Safety Board ("NTSB") Criteria Miles in Phase 1A only. These are pipeline segments that are located in Class 3 and 4 locations, and Class 1 and 2 High Consequence Areas (HCAs). At this time, Sempra's cost estimates for the Plan are classified as "Class 5". Until Sempra provides a better estimate and additional confirmation of pressure test costs, the Commission should not authorize any funding for Phase 1B or Phase 2 MAOP validation efforts.
- reject Sempra's proposal to include pipeline segments located in Class 1 and 2 non-HCAs, referred to as "Accelerated Miles", in Phase 1A because Sempra has not adequately justified the proposed work.

The Commission should reject Sempra's proposal to replace, instead of pressure test, 260 miles of pipelines in Phase 1A because the criteria Sempra used to identify pipelines for replacement are not adequately supported.

- reduce Sempra's Plan cost by $74 million for pipelines managed as part of the SoCalGas and SDG&E Transmission Integrity Management Program ("TIMP"). Sempra's TIMP is funded through rates set in the General Rate Case process. Pipelines that are pressure tested as part of the Plan will meet the requirements of TIMP.
- reject Sempra's proposal to perform in-line inspections using TFI technology on 607 miles of pipelines *before* pressure testing., Sempra argues that the purpose is to determine if this would be an equivalent method to strength test a pipeline. Sempra requests $8 million for in-line inspections and $54 million for

repairs. Current Federal regulations do not recognize TFI technology as an equivalent means to strength test a pipeline.

- reject the proposal to replace wrinkle bends as part of the Plan. The replacement of wrinkle bends should continue to be managed under the TIMP program and should not be included in the Plan.
- require Sempra to consider the location of pipelines and risk assessments performed based on TIMP and maintenance data collected from O&M activities such as corrosion detection and leak surveys, as part of the sub-prioritization of pipelines for pressure testing. Sempra's current sub-prioritization methodology does not account for pipeline location, risk assessments from TIMP, or maintenance data in ranking pipeline for MAOP validation.

III. EXPLANATION OF DRA RECOMMENDATIONS

A. Sempra's Response to the National Transportation Safety Board's Recommendations and to Commission Resolution L-410

Sempra's Pipeline Safety Enhancement Plan has its roots in the company's response to the National Transportation Safety Board's (NTSB) recommendations, and the Commission's Resolution L-410. On April 15, 2011, Sempra submitted the "Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations", ("Report"). In this Report, Sempra states that SoCalGas and SDG&E operate a total of 1,622 Criteria Miles: 1,416 SoCalGas miles and 206 SDG&E miles.[5] Sempra uses the term "Criteria Miles" to refer to pipelines in "Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas ("HCAs")."[6]

[5] *See* Report of Southern California Gas Company and San Diego Gas and Electric Company on Actions Taken in Response to NTSB Safety Recommendations.

[6] The Report, p. 1.

Of the total 1,622 Criteria Miles, Sempra identified 383 miles for SoCalGas and 64 miles for SDG&E that require, "…additional analysis and action to verify the stability of the long seam at the pipeline segment's MAOP."[7] Sempra also calls the 383 SoCalGas miles and 64 SDG&E miles "Category 4" pipeline segments. Sempra uses the terms "Category 4," "Criteria," and "Category 4 Criteria" interchangeably to refer to pipelines located in Class 3 and 4 locations and Class 1 and 2 HCAs. These Category 4 pipelines essentially become the pipeline segments that Sempra proposes in its Pipeline Enhancement Safety Plan to hydrostatic-test or replace, and to inspect using transverse field inspection (TFI) pigging.[8]

The remaining 1,175 Criteria miles[9] are categorized as Category 1, Category 2, and Category 3 miles. Sempra's definitions of these pipeline miles are as follows: "Category 1 includes only those pipelines and pipeline segments that have documentation of a hydrostatic pressure test to at least 1.25 times the MAOP per NTSB Safety Recommendation P-10-2 (Urgent). Category 2 includes those pipelines and pipeline segments that have documentation of a post-construction strength test to at least 1.25 times the MAOP using a medium other than water. Category 3 includes pipelines and pipeline segments for which documentation validates that the highest in-service operating pressure is at least 1.25 times the current MAOP."[10] Sempra explains that, "Because a pipeline strength test is based upon the pressure at which the pipeline is subjected and is not dependent upon the test media used, the media has no bearing on the outcome of the test. Accordingly, Category 2 pipelines and pipeline segments are equivalent in all relevant respects to Category 1 pipelines and pipeline segments."[11]

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[7] The Report, p.11.

[8] Amended Testimony, Chapter IV, see pp. 40-41, 50.

[9] 1,622 Criteria Miles – 383 SoCalGas Miles – 64 SDG&E Miles = 1,175 Remaining Criteria Miles

[10] The Report, pp.7-8.

[11] Ibid.

B. DRA Recommends that Only Category 4 Criteria Miles be Addressed in Phase 1A

1. DRA Takes Issue with the Inclusion of non-HCA Segments and Segments with Demonstrated Safety Margin

Sempra's Plan consists of pipeline segments located in Class 1, Class 2 High Consequence Areas and Class 3 and Class 4, as well as pipeline segments located in Class 1 and Class 2 non-HCA. Sempra calls the non-HCA miles, "Accelerated Miles." Sempra's proposal for hydrostatic testing of SoCalGas' pipelines consists of more non-HCA segments than HCA ones. For Phase 1A, Sempra proposes to test 185 non-HCA miles compared to 176 HCA miles.[12] For replacement, Sempra proposes to replace a total of 136 miles of non-HCA pipelines and 153 miles of HCA pipelines.[13] Sempra has not provided adequate support for including the non-HCA segments in the Plan at the level requested. Sempra's Plan should exclude the Accelerated Miles for several reasons.

First, Sempra is including for pressure testing or replacing pipeline segments identified as "Accelerated," that may have already had the safety margin validated. The Plan includes Criteria segments categorized as Category 1, 2, and 3. The Plan also includes non-HCA segments that may have already had the safety margin validated. According to Sempra, "The Class 1 and 2 non-HCA miles identified… [in the Plan] have undergone a records review and can be characterized per one of the four categories identified in Table IV-4 of the Testimony."[14] In other words, "Accelerated" mileage includes segments that are identified as Category 1, 2, and 3, located in both HCAs and non-HCAs. Category 1, 2, and 3 segments have already demonstrated a safety margin through prior strength testing or with MAOP

[12] Amended Testimony, p. 108.

[13] Amended Workpapers, pp. WP-IX-1-36, 1-29, 1-25.

[14] Sempra's Response to DRA-DAO-21, Q.4 (d).

reductions.[15] These segments do not need to be addressed in the Plan at all because the safety margins have been validated.

Second, Sempra is including mileage for the Plan work without first knowing the scope of work required. Sempra states, "The actual scope of Accelerated Miles to be included in each individual project will be developed during the engineering, design, and execution planning phases of the Plan."[16] Sempra also states, "the assumptions regarding the scope of Accelerated Miles …were for the purpose of developing an overall high level cost estimate for the Plan as a whole."[17]

Sempra has not performed any analyses or assessments to show that it is better to accelerate the testing and replacement of pipelines located in non-populated areas, and are identified for Phase 2, into Phase 1A. DRA asked Sempra to provide a copy of all studies, assessments or evaluations performed to determine that segments in non-populated areas should be included in Phase 1A work as "Category 4 Criteria" or "Accelerated" miles. Sempra responded, "Segments in less populated areas (Class 1 and 2 non-HCAs) that are proposed in the Phase 1A scope are considered "Accelerated" miles. Specific studies, assessments, or evaluations have not yet been performed to determine whether to accelerate segments prioritized for Phase 2 per the Decision Tree into the proposed Phase 1 scope. The high level cost estimate developed for the PSEP assumes that it will be more cost efficient and operationally advantageous for some Phase 2 miles to be accelerated and addressed in Phase 1. Specific studies/analyses will be performed to determine the appropriateness of accelerating specific Phase 2 segments into Phase 1 during the engineering, design, and execution planning phases of the PSEP."[18]

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[15] Amended Testimony, p. 50.
[16] Sempra's Response to DRA-DAO-13, Q. 3.
[17] Ibid.
[18] Sempra's Response to DRA-DAO-15, Q. 1(b).

Sempra is including non-HCA segments in Phase 1A without first completing the records review for these segments and without considering any safety validation results in planning Phase 1A pressure testing or pipeline replacement.[19] Sempra states in Testimony, "The records review of transmission segments in non-High Consequence Area Class 1 and 2 locations is underway and is expected to be completed by July 2012."[20] As of April of 2012, Sempra has not completed its records review of non-HCA Class 1 and 2 pipelines.[21] As of this date, Sempra does not know the number of miles that do not have pressure test records documenting a pressure test to at least 1.25 times MAOP. Sempra states, "This effort is still in progress with 933 remaining at SoCalGas and two miles remaining at SDG&E."[22] The work planned for these segments are scheduled for Phase 2 therefore the records review and safety validation efforts are incomplete. The Accelerated Mileage identified for Phase 1A were included prematurely.

Sempra's current proposal to include non-HCA pipelines in Phase 1A without first completing a search for the records of these segments and validating the safety margin of these segments will inevitably include testing and replacing pipelines unnecessarily. Furthermore, DRA is concerned that Sempra is misinterpreting the Commission's intent in D.11-06-017 by using the wrong criteria for MAOP validation.

According to Sempra, SoCalGas and SDG&E estimate that an additional 2,000 miles of transmission segments will need to be assessed to determine whether they require pressure testing or replacement. Sempra assumes in its filing that, "the CPUC will require pressure testing or replacement of pipeline installed prior to 1970 since

[19] Sempra's Response to DRA-DAO-31, Q.1(d).

[20] Amended Testimony, p. 50.

[21] Sempra's Response to DRA-DAO-21, Q. 4.

[22] Sempra's Response to DRA-DAO-21, Q. 4 (a) (ii).

modern standards were not in place before that time."[23] Sempra is interpreting D.11-06-017 to require all pipeline segments installed prior to 1970 to be tested in accord with 49 CFR 192.619, excluding subsection 192.619 (c).

D.11-06-017 states, "This decision orders all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plans) to achieve the goal or orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested."[24] D.11-06-017 does not require the digging up and testing to Subpart J those pipeline segments that have been previously tested.

Based on Sempra's interpretation of the Decision, SoCalGas and SDG&E are erroneously including segments that have previously been tested, and met the elements required by the regulations in effect, in the scope for Phase 2 and then accelerating these segments into Phase 1A as part of its Accelerated Miles.

Sempra does not have adequate support to accelerate non-HCA segments into Phase 1A. The reasons Sempra provides as support for accelerating pipeline work into Phase 1A are not supported with any analysis or studies: (1) to maximize the cost effectiveness and minimize the impacts to customers of execution of the proposed Plan[25], (2) in light of operational and economic considerations[26] and (3) "…due to operational necessity and project efficiency."[27]

The Decision Tree was not used to identify the Accelerated segments for pressure testing or for replacement as part of Phase 1A.[28] Sempra used the Decision

[23] Sempra's Response to DRA-DAO-29, Q. 4 (b).

[24] D.11-06-017, p. 1.

[25] Amended Testimony, p. 108.

[26] Amended Testimony, p. 61, footnote 46.

[27] Amended Testimony, p. 52.

[28] Sempra's Response to DRA-DAO-9, Q.1(c).

Tree outcomes of the Criteria segments and then added the non-HCA segments to the scope of work outside of the decision tree. There is no documentation of how this was done.

Sempra used the outcomes of the decision tree to determine and prioritize "accelerated miles" into Phase 1A.[29] Sempra states, "The process shown in Figure IV-1 on page 61 of the Testimony is used to establish the overall phasing for Phases 1A, 1B and Phase 2 work. After these basic phasing requirements were established, estimates for pressure testing in Phase 1A were performed and this included estimates for pressure test boundaries. Phase 1A pressure test boundaries were extended to include adjoining phase 2 pipe segments if those segments were determined through subject matter expert review to be potentially cost effective or reduce customer impacts…"[30]

When asked how pressure test boundaries were determined, Sempra responded that high level judgment by subject matter experts was made to "include adjoining Phase 2 pipe segments" if doing so had the potential to be more cost effective or reduce impacts to customers.[31] When asked for the identification of these subject matter experts, Sempra identified them as "…field services personnel who are most familiar with the pipelines addressed in the PSEP and who are best equipped with the knowledge to make high level judgments regarding which Phase 2 segments could be appropriate to accelerate into the Phase 1 scope in order to be more cost effective or reduce impacts to customers."[32]

No explanation of the review process or copies of the "subject matter expert" reviews were provided because none had been captured.[33] No evaluations, analyses,

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[29] Sempra's response to DRA-DAO-9, Q.1.

[30] Sempra's Response to DRA-DAO-14, Q.1.

[31] Sempra's Response to DRA-DAO-12, Q. 1, (b).

[32] Sempra's Response to DRA-DAO-14, Q. 1(c).

[33] Sempra's Response to DRA-DAO-14, Q. 1 (d).

or reviews were performed by these subject matter experts because the "…analysis [will be] performed to determine which Phase 2 segments to actually accelerate into Phase 1 will be documented in the engineering, design, and execution planning phases of the PSEP."[34]

No cost benefit analyses were performed to determine the cost effectiveness of including Accelerated segments in Phase 1A. Sempra states that these analyses will be performed in Phase 2.[35]

No customer impact studies have been performed to accelerate non-HCA segments into Phase 1A. Sempra states, "The assumption that some segments prioritized for Phase 2 per the Decision Tree will be accelerated into the proposed Phase 1 scope to minimize customer impacts was made based on very high level assumptions and judgments by subject matter experts."[36]

Accelerated segments seem to be included primarily to inflate the costs of the Plan. Sempra's mileage in the Plan is dependent on the amount of money it plans to spend per year and not whether the pipelines identified for testing and replacement need to be addressed in the first place. Sempra states, "the number of miles to be pressure tested in each year of Phase 1A is assumed to be proportionate to the cost estimated to be spent each year."[37]

There is no support for the inclusion of these accelerated segments. These segments do not need to be prioritized in Phase 1A because this will delay the testing and replacement of prioritized segments/pipelines located in highly populated, high consequence areas that need to be strength tested first. This is a safety issue that should be considered. This issue is highlighted by the pipelines that are predominantly made up of Accelerated segments. Prioritizing non-HCA segments for

[34] Sempra's Response to DRA-DAO-14, Q. 1(e).

[35] Sempra's Response to DRA-DAO-14, Q. 1(f).

[36] Sempra's Response toDRA-DAO-14, Q.1(g).

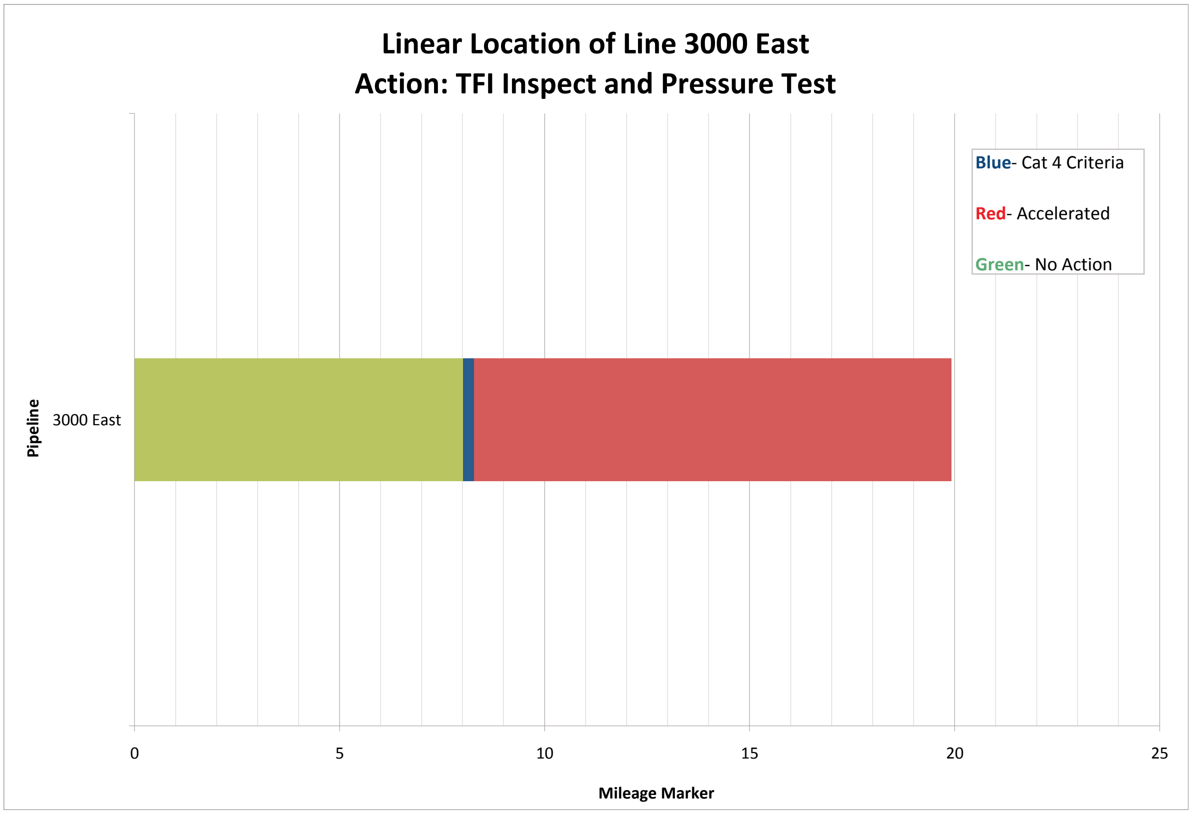
[37] Sempra's Response to DRA-DAO-2, Q. 8.

testing or replacing as part of Category 4 Criteria mileage means that segments located in more populated areas or in high consequence areas will be delayed when these segments should be addressed first. Sempra's workpapers demonstrate this. In the workpapers, the pipeline, and not the individual segments, is ranked in order to be addressed. In the current priority process, an Accelerated segment located in a non-populous area would be pressure tested or replaced as part of a line with a higher priority, before a Criteria Category 4 segment of a lower priority line would be addressed. For SoCalGas, 299 miles of non-HCA miles are ranked with the same criteria for priority as the 321 Criteria miles.[38]

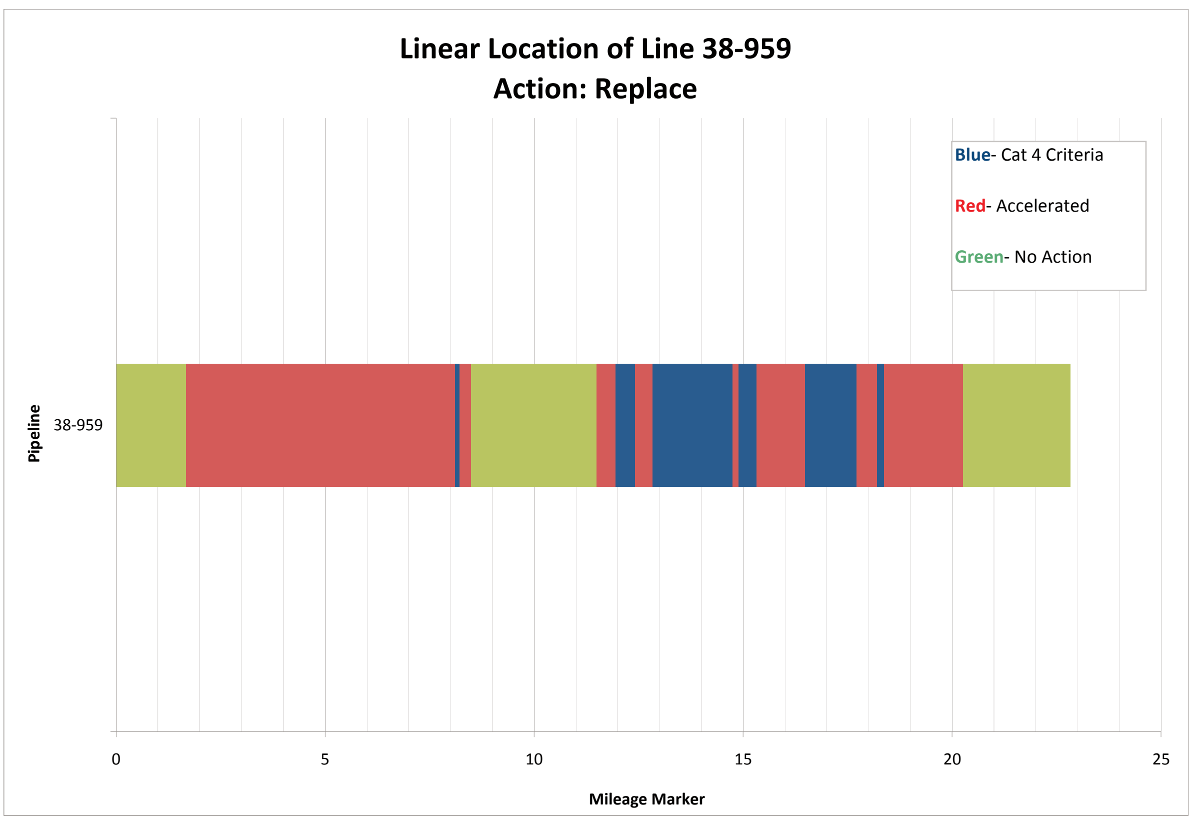
In the Plan's workpapers, there are several lines that include more Accelerated than Criteria segments. A small sample of those lines are: (1) Line 41-6000-2—36 miles with 70% Accelerated to 30% Criteria segments,[39] (2) Line 4000—4 miles with 84% Accelerated to 16% Criteria[40], (3) Line 3000 East—12 miles with 97% Accelerated to 3% Criteria[41], (4) Line 2001West—6 4 miles with 75% Accelerated to 16% Criteria[42], and (5) Line 30-32—3 miles with 68% Accelerated to 32% Criteria[43].

Some examples of pipelines where there is a significant number of Accelerated miles compared to Criteria miles are presented in linear charts below.

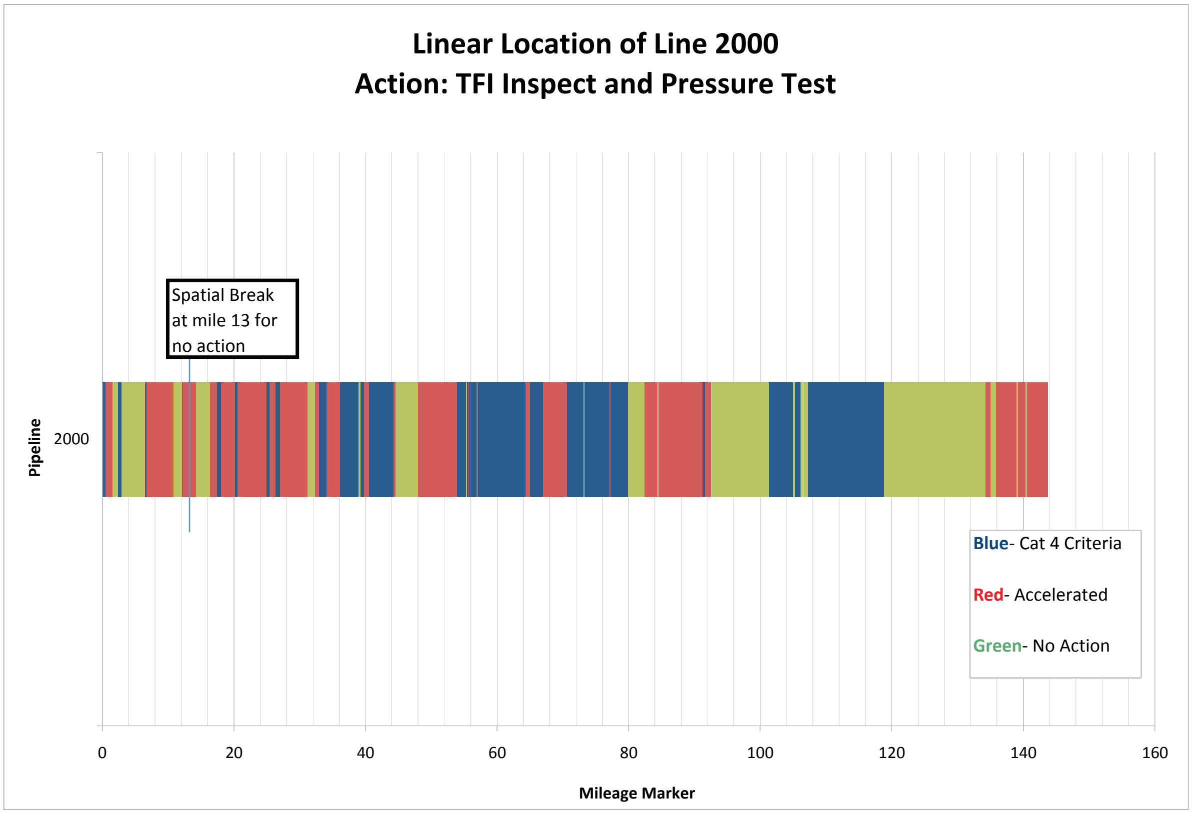
[38] Amended Workpapers, pp. WP-IV- 3 of 12 to 9 of 12.
[39] Amended Workpapers, p. WP-IX-B170.
[40] Amended Workpapers, p. WP-IX-1-A85.
[41] Amended Workpapers, p. WP-IX-1-A82.
[42] Amended Workpapers, p. WP-IX-1-A71.
[43] Amended Workpapers, p. WP-IX-B7.


Linear Location of Line 3000 East
Action: TFI Inspect and Pressure Test
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
Pipeline
3000 East
0
5
10
15
20
25
Mileage Marker

1


Linear Location of Line 38-959
Action: Replace
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
Pipeline
38-959
0
5
10
15
20
25
Mileage Marker

2


Linear Location of Line 2000
Action: TFI Inspect and Pressure Test
Spatial Break at mile 13 for no action
Pipeline
2000
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
0
20
40
60
80
100
120
140
160
Mileage Marker


Linear Location of Line 2001 west
Action: TFI Inspect and Pressure Test
Pipeline
2001 West
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
0
20
40
60
80
100
120
140
160
Mileage Marker

For all the reasons discussed above, DRA recommends that the Commission reject Sempra's proposal to include the non-HCA, "Accelerated" segments in the Plan. For Phase 1A, DRA recommends that only Criteria miles, those that are located in Class 3, Class 4, and Class 1 and 2 High Consequence Areas, be addressed.

C. The Commission Should Exclude Non-Transmission Pipelines

In the Plan, Sempra has segregated its plan into separate proposals for SoCalGas, for SDG&E, and for Transmission and Distribution pipelines for both utilities. Sempra states that the pipelines identified as "Distribution" meet the definition of the 49 CFR 192 for a transmission pipeline but is designated as such in the Plan because these pipelines meet the definition of what is used to identify these pipelines functionally and in alignment with 18 CFR 201 definitions.[44]

DRA does not take issue with the inclusion of pipelines identified functionally as Distribution but meet the definition of the 49 CFR 192 for a transmission line in the Plan. However, DRA takes issue with the inclusion of pipelines that operate at less than 20% Specified Minimum Yield Strength or DOT defined as distribution. The segments that make up these pipelines do not meet the definition of a transmission pipeline according to Commission General Order 112, which identifies transmission pipelines as operating at 20% or more of SMYS.[45] These segments also do not meet the definition of a transmission line per Title 49 of Part 192:

> **§ 192.3 Definitions.**
>
> Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

[44] Sempra's Response to DRA-DAO-17, Q. 1.
[45] D.11-06-017, footnote 3.

In the Sempra Decision Tree database, which contains all pipeline segments identified as Category 4 Criteria, there are 15 miles that operate below 20% SMYS[46]. DRA requested that Sempra confirm that these pipelines are transmission and not distribution pipelines. Sempra responded, "In some instances a pipeline will have segments that operate below 20% SMYS and above 20% SMYS, however the data collection was performed by line number to maintain continuity. SoCalGas and SDG&E plan to serve supplemental testimony in this proceeding to explain the inclusion of some small distribution segments within the scope of Phase 1 of the proposed PSEP."[47] Sempra further states, "As will be explained in our forthcoming Supplemental Testimony, these segments were identified as transmission during the population of the database."[48]

In the Supplemental Testimony filed on June 4, 2012, Sempra identified a total of 28 miles of distribution pipelines—13 more miles than shown in the Plan database provided to DRA which shows a total of 15 miles that are operating below 20% SMYS.[49] Sempra states, "The length of the distribution pipe included in our proposed Plan accounts 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."[50]

Sempra has not identified the criteria that qualify these pipelines as meeting the requirements of the Plan. Sempra states in its Supplemental Testimony that these pipelines technically do not fall within the Commission's directive in D.11-06-017 to propose an implementation plan to address transmission lines.[51] Sempra also has not

[46] Sempra's Response to DRA-DAO-16, Q.6.
[47] Sempra's Response to DRA-TCAP-PSEP-33, Q.1.(a).
[48] Sempra's Response to DRA-TCAP-PSEP-33, Q. 1(b).
[49] Sempra's Supplemental Testimony, Dated June 4, 2012, pp. 1-2.
[50] Sempra's Supplemental Testimony, Dated June 4, 2012, pp. 1-2.
[51] Ibid., p. 1.

provided any support as to why these pipelines should be included as part of the work activities identified for transmission lines in the Plan.

Although Sempra claims that it is more practical to include these distribution segments within the scope of Phase 1A work, no engineering analysis or cost benefit studies have been provided as support for its claim. Sempra states that the utilities won't be able to determine whether or not the inclusion of distribution pipe is cost effective or more practical until a later phase.[52]

Sempra has not asserted in its testimony or application that it needs to validate the MAOP of its distribution lines. The Commission should reject the inclusion of these 28 miles of distribution pipelines from the Plan because these pipelines would be more appropriately addressed as part of SoCalGas' and SDG&E's Distribution Integrity Management Program (DIMP) or with its next GRC. If these distribution pipelines are included in Phase 1A of the Plan, then ratepayers should not be responsible for the cost of testing or replacing these lines.

Sempra is currently receiving ratepayer funding to manage its DIMP and will receive additional funding in its Test Year 2012 GRC. DIMP is a broad program that encompasses SoCalGas' and SDG&E's entire systems including HCAs.[53] Sempra's DIMP must address seven specific elements required by PHMSA: (1) knowledge of system; (2) identify threats; (3) evaluate and rank risk; (4) identify and implement appropriate measures to mitigate risks; (5) measure performance, monitor results, and evaluate effectiveness; (6) periodic evaluation and improvement; and (7) report results.

Sempra should address these 28 miles of distribution pipelines as part of the DIMP by evaluating the threats pose by these segments, risk rank these threats, and mitigate them accordingly. If not addressed in the 2012 Test Year GRC cycle, then

[52] Sempra's Supplemental Testimony, pp. 2- 4.

[53] A.10-12-006, Exhibit SCG-5R, Testimony of Raymond Stanford, p. RKS-34.

Sempra should request funding in its next GRC. Additional funding to test or replace these distribution lines should not have to be paid for by ratepayers again.

Sempra has not provided any engineering or cost benefit analyses in the Plan to justify that it is necessary or more beneficial to include the distribution segments as part of the Plan, the purpose of which is to validate the MAOP of transmission pipelines.

DRA recommends the removal of these segments from the work identified for the Plan and a reduction of costs associated with these segments. The Supplemental Testimony shows a total number of 38 distribution lines identified to be addressed in the Plan. Of these 38 lines, only 3 lines with a total mileage of 0.3 miles are scheduled for hydrostatic testing. The remaining 35 lines totaling 27.4 miles are scheduled for replacement. Sempra's estimated cost associated with these pipelines is approximately $72 million.[54] These distribution lines are more appropriately addressed in the context of a GRC request for distribution mains and/or a different pipeline replacement program.

Additionally, DRA recommends the removal of $1 million for 0.08 miles of non-transmission mileage identified in Table 2 of the Supplemental Testimony.[55] Sempra states that it is reasonable to continue to include the 0.08 miles of distribution segments in Phase 1A although it admits that these segments are not adjacent or sandwiched between transmission segments. Sempra provides no support in its Plan showing or in its Supplemental Testimony to demonstrate that pipelines outside the scope of the Commission's directives should be addressed as part of Phase 1A.

If Sempra believes that it is necessary to also strength test or replace non-transmission pipelines, then ratepayers should not be responsible for the $73 million total estimated cost to address non-transmission pipelines in the Plan.

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[54] Using Sempra's numbers: 28 miles out of 200 total miles is equal to 14% of the work planned and at $72 million is 14% of the total $514 million. Sempra's response to provide DRA with numbers associated with the Supplemental Testimony, dated June 8, 2012.

D. Phases 1A (2012-2015), 1B (2016-2021), and Phase 2 (also to begin in 2016)

Sempra proposes to implement its Plan in multiple phases, Phase 1A, Phase 1B, and Phase 2. Phase 1A is expected to span from 2012-2015 and Phase 1B is proposed to span from 2016-2021. Phase 2 is expected to be implemented in parallel with Phase 1B, which begins in 2016.

For Phase 1A, Sempra proposes to replace 246 miles of SoCalGas pipelines and 49 miles of SDG&E and to pressure test 361 miles of SoCalGas and 1 mile of SDG&E pipelines.[56] The combined total mileage of 657 miles proposed for both utilities include pipelines that were identified as NTSB Criteria Miles or Category 4 Miles in the Report in Response to the NTSB Recommendations above. In the Plan testimony, the number of NTSB Criteria Miles changed from 383 to 322 for SoCalGas and from 64 to 63 for SDG&E.[57]

A summary of Sempra's proposal for Phase 1A pipeline MAOP validation work, in-line inspection, and valve retrofit is presented in the Table below.

Table 1

Sempra's Base Case—Phase 1A Pipeline and Valve Work

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

Source: Amended Testimony, p. 5

(continued from previous page)

55 Sempra's Supplemental Testimony, p. 5.

56 Amended Testimony, p. 5.

57 Amended Testimony, p. 50.

For Phase 1B, Sempra proposes to replace all pre-1946 pipeline segments for SoCalGas at a cost of $884 million.[58] There is no pipeline pressure test or pipeline replacement in lieu of a pressure test, proposed for any other SoCalGas pipelines. Sempra proposes to pressure test 45 miles of SDG&E's Line 1600 at a cost of $10 million, and to replace 54 miles of the same line at a cost of $318 million.[59] Sempra does not propose any additional pressure tests or pipeline replacement in lieu of a pressure test for any other lines, or to replace pre-1946 pipelines for SDG&E. A summary of Sempra's proposal for Phase 1B is presented in Table 2 below.

Table 2

Sempra's Base Case—Phase 1B Pipeline and Valve Work

SoCalGas	2016	2017	2018	2019	2020	2021	Total Miles
Replacement (miles)	-	-	-	-	-	-	-
Pressure Test(miles)	-	-	-	-	-	-	-
In-Line Inspection (miles)	-	-	-	-	-	-	-
Valve Retrofit (valves)	$36	$36	$36	$36	$37	$39	220
SDG&E	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total Miles**
Replacement (miles)	-	-	54	-	-	-	54
Pressure Test(miles)	-	-	-	45	-	-	45
In-Line Inspection (miles)	-	-	-	-	-	-	-
Valve Retrofit (valves)	7	7	7	7	7	7	42

Source: Workpapers, pp. WP-IX-1-17, 1-34 for pipelines. For SoCalGas valves, Workpapers, p. WP-IX-2-75 of 116 and SDG&E valves, WP-IX-2-62 of 116.

For Phase 2, Sempra proposes a total estimate of $1.7 billion—$1.6 billion for SoCalGas and $100 million for SDG&E to pressure test 478 miles, replace 362 miles, and ILI inspect 1,260 miles.[60] A summary of the planned work for Phase 2 is presented in the table below.

[58] Amended Workpapers, pp. WP-IX-1-44 to 1-45

[59] Amended Workpapers, pp. WP-IX-1-17 and WP-IX-1-34.

[60] Amended Workpapers, p. WP-IX-1-58.

Table 3

Sempra's Plan—Phase 2 Pipeline Work

	Miles			Cost (Millions of 2011$)			
	ILI Mileage	Pressure Test Mileage	Pipe Replacement Mileage	ILI O&M	Pressure Test O&M	Pipe Replacement Capital	Total Phase 2 (Rounded)
	(60%)	(57%)	(43%)	($86,000 / mile)	($479,000 / mile)	($3.58 Million / mile)	
SoCalGas	1200	455	345	$ 103.2	$ 218.1	$ 1,235.3	**$1.6 Billion**
SDG&E	60	23	17	$ 5.2	$ 10.9	$ 61.8	**$100 Million**
Total	1260	478	362	$ 108.3	$ 229.0	$ 1,297.0	**$1.7 Billion**

Source: Sempra's Workpapers, p. 1-58.

1. The Commission Should Address and Authorize Funding for Phase 1A at This Time and Consider Phase 1B and Phase 2 in the Next Sempra GRC

Sempra requests $1.7 billion to address pipeline MAOP validation for the years 2012-2015 as part of the proposal for Phase 1A.[61] Of this total, $1.4 billion is allocated to SoCalGas and $237 million is allocated to SDG&E.[62]

DRA recommends the Commission only address the pipeline segments identified for MAOP validation in Phase 1A in this proceeding. DRA recommends that the pipelines Sempra identified to be pressure tested or replaced in Phase 1B and Phase 2 be addressed in the next Sempra GRC. By the time Sempra completes the Phase 1A pipeline work, the Commission will have actual cost data for pipeline MAOP validation and will be better able to assess the reasonableness of the pipeline work and the related cost estimates for the later phases.

Sempra's cost estimates for pipeline replacement and pressure tests were developed by its consulting firm, SPEC Services. Sempra did not compare SPEC's

[61] Amended Testimony, p. 5.
[62] Amended Testimony, p. 5.

cost estimates for pipeline replacement and pressure test with industry cost for materials, construction, or engineering analysis.[63] Sempra also did not perform a comparison of SPEC's cost estimates with SoCalGas' or SDG&E's historical costs for materials, construction, and engineering analysis for replacement and hydrostatic test projects.[64]

In its Application, Sempra says its "Cost estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning."[65] Sempra describes the cost estimates used in this Application as "Class 5 or slightly better."[66] Sempra defines a Class 5 estimate as follows:

> "This classification system was developed by the Association for the Advancement of Cost Engineering (AACE International). It separates cost estimates into the various classes based on the level of project definition and also assigns expected accuracy ranges.
>
> Per AACE, a Class 5 estimate has 0% to 2% project definition, can be considered a "conceptual" estimate, is typically used for such purposes as project screening or assessment of initial viability, and has an expected accuracy range of -20% to -50% on the low side and +30% to +100% on the high side."[67]

A Class 5 estimate is not a very good indicator of how much a pressure test will ultimately cost. An accuracy range of -20% to -50% on the low side and +30% to +100% on the high side does not signify a very reliable cost estimate.

[63] Sempra's Response to DRA-DAO-07, Q. 2(b).
[64] Sempra's Response to DRA-DAO-07, Q. 2(c).
[65] Amended Testimony, p. 103.
[66] Sempra's Response to DRA-DAO-19, Q.2 (a).
[67] Sempra's Response to DRA-DAO-19, Q. 2(a).

When asked why Sempra had presented "Level 5" cost estimates, Sempra responded that, "[d]ue to the large number of projects proposed in the PSEP, and the expedited timeframe given to develop and file the plan, it was not feasible to prepare a more precise estimate."[68] DRA recognizes that Sempra had a limited amount of time to prepare the Plan estimates, but since the filing of this application, there has been no cost update.

Sempra is requesting $1.7 billion for SoCalGas and SDG&E to test or replace pipelines in the next 4 years.[69] Instead of supporting this request with engineering analysis or cost benefit studies, Sempra's proposals are based on "engineering judgment... based on the collective experience and knowledge of those involved."[70]

There is no assurance from Sempra that the work proposed for Phase 1A will be completed in the timeframe identified. According to Sempra, "Development of a detailed and accurate schedule for a project of this size requires sufficient completion of engineering and design work, operational planning, permitting studies, community impact studies, and other aspects of project execution and planning. Until this engineering and execution planning is completed, and the extent that the execution challenges and risks…can be mitigated, the certainty of the schedule cannot be predicted with certainty."[71] Sempra further states, "In the absence of any detailed planning, the cost estimates assumed construction and engineering activities to be carried out by third-party contract labor. The specific roles of company and contractor labor will be determined after detailed engineering and execution planning has been completed."[72]

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[68] Sempra's Response to DRA-DAO-19, Q. 2(b).

[69] Amended Testimony, p. 5.

[70] See the discussion of Sempra's hydrostatic test and pipeline replacement costs in Section E (3) (b) of this Report.

[71] Sempra's Response to DRA-DAO-9, Q. 4(b).

[72] Sempra's Response to DRA-DAO-9, Q. 4(e).

In this Application, Sempra proposes a plan for Phase 1A that is at a very high level and contains many unknowns. Sempra acknowledges that there are no engineering analyses, no cost benefit analyses, no studies of any kind to support the level of worked its plan sets out for Phase 1A. Based on the limitations associated with Sempra's plan, DRA recommends that the Commission address Phase 1B and Phase 2 work when Sempra has undertaken the execution of the work activities planned for Phase 1A. After such experience, Sempra can demonstrate the level of work completed and will have actual cost data that can be used to forecast the next level of testing and replacement work with more accuracy than its current Class 5 estimate.

2. The Commission Should Adopt a One-Way Balancing Account Based on Uncertainties Associated with Class 5 Cost Estimates

DRA recommends adopting a one-way balancing account treatment of the cost to pressure test pipelines. Due to the lack of engineering design and analyses in the level of work and Class 5 cost estimates proposed in the Plan by Sempra, DRA recommends that ratepayers be protected from the uncertainties of Sempra's proposal.

The one-way balancing account will provide Sempra with a spending target but also ensure that money is spent prudently. If expenditures do not meet the spending target, the unspent funds are returned to the ratepayers. If the expenditures exceed the target, that amount over the target is not recoverable through rates and is absorbed by shareholders.

E. The Commission Should Adopt the Base Case, with Some Modifications, and Reject the Proposed Case

1. Sempra's Base Case versus Proposed Case

Within the Phase 1 proposal, Sempra has presented 2 plans to address D. 11-02-019 requirements: one Sempra identifies as the Proposed Case and the other it refers to as the Base Case. The Base Case addresses the requirements of D.11-06-017 and the Proposed Case requests approval of additional measures beyond the Commission's orders. According to Sempra:

> SoCalGas and SDG&E strive to be proactive and innovative in our approach to pipeline safety and reliability. Therefore, our proposed plan also offers proposals to enhance our system beyond the measures strictly required under D.11-06-017, and includes alternatives that can be adopted by the Commission…[73]

The Base Cases for SoCalGas and SDG&E include pipeline replacement, pressure testing, inline inspection, Remote Control and Automatic Shutoff Valves, and Interim safety enhancement measures. The Proposed Cases for SoCalGas and SDG&E include expenses in addition to the Base Case, plus expenses for the following categories: (a) Mitigation of Pre-1946 Construction Methods, (b) Technology Enhancements, and (c) Enterprise Asset Management System.[74]

For ease of reference, DRA describes the primary differences between the Proposed Case and the Base Case for both Phases 1A and Phase 1B below. Although the cost differences between the Proposed Case and the Base Case identified for Phase 1A are relatively small, the costs increase significantly in the Proposed Case in Phase 1B. The Proposed Case projects start small in Phase 1A but begin to accumulate substantial costs in Phase 1B if the Commission approves Sempra's enhancement measures. This is especially apparent with the proposal to replace Pre-1946 pipelines in SoCalGas' plan for $1.1 billion.[75]

For SoCalGas, the Base Case proposal is $1.4 billion for years 2011-2021, which includes $817 million for pipeline replacement, $181 million for pressure testing, $58 million for In-Line Inspection, $315 million for Remote Control and Automatic Shutoff Valves, $11 million for Interim Safety Enhancement Measures,

[73] Amended Testimony, p. 2.

[74] Amended Testimony, Appendix B.

and $1 million for Implementation costs.[76] The SoCalGas Proposed Case for years 2011-2021 costs $2.5 billion and exceeds the Base Case by $1.2 billion.[77] The Proposed Case includes an additional $1 billion for Mitigation of Pre-1946 Construction Methods, an additional $64 million for Technology Enhancements and an additional $6 million for Enterprise Asset Management System.[78]

For SDG&E, the Base Case proposes $594 million in costs, which includes $515 million for pipeline replacement, $11 million for Pressure Testing, $4 million for In-Line Inspection, $64 million for Remote Control and Automatic Shutoff Valves, $2 million for Interim Safety Enhancement Measures, and $1 million for Implementation Costs.[79] The SDG&E Proposed Case exceeds the Base Case by $9 million and includes $9 million in additional expenses for Technology Enhancements ($9 million) and Enterprise Asset Management System ($1 million).[80]

A summary of the differences between the Proposed Case and the Base Case for SoCalGas and for SDG&E is presented in the tables below.

(continued from previous page)

75 Amended Testimony, Appendix B.

76 Amended Testimony, Appendix C, p. C-1.

77 Amended Testimony, Appendix B.

78 Ibid.

79 Amended Testimony, Appendix, p. C-2.

80 Amended Testimony, Appendix, p. B-2.

<u>Table 4</u>

SoCalGas
Base Case and Proposed Case for <u>Phase 1A</u>
(In Millions of Dollars)

BASE CASE	**Direct Costs**	**2012**	**2013**	**2014**	**2015**	**Total**
	Pipeline Replacement (Capital) ($132 M for Transmission +$686 M for Distribution)	$90	$243	$243	$243	$818
	Pressure Testing (O&M)	$36	$49	$48	$48	$182
	In-Line Inspection (O&M)	$12	$15	$15	$15	$58
	Remote Control &Auto Shutoff Valves	$26	$28	$34	$34	$120
	Interim Safety Enhancement Measures	$4	$0	$0	$0	$4
	Implementation Costs	$1	0	0	0	$1
	Annual Base Case Total	**$169**	**$335**	**$340**	**$340**	**$1,184**
PROPOSED CASE	**Base Case Total + the Following:**					
	Mitigate Construction/Fabrication Methods (Replace 3996 Wrinkle Bends)	$29	$57	$57	$57	$200
	Technology Enhancements	$15	$17	$8[81]	$7[82]	$47
	Enterprise Asset Management	$6	$0	0	0	$6
	Proposed Case Annual Total	**$219**	**$410**	**$405**	**$405**	**$1,439**

Source: Direct Costs from Appendix C of the Amended Testimony, p. C-1.

[81] $7 million is for Capital and $1 million is for O&M.
[82] $6 million is for Capital and $1 million is for O&M.

Table 5

SDG&E
Base Case and Proposed Case for Phase 1A
(In Millions of Dollars)

BASE CASE	**Direct Costs**	**2012**	**2013**	**2014**	**2015**	**Total**
	Pipeline Replacement (Capital) ($14 M for Transmission + $182 M for Distribution)	$23	$58	$58	$58	$197
	Pressure Testing (O&M)	-	-	-	-	-
	In-Line Inspection (O&M)	-	-	$4	-	$4
	Remote Control & Auto Shutoff Valves	$5	$6	$7	$7	$25
	Interim Safety Measures	$1	$0	$0	$0	$0
	Implementation Costs	$1	$0	$0	$0	$1
	Annual Base Case Total	**$29**	**$64**	**$70**	**$65**	**$228**
PROPOSED CASE	**Base Case Total +The Following:**					
	Technology Enhancements	$2	$2	$1	$1	$6
	Interim Safety Measures	$1	$0	$0	$0	$1
	Proposed Case Total	**$32**	**$67**	**$71**	**$66**	**$236**

Source: Pipeline miles from the Amended Testimony, p. 5. Direct Costs from Appendix C of the Amended Testimony, p. C-2.

2. Why the Commission Should Adopt the Base Case, with Some Modifications, and Reject the Proposed Case

Sempra requests funding to perform the work activities identified in the Proposed Case, and not the Base Case. DRA recommends that the Commission reject the Proposed Case and adopt the Base Case, with modifications, instead. Sempra's Proposed Case has added activities and projects that are costly and unnecessary to achieve the safety directives of D.11-06-017.

D.11-06-017 directed California utilities to replace or test transmission pipeline that have not been pressure tested. The Decision should not be used as an opportunity to "enhance" their systems by accelerating certain replacements or to improve the way they manage their technology. Funding for these proposed investments should be requested in the utilities' GRCs. DRA recommends that all of the funding for additional activities Sempra requests in the Proposed Case be denied. DRA recommends that Sempra's proposal in its Base Case to conduct in-line inspections of pipelines prior to pressure testing be rejected. DRA's analysis is presented below.

a. The Commission Should Reject Sempra's Proposal To Replace Wrinkle Bends (as Part of the Proposed Case)

Sempra requests $199.8 million to replace 3,996 wrinkle bends as part of its proposal to Mitigate Construction/Fabrication Methods.[83] Sempra says its proposal is to replace wrinkle bends on lines scheduled to be pressure tested first so that the construction threats are removed before the pressure tests.[84] Sempra states that these wrinkle bend replacements are scheduled to start in the second half of 2012 and be completed by the end of 2015.[85] The wrinkle bend replacement plan in Phase 1A and Phase 1B is part of Sempra's proposal to mitigate construction/fabrication threats that include the replacement of all pre-1946 pipelines in Phase 1B.

Sempra has not demonstrated that this proposal is just and reasonable, and it therefore should be rejected. First, Sempra acknowledges that its proposal to replace wrinkle bends goes beyond the requirements of D.11-06-017.[86] Nor has Sempra demonstrated that including these costs in this proceeding will actually be beneficial to customers. Sempra's Base Case proposal to pressure test and replace its pipelines in the next four years will significantly increase rates; Sempra has not justified the additional costs to accelerate the replacement of 3,996 wrinkle bends in the Proposed Case. Sempra is currently managing wrinkle bends as part of its Transmission Integrity Management Program.

Second, Sempra has not supported the cost estimate of the 3,996 wrinkle bend replacement. In its workpapers, Sempra estimated that the unit cost of replacing a

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[83] Amended Workpapers, WP-IX-1-48.

[84] Amended Workpapers, WP-IX-1-46.

[85] Ibid.

[86] Amended Testimony, pp. 42, 51, 55 and Response to PZS2-5.

wrinkle bend would be $75,000 "based on historical projects."[87] In the same workpaper, Sempra reduced the unit cost to $50,000 each on the lines scheduled to be pressure tested "due to efficiency gains."[88] To attempt to verify Sempra's cost estimates, DRA requested a copy of all historical projects and calculations used to determine the unit cost of wrinkle bend replacement. SoCalGas/SDG&E did not provide any copies, stating instead that "The cost estimate of $50,000 per Phase 1A wrinkle bend is a high-level allowance for replacement of these pipe features."[89] At a later date, Sempra provided a response which states, "This cost figure represents a high level allowance for the replacement of these pipe features. Question 1(g) of TY2012 GRC data request DRA-SCG-022-DAO identifies an average repair cost per foot of $1,343 based on data from the 2005 to 2009 timeframe. Assuming that a 25-foot section of pipe would be replaced for each wrinkle bend repair yields approximately $33,575 per repair. From the same TY2012 data response, Question 6(e), the average expense per excavation dig was approximately $40,000. Combining these two values and rounding up slightly equals $75,000, thus giving validation that the assumption used in the PSEP filing for wrinkle bend replacements is reasonable. Each project may have unique circumstances that could result in actual costs being above or below this assumed unit cost."[90] No actual cost of any wrinkle bend replacements was identified; only averages of pipeline repairs from the 2005-2009 timeframe were provided.

Finally, wrinkle bend replacement is an issue currently addressed in Sempra's TIMP. This issue should continue to be addressed there. SoCalGas currently receives funding for and performs wrinkle bend replacement through its Baseline Assessment within the TIMP. In the course of assessing its pipelines for threats, wrinkle bends

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[87] Amended Workpapers, p. WP-IX-1-48. Footnote 1.

[88] Ibid, at Footnote 2.

[89] Sempra's Response to DRA-DAO-21, Q. 2(b).

[90] Sempra's Response to DRA-DAO-24-Q.3(a).

are replaced if deemed “not stable.” Wrinkle bends deemed “stable” are allowed to remain in service per federal regulations [CFR 49, 192, Subpart O, and B31.8S].[91] According to Sempra, “Within the TIMP, the wrinkle bends identified as part of the PSEP are currently considered as stable in the absence of other factors that may exacerbate their condition (such as external forces that may subject the wrinkle bends to movement).”[92] These wrinkle bends have been assessed by Sempra recently as part of TIMP and will continue to be monitored and reassessed at least once every seven years as part of federal requirements regulating TIMP. Additional funding to replace wrinkle bends should be requested by Sempra in its next GRC in conjunction with its TIMP.

In the 2012 GRC, Sempra requested $25 million in expenses to manage its TIMP program[93], which is an increase of $14 million above the base year 2009 level. Since its baseline assessment is scheduled to be completed by the end of 2012, Sempra should evaluate and identify threats associated with its transmission pipelines and manage them accordingly.

Wrinkle bends identified as “unstable” should have been replaced by Sempra as part of TIMP. In its Test Year 2012 GRC, Sempra did not identify the issue of wrinkle bends as a threat to its system and failed to propose a system-wide accelerated replacement of wrinkle bends in that proceeding. Sempra has not provided any showing that these 3,996 wrinkle bends need to be addressed to meet the requirements of D.11-06-017, or that they need to be replaced during the next 4 years.

For all the reasons stated above, DRA recommends rejecting this proposal as part of this Pipeline Safety Enhancement proceeding. Sempra should continue to address wrinkle bends as part of its management of TIMP.

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[91] Sempra’s statement to DRA during April 25, 2012 Conference Call.

[92] Sempra’s Response to DRA-24, Q. 3 (f).

[93] A.10-12-006, Exhibit-SCG-05-R, Revised Prepared Testimony of Raymond K. Stanford, p. RKS-25.

As for the Pre-1946 pipelines, Sempra is currently managing these lines as part of the requirements of Subpart O. According to Sempra, SoCalGas and SDG&E have already identified and retrofitted, and in-line inspected all pre-1946 transmission pipelines that were constructed using acceptable welding techniques and are operationally suited to in-line inspection.[94] The Pre-1946 pipelines identified for replacement in Phase 1B are the remaining non-piggable pipelines located in non-populated areas and are not planned to be retrofitted to allow for in-line inspection.[95]

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 associated 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.

b. The Commission Should Reject Sempra's Proposal To Include Expenses For Technology Enhancements (As Part Of The Proposed Case)

i. Sempra Has Not Justified Its Proposal To Enhance A System It Testifies Is Safe

Sempra requests $53 million ($47 million for SoCalGas and $6 million for SDG&E) to install fiber optic cabling and methane detection instruments as a safety enhancement.[96] Sempra proposes to install about 280 miles of fiber optic technology in association with pipeline replacements during phase 1.[97] Sempra states, "Fiber optic right-of-way monitors will help SoCalGas and SDG&E identify when intrusions

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[94] Sempra's Response to DRA-DAO-9, 2(c).

[95] Sempra's Response to DRA-DAO-9, 2(a).

[96] Amended Testimony, Appendix B.

[97] Amended Testimony, pp.85-86.

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."[98] Sempra proposes to "further enhance" its system 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 of a high-pressure, large-diameter gas transmission pipeline.[99]

Sempra proposes to develop a new data collection, storage, alarm processing and data management system to collect information from the methane detection and fiber optic monitors. Sempra states that the data collection and management system (DCMS) will provide the health/status of all fiber optic and methane detection monitors by way of daily status reporting and remote data collection.[100] Also, the DCMS will receive alarm information initiated by any fiber optic or methane detection monitor with a latency of less than 2 minutes.[101] Sempra states that DCMS will also provide permanent storage of all events with appropriate time and date stamping of events. Sempra says DCMS will accommodate future expansion to 10,000 monitoring points and multiple sensor types, as well as support near real-time graphical viewing presentation of alarms on SoCalGas/SDG&E mapping products and provide connectivity with automated customer notification system.[102]

Sempra's proposal for additional technology enhancements is above and beyond the scope of the Commission's directives. Sempra has repeatedly claimed that it is confident in the safety of its system as in its Report to the NTSB as well as in its Testimony in this proceeding. Even if it proposes to address certain pipelines in the Plan, Sempra believes that these pipelines are operating safely today. In the

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[98] Amended Testimony, p. 85.
[99] Amended Testimony, pp. 86-87.
[100] Amended Testimony, p. 87.
[101] Amended Testimony, p.87.
[102] Amended Testimony, pp. 87-88.

Report on Actions Taken in Response to the NTSB Recommendations, Sempra states, "During the course of their records review, SoCalGas and SDG&E did not discover any documented inconsistencies that would call into question the standard engineering practices used throughout the years, nor cause concern regarding the current pressure-carrying capacity of in-service pipelines…"[103] Although SoCalGas and SDG&E have identified pipelines that need to be pressure tested or replaced— Category 4 miles that are the focus of this proceeding and the Commission's objective to ensure that California pipelines are operating safely, the utilities testify, "Nothing in our records review process revealed any significant concerns with the currently-established MAOPs for Category 4 pipelines. Accordingly, we remain confident that these pipelines are operating safely."[104]

Sempra's Annual Reports to PHMSA regarding its transmission integrity program continue to show a system that is operating safely. A summary of the number of leaks, failures, and incidents from 2003-2010 is presented below.

Table 6

SoCalGas and SDG&E

Year	Failures	Incidents	Leaks
2003-2004	1	0	10
2005	2	0	2
2006	1	0	1
2007	5	0	6
2008	0	0	0
2009	0	1	0
2010	0	0	2

Source: Response to DRA-PZS-02-Q.1(f)

According to Sempra, the metrics used for evaluation of each utility's safety record for the transmission pipeline integrity program are leaks, failures, and

[103] The Report, p. 10.
[104] The Report, p. 3.

incidents as required by 49 CFR 192.945(a) and are defined as follows[105]:

> **Leaks** are unintentional escapes of gas from a pipeline that are not reportable as Incidents under 49 CFR 191.3. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak.
>
> **Failure** is defined in ASME/ANSI B31.8S as the "general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use." Failures that result in an unintentional release of gas are reported as leaks.
>
> **Incident**, as defined in 49 CFR 191.3, "means any of the following events: (1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences: (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;(iii) Unintentional estimated gas loss of three million cubic feet or more; (2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident. (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition."

ii. Sempra's Proposal is Beyond the Directives of D.11-06-017

Sempra is proposing enhancements to its operations that are above and beyond the requirements of the Decision. Nothing in D.11-06-017 requires Sempra or any utility to find ways to monitor disturbances on its system as part of the Pipeline Safety Enhancement proceeding. The Decision directed California gas operators to test or replace transmission pipelines that have not been pressure tested. Sempra has not shown why its proposal for fiber optic and methane detection monitors, or DCMS, should be included as part of the Plan.

Sempra's references to facilities that are high-occupancy and pose evacuation challenges do not justify including the costs of this proposal in this proceeding.

[105] Sempra's Response to DRA-PZS-02, Q. 1(f).

Sempra already treats high-occupancy areas differently. These areas are defined as High Consequence Areas and Sempra receives additional funding to manage the transmission pipelines located in these areas as part of its TIMP program.

As part of TIMP, Sempra is required to identify the threats to its pipelines in HCAs, analyze the risk posed by these threats, collect information about the physical condition of its pipelines, and take actions to minimize applicable threats and integrity concerns before pipeline failures occur. If methane detection monitors will enhance the safety and integrity of the lines in high-occupancy, high consequence areas, then the company should leverage the installation of these monitors in the TIMP program.

Leaks that the fiber optic monitors are designed to pick up are normal day to day risks that Sempra has to manage. Sempra performs leak surveys on a regular basis. Abnormal vibrations from right-of-way activity, such as by construction crews working in an area are also risks Sempra must manage, and Sempra is part of the Underground Service Alert that manages the third party constructions and dig-ins.

If Sempra wants to pursue ratepayer funding of system enhancements, it should do so in its General Rate Case. By that time, Sempra will have prepared a cost benefit analysis to determine if the benefits of these projects outweigh the costs and if this is a prudent use of ratepayer funding. Sempra's request in this proceeding to saddle ratepayers with additional costs for fiber optic and methane detection should be rejected.

c. The Commission Should Reject Sempra's Proposal to Include Costs Associated with Enterprise Asset Management (as Part of the Proposed Case)

Sempra seeks $7 million ($6 million for SoCalGas and $1 million for SDG&E) to design a comprehensive Enterprise Asset Management System (EAMS) as part of its Plan.[106] Sempra states that the EAMS will focus on applying industry record management practices and information technology solutions to govern, record, store,

[106] Amended Testimony, Appendix B.

secure, maintain, assess, search and analyze transmission pipeline system data.[107] According to Sempra, the EAMS will support leading records and data governance practices and controls; ensure the validity, traceability and completeness of pipeline data; and provide Sempra personnel with secure, anytime, anywhere access to critical system data.[108]

DRA recommends rejection of the requested $7 million for the EAMS because Sempra acknowledges that this proposal goes well beyond the directives of the Commission to pressure test or replace pipelines located in Class 3, 4 and Class 1, 2 High Consequence Areas.[109]

Sempra responded to the NTSB recommendations and prepared its Plan as required by D.11-06-017 using its current records and data management system. Sempra reviewed pipeline records and determined whether or not specific lines should be identified for pressure testing or replacement using its current system. If the current records and data management systems are inadequate, SoCalGas and SDG&E should raise this issue in their next General Rate Case applications. Moreover, the cost of record keeping is already embedded in rates: Sempra's ratepayers are already paying for accurate and orderly record keeping of pipeline information. Sempra acknowledges that:

> Record keeping is part of SoCalGas' and SDG&E's existing pipeline integrity program. Transmission pipeline data is stored and organized in a manner that supports the analysis and decision making required for pipeline integrity work.[110]

[107] Amended Testimony. p. 92.
[108] Ibid.
[109] Sempra Response to PZS-2, Q.5, (b).
[110] Response to PZS-2, Q.4 (c).

In its Test Year 2012 GRC, SoCalGas and SDG&E provided testimony describing a set of enterprise, technology-based initiatives intended to make the utilities more efficient. The program is called Operational Excellence.[111] In the last GRC, Sempra requested $545 million to implement the Operational Excellence Program or OpEx 20/20.[112] According to SoCalGas' testimony in that case, "the non-financial benefits [of OpEx 20/20] include…more accurate and timely asset information and ready access to information in the field for front line supervisors, technicians and crews."[113]

The OpEx 20/20 is an enterprise program composed of three major work streams containing 12 projects.[114] One of these projects is the Geographic Information System (GIS). In its Test Year 2012 GRC testimony, SoCalGas states that, "the GIS project implements an industry standard, enterprise-wide geographic information system that supports SoCalGas and SDG&E gas transmission and distribution, electric transmission, substation, distribution, and vegetation management, and Sempra Utilities land services, environmental, and telecommunication. Critical to this GIS is a centralized asset register with validated asset attribute data, integration to other key asset management systems and applications such as outage management, network modeling, work management, graphical work design, and mobile data devices."[115]

In addition to the data management and integration through OpEx 20/20, SoCalGas and SDG&E currently use several databases for record and data management of transmission and distribution pipelines. These data bases record, store, secure, maintain, search and analyze and provide access to the transmission and

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[111] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-1.
[112] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-1.
[113] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-3.
[114] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-3.
[115] Ibid., p. RP-2A.

distribution pipeline system data. For SoCalGas, the databases and applications currently in use are[116]: (1) Maximo, (2) SAP, (3) Enterprise GIS, (4) High Pressure Pipeline Database, (5) NTSB Access Database, (6) PDMS, (7) Bell Hole Inspections, (8) Casings, (9) DREAMS, and (10) Falcon/DDB. For SDG&E, the utility currently uses the same databases and applications as SoCalGas with the exception of the Falcon/DDB. Instead, SDG&E uses Gport.

The primary functions of each database are described below:

a. Maximo---Oracle database of all maintenance work performed by Transmission and Storage Operations personnel on pipelines, equipment and facilities.

b. SAP—SAP plan Maintenance (PM) is used to record and manage preventative maintenance and inspection activities for distribution operated pipelines.

c. Enterprise GIS—Spatial data repository for Transmission and Distribution assets. Network Model and spatial analysis tools to support system modeling.

d. High Pressure Pipeline Database—Spatial data repository for High Pressure Pipelines. Spatial analysis tools that primarily support Pipeline Integrity.

e. NTSB Access Database—MAOP records collection and segment categorization.

f. PDMS— Pipeline Document Management System (PDMS) contains construction records.

g. Bell Hole Inspections—Access database of excavation inspections and locations conducted as part of the Pipeline Integrity Management Program.

[116] Sempra's Response to DRA-DAO-34, Q. 2.

h. Casings—Access database used to inventory casing locations and extents.

i. DREAMS—the Distribution Risk Evaluation and Monitoring (DREAMS), an Oracle database used by Pipeline Integrity as a repository for leak records on medium pressure distribution pipelines.

j. Falcon/DDB—Transmission and storage construction drawing Oracle database and viewer.

k. GPort—Plant maintenance information for valve and historic regulator station maintenance records.

Sempra has not demonstrated that the eleven existing databases and applications currently in use are inadequate for the management of data and records for purposes of meeting the requirements of D.11-06-017. Sempra says that the EAMS will provide personnel with "...secure, remote, anytime, anywhere access to critical pipeline information through a web portal using a variety of mobile computing devices,[117] but has not shown the need for this level of access and availability to information in this proceeding.

Sempra's ratepayers are already paying for eleven databases and applications, in addition to OpEx 20/20, for data and record management. Sempra has not demonstrated that ratepayer funding for Enterprise Asset Management is necessary for Sempra to meet the requirements of D.11-06-017. DRA, therefore, recommends the Commission reject Sempra's request for additional ratepayer funding of $7 million for the program.

[117] Amended Testimony, p. 93; comments at May 30, 2012 Workshop.

3. Flaws in the Sempra Decision Tree Outcomes

a. Sempra's Decision Tree

Sempra says its proposal to pressure test or replace a pipeline segment is determined by the outcomes of its Decision Tree. The Decision Tree prioritizes work for one of three phases, Phase 1A, Phase 1B, and Phase 2.[118]

Sempra's Decision Tree starts with all pipeline operated in a Class 3 or 4 locations or High Consequence Area (Criteria Segments) for which Sempra does not have documented pressure carrying capability of ≥ 1.25*MAOP or Maximum Allowable Operating Pressure. Applying the Decision Tree, Criteria Segments with no safety validation or validated at less than 1.25*MAOP would be addressed in Phase 1A and all other Criteria segments that have ≥ 1.25*MAOP would be addressed in Phase 1B or Phase 2.

The starting point of the Decision Tree is also the 1,622 miles of NTSB Criteria Miles identified in the Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations.[119]

There are 5 outcomes for pipeline segments that go through Phase 1A of the Decision Tree. Outcome #1 is Complete Direct Examination or Replace and Abandon. Outcome #2 is Replace and Abandon. Outcome #3 is Complete TFI in-line inspection. Outcome #4 is Pressure Test. Outcome #5 is TFI inspect and Pressure Test.

For Phase 1B, there are 4 outcomes. Outcome # 6, which is directly linked to Outcome #3, is Install New Line and Pressure Test Existing Line. Outcome # 7 is Replace. Outcome #8 is to move pipeline into Phase 2. Lastly, Outcome #9 is No Further Action.

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[118] Amended Testimony, p. 61.
[119] The Report, p. 11.

A summary of the number of miles of Category 4 pipelines identified in the Decision Tree and used to develop the Plan's scope is presented below.

Table 7

Sempra Testimony, Decision Tree Outcome for Phase 1A

Category 4 Criteria Miles

	SoCalGas	SDG&E	Total
Outcome #1, NDE or Replace	2 miles	0 miles	2 miles
Outcome #2, Replace and Abandon	126 miles[120]	28 miles[121]	154 miles
Outcome #3, TFI inspection	0 miles	0 miles[122]	0 miles
Outcome #4, Pressure Test	11 miles	1 mile	12 miles
Outcome #5, TFI inspection & Pressure Test	165 miles	0 miles	165 miles
TOTAL CATEGORY 4 Miles	**304 miles**	**29 miles**	**333 miles**

Source: Sempra's Response to DRA-DAO-5, Q. 1, the Plan workpapers, Chapter IV.

b. DRA Takes Issue with Sempra's Decision Tree Outcomes

In general, Sempra's Decision Tree is efficient at addressing the Commission's order of identifying and prioritizing the testing of pipelines that lack records of having had a pressure test. However, there are several decision outcomes that DRA opposes.

DRA disagrees with Outcome #1 which identifies pipelines to replace and abandon if the pipeline segments are less than 1000 feet in length. DRA disagrees with Outcome #2, which identifies pipelines to replace and abandon if the pipeline segments are non-piggable and cannot be taken out of service with manageable customer impact. DRA disagrees with Outcome #5, which identifies pipelines to

[120] For SoCalGas, a total of 145 miles are scheduled for replacement with 128 miles of new construction (2 miles from Outcome #1 and 126 miles from Outcome #2) and 16 miles of abandonment. Response to DRA-DAO-5, Q.1.

[121] For SDG&E, a total of 32 miles are scheduled for replacement with 28 miles of new construction and 5 miles of abandonment. Response to DRA-DAO-5-Q.1.

[122] SDG&E proposes to TFI inspect and repair 54 Accelerated miles in 2014 for a total of $4 million.

perform TFI inspection and Pressure Test. DRA also disagrees with Sempra's sub-prioritization methodology. DRA recommends that Sempra incorporate the Class location of individual segments in the sub-prioritization methodology. Finally, DRA disagrees with the inclusion of pipeline segments located in non-populated areas, outside of the Decision Tree as Phase 1A work instead of a later phase.

DRA's analyses and recommendations for pipelines specific to these Decision Tree outcomes are addressed in the sections below.

1. Pipeline Replacements

Sempra uses two criteria from the Decision Tree to determine pipeline replacements: (1) all segments that are 1,000 feet or less in length, and (2) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing and that are not piggable.

i. Pipeline Segments ≤1,000 Feet

Sempra has identified two miles of SoCalGas transmission pipelines with segments less than 1,000 feet that need to be addressed in Phase 1A.[123] Sempra states, "For short segments of pipe, the logistical costs associated with pressure testing (permitting, construction, water handling, service disruptions for non-looped system) can approach or exceed the cost of replacement.[124] Sempra's proposal to replace instead of hydrostatic test segments less than 1,000 feet should be rejected. Sempra did not adequately support this proposal.

Alternatively, Sempra requests the option to perform a complete inspection of the pipeline segment using non-destructive examination (NDE) methods, such as ultrasonic, radiographic and magnetic particle inspection techniques. Sempra states that non-destructive examination offers an equivalent means to validate the strength

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[123] Amended Testimony, p. 53.

[124] Amended Testimony, p.53.

of the pipeline segment.[125] Also, Sempra states that the use of these techniques will reduce the time, costs, customer impacts and construction hazards associated with replacement.[126]

DRA takes issue 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. Instead, DRA recommends that these short segments be pressure tested. Pressure testing a pipeline segment continues to be the recommended method to strength test a pipeline segment according to the 2010 ASME code. Pressure testing a pipeline segment continues to be required by Title 49 CFR, Subpart J.

Sempra has no basis for its proposal of automatically replacing segments less than 1,000 feet. Sempra's statement that the cost of pressure testing these short segments can approach or exceed the cost of replacement is unsupported. Although Sempra claims in testimony that it is more cost effective to replace these segments, Sempra did not perform any cost benefit analyses to support this claim. Sempra states, "…SoCalGas and SDG&E did not conduct a formal cost/benefit analyses to determine that pressure testing of short pipeline segments less than 1,000 feet in length would exceed the cost of replacement. This determination was based on engineering judgment."[127] Sempra further states, "Once detailed planning and engineering/design is completed, there may be cases where it is determined that a pressure test is more cost effective than a replacement."[128]

In the past, SoCalGas has performed several pressure tests on segments that are shorter than 1,000 feet as part of its Transmission Integrity Management Program. Between 2005 and 2011, SoCalGas performed pressure tests on multiple segments

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[125] Amended Testimony, p. 54.

[126] Amended Testimony, p.54.

[127] Sempra's Response to DRA-DAO-3, Q. 1.

[128] Ibid.

ranging from as short as 52.8 feet to as long as 17.85 miles.[129] When asked if in the past SoCalGas had replaced instead of pressure test pipeline segments less than 1,000 feet because it was more cost effective to do so, Sempra was non-responsive.[130]

DRA recommends that the Commission reject the proposal to replace the segments that make up the 2 SoCalGas miles. Instead, DRA recommends that Sempra pressure test these segments. Without adequate justification to replace instead of test, it is unreasonable for Sempra to request the more costly option. If the Commission finds NDE methods achieve the same standard of safety as hydrostatic testing, DRA would not take issue with the use of NDE methods.

ii. Pipeline Segments >1000 Feet that Sempra Says Cannot Be Taken Out of Service with Manageable Customer Impact, and not Piggable (Outcome #2)

Sempra's Decision Tree also identifies a pipeline segment for <u>replacement</u> if it meets the following criteria: (1) the pipeline segment is located in a Class 3 or 4 location of High Consequence Area and does not have documented pressure carrying capability of $\geq$ 1.25 MAOP and (2) the pipeline cannot be taken out of service with manageable customer impact, and (3) the pipeline has not been retrofitted to accommodate an in-line inspection tool (non-piggable).

Sempra requests a total of $818 million in capital expenditures to replace a total of 260 miles of Criteria and Accelerated pipelines.[131] 2.14 miles were based on Outcome #1[132] and 257 miles were based on Outcome #2.[133] Of the total 260 miles, 42 miles will be abandoned and 28 new segments will be added.[134] The net total of

[129] Sempra's Response to DRA-DAO-2, Q. 14.
[130] Sempra's Response to DRA-DAO-3-3.
[131] Amended Workpapers, p. WP-IX-1-22.
[132] Amended Workpapers, p. WP-IV-5 of 12.
[133] Amended Workpapers, p. WP-IV-7 of 12.
[134] Amended Sempra Response to DRA-DAO-5, Q.1.

new pipeline construction is 246 miles.[135] Of this total, 128 miles, or 52 percent, are identified as Criteria Miles and 118 miles, or 48 percent, are identified as Accelerated Miles.[136]

Sempra requests a total of $197 million in capital expenditures to address 102 miles of SDG&E pipelines.[137] Of this total, $14.3 million is allocated to address the design and engineering work for 54 miles of Line 1600.[138] One hundred percent of the 54 miles of Line 1600 is designated as Accelerated. The remaining $182.2 million is for the replacement of 48.5 miles of SDG&E Distribution pipelines.[139] The Accelerated segments make up 42 percent of the total planned replacement of the Distribution pipelines.[140]

2. The Commission Should Reject Sempra's Proposal To Replace Instead of Pressure Test Pipeline Segments >1,000 Feet Based on Unsupported Assumptions about "Manageable Customer Impact"

Sempra's main criterion to identify pipelines for replacement is whether or not they can be taken out of service with manageable customer impact. Conceptually, this sounds reasonable, but Sempra's explanation of how the company determines a "manageable customer impact" is inadequate and unsubstantiated.

Sempra says "Manageable Customer Impact" means: "…an acceptable level of negative effects to our customers as a result of the PSEP."[141] The criteria Sempra used to determine whether a segment can be taken out of service are "…based upon

[135] Sempra's Response to DRA-5, Q. 1.
[136] Ibid.
[137] Amended Workpapers, pp. WP-IX-1-33 and WP-IX-1-35.
[138] Amended Workpapers, p. WP-IX-1-34.
[139] Amended Workpapers, p. WP-IX-1-36.
[140] Amended Workpapers, p. WP-IX-1-36.
[141] Sempra's Response to DRA-DAO-7, Q.1.

specific pipeline and local system characteristics that may include, but are not limited to system looping and flexibility; impact to capacity; curtailment to non-core customers; impact to shippers, customers, and the gas market; availability of alternative sources of gas; anticipated outage duration; and the ability to mitigate these negative impacts through construction of parallel systems."[142]

This "criteria" is too vague and subjective to be relied on by the Commission as the basis of ordering ratepayer funding of hundreds of millions of dollars.

iii. The Criteria Used To Determine Manageable Customer Impact Were Based on Judgment and Not Engineering Analyses

Sempra performed no specific analyses on any actual segments or pipelines to determine possible impacts on customers if a line were tested instead of replaced. Sempra provided no data regarding system looping and flexibility; impact to capacity; curtailment to non-core customers; impact to shippers, customers, and the gas market; availability of alternative sources of gas; anticipated outage duration; and the ability to mitigate these negative impacts through construction of parallel systems. Sempra provided no support for any of the criteria identified as influencing factors in determining whether to replace instead of test a segment of pipeline.

Sempra states the following: "Specific studies or analyses have not yet been performed to identify all customer impacts, and the economic consequences of those impacts, that would be incurred as a result of each specific PSEP pipeline segment being removed from service for the assumed two to six weeks necessary to perform a pressure test. Evaluation of the customer impacts and the cost effectiveness of pressure testing as compared to replacement on a segment-by-segment basis will be conducted during the engineering, design, and execution planning phases of the PSEP."[143]

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[142] Sempra's Response to DRA-DAO-7-1.

[143] Sempra's Response to DRA-DAO-20-Q.4.

DRA asked if Sempra explored alternatives to serving customers in the areas where lines and segments have been identified for replacement because Sempra determined that they cannot be taken out of service with manageable customer impact. Sempra states, "The development of the pressure test and replacement scope for the PSEP was done at a high level and all options to manage customer impacts have not yet been evaluated. Such evaluation, including an analysis regarding the viability of alternatives to serve customers while pipelines are out of service for pressure testing, will occur during the engineering/design phase of each project."[144]

As with so much else in Sempra's Plan, there is scant, if any, verifiable support; rather, there are only unverified assertions that everything will be designed and engineered at some point in the future.

iv. The Commission Should Reject Sempra's Unsupported Assertion that Un-piggable Pipelines Should Be Replaced

Sempra's other proposal that pipelines that are not-piggable must be replaced is similarly unsupported. Sempra has not identified any explanation as to why non-piggable pipelines cannot be pressure tested and why, consequently, the Commission must adopt the more expensive alternative of replacement.

Given the Sempra estimate for replacement at seven times higher than for pressure testing[145], there is a disincentive for Sempra to pursue an action that is lower in costs. Absent clear evidence that it is absolutely necessary to replace these particular pipeline segments, Sempra should not be allowed funding for any pipeline replacement in the current proceeding.

v. Pipeline Replacement Projects Should Be Rejected Because Sempra Is Trying To Use the Plan To Increase Capacity Without Justification

[144] Sempra's Response to DRA-DAO-20, Q. 5.

[145] The average cost of pipeline replacement in the Plan is $3.5 million per mile and the average cost of a hydrostatic test is $500,000 per mile.

Sempra proposes to increase the size of its pipelines for many replacement projects proposed in the Plan. DRA reviewed the Sempra proposal for SoCalGas Distribution Replacement and found that 21of the 54 individual projects (or 40%) that had its own workpapers, show an increase in pipeline diameter for the proposed new replacement.[146] The increase in diameter ranges from 1" to several inches in size.

There are several examples that warrant concern due to significant increases in pipeline diameter.

a. Line 41-6000-2 and L-6914 Should be Removed from the Plan

The proposal to abandon Line 41-6000-2 and extend Line 6914 appears to be a project designed to address issues above and beyond the scope of D.11-06-017. Sempra proposes to abandon 36 miles of Line 41-6000-2, with segment diameter range from 6"-16" and install 14 miles of new segments with smaller diameter ranging from 2" to 6". These segments are then used to tie L-6914 in to the existing pipeline system with an additional 14 miles of pipelines with a diameter of 10" and 24".[147] The total cost of this project is \$77.8 million with \$24.8 million for the abandonment and replacement of Line 41-6000-2 [148] and \$53 million for the extension of Line 6914.[149]

This project does not appear to have been planned based on the criteria used in the Decision Tree. While the 36 miles of pipelines proposed for abandonment are identified as having come from Box 2 of the Decision Tree, no action plan was identified for L-6914. DRA asked Sempra about this project and Sempra stated that it was a "capacity planning" project. The one sentence statement in Sempra's

[146] DRA did not look at any small projects that Sempra grouped together and that did not have its own workpapers.

[147] Amended Workpapers, pp. WP-IX-1-B170-B172, and WP-IX-1-A89-A91.

[148] Amended Workpapers, p. WP-IX-1-B170.

[149] Amended Workpapers, p. WP-IX-1-A89.

workpapers, “The extension of existing L-6914 will allow for the abandonment of 41-6000-2” does not provide adequate support for this project.[150] In fact, L-6914 was installed in 2009 and is not a pipeline that should be included in the group of pipelines affected by the Decision to test or replace.[151]

Table 8

Line 6914/Line 41-6000-2

Abandoned					New Construction				
Accelerated	Criteria Category 4								
6.625”-16”	6.625”	8.625”	10.625”	16”	2”	4”	6”	10”	24”
25 miles	6 miles	2 miles	3 miles	.15 miles	2 miles	211 ft	10 miles	3 miles	11 miles
36 miles to be abandoned					Install new 28 Miles* (rounding)				

b. SoCalGas Distribution--Line 38-959 (From 6.25” to 12.75”)

SoCalGas proposes to replace 15.6 miles of Line 38-959 at a cost of $28.3 million.[152] Sempra states, “This system needs pressure betterment due to low pressure problems.”[153] If this is a system planning issue, Sempra should have addressed this as part of the 2012 GRC application or plan to request it in its next GRC, and not in the Plan.

Sempra has not explained why doubling of pipeline diameter for this line is required by D.11-06-017.

[150] Amended Workpapers, p. WP-IX-1-A89.

[151] Sempra’s Response to DRA-16, Q. 6, Decision Tree Database.

[152] Amended Workpapers pp. WP-IX-1-B136 to B138

[153] Amended Workpapers, p. WP-IX-1-B138.

<u>Table 9</u>

Line 38-959

Abandoned			New Construction
Accelerated	Criteria Category 4		
6.625”	4.5”	6.25”	12.75”
11.3 miles	0 miles	4.3 miles	15.6 miles
Replace 15.6 miles			Install new 15.6 miles

c. Line 38-539 (SoCalGas Dist.)

Sempra requests a total of $31 million to replace 12 miles of Distribution pipelines of Line 38-539.[154] 2.3 miles of the total are identified as “Criteria” and 9.7 miles are identified as “Accelerated.” It appears that Sempra is proposing a capacity upsizing project. Sempra proposes to replace pipeline segments with 6.625” and 8.625” in diameter with 10.75” in new construction. The notes in the workpapers show: (1) “Include non-criteria Cat 4 segments” and (2) Upsize to 10” per Master Planning.

<u>Table 10</u>

Line 38-539 (SoCalGas Dist.)

Abandoned			New Construction
Accelerated	Criteria Category 4		
6.625” and 8.625”	6.625”	8.625”	10.75”
9.7 miles	2.1 miles	.22 miles	12 miles
Replace 12 miles			Install new 12 miles

The proposal to replace existing pipelines with new segments to increase capacity does not meet the objective of Commission Decision 11-06-017. Sempra’s proposal is above and beyond the requirements of the Commission. The objective of the Decision is to validate the MAOP of the pipelines that were not pressure tested. Sempra is using the opportunity of the Plan to increase the capacity of its system without any support. Sempra has not performed or presented any cost benefit

[154] Amended Workpapers, pp. WP-IX-1-B129 to B130

analyses or justification as to why the capacity of these lines needs to increase. Sempra's proposal to replace pipelines should be rejected.

vi. Absent Adequate Support for Pipeline Replacement, DRA Recommends Testing All Sempra Identified Category- 4 Lines.

D.11-06-017 states, "…the Implementation Plan must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[155] The Commission requires California utilities to pressure test its transmission pipelines that do not have records to verify that a pressure test has been performed. For those instances where a pipeline segment must be replaced instead of test, criteria must be developed and used to support the replacement work. Sempra's Plan does not provide support for the criteria used to replace pipeline instead of performing a hydrostatic test.

Absent thorough engineering analysis, customer impacts studies, and the economic consequences of those impacts in the Plan, the current pipeline replacement proposals are not adequately supported. DRA recommends funding to perform the hydrostatic tests on the Category 4 pipelines that Sempra has identified for replacement.

3. Absent any Support for the Acceleration of non-HCA Pipelines into Phase 1A, The Commission Should Authorize Funding To Pressure Category 4 Pipelines Only

Sempra requests a total of $182 million in O&M expenses to pressure test 355 miles of SoCalGas pipelines in Phase 1A.[156] Sempra does not propose to pressure test any SDG&E pipelines in Phase 1A.

[155] D.11-06-017, p. 31.

[156] Amended Workpapers, pp.WP-IX-1-5, WP-IX-1-9, and WP-IX-1-13.

The pipeline is pressure tested if it meets the following criteria: (1) the pipeline segment is located in a Class 3 or 4 location of High Consequence Area and not has documented pressure carrying capability of $\geq$ 1.25 MAOP, (2) the sum of the pipeline Criteria Miles is more than 1,000 feet in length, (3) pipeline can be taken out of service with manageable customer impact; and (4) the pipeline has not been retrofitted to accommodate an in-line inspection tool. If the pipeline meets all of these requirements then it will be assigned Outcome #4, "Pressure Test". If any of the pipelines is Pre-1946, it will be abandoned and replaced instead.[157] Sempra's Workpapers show a total of 25 miles identified for pressure testing. Of this total, 11 miles are categorized as Criteria Miles and 14 are categorized as Accelerated Miles.[158]

The pipeline is identified for TFI inspection and pressure testing if: (1) the pipeline segment is located in a Class 3 or 4 location of High Consequence Area and not has documented pressure carrying capability of $\geq$ 1.25 MAOP and (2) the sum of the pipeline Criteria Miles is more than 1,000 feet in length, and (3) pipeline can be taken out of service with manageable customer impact and (4) the pipeline has been retrofitted to accommodate an in-line inspection tool. If the pipeline meets all of these requirements then it will be assigned Outcome #5, "TFI Inspect and Pressure Test". Sempra's Workpapers identified a total of 335 miles for TFI inspection and pressure testing. Of this total, 165 miles are Criteria Miles and 170 miles are Accelerated Miles.[159] Although the Decision Tree identified 335 miles for TFI inspection, Sempra is proposing to TFI inspect a total of 667 miles of pipelines, which is an additional 332 miles of pipelines above the Decision Tree figure.[160]

157 Amended Testimony, p. 61, Decision Tree, Note 1.
158 Amended Workpapers, p. WP-IV-8 of 12.
159 Amended Workpapers, p. WP-IV-9 of 12.
160 Amended Workpapers, p. WP-IX-1-40.

Sempra's proposal for pressure testing and for ILI and pressure testing, as proposed in its workpapers, is summarized below.

Table 11

	Costs	Total Miles	Accelerate Miles	Criteria Miles
Pressure Tests				
SoCalGas				
Distribution	$3,500,000	17	10	7
Transmission	$177,100,000	335	170	165
Storage	$1,200,000	3	3	0
SDG&E	$300	0	0	0
TOTAL	**$182,100,000**	**355**	**183**	**172**
ILI				
		Total Miles		
SoCalGas	$58,000,000	667	-	-
SDG&E	$4,300,000	52	-	-
TOTAL	$62,300,000	719	-	-

Source: Sempra's Amended workpapers, WP-IX-1- 5 and WP-IX-1-9.

For SoCalGas, Sempra proposes to test a total of 355 miles of Category 4 and Accelerated pipelines.[161] Of this total, 172 miles, or 48 percent are categorized as Criteria Miles and 183 miles, or 52 percent, are categorized as Accelerated Miles. Sempra is proposing to test more Accelerated miles than Criteria miles. The average unit cost per mile is $513,000 per mile.[162]

i. Historical Hydrostatic Tests

DRA attempted to provide a comparison of Sempra's consultant's, (SPEC), estimate to Sempra's hydrostatic test cost estimate for transmission pipelines assessed as part of the utilities' day-to-day maintenance and as part of the management of TIMP. However, Sempra did not provide the historical data in a format that would provide a meaningful comparison to the SPEC estimates.[163]

[161] Amended Workpapers, p. Wp-IX-1-5 and 1-9.
[162] Total hydrostatic test cost estimate of $182 million divided by 355 miles.
[163] Sempra's Response to DRA-DAO-2, Q. 14.

Sempra did not provide a breakdown of the cost elements of the historical testing projects so that these cost elements could be compared with what SPEC had estimated.

According to Sempra, the historical costs associated with the hydrostatic tests performed on transmission pipelines under TIMP are co-mingled with other project costs or these costs are not representative of hydrostatic testing of an in-service pipeline.[164] Sempra did not identify the recorded costs of hydrostatic testing in the same format that it developed the Plan forecasts. In the SPEC's hydrostatic test estimates, costs for Materials, Construction, SCG Labor/Inspection, Design, Engineering, Construction, and Environmental elements are identified for each line.

DRA requested historical costs to perform hydrostatic tests on lines that are "new", "relocated," "repaired", or "related situation" from 2001 to 2011, and asked that Sempra identify cost variances, if any exists between the different categories. Sempra did not provide the data which DRA requested. Sempra states, "This test is an integral part of the project, but typically only a small part of the entire job scope and cost. The costs specific to the hydrostatic test are embedded with other project planning and execution costs and cannot be separated from the total construction costs."[165]

Sempra explained that SoCalGas has not performed many pressure tests on in-service existing pipeline segments. Sempra states, "Although infrequent, there have been additional projects that were more hydrostatic testing-specific and not part of our TIMP assessment activities. The Table below shows recent examples of these types of projects, along with the miles tested and the total project costs."[166]

[164] Sempra's Response to DRA-DAO-30, Q.1, Sempra's Response to DRA-DAO-2, Q. 14.
[165] Sempra's Response to DRA-DAO-30, Q.1.
[166] Ibid.

Table 12
Hydrostatic Testing Projects
Pipelines and Cost of Inspection
(Thousands, fully loaded, nominal dollars)

Line #	Miles Hydrostatic Tested	Pressure Test Year	Total Expense
Line 4000	0.6	2007	$ 484
Line 6916 S	8.9	2010	$ 2,908
Line 1022	0.4	2011	$ 1,001

Source: Sempra Response DRA-DAO-30, Q.1.

The data provided by Sempra shows an average cost of $439,000 per mile for 10 miles of hydrostatic tests. The average cost for the 8.9 miles tested in 2010 was $327,000 per mile.

As for the TIMP projects, Sempra identified the following and distinguished the difference in costs to perform hydrostatic testing of an in-service line versus a newly constructed line:

Table 13

Pipeline	Length	Comments
1229	0.51	Long line example provided below
PGR6 (multiple Segments)	0.49	Short segment example provided below
PGR6-D	0.02	Short segment example provided below
PGR6-E	0.06	Short segment example provided below
PGR6-F	0.02	Short segment example provided below
PGR6-F1	0.02	Short segment example provided below
PGR6-F2	0.02	Short segment example provided below
PGR6-G	0.04	Short segment example provided below
80	0.06	Mixed costs provided below – see note 1
G80.01	0.08	Mixed costs provided below – see note 1
G80.02	0.07	Mixed costs provided below – see note 1
G80.03	0.05	Mixed costs provided below – see note 1
324	0.48	N/A – new construction, see note 2
6906	17.85	N/A – new construction, see note 2
6906XO1	0.05	N/A – new construction, see note 2
44-137	0.01	N/A – misc. segments, see note 3
44-137BO1	0.01	N/A – misc. segments, see note 3

<u>Pressure Testing Costs for In-service Piping</u>

Line 1229 - Long Line Example

Total Pressure Test Miles: 0.5

Pressure Test Year	Labor	Non-Labor	Totals
2006	**$32,791**	**$471,609**	**$504,400**

PGR-6 – Short Segment Example

Total Pressure Test Miles: 0.7
No. of Pressure Test Segments: 7
Avg. Pressure Test Length: 0.1

Pressure Test Year	Labor	Non-Labor	Totals
2010	**$22,623**	**$209,095**	**$231,718**

<u>Pressure Testing Costs for Mixed Assessment & New Construction Projects</u>

LINE 80 - Mixed Assessment Costs (see note 1)

Total Pressure Test Miles: 0.3
No. of Pressure Test Segments: 4
Avg. Pressure Test Length: 0.08

Date	Labor	Non-Labor	Totals
2010	**$42,467**	**$949,983**	**$992,450**

Line 324 Relocation and Pressure Test (see note 2)

Total Miles: 0.5

Date	Labor	Non-Labor	Totals
2009	**$43,090**	**$1,961,219**	**$2,004,309**

Line 6906 Construction and Pressure Test (see note 2)

Total Miles: 17.9

Line 6906 was completed under a collectable work agreement. The total cost of this project was approximately $44M.

Sempra explains the testing of the above lines:

"L80 pipeline was assessed using a combination of both in-line inspection and pressure testing. These combined costs were an integral part of the job planning, and shared many of the same resources for planning and execution. As a result these <u>combined costs cannot be separated</u>.

Lines 6906 and 324 were <u>new construction projects</u>, and <u>the costs for pressure testing are not representative of a pressure test for in-service piping.</u>

Commissioning pressure tests are inherently part of the total commissioning effort; these embedded costs are an integral part of project planning and execution and cannot be separated from the total construction costs.

Additionally, new construction projects do not incur the water handling and disposal issues associated with in-service pipelines. These water management costs can be significant, and are not reflected in new construction projects. These small segments of pipeline represent miscellaneous pressure tests required as part of the installation of new components (for example, the testing of fittings, tees, taps, etc.) needed to support larger projects. These costs are commingled with the larger project costs and do not represent typical pressure test costs. These costs are negligible and unrepresentative of pressure testing costs for existing segments and have not been provided.
Costs are not available in the workpaper format used by SPEC Services, therefore the costs provided below reflect the total costs associated with these projects."[167]

In the explanation of the costs for the TIMP lines provided above, Sempra implied that the cost of testing an in service line is more expensive than the cost of testing a brand new line because of water management costs.

Although the average cost per mile gives some indication of how much it would cost to perform hydrostatic testing, the cost of testing a segment is a better indicator of testing costs. Sempra's proposal to test SoCalGas' transmission lines in the Plan shows a much higher estimate per test segment when compared to both in-service testing and to new construction testing. In the Plan, Sempra proposes an average unit cost of $1,402,000 per test segment for 122 segments, for the SoCalGas Transmission pressure testing projects. For the Distribution lines, Sempra proposes an average unit cost of $298,000 per segment for 10 segments. There is no pressure testing proposed for SDG&E.

Sempra's average unit cost per segment of $1.4 million for SoCalGas Transmission pressure testing projects is excessive and without justification. DRA concludes that Sempra's variable costs per test project, which accounts for the volume of each test segment and the amount of water required, are too high.
DRA developed its own cost model which uses a different water cost than Sempra's estimate for each of the lines proposed for Phase 1A. The detailed analyses used to

develop DRA's hydrostatic test costs are presented in Witness Tom Roberts' testimony, Exhibit DRA-2A.

ii. Repairs estimated per Test Segment.

Sempra estimates a total of 1 repair per pressure test segment for SoCalGas and SDG&E transmission and distribution pipelines in its workpapers.[168] Sempra states the following as the basis of this estimate, "Based on historical projects, it was estimated that an average of one repair would be needed for each pressure test segment, and the repairs would cost an average of $50,000 (10% labor and 90% non-labor) each."[169] The table below provides a summary of the number of repairs estimated for each pipeline category.

Table 14

Sempra Pressure Test & Repair Estimates

(In 000's of Dollars)

	Pressure test Miles	Number of Repairs	Repair Costs	Pressure Test Costs	Total Costs
SOCALGAS					
Transmission	335 miles	122	$6,100	$171,000	$177,100
Distribution	17 miles	10	$500	$2,982	$3,500
SDG&E					
Transmission	-	-	-	-	-
Distribution	.3 miles	1	$50	$210	$300
TOTAL	352.3 miles	133			$180,900
Cost per Mile with Proposed Repairs					$513 per mile
Cost per Mile without Repairs					$494 per mile

(continued from previous page)

167 Sempra's Response to DRA-DAO-2, Q. 14.

168 Amended Workpapers, pp. WP-IX-1-6, WP-IX-1-10, WPWP-IX-1-17, and WP-IX-1-19.

169 Ibid.

DRA requested that Sempra identify the "historical projects" used to determine the number of repairs necessary and the repair cost. DRA requested that Sempra provide a copy of the work orders for testing and/or for repairing, including the project scope if available, which shows the project start and end dates, the details of the hydrostatic test and/or repair, along with the expenses incurred for the test and/or repair, for all the identified "historical projects". Sempra did not provide this data.[170] Sempra states, "Given the short timeframe allotted for preparation of the PSEP, subject matter expertise was relied upon to determine the scope and estimated cost associated with post-pressure test repair work. A specific set of projects was not consulted, but rather institutional knowledge of previous repair work was applied to determine a reasonable, high level allowance to include as part of the total cost of the pressure testing effort. Every project contains unique circumstances that can affect both scope and cost."[171]

Sempra's proposal to perform 133 repairs on 352 miles of SoCalGas pipelines is without support. The rate of 0.4 repairs per mile has no factual basis. As discussed above in Section E (2)(b)(i), Sempra's current transmission system does not require this level of repair.

For comparison purposes, in 2011 PG&E tested approximately 164 miles of transmission pipeline. PG&E experienced 2 ruptures, and 1 small leak.[172] A total of 3 repairs were needed. Sempra's estimate of 133 repairs needed for 352 miles of pipelines tested is excessive.

Sempra stresses in its Report to the NTSB and testifies in its Plan that its systems are safe.[173] Sempra specifically stated in the Report, "Nothing in our records review process revealed any significant concerns with the currently-established

[170] Sempra's Response to DRA-DAO-6, Q. 3.
[171] Sempra's Response to DRA-DAO-6, Q. 3.
[172] PG&E's Presentation to the CPUC on Hydrostatic Testing Process and Lessons Learned, p. 12.
[173] Amended Testimony, p. 1.

MAOPs for Category 4 pipelines. Accordingly, we remain confident that these pipelines are operating safely."[174] Sempra further states that the majority of the Category 4 pipelines (207 miles out of 385 miles of Category 4 pipelines) has been assessed as part of its ongoing pipeline integrity program using smart pigs, and that these assessments give the utilities additional confidence in the integrity of the pipeline.[175]

Sempra's proposal for the number of hydrostatic test repairs and costs should be disregarded because there is no support for the estimates. Sempra has not provided any analysis or factual evidence demonstrating that its system will leak or rupture following the performance of a hydrostatic test. Sempra has not justified the level of repairs estimated for the proposed hydrostatic tests.

Based on the fact that Sempra testifies its system is safe and PG&E had only 3 repairs following one year's worth of testing 164 miles of transmission pipeline, Sempra's estimate of 133 repairs is unlikely and excessive. DRA recommends the Commission reject Sempra's request for repair costs associated with Sempra's hydrostatic tests. If there are any repairs needed, the cost will be de minimis based on Sempra's safety record.

iii. DRA Recommends Pressure Testing of Category 4 Pipelines

DRA recommends pressure testing of all pipelines located in Class 3 and 4 and Class 1 and 2 HCAs that have not been pressure tested. In the Plan, Sempra has identified these pipelines as Category 4 pipelines. As discussed above, Sempra has not provided adequate support for including the number of Accelerated pipelines with the Category 4 pipelines in the first phase of its Plan. Sempra's reasoning that including the Accelerated pipelines as part of Phase 1A work would be more operationally efficient and economical is not supported. DRA recommends that the

[174] The Report, p. 3.

[175] Ibid.

Commission exclude the number of Accelerated pipelines as part of Phase 1A work until Sempra can demonstrate that by including Accelerated pipelines, the utility would gain efficiency and ratepayers would benefit from the cost savings of including this work in Phase 1A.

4. The Commission Should Reject the Contingency Percentages and Amounts Proposed by Sempra

Sempra proposes an overall contingency amount of $162 million[176] for the pipeline replacement projects and $30 million[177] for hydrostatic test projects.

The contingency percentages that SPECs applied, 20 percent for projects costing more than $2 million and 30 percent for projects less than $2 million, seem arbitrarily high. Sempra explains, "We typically assign a contingency cost of 30% to all of our ROM [rough-order of magnitude] cost estimates to account for uncertainty associated with a true understanding of the project scope."[178] Sempra further states, "For typical pipeline projects most costs are tied directly to the pipeline footage (ie materials and construction labor). However there are some costs including environmental permitting and right-of-way acquisition that tend to decrease on a per foot basis as the size of the project increases. There is also an indication that material and construction labor costs will tend to decrease as the size of the project increases due to competitive pricing and the desire of suppliers to reduce profit for volume. Considering these factors, the estimates generated for SCG identified a threshold of $2 million at which the contingency amount could logically be reduced from 30% to 20%"[179]

Sempra did not provide adequate support for the contingency percentages used in the Plan. Sempra identifies the following "uncertainties" that the contingency

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[176] Sempra's Response to DRA-DAO-32, Q. 2(a).
[177] Sempra's Response to DRA-DAO-32, Q. 1(a).
[178] Sempra's Response to DRA-DAO-1-5.
[179] Ibid.

amounts were applied to: "…definitive designs and material takeoffs, labor market, cost of materials, availability of right-of-way, public relations issues, environmental/permit restrictions on the construction effort, soil conditions, etc..."[180] Although specific percentages were applied to address "uncertainties", Sempra could not quantify these "uncertainties" and did not explain how the percentages were derived. Sempra also did not identify project "unknowns" and "risks" that the contingency amounts would cover or how these "unknowns" and "risks" are quantified as 20% or 30%.

Sempra stated that individual costs were based on a reliance on past project experience. Yet Sempra could not identify or provide any details about these past projects wherein cost estimates were derived.[181] Sempra simply stated that it was for projects that SPEC Services were involved for various clients.[182]

The 20% and 30% contingency percentages Sempra proposes are unreasonably high and without support. DRA recognizes that a contingency amount is necessary to address the uncertainties in the current forecasts. In the absence of a proper contingency analysis, the Commission should approve a contingency amount of no more than 8%, which is comparable to amounts the Commission has approved for more complicated projects such as PG&E's, SoCalGas', and SDG&E's Advanced Metering Infrastructure (AMI) projects.

A review of all Commission authorized contingency amounts for all AMI-related applications show an average of 8.1%:

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[180] Sempra's Response to DRA-DAO-19, Q. 3(f).

[181] Response to DRA-DAO-19-Q.3(b).

[182] Response to DRA-DAO-19, Q.3(a).

Table 15

Commission Authorized Contingency Percentages for CA Utilities

(in Millions of Dollars)

Project	Cost Adopted	Contingency Adopted	Contingency % Adopted	Citation
SoCalGas	$1,051	$68.7	7.0%	D.10-04-027 in A.08-09-023, pp.2-37.
SDG&E	$572	$33.8	6.3%	D.07-04-043 in A.05-03-015, p. 38.
PG&E Original	$1,739	$128.8	8.0%	D.09-03-026 in A.07-12-009, p. 87
PG&E Upgrade	$467	$49	11.7%	D.09-03-026 in A.07-12-009
SCE	$1,634	$130.1	8.7%	D.08-09-039 in A.07-07-027; Dec. 5, 2007 errata Testimony, SCE-2, p. 14
ALL AMI	$5,463.4	$410.4	8.1%	Avg. for All Projects

In no event should the Plan have a *higher* contingency than the average AMI contingency for all projects. On this basis, absent a proper contingency analysis, DRA recommends that the contingency for the Plan be no more than 8%.

Based on the past three General Rate Cases, Sempra has used contingency percentages that ranged between 7% and -15% of project costs.[183] Sempra states, "Contingencies were most often used on projects in locations where various construction, permitting and environmental fees are not well defined in the early project development phases."[184] Although the scale of work is much larger for the Plan, the type of activity is quite limited in nature to test or replace pipelines. Testing and replacing pipelines are activities that SoCalGas and SDG&E perform on a regular basis. With the Plan, Sempra is proposing work activities that are not any different

183 Sempra's Response to DRA-DAO-27, Q. 2.

184 Ibid.

than, and with a similar time frame as, the work activities proposed in a general rate case.

DRA recommends using an 8% contingency for the Plan estimates based on the reasons discussed. The 8 percent is within the contingency percentage range used in the past 3 general rate cases by Sempra. Since the projects proposed in the Plan are similar in nature to pipeline projects proposed in the GRC, where various construction, permitting and environmental fees are not well defined and these projects are also in the early stages of planning, the 8 percent contingency is appropriate.

5. The Commission Should Reject Sempra's Proposal To Perform In-Line Inspection Prior to Performing Pressure Tests as Part of the Base Case Proposal

Sempra requests a total of $62 million ($58 million for SoCalGas and $4 million for SDG&E) to in-line inspect using transverse field inspection (TFI) tools, *and for estimated repairs*, prior to pressure testing the Criteria segments identified for pressure testing.[185] Of the $62 million proposed, $8 million is for the inspection of 667 miles in SoCalGas' territory and 54 miles in SDG&E's territory. The remaining $54 million is for the repairs of potential problems identified by the inspections. Sempra's repair estimate is based on an average of one repair per mile of pipe inspected at a unit cost of $75,000 per repair.[186]

According to Sempra, "…TFI tools can be used to facilitate proactive mitigation of any pipeline anomalies that may lead to a potential pipeline failure at high pressure test levels."[187] Sempra states that by mitigating potential sources of

[185] Amended Workpapers, pp. WP-IX-1-39 through WP-IX-1-43.
[186] Amended Workpapers, pp. WP-IX-1-39 through WP-IX-1-43.
[187] Amended Testimony, p. 57.

pressure test failures before conducting the pressure test, the company can avoid the pitfalls associated with entering into a cycle of pressure test failures.[188]

Sempra also seeks authorization to analyze the data obtained through the inspection process to validate TFI as an equivalent means of validating the long seam stability of in-service pipelines. Sempra states, "SoCalGas and SDG&E seek to analyze and compare the results of pressure testing with the results of in-line inspections in Phase 1, in order to demonstrate that TFI provides an equivalent alternative to pressure testing for Phase 2 pipelines."[189]

DRA asked Sempra to provide a copy of the research/study's scope, objectives, details on how data will be collected and analyzed, and how results will be interpreted to validate TFI. SoCalGas and SDG&E have indicated that they have yet to develop a research scope or proposal for the TFI validation study.[190]

DRA recommends rejecting the entire proposal of $62 million to inspect 721 miles of pipelines prior to pressure testing and to perform 721 repairs to these lines for several reasons. DRA's recommendation is based on the fact that these lines have been recently inspected and any problems identified as a result of these inspections should have been corrected. According to Sempra, "These pipelines have already been inspected with a magnetic flux leakage (MFL) in-line inspection tool as part of our existing pipeline integrity management program, with re-assessments scheduled to occur over the next five years."[191] Sempra further states, "During the re-assessment, in addition to running the MFL tool, a transverse flux in-line inspection (TFI) tool will also be utilized to allow for evaluation of the condition of the long seam as well."[192]

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[188] Ibid.

[189] Amended Testimony, p. 57.

[190] Sempra's Response to DRA-31, Q.3

[191] Amended Workpapers, pp. WP-IX-1-38 and WP-IX-1-42.

[192] Ibid.

These statements show that the Criteria segments planned to be inspected using the TFI tool have already been inspected, with the MFL tool, as part of SoCalGas' and SDG&E's transmission integrity management program and that these same segments are scheduled to be re-assessed using the TFI tool in the next five years. These re-assessments will also be performed as part of the TIMP program.[193]

If SoCalGas or SDG&E wants to supplement the assessment tools and methods used to re-assess transmission pipelines as part of the TIMP, then the utilities can manage this as part of the TIMP program.

Sempra has not demonstrated why performing another round of inspection to search for potential problems for repair is prudent when there is no indication that the system is in need of additional mitigation. Its workpapers show that the segments proposed for TFI had recently been in-line inspected in the past 2 years because the re-assessments are scheduled to occur over the next five years.[194] TIMP regulations require operators to reassess a segment that has completed a baseline assessment within seven years of the completion of the last assessment.[195] Moreover, Sempra states repeatedly in the Report and in the Plan that it remains confident in its existing transmission pipeline integrity program and that it has an excellent safety record.[196]

DRA recommends that the proposal be rejected because the 721 miles of inspection and 721 repairs are unsupported. DRA asked Sempra to provide a copy of all supporting analyses, assessments, and calculations performed, to determine the 667 miles for inspection when only 170 miles are identified as Criteria miles located in Class 3 and 4 and High Consequence Areas, Sempra responded with the following statement:

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[193] Sempra's Response to DRA-DAO-24, Q.1.

[194] Amended Workpapers, p. WP-IX-1-38.

[195] TIMP requirements as identified by Sempra in the 2012 GRC Application, Testimony of SoCalGas witness, Raymond Stanford, p. RKS-30.

[196] Amended Testimony, p. 1.

> "The boundaries of the in-line inspections proposed as part of the PSEP will be determined by the locations of existing launcher and receiver facilities. This approach aligns with one of the overarching objectives of the PSEP, to maximize the cost effectiveness of investments in the SoCalGas transmission system….Please refer to pages WP-IX-39 and WP-IX-1-43 of the workpapers supporting Chapter IX of the Testimony for the number of in-line inspections and the total in-line inspection mileage per pipeline proposed in the PSEP."[197]

This response does not adequately support the excessive level of inspection mileage proposed in the Plan.

The explanation Sempra provided for the 667 miles of inspection does not adequately justify the level of miles planned for inspection:

> "The placement of in-line inspection launcher and receiver facilities is typically based on the configuration and operation of the pipeline and it is customary to space them as far apart as practical to maximize the inspection length. As a result, the launcher receiver facilities are commonly located in less populated areas, and a single inspection can include a range of Location Class types and both HCA and non-HCA."[198]

Sempra's proposal of one repair per mile, resulting in a total of 721 repairs for the 721 miles of inspection, is not adequately supported as well. The only support provided for the repair estimate is Sempra's statement, "the assumption that one repair would be required per mile of pipe inspected with a TFI tool constitutes a high-level allowance for post-inspection repair work. Actual inspection data may dictate the need for more than one repair per mile in some cases or fewer than one repair per

[197] Sempra's Response to DRA-24, Q. 1(b).

mile in others."[199] No studies, assessments, or analyses were performed to determine the repair estimates.

The number of repairs estimated is excessive and has no factual basis. Its transmission system does not require this level of repair. According to the Annual Report for Calendar Year 2010 Natural or Other Gas Transmission and Gathering Systems that Sempra filed with the Department of Transportation, Pipeline and Hazardous Material Safety Administration, SoCalGas inspected 1,502 miles of transmission pipelines and repaired 148 anomalies both within an HCA segment and outside of an HCA segment. This is equivalent to a rate of repair of less than 0.1 repairs per mile of pipeline inspected. As for SDG&E, in 2010, the utility in-line inspected a total of 90 miles and recorded zero repairs.

As for the repair cost of $75,000 per repair, Sempra has not adequately supported this estimate either. The only support provided was the statement from Sempra: "The cost of $75,000 per repair represents a high-level estimate for post-inspection repair work."[200] No cost estimates, studies, assessments, or analyses performed to determine the cost of TFI runs were provided.

This request is above and beyond the directives of the Commission to pressure test or replace pipelines that have not been pressure tested. Although the Commission states in D.11-06-017 that, "The Implementation Plans may include alternatives that demonstrably achieve the same standard of safety…" DRA asserts that Sempra's proposal to perform ILI studies in the Plan is not on par with the directives of the Commission.

At this time, the TFI technology has not been confirmed or validated by any regulation agency to provide an equivalent means to strength test a pipeline. The

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[198] Sempra's Response to DRA-DAO-24, Q. 1(c).

[199] Sempra's Response to DRA-DAO-21, Q. 3(b).

[200] Sempra's Response to DRA-DAO-21, Q. 3 (d).

latest 2010 ASME Code for Pressure Piping continues to advise that "…Pressure testing with water is recommended whenever possible."[201] For transmission pipelines operating at high pressure, the ASME Code specifies the following:

> Section 841.3.2 states, "Pressure Test Requirements to prove strength of pipelines and mains to operate at hoop stresses of 30% or more of the Specified Minimum Yield Strength of the pipe…the recommended test medium is water."[202]

Federal regulations currently do not recognize TFI as an equivalent means to validate the safety margin of a pipeline. Title 49 CFR, Part 192, Subpart J, Section 192.503 requires that all new segments of pipe or a new segment that has been relocated or replaced be strength tested using liquid, air, natural gas, or inert gas.

The TFI tool has been in existence since 1999, but Sempra has used it to inspect only 2 miles in its territory.[203] Sempra has stated that the preferred assessment method for both SoCalGas and SDG&E is in-line inspection using MFL technology.[204] TFI does not appear to be favored as an assessment tool by Sempra. According to Sempra, "In general, the ILI [MFL] is the preferred choice for assessment at SoCalGas due to the fact that the pipeline systems are conducive to accommodating ILI tools (gas flow, pipeline pressure, diameter, etc), measurements are collected along the entire length of the line, and in general, service impacts to customers are usually manageable. Lastly, the execution of reassessments every seven years as required by regulations is more practical using ILI compared to other assessment methods."[205] TFI is not currently an equivalent strength validation tool

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[201] ASME, ASA B 31 8 2010, Section 841.3, Testing after Construction, p. 45.

[202] ASME Code for Pressure Piping, 2010, p. 46.

[203] Sempra's Response to DRA-DAO-15, Q. 3 (c).

[204] Sempra's Response to DRA-DAO-18-Q.1

[205] Sempra's Response to DRA-DAO-18-Q. 1(a).

compared to hydrostatic-testing. Sempra has not demonstrated that it is an equivalent validation tool in its Plan. Sempra is not requesting to perform TFI inspections in lieu of hydrostatic testing anywhere in the Plan. DRA is not convinced that ratepayers should fund a technology that Sempra has not embraced.

Sempra's current system design is not capable of accommodating in-line inspections using the TFI tool. Sempra could not identify how much of the SoCalGas or SDG&E system has been retrofitted to accommodate the TFI tool.[206] There is also an issue with the lack of vendors and tool options at this time. Sempra states, "We have found that the number of vendors and tool options for this technology is limited. This results in restricted tool availability due to scheduling conflicts as well as the need to complete a detailed analysis to verify that each of the identified pipelines is has a configuration that is compatible with the TFI tools that are available."[207]

Sempra has not developed the TFI aspect part of its Plan. Sempra states, "SoCalGas and SDG&E have not yet developed a research scope or proposal to fund a TFI validation study."[208] Since the TFI proposal is not yet developed, DRA cannot ascertain how the TFI validation study can be used to compare to the hydrostatic tests so that results can be compared. According to Sempra, the TFI study will be a validation study in which the pipeline would be pigged using TFI technology and then exposed and directly examined so that a comparison of reported anomalies from the inspection could be compared to actual anomalies. It does not appear that the anomalies reported from the inspection would be compared to the anomalies experienced from the hydrostatic tests because Sempra would repair any anomalies detected from the inspection prior to performing a hydrostatic test. It is not clear how the TFI study will be used to demonstrate that it would be an equivalent tool as the

206 Sempra's Response to DRA-DAO-27, Q.9.

207 Sempra's Response to DRA-DAO-27, Q.9.

208 Sempra's Response to DRA-DAO-31, Q.3.

hydrostatic test for strength testing if the repairs are made. If a pipe leaks or ruptures based on a pressure test, it would unlikely be from the same anomalies detected from the inspection because these anomalies would have been repaired.

For all the reasons stated above, DRA opposes ratepayer funding of Sempra's proposal to perform TFI inspection on all lines prior to hydrostatic testing, and in particular, the $54 million in repair costs.

DRA is open to the use of efficient or effective alternatives to hydrostatic testing such as TFI. The possibility of alternatives can be explored through a different forum dedicated to studying alternative approaches, methodologies, tools, etc., that can achieve the same standard of safety as hydrostatic testing. Involved participants could include representatives from the utilities, experts in the ILI field who specialize in TFI tools, and safety regulators from the federal and state safety regulators. If it turns out that TFI could be a true equivalent method to hydrostatic testing, then it could be funded in the future as an alternative to funding hydrostatic testing.

F. DRA Recommends Sempra Perform Hydrostatic Testing of 324 Miles of Category 4 Pipelines.

Sempra has identified several different sets of numbers for the Criteria/Category 4 pipelines and Accelerated pipelines in its testimony, in its workpapers, and in the Decision Tree database. DRA has not been able to validate the data that Sempra used to generate the results of the Decision Tree. DRA has not been able to validate the scope of the Plan based on the Decision Tree database Sempra provided.[209]

Although Sempra identifies the total DOT defined transmission mileage for SoCalGas as 3,757 miles and for SDG&E as 251 miles,[210] the Decision Tree database shows 3,131 for SoCalGas and 251 for SDG&E. In its Testimony, Sempra identifies

[209] Sempra's response to DRA-DAO-16, Q. 6

[210] Sempra's response to DRA-DAO-16, Q. 2.

206 miles of Category 4 pipelines for hydrostatic testing.[211] In its workpapers, Sempra identifies a lower number, 171.5 miles, for hydrostatic testing.[212] In the Decision Tree database, Sempra identifies an even lower number, 168 miles, of Category 4 pipelines for hydrostatic testing.[213]

For pipeline replacements, Sempra's Testimony identifies 156 miles of Category 4 pipelines.[214] Sempra's Decision Tree database also identifies 156 miles of Category 4 pipelines for replacement.[215] However, Sempra's workpapers identifies only 152.5 miles for replacement.[216]

DRA recommends the Commission require Sempra to explain the differences in the number of pipelines identified in its testimony and workpapers, and the number of miles of pipelines identified in the Decision Tree database, and to provide additional assurance that the Plan's scope is accurate, reliable, and can be validated. DRA also recommend that the commission require Sempra do the following with regard to any changes made to the Plan's data which ultimately drive the scope and cost of mitigation: (1) justify any deviations from the decision tree outcome/mitigation due to new data, (2) justify any deviations from the decision tree outcome/mitigation due to engineering judgment, (3) Sempra's implementation of the "ors" in the decision tree, (4) justify any acceleration of Phase 2 segments into Phase 1, (5) justification for any diameter increases, (6) justification for any line relocations, and (7) justification of any engineering condition assessment.

The original 385 miles of Category 4 pipelines cannot be confirmed at this time. The Decision Tree database only shows a total of 324 miles of Category 4

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[211] Sempra's Amended Testimony, p. 108.

[212] Sempra's workpapers, p. WP-IX-1-5, WP-IX-1-9, and WP-IX-1-13.

[213] Sempra's Testimony, p. 108. Sempra's Response to DRA-16, Q. 6.

[214] Sempra's Amended Testimony, p. 110.

[215] Amended Testimony, p. 110. Sempra's Response to DRA-16, Q. 6.

[216] Amended Workpapers, p. WP-IX-1-25, WP-IX-1-29, WP-IX-1-36.

pipelines. Until Sempra can substantiate that additional pipelines need to be addressed, DRA recommends that 324 miles of Category 4 pipelines be hydrostatic tested. DRA used this group of 324 miles of Category 4 pipelines to determine the ratepayer/shareholder cost sharing proposal in Exhibit 1.

DRA recommends the Commission reject Sempra's cost estimate for hydrostatic testing because it is excessive and not adequately supported. DRA recommends the Commission adopt the DRA cost estimates presented in Exhibit DRA-2A.

DRA used 327 miles for project scope instead of 324 miles of Category 4 pipelines. This number comes from a total of 171.5 miles of Category 4 pipelines identified by Sempra in its' workpapers and [217] a total of 155.8 miles of Category 4 pipelines identified by Sempra for replacement in the Decision Tree database. It was necessary for DRA to rely on two different sources, Sempra's workpapers and the Sempra Decision Tree database, in order to come up with the hydrostatic testing cost calculations for the 327 miles because this was the most efficient way to develop the cost model and to apply it to the numerous projects Sempra proposed in the Plan.

To determine DRA's hydrostatic test cost estimate, DRA analyzed all the cost elements that make up Sempra's proposed hydrostatic test, which were only identified in its workpapers. DRA then applied its hydrostatic test assumptions to the group of pipelines Sempra proposed for replacement. Due to the numerous pipelines Sempra proposed for replacement, the most efficient way for DRA to apply our cost model was to use the Decision Tree database to estimate the hydrostatic test costs. A more detailed description of DRA's cost method and explanation of DRA's cost model can be seen in Exhibit DRA-2A.

DRA's cost model shows a total of \$78.2 million for the hydrostatic testing of 327 miles of Category 4 pipelines. A breakdown of the DRA cost estimates for the "Sempra proposed hydrostatic test" lines and for the "Sempra proposed replacement" lines for SoCalGas and SDG&E, and for Distribution versus Transmission, are presented in the two tables below.

Table 16

DRA Proposed Cost of Hydrostatic Testing
for Sempra's Proposed Hydrostatic Testing Pipelines.
(In Millions of Dollars)

Sempra Designated Hydrostatic test					
	Total	2012	2013	2014	2015
SoCalGas-Distribution, Company Labor	0.03	0.01	0.01	0.01	0.01
SoCalGas-Distribution, Non-Company Labor	0.94	0.19	0.25	0.25	0.25
SoCalGas-Transmission, Company Labor	0.90	0.18	0.24	0.24	0.24
SoCalGas-Transmission, Non-Company Labor	32.82	6.56	8.75	8.75	8.75
SDG&E-Distribution, Company Labor	$ -	$ -	$ -	$ -	$ -
SDG&E-Distribution, Non-Company Labor	$ -	$ -	$ -	$ -	$ -
SDG&E-Transmission, Company Labor	$ -	$ -	$ -	$ -	$ -
SDG&E-Transmission, Non-Company Labor	$ -	$ -	$ -	$ -	$ -
TOTAL	$ 34.7	$ 6.9	$ 9.2	$ 9.2	$ 9.2

(continued from previous page)

217 Amended Workpapers, p. WP-IX-1-5, WP-IX-1-9, and WP-IX-1-13.

Table 17

DRA Proposed Cost of Hydrostatic Testing for Sempra's Proposed Replacement Pipelines (In Millions of Dollars)

Sempra Designated Replacement					
	Total	2012	2013	2014	2015
SoCalGas-Distribution, Company Labor	0.84	0.17	0.22	0.22	0.22
SoCalGas-Distribution, Non-Company Labor	29.85	5.97	7.96	7.96	7.96
SoCalGas-Transmission, Company Labor	0.21	0.04	0.05	0.05	0.05
SoCalGas-Transmission, Non-Company Labor	7.30	1.46	1.95	1.95	1.95
SDG&E-Distribution, Company Labor	0.14	0.03	0.04	0.04	0.04
SDG&E-Distribution, Non-Company Labor	5.11	1.02	1.36	1.36	1.36
SDG&E-Transmission, Company Labor	0.00	0.00	0.00	0.00	0.00
SDG&E-Transmission, Non-Company Labor	0.00	0.00	0.00	0.00	0.00
TOTAL	$43.5	$8.7	$11.6	$11.6	$11.6

G. DRA Recommends No Ratepayer Funding for Pipelines Installed After 1935

Sempra provided an Excel file containing the installation date of all pipeline segments identified for hydrostatic test or replacement in its Plan.[218] The data contained in this file shows a total of 324 miles of pipelines categorized by Sempra as Category 4 Criteria Miles. These specific pipelines need to be addressed immediately because they are located in more populated areas or are in High Consequence Areas. DRA recommends that only these Category 4 Criteria miles be addressed in Phase 1A for the reasons discussed above.

[218] Sempra's Response to DRA-DAO-16, Q.6.

DRA recommends that shareholders, and not ratepayers, fund the cost of hydrostatic testing of 312 miles of pipelines installed in 1935 to the present. DRA's recommendations are based on the discussion in DRA Witness David Peck's testimony. See Exhibit DRA-1.

Table 18 below provides a summary of the mileage proposed for hydrostatic-testing and pipeline replacement in the Plan.

Table 18

Decision Tree Database—
Number of Category 4 Criteria Miles (without L1600, without Storage)

Total Mileage in the Plan's Database: **324 Category 4 Criteria Miles**		
	Hydrostatic-testing	**Pipeline Replacement**
Year Installed	Mileage	Mileage
1900-1934	0	12
1935-1954	145	89
1955-1960	11	33
1961-Present	13	21
Total Hydrostatic Test Miles	**169**	**155**

Source: Sempra's Response to DRA-DAO-16, Q.6

H. The Plan Cost Estimates Should Be Reduced for Pipelines Managed By the TIMP

Sempra identified a total of 383 Category 4 miles in the Plan currently managed under the Transmission Integrity Management Program (TIMP). See Table 19 below. Of this total 206 miles are planned for pressure testing and 156 miles are planned for replacement.[219]

[219] Sempra's Response to DRA-DAO-7, Q.3(b) and (c).

Table 19

PSEP Criteria Miles Currently Managed Under TIMP			
Abandon	**Replace**	**Hydrostatic-test**	**Total Criteria**
21 miles	**156 miles**	**206 miles**	**383 miles**

Source: Sempra's Response to DRA-DAO-7, Q.3(b) and (c).

TIMP regulations require assessments to be performed in compliance with the requirements of CFR 49, Subpart O Section 192.921. The assessment methods prescribed by 49 C.F.R., Subpart O and used by SoCalGas and SDG&E include direct assessment, pressure testing, and in-line inspection. The TIMP rules specify how pipeline operators must identify, assess, prioritize, evaluate, repair and validate the integrity of gas transmission pipelines. The rules focus on the potential impacts of pipeline failures or leaks on heavily populated or occupied areas, referred to as High Consequence Areas ("HCAs"). Under TIMP regulations Sempra will have completed assessing all of its HCA transmission pipelines as part of the Baseline Assessment by December of 2012. Thereafter, Sempra will need to reassess the lines on a periodic cycle within the next seven years.

The abandonment, replacement and hydrostatic testing of these 383 miles as part of the Plan will also enable Sempra to meet the TIMP requirements of reassessing these pipelines in the next seven years. The abandonment of 21 miles will remove these pipelines from the TIMP and Sempra will not need to assess these pipelines again. The replacement and hydrostatic testing of the remaining 362 miles will meet the assessment methods required by TIMP.

Sempra requests funding for the assessments and reassessments of TIMP pipelines in its General Rate Case applications. In the most recent GRC filed in December 2010, Sempra requested $25 million each year, starting in 2012, for the assessment and reassessment of pipelines as part of the TIMP.[220] Since Sempra is

[220] A.10-12-006, Witness Raymond Stanford Testimony, p. RKS-25 and RKS-31.

managing the assessment work of these specific lines under TIMP, DRA recommends an adjustment to the Plan cost estimates to reflect the accounting of these 383 miles in that program. If the Plan cost estimates for these 383 miles are not adjusted, then Sempra would receive funding for the assessment/management of the same pipelines twice, as part of the GRC and as part of the Plan.

DRA recommends adjusting the cost of the 383 miles of the Plan by the same amount of funding that Sempra would otherwise be receiving from the GRC process. Using Sempra's 2012 GRC proposed estimate unit cost of $192,000 per mile[221] for pipeline assessments under TIMP, the total adjustment amount for 383 miles is $74 million.

I. The Costs for Line 1600 Should Be Addressed in Phase 1B

Sempra requests $14.3 million in Phase 1A for work associated with the planned replacement of Line 1600 in Phase 1B. The total project is estimated at $332.5 million. Sempra estimated that approximately 4% of the total costs, or $14.3 million, will occur in Phase 1A.[222]

DRA recommends the removal of $14.3 million from Phase 1A. DRA recommends that all costs associated with the replacement of Line 1600 be rejected. Sempra has allocated 4% of the total cost of replacing Line 1600 to Phase 1A. This amount is for the design and engineering work of Line 1600.

In Phase 1A, Sempra plans to perform TFI inspections and perform repairs on 53.6 miles of Line 1600 at a cost of $4.3 million. In Phase 1B, Sempra will pressure test and repair this same at a cost of $10.2 million, and then Sempra will replace this line and change its capacity by increasing the pipeline diameter from 16" to 36" at a total cost of $332.5 million.

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[221] Sempra 2012 GRC Testimony, A.10-12-006, Witness Raymond Stanford, Exhibit SCG-5, pp. RKS-25 and RKS-31.

[222] Amended Workpapers, p. WP-IX-1-34.

The entire 53.6 miles of Line 1600 scheduled for TFI inspections during phase 1A are identified as "Accelerated" miles[223] and therefore should be excluded from Phase 1A. Sempra has not presented any evidence as to why Line 1600 needs to be addressed in Phase 1A or why the cost to perform the work associated with increasing the capacity of Line 1600 should be addressed in Phase 1A.

If Sempra wants to increase the capacity of Line 1600, as demonstrated in the proposal to increase the pipeline diameter from 16" to 36", Sempra should address this project in a separate application.

J. Sempra Should Modify the Sub-Prioritization Process of the Decision Tree

According to Sempra, after a pipeline segment is assigned a numbered box from the Decision Tree, it has the same outcome as all other segments. It is within each numbered box that Sempra will perform the detailed planning and rank the order of work based upon segment-specific characteristics that appropriately reflect the risk factors for that segment.[224] For presentation purposes in the Plan, Sempra ranks the order of work based on the potential impact radius for each pipeline segment divided by its long seam factor. Sempra states, "…the pipeline segments are sub-ranked for scheduling purposes primarily based on the consequence failure of each segment."[225]

For the sub-prioritization methodology, Sempra ranks and schedules the pipeline for hydrostatic test or replacement based on (1) Potential Impact Radius (PIR), (2) Long Seam Type, and (3) %SMYS.

Although DRA generally agrees with the sub-prioritization process proposed by Sempra, DRA believes that the sub-prioritization process could be enhanced by including the class locations of the pipeline segments. The PIR, as defined by Sempra, only measures the distance of impact from outside the vicinity of a pipeline

[223] Amended Workpapers p. WP-IX-1-34.
[224] Amended Testimony, page 62.
[225] Amended Testimony, p. 63.

rupture. Sempra defines PIR as, "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."[226]

The PIR increases as the diameter of the pipeline increases and as the pressure in the pipeline increases. The PIR measures the distance and not the population density. The impact will be greater in a more populated Class 3 than in a less populated Class 1. Sempra should consider Class location in addition to the PIR in ranking the work proposed.

The definition of Class Locations based on 49 CFR 192.5 is summarized as follows:

> *A "class location unit" is an onshore area that extends 220 yards on either side of the centerline of any continuous 1 mile length of pipeline.*
>
> *Class 1—A Class location unit has 10 or fewer buildings intended for human occupancy.*
>
> *Class 2— A Class location unit has more than 10 but fewer than 46 buildings intended for human occupancy.*
>
> *Class 3—A Class location unit has 46 or more buildings intended for human occupancy; or pipeline lies within 100 yards of either a building or place of public assembly that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period.*
>
> *Class 4—A Class location unit where buildings with four or more stories above ground are prevalent.*

[226] Amended Testimony, p. 63.

In the sub-prioritization process, if appropriate Sempra should consider ranking pipeline segments in descending order of class location from Class 3[227] 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.

IV. CONCLUSIONS

DRA recommends that the Commission adopt DRA's proposal for Sempra to focus on the group of pipelines that SoCalGas and SDG&E have identified as Category 4/NTSB Criteria Miles. These pipelines are presumably the highest priority from a safety standpoint. At issue in the Sempra Plan is an extension of project scope that is above and beyond the directives of D.11-06-017, which was aimed at high-priority safety measures. It is evident from this filing that Sempra is trying to use this opportunity to enhance its system—a system that it claims is operating safely. Sempra's safety record demonstrates that it is a safe system, with 1 incident from 2003-2010 and declining leak levels.[228] Sempra states repeatedly in its Report to the NTSB as well as in its filing in this proceeding that it is operating a safe system. Sempra believes that the Category 4 pipelines it has identified as needing MAOP validating are operating safely and that nothing in its records review process indicated otherwise.

The Plan was developed at a high level and without any engineering analysis or cost benefit studies to support it. As a result, the Sempra proposed actions are

[227] Sempra does not operate any transmission pipeline segments in a Class 4 location.
[228] Sempra's Response to DRA-PZS-02, Q. 1(f).

unsupported. The cost estimates have no support and range between -50% to upwards of +100%. The Plan proposes to accelerate Phase 2 pipelines that make up 48% of the planned work for SoCalGas and 40% of the planned work for SDG&E into Phase 1A. In the face of so many uncertainties, DRA recommends that the Commission focus only on the highest priority pipelines—the Category 4 pipelines. DRA recommends that the Commission only authorize funding to test these pipelines as well because Sempra has not adequately supported the alternative proposal to replace. The Commission should also reject all requests to enhance the utilities' systems above and beyond the requirements of D.11-06-017.

ATTACHMENT A

Statement of Qualifications

Q.1 Please state your name and address.

A.1 My name is Dao A. Phan. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Division of Ratepayer Advocates Energy Cost of Service and Natural Gas Branch.

Q.3 Briefly describe your educational background and work experience.

A.3 I have a Master of Arts Degree in Political Science from San Francisco State University and a Bachelor of Arts Degree in Political Science from California State University, Hayward. I have testified before the Commission as an expert witness in numerous Commission enforcement and regulatory proceedings. The areas and proceedings that I have been an expert witness in are as follows: (1) gas distribution operations and maintenance in the Pacific Gas and Electric Company 2003 General Rate Case (A.02-11-017), (2) gas transmission and storage operations and maintenance and capital expenditures in the Pacific Gas and Electric Company transmission and storage 2005 General Rate Case (A.04-03-021), (3) gas distribution capital expenditures in the Southern California Gas Company's 2004 cost of service application (A.02-12-027), (4) PG&E long-term electric procurement RFO application (A.06-04-012) (5) gas distribution O&M, customer service issues, and customer accounts in PG&E's 2007 GRC Application (A.05-12-002), (6) PG&E's long term electric procurement RFO application (A.06-04-012), (7) O&M expenses for Gas Distribution, Transmission, Underground Storage, Engineering, and Procurement in the Southern California Gas Company's TY 2008 GRC Application (A. 06-12-010), and (8) Gas Distribution operation and maintenance expenses, plus Technical Training and Applied Technology Services costs for the PG&E 2011 GRC Application (A.09-12-020). Most recently, I was the DRA witness for Compensation and Incentives, Shared Services Billing Policy and Process, SoCalGas O&M expenses for Gas Distribution, Transmission, Engineering, and Underground Storage, and SoCalGas Procurement expenses in the Southern California Gas Company's TY 2012 GRC Application (A.10-12-006).

Q.4 What is your area of responsibility in this proceeding?

A.4 I am responsible for Exhibit DRA-2, which addresses Sempra's Pipeline Safety Enhancement Plan.

Q.5 Does that complete your prepared testimony?

A.5 Yes, it does.

EXHIBIT C

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST DRA-DAO-29)

QUESTION DRA-DAO-29-01:

For the 3,996 wrinkle bends scheduled for replacement during the 2012-2015 time frame, please identify the affected lines, segments (station start/stop), and segregate the lines installed before and after August 1970 in a searchable Excel format.

RESPONSE DRA-DAO-29-01:

DRA-DAO-29, Q1

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST DRA-DAO-29)

QUESTION DRA-DAO-29-02:

Of the 385 Category 4 NTSB Criteria miles identified on page 50, how many miles are proposed to be completed in Phase 1A for SoCalGas and for SDG&E? Are there any remaining miles scheduled for Phase 1B?

RESPONSE DRA-DAO-29-02:

The approximately 30 Category 4 Criteria Miles on L-1600 in SDG&E's service territory are proposed to be pressure tested in Phase 1B due to the extended time that is estimated to be required to design, permit, and build and put into service the new replacement pipeline needed in order to take out of service and pressure test the existing Line 1600.. All other Category 4 Criteria miles are proposed to be addressed in Phase 1A. However, as noted on page 60 of the Testimony, "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 construct new infrastructure to maintain service during pressure testing." Therefore, if during the design and engineering phase of the PSEP, other Phase 1A lines are identified that cannot be tested or replaced during the Phase 1A timeframe, then those lines would be addressed in phase 1B as well.

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST DRA-DAO-29)

QUESTION DRA-DAO-29-03:

Please provide the following:

(a) explain the difference of 385 Category 4 NTSB Criteria miles that need to be tested or replaced and the 362 miles (P. 108 identifies the 206 miles for pressure testing and P. 110 identifies 156 miles for replacement) Criteria Miles planned for Phase 1;
(b) identify and explain in detail the actions that have been taken to address the 23 miles difference,
(c) Identify the line number and segment, and explain the action plan(s) proposed for the 23 miles of Category 4 NTSB Criteria miles if not yet addressed. Also provide the number of miles that are part of the TIMP
(d) Please explain the decision tree process for the 23 miles in (b) above and identify the outcomes for these lines.

RESPONSE DRA-DAO-29-03:

a. The difference between the total Category 4 Criteria mileage and sum of the Category 4 Criteria mileage proposed for replacement and pressure testing is accounted for by the Category 4 Criteria mileage proposed for abandonment.

b. These segments are proposed to be abandoned.

c. Please reference Appendices IX-1-A through IX-1-D for the pipelines and segments with "Abandon" as the Phase 1A action item.

d. Please reference the workpapers supporting Chapter IV of the testimony. These segments have been prioritized per the Decision Tree into boxes 1 or 2. During the review to identify the high level scope, however, it was estimated that no replacement segment would be needed. In the case of L-41-6000-2, this line would effectively by replaced by the extension of L-6914.

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST DRA-DAO-29)

QUESTION DRA-DAO-29-04:

Please answer the following questions regarding the statement on page 18 of the testimony, "Based on preliminary review of records and assumptions based on the review of pipelines located in Class 3 and 4 locations and High Consequence Areas, SoCalGas and SDG&E estimate that about an additional 2,000 miles of transmission pipeline segments will need to be assessed to determine whether they require pressure testing or replacement...":

a) Please describe in detail the "preliminary review of records" undertaken and provide a copy of all documents used to determine that this review leads to an estimate of an additional 2,000 miles of transmission pipelines that need to be assessed.
b) Please identify the "assumptions" referenced in this statement and provide a copy of all documents and or calculations used to determine that this review leads to an estimate of an additional 2,000 miles of transmission pipelines that need to be assessed.
c) Please explain how Sempra identified the additional 2,000 miles of transmission pipelines.
d) Please state whether or not the number of Accelerated pipelines included in Phase 1A is part of the group of 2,000 miles of transmission pipelines that need to be addressed.

RESPONSE DRA-DAO-29-04:

a) In D.11-06-017, the Commission concludes that "all natural gas transmission pipelines must be brought into compliance with modern standards of safety. Historic exemptions must come to an end with an orderly and cost-conscience [sic] implementation plan." To effectuate that change, the Commission directed all California pipeline operators to propose plans "to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 192.619(c). In general, pipeline installed prior to July 1, 1970 will need to be either pressure tested or replaced in order to meet this requirement. The estimate of approximately 2,000 miles for Phase 2 was derived by making adjustments to the miles of pipeline constructed prior to 1970 by subtracting the miles proposed to be addressed in Phase 1.
The attached PHMSA annual report has the miles of transmission line constructed

by decade[1]. The miles from Phase 1 are summarized in Tables IV-4, IX-5, IX-7, and Table IX-14. Accelerated replacement miles, less looping at SDG&E, is summarized in WP-IX-1-36. Please see page WP-IX-1-57 of the workpapers supporting Chapter IX of the Testimony for the derivation of the 2,000 miles.

2010 SCG Trans DOT Report 7100 2-1 (PH 2010 SDGE Trans DOT Report 7100 2-1

b) It is assumed that the CPUC will require pressure testing or replacement of pipeline installed prior to 1970 since modern standards were not in place before that time. Please see page WP-IX-1-57 of the workpapers supporting Chapter IX of the Testimony.

c) Please see page WP-IX-1-57 of the workpapers supporting Chapter IX of the Testimony.

d) Per the calculation detailed in the table found on page WP-IX-1-57 of the workpapers supporting Chapter IX of the Testimony, the Accelerated miles proposed to be included in the Phase 1A scope are not included in the estimated 2,000 miles of transmission pipeline segments that will need to be assessed to determine whether they require pressure testing or replacement in Phase 2.

[1] The annual DOT report was filed August 15, 2011. The pre 1970 mileage on the report and workpaper page WP-IX-1-57 differs by 15 miles (0.6%) at SoCalGas, and 3 miles (1.8%) at SDG&E. This discrepancy is likely due to human error. Correction of this error does not change the estimate of approximately 2,000 miles at SoCalGas and 100 miles at SDG&E.

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST DRA-DAO-29)

QUESTION DRA-DAO-29-05:

Please define and provide the criteria used to determine the following terms as used by Sempra in its operations and in the PSEP filing and:

a) Complete Test Records;
b) Sufficient Documentation;

RESPONSE DRA-DAO-29-05:

a) The phrase "complete test records" is not routinely used by Sempra in its operations and does not appear anywhere in the PSEP filing or supporting testimony. SoCalGas and SDG&E believe the term "traceable, verifiable and complete" was used for the first time in the industry in NTSB's January 3, 2011 safety recommendations to PG&E and the definition and applicability of this term in the natural gas industry has not yet been established.

b) Page 10 of the Testimony describes one key element of the PSEP as "a plan to test or replace all pipeline segments that do not have sufficient documentation of pressure testing to satisfy the requirements of 49 CFR 192.619(a)(b) or (d)." In this context, sufficient documentation is defined as records that include all elements required by the cited regulations.

Section IV.D of the testimony explains that in Phase 1A, SoCalGas and SDG&E prioritize those transmission pipeline segments in populated areas that do not have sufficient documentation to validate a post-construction pressure test of at least 1.25 x MAOP. In this context, sufficient documentation can be described as at least two corroborating documents demonstrating that a 1.25 x MAOP pressure test was performed or one primary document such as a Design Data, Test Chart or Hydrotest Log.

EXHIBIT D

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST FROM SCGC-10)

QUESTION SCGC-10.1:

Comparing Table 3 provided in response to SCGC's Motion to Compel to Table 2.1 provided in response to SCGC Data Request 2, the figures in the total column do not appear to match for each category under the Phase 1B Proposed Case, Phase 1A Base Case, the Phase 1B Base Case, and the SDG&E Distribution category under the Phase 1A Proposed Case. (Note that the combined SoCalGas Backbone/Local Transmission in Table 3 would be compared to the SoCalGas Transmission in Table 2, but otherwise the labels would correspond directly.) The difference seems to occur primarily in the 2023+ column but may appear in other columns.

SCGC-10.1.1

Please explain in detail what causes the difference in the revenue requirement between the two versions.

SCGC-10.1.2

Please identify specific changes in capital or O&M costs or changes in other inputs to the revenue requirement model and explaining the reason for making these changes.

RESPONSE SCGC-10.1.1

The difference in the revenue requirement between the two versions is due to a formula error in the 2023+ column of Table 2.1 provided in response to SCGC Data Request 2. The column 2023+ is supposed to represent the end of the assets book life and full cost recovery. However the formula in the original Table 2.1 only captured year 2023 cost. The formula has now been corrected to capture 2023+ costs.

The below table provides the corrected Table 2.1

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST FROM SCGC-10)

Table 2.1: Revenue Requirements by Phase

(in millions of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Phase 1A Proposed Case														
SoCalGas - Transmission	$ 5.50	$ 57.41	$ 83.70	$ 120.58	$ 144.21	$ 88.75	$ 84.44	$ 78.34	$ 71.70	$ 69.34	$ 67.05	$ 64.79	$ 1,315.79	$ 2,252
SoCalGas - Distribution	$ 0.86	$ 0.21	$ 16.41	$ 61.59	$ 102.38	$ 142.57	$ 135.62	$ 130.23	$ 124.37	$ 120.06	$ 115.89	$ 111.82	$ 1,314.29	$ 2,376
SoCalGas - Storage	$ -	$ 0.29	$ 0.39	$ 0.40	$ 0.42	$ (0.00)	$ 0.00	$ (0.00)	$ 0.00	$ (0.00)	$ 0.00	$ (0.00)	$ 0.00	$ 2
SDG&E - Transmission	$ 0.22	$ 0.01	$ 0.79	$ 8.40	$ 3.81	$ 6.22	$ 5.82	$ 5.18	$ 4.47	$ 4.32	$ 4.17	$ 4.03	$ 77.71	$ 125
SDG&E - Distribution	$ 0.71	$ 0.34	$ 4.40	$ 16.13	$ 26.93	$ 37.66	$ 35.88	$ 34.68	$ 33.36	$ 32.28	$ 31.23	$ 30.21	$ 460.01	$ 744
Phase 1B Proposed Case														
SoCalGas - Transmission	$ -	$ -	$ -	$ -	$ -	$ 2.53	$ 26.67	$ 50.63	$ 75.38	$ 90.22	$ 105.83	$ 117.94	$ 2,507.50	$ 2,977
SoCalGas - Distribution	$ -	$ -	$ -	$ -	$ -	$ 0.83	$ 19.71	$ 37.10	$ 53.96	$ 70.27	$ 86.50	$ 101.37	$ 1,428.62	$ 1,798
SoCalGas - Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SDG&E - Transmission	$ -	$ -	$ -	$ -	$ -	$ 0.37	$ 21.79	$ 41.93	$ 76.11	$ 60.08	$ 58.94	$ 56.92	$ 1,140.68	$ 1,457
SDG&E - Distribution	$ -	$ -	$ -	$ -	$ -	$ 0.26	$ 1.08	$ 1.93	$ 2.78	$ 3.55	$ 4.33	$ 4.78	$ 81.85	$ 101
Phase 1A Base Case														
SoCalGas - Transmission	$ 5.50	$ 56.37	$ 78.71	$ 92.69	$ 106.37	$ 41.16	$ 39.19	$ 38.10	$ 36.82	$ 35.61	$ 34.44	$ 33.27	$ 675.10	$ 1,273
SoCalGas - Distribution	$ 0.86	$ 2.20	$ 16.72	$ 57.88	$ 98.96	$ 139.53	$ 132.74	$ 128.68	$ 124.21	$ 119.91	$ 115.75	$ 111.69	$ 1,312.65	$ 2,362
SoCalGas - Storage	$ -	$ 0.29	$ 0.39	$ 0.40	$ 0.42	$ (0.00)	$ 0.00	$ (0.00)	$ 0.00	$ (0.00)	$ 0.00	$ (0.00)	$ 0.00	$ 2
SDG&E - Transmission	$ 0.22	$ 0.37	$ 0.82	$ 6.68	$ 2.09	$ 4.58	$ 4.25	$ 4.16	$ 4.01	$ 3.88	$ 3.75	$ 3.62	$ 69.94	$ 108
SDG&E - Distribution	$ 0.71	$ 0.61	$ 4.45	$ 15.64	$ 26.47	$ 37.26	$ 35.49	$ 34.47	$ 33.34	$ 32.26	$ 31.21	$ 30.19	$ 459.73	$ 742
Phase 1B Base Case														
SoCalGas - Transmission	$ -	$ -	$ -	$ -	$ -	$ 1.49	$ 6.73	$ 11.63	$ 16.62	$ 21.60	$ 26.64	$ 29.39	$ 630.12	$ 744
SoCalGas - Distribution	$ -	$ -	$ -	$ -	$ -	$ 0.55	$ 3.33	$ 5.12	$ 6.23	$ 7.29	$ 8.35	$ 8.00	$ 111.83	$ 151
SoCalGas - Storage	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SDG&E - Transmission	$ -	$ -	$ -	$ -	$ -	$ 0.23	$ 21.70	$ 41.70	$ 75.71	$ 59.65	$ 58.47	$ 56.60	$ 1,136.11	$ 1,450
SDG&E - Distribution	$ -	$ -	$ -	$ -	$ -	$ 0.22	$ 1.07	$ 1.87	$ 2.68	$ 3.45	$ 4.22	$ 4.71	$ 81.23	$ 99

<u>RESPONSE SCGC-10.1.2</u>

Please see Response to 10.1.1. There were no changes in capital or O&M costs or changes in other inputs to the revenue requirement model.

QUESTION SCGC-10.2

At page 6 of the CPSD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.2.1

For each of the four cases analyzed, SoCalGas identifies a revenue requirement for both SoCalGas and SDG&E distribution. Please explain in detail why pipelines categorized as distribution under FERC accounting definitions would be included as part of SoCalGas/SDG&E's PSEP.

SCGC-10.2.2

For each of the four "enhancements related to distribution facilities" described in above quote, that is, (1) preventing backflow of gas, (2) installation of flow meters, (3) expansion of SCADA system, and (4) expansion of Companies' private radio networks, please identify the associated amount of the SoCalGas and SDG&E distribution revenue requirement.

RESPONSE SCGC-10.2.1

SoCalGas and SDG&E utilize FERC functional reporting to classify and record costs related to their pipeline system. Therefore, the costs for operations and maintenance of our pipelines are recorded according to their FERC accounting definition, which may differ from the DOT definition (Operational).

The D.O.T defines a Transmission line as a pipeline, other than a gathering line, that:
(1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field. (D.O.T. Definition)

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(DATA REQUEST FROM SCGC-10)

RESPONSE SCGC-10.2.2

As described in our Amended Testimony on pages 81-83

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

The below table summarizes the SoCalGas and SDG&E Distribution direct costs associated with the four elements identified in SCGC-10.2.2

Direct Cost Summary
(in thousands of 2011 dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	2,248	2,248	4,865	5,468	6,070	5,400	3,099	2,408	2,408	2,408	36,621
SoCalGas - O&M	-	1	1	25	155	394	997	1,008	929	935	942	5,387
Total SoCalGas	**-**	**2,249**	**2,250**	**4,890**	**5,622**	**6,464**	**6,397**	**4,108**	**3,336**	**3,343**	**3,349**	**42,009**
SDG&E - Capital	-	53	1,078	1,556	1,556	532	532	532	413	413	413	7,078
SDG&E - O&M	-	0	63	127	127	107	109	111	112	113	114	980
Total SDG&E	**-**	**53**	**1,140**	**1,683**	**1,683**	**639**	**640**	**642**	**525**	**526**	**527**	**8,059**

The below table summarizes the loaded and escalated cost of the direct costs provided in the above table.

Loaded and Escalated Cost Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	2,889	2,983	6,336	7,184	8,002	7,321	4,153	3,301	3,382	3,459	49,010
SoCalGas - O&M	-	1	2	34	240	529	1,262	1,312	1,248	1,288	1,331	7,247
Total SoCalGas	**-**	**2,890**	**2,985**	**6,370**	**7,424**	**8,531**	**8,583**	**5,465**	**4,549**	**4,671**	**4,790**	**56,257**
SDG&E - Capital	-	63	1,254	1,867	1,909	664	674	688	547	560	573	8,799
SDG&E - O&M	-	0	93	194	200	183	191	199	206	213	220	1,700
Total SDG&E	**-**	**63**	**1,348**	**2,060**	**2,109**	**847**	**866**	**887**	**753**	**773**	**793**	**10,499**

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST FROM SCGC-10)

The below table summarizes the revenue requirement of the loaded and escalated costs above.

Revenue Requirement Summary

(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Total SoCalGas	-	1	522	1,027	2,322	3,787	5,844	7,010	7,471	7,882	8,295	7,304	95,948	147,413
Total SDG&E	-	0	107	432	748	1,039	1,123	1,219	1,312	1,376	1,442	1,274	20,657	30,727

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST FROM SCGC-10)

QUESTION SCGC-10.3

At page 11 of the CPSD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.3.1

On a line-by-line basis, please identify the difference in the amount of capital and O&M expense that would be associated with pressure testing rather than replacing these pre-1946 non-piggable pipelines.

SCGC-10.3.2

Please identify the difference in revenue requirement that would be associated with pressure testing rather than replacing these pre-1946 non-piggable pipelines.

RESPONSE SCGC-10.3.1

It should be noted that this finding by CPSD states that the SoCalGas/SDG&E "decision tree process for Phase 1B needs to evaluate the pressure testability of pre-1946 non-piggable pipe." This finding does not presume that it will be feasible to pressure test any of these pipelines, as implied by this data request question.
Moreover, as stated in the January 27 Comments of Southern California Gas Company and San Diego Gas & Electric Company on Technical Report of the Consumer Protection and Safety Division:

> SoCalGas and SDG&E disagree with this finding and continue to support their proposal to replace rather than pressure test pre-1946 non-piggable pipelines due to the inability of both pressure testing and in-line inspection to validate the integrity of these pre-WWII era girth welds that are now at least 65 years old. We do not believe it is prudent to use ratepayer funds to pressure test pipelines that will subsequently require more ratepayer funds for replacement to address aged girth welds and the inability to use ILI on the pipelines.

The cost estimates for replacement in Phase 1B of pre-1946 non-piggable pipe were developed at a high level based on a total installed cost-per-foot matrix compiled by SPEC Services. The total estimated Capital spend for this activity is detailed on pages WP-IX-1-49 through WP-IX-1-56 of the workpapers supporting Chapter IX of the testimony.

Cost estimates for pressure testing pre-1946 non-piggable pipe segments operating below 30% SMYS in Phase 1B were not developed for the PSEP filing. For purposes of responding to this data request, a very high level estimate can be obtained by taking the average per-mile pressure testing cost, as calculated using the information on pages WP-IX-1-2 through WP-IX-1-20 of the workpapers supporting Chapter IX of the Testimony, and applying that factor to the mileage of each pipeline operating below 30% SMYS proposed for replacement in Phase 1B. Actual costs could be significantly higher due to testing requirements, pipeline location, elevation changes, environmental restrictions, etc.

The attached spreadsheet identifies for each pipeline the estimated replacement cost, per the filing, and a high level estimate of the pressure test cost, using the average per-mile cost (approx. $0.5 million per mile) as explained above, for these pre-1946 non-piggable pipelines operating below 30% SMYS. As acknowledged in CPSD's finding, detailed analysis would need to be performed to determine the pressure testability of these pipeline segments.

SCGC-10.3.1

The table below summarizes the estimated direct costs associated with the replacement (Capital) and pressure testing (O&M) of the pre-1946 non-piggable pipelines operating below 30% SMYS. The Capital costs are represented as negative numbers to facilitate a comparison to the costs in the PSEP filing.

Direct Cost Summary
(in thousands of 2011 dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	-	-	-	-	(42,908)	(42,908)	(42,908)	(42,908)	(42,908)	(42,908)	(257,448)
SoCalGas - O&M	-	-	-	-	-	5,776	5,776	5,776	5,776	5,776	5,776	34,658
Total SoCalGas	**-**	**-**	**-**	**-**	**-**	**(37,132)**	**(37,132)**	**(37,132)**	**(37,132)**	**(37,132)**	**(37,132)**	**(222,790)**
SDG&E - Capital	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E - O&M	-	-	-	-	-	-	-	-	-	-	-	-
Total SDG&E	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

RESPONSE SCGC-10.3.2

The below table summarizes the loaded and escalated cost of the direct costs provided in Response SCGC-10.3.1

Loaded and Escalated Cost Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	-	-	-	-	(52,626)	(53,658)	(55,001)	(56,368)	(57,898)	(59,468)	(335,020)
SoCalGas - O&M	-	-	-	-	-	6,906	7,074	7,244	7,415	7,585	7,763	43,986
Total SoCalGas	**-**	**-**	**-**	**-**	**-**	**(45,720)**	**(46,584)**	**(47,757)**	**(48,954)**	**(50,313)**	**(51,705)**	**(291,034)**
SDG&E - Capital	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E - O&M	-	-	-	-	-	-	-	-	-	-	-	-
Total SDG&E	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

The below table summarizes the difference in the estimated revenue requirement associated with pressure testing rather than replacing pre-1946 non-piggable pipelines operating below 30% SMYS, assuming the customer impacts associated with pressure testing can be managed.

Revenue Requirement Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Total SoCalGas	-	-	-	-	-	7,150	(1,700)	(9,966)	(18,333)	(26,652)	(34,934)	(51,664)	(941,265)	(1,077,365)
Total SDG&E	-	-	-	-	-	-	-	-	-	-	-	-	-	-

QUESTION SCGC-10.4

At page 13 of the CPSD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.4.1

On a line-by-line basis, please identify the portions of SoCalGas/SDG&E prioritized projects that include low priority pipe.

SCGC-10.4.2

On a line-by-line basis, please identify the amount of capital and O&M expense that would be associated with testing and/or replacing this low priority pipe.

SCGC-10.4.3

On a line-by-line basis, please identify the amount of revenue requirement that would be associated with testing and/or replacing this low priority pipe.

RESPONSE SCGC-10.4.1

Based upon our discussion during a Meet and Confer held on April 23, SoCalGas/SDG&E and SCGC have agreed to modify the question for 10.4. SoCalGas/SDG&E will now respond to this question with a case study of five selected pipeline projects that will include a revenue requirement associated with testing and/or replacing accelerated miles. Per our agreement, SoCalGas/SDG&E will strive to provide our response to 10.4 on or before May 18.

RESPONSE SCGC-10.4.2

See Response SCGC-10.4.1.

RESPONSE SCGC-10.4.3

See Response SCGC-10.4.1.

QUESTION SCGC-10.5

At page 19 of the CPSD report regarding SoCalGas/SDG&E's PSEP, it states:

> **FINDING**: The Companies have not justified running a TFI tool on all piggable lines prior to pressure testing unless such a run allows them to supplant IMP activities for that segment.
>
> **FINDING**: There may be opportunities, not addressed by the PSEP, where, with proper planning and coordination, PSEP activities could supplant some of the activities and costs related to the Companies' ongoing IMP activities.

SCGC-10.5.1

On a line-by-line basis, please identify any pipelines for which running a TFI tool would enable SoCalGas/SDG&E to "supplant IMP activities."

SCGC-10.5.2

Please identify the associated reduction in capital cost, O&M expense, and/or revenue requirement associated with each pipeline identified in the response to the previous question.

SCGC-10.5.3

On a line by line basis where SoCalGas/SDG&E have proposed running the TFI tool prior to pressure testing, please identify the amount of capital and O&M expense that would be avoided if the TFI tool is not run prior to pressure testing.

SCGC-10.5.4

On a line by line basis where SoCalGas/SDG&E have proposed running the TFI tool prior to pressure testing, please identify the revenue requirement that would be avoided if the TFI tool is not run prior to pressure testing.

RESPONSE SCGC-10.5.1

There are no pipelines for which a TFI tool run would "supplant IMP activities."

Please refer to pages 11-13 in our January 27 Comments of Southern California Gas Company and San Diego Gas & Electric Company on Technical Report of the Consumer Protection and Safety Division for a full response to the finding referenced above.

RESPONSE SCGC-10.5.2

Not applicable. See Response SCGC-10.5.1.

RESPONSE SCGC-10.5.3

The direct cost estimates for performing TFI inspections, validation digs, and post-inspection repairs on piggable lines prior to pressure testing are detailed on pages WP-IX-1-38 through WP-IX-1-43 of the workpapers supporting Chapter IX of the testimony. The attached spreadsheet identifies these costs on a per pipeline basis, and the table below summarizes these costs.

SCGC-10.5.3

Direct Cost Summary
(in thousands of 2011 dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	-	-	-	-	-	-	-	-	-	-	-
SoCalGas - O&M	-	11,570	15,427	15,427	15,427	-	-	-	-	-	-	57,851
Total SoCalGas	**-**	**11,570**	**15,427**	**15,427**	**15,427**	**-**	**-**	**-**	**-**	**-**	**-**	**57,851**
SDG&E - Capital	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E - O&M	-	-	-	4,320	-	-	-	-	-	-	-	4,320
Total SDG&E	**-**	**-**	**-**	**4,320**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4,320**

RESPONSE SCGC-10.5.4

The below table summarizes the loaded and escalated cost of the direct costs provided Response SCGC-10.5.3

Loaded and Escalated Cost Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	-	-	-	-	-	-	-	-	-	-	-
SoCalGas - O&M	-	12,862	17,598	18,051	18,568	-	-	-	-	-	-	67,078
Total SoCalGas	**-**	**12,862**	**17,598**	**18,051**	**18,568**	**-**	**-**	**-**	**-**	**-**	**-**	**67,078**
SDG&E - Capital	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E - O&M	-	-	-	4,984	-	-	-	-	-	-	-	4,984
Total SDG&E	**-**	**-**	**-**	**4,984**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4,984**

The below table summarizes the revenue requirement of the loaded and escalated costs above.

Revenue Requirement Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Total SoCalGas	-	13,316	18,171	18,675	19,207	(12)	1	(0)	0	(0)	0	(0)	0	69,359
Total SDG&E	-	-	-	5,190	(4)	0	(0)	0	(0)	0	(0)	0	(0)	5,186

QUESTION SCGC-10.6

On page 21 of the CSPD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.6.1

Please identify how much capital and O&M costs would be increased by this recommendation.

SCGC-10.6.2

Please identify how much capital and O&M costs would be increased by this recommendation. (duplicate question)

RESPONSE SCGC-10.6.1

Both the Base Case and Proposed Case in the PSEP Filing include costs to replace the segments referenced in the question. Therefore, implementing this finding would not change the estimated Capital or O&M costs.

Per Section IV.D.1(a)(2), use of direct examination and application of non-destructive examination (NDE) methods is a proposed alternative to replacement or pressure testing that, in some cases, could reduce costs, customer impacts, and construction hazards while still providing an equivalent means to validate the strength of the pipe segment.

Section IX.D, on page 118 of our Testimony, Projected Cost Savings if Direct Examination is Authorized as an Alternative to Pressure Testing Shorter Pipeline Segments, includes a high level estimate of the cost savings that could potentially be realized in Phase 1 if authorization is given to use direct examination in lieu of replacement or pressure testing.

RESPONSE SCGC-10.6.2

Since the referenced finding does not result in a change in the estimated Capital or O&M costs in the PSEP filing, there is also no change in revenue requirement.

QUESTION SCGC-10.7

On page 21 of the CSPD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.7.1

Please identify the amount of capital and O&M expense that would be avoided if the 2100 proposed methane leak detection monitors were not installed.

SCGC-10.7.2

Please identify the revenue requirement that would be avoided if the 2100 proposed methane leak detection monitors were not installed.

RESPONSE SCGC-10.7.1

Details pertaining to the direct cost estimates for the methane leak detection monitors can be found on pages WP-IX-3-32 through WP-IX-3-33 of the workpapers supporting Chapter IX of the Testimony. A summary of the direct costs can be found in Table IX-15 of the Testimony on page 117. The total Phase 1 cost for this activity is as follows:

Capital - $9.62 million
O&M - $0.9 million

Direct Cost Summary
(in thousands of 2011 dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	-	846	1,692	846	846	846	846	846	846	846	8,462
SoCalGas - O&M	-	-	15	45	60	75	90	105	119	134	149	791
Total SoCalGas	**-**	**-**	**861**	**1,737**	**906**	**921**	**936**	**951**	**966**	**981**	**996**	**9,254**
SDG&E - Capital	-	-	116	232	116	116	116	116	116	116	116	1,161
SDG&E - O&M	-	-	2	6	8	10	12	14	16	18	20	109
Total SDG&E	**-**	**-**	**118**	**238**	**124**	**126**	**128**	**130**	**133**	**135**	**137**	**1,270**

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST FROM SCGC-10)

RESPONSE SCGC-10.7.2

The below table summarizes the loaded and escalated cost of the direct costs provided Response SCGC-10.7.1

Loaded and Escalated Cost Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	-	966	2,003	1,036	1,060	1,082	1,111	1,139	1,170	1,204	10,770
SoCalGas - O&M	-	-	21	65	89	115	141	169	197	227	258	1,283
Total SoCalGas	**-**	**-**	**987**	**2,068**	**1,125**	**1,175**	**1,223**	**1,279**	**1,336**	**1,398**	**1,462**	**12,053**
SDG&E - Capital	-	-	128	266	138	141	144	147	151	155	160	1,430
SDG&E - O&M	-	-	3	9	12	15	19	22	26	30	34	171
Total SDG&E	**-**	**-**	**131**	**275**	**149**	**156**	**162**	**170**	**177**	**186**	**194**	**1,601**

The below table summarizes the revenue requirement of the loaded and escalated costs above.

Revenue Requirement Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Total SoCalGas	-	-	22	232	584	752	934	1,113	1,294	1,475	1,658	1,547	29,458	39,069
Total SDG&E	-	-	3	31	78	101	125	149	173	197	222	207	3,948	5,233

QUESTION SCGC-10.8

On page 23 of the CSPD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.8.1

On a line by line basis where SoCalGas/SDG&E have proposed removing wrinkle bends or oxy-acetylene girth welds, please identify the amount of time that is associated with the removal of the wrinkle bends/girth welds.

SCGC-10.8.2

On a line by line basis where SoCalGas/SDG&E have proposed removing wrinkle bends or oxy-acetylene girth welds, please indicate whether the removal of the wrinkle bends/girth welds becomes at any time a critical path item for scheduling purposes.

SCGC-10.8.3

If the answer to the previous question is "yes," on a line-by-line basis, please identify how much time would be required to complete only the non-discretionary activities.

RESPONSE SCGC-10.8.1

As explained on page 20 of our January 27 Comments on the Technical Report of the Consumer Protection and Safety Division:

> Removal of wrinkle bends did not drive the estimated pressure testing clearance times in the SoCalGas and SDG&E Pipeline Safety Enhancement Plan. Therefore, the time required to remove wrinkle bends was not a driver in the test or replace decision-making process. Rather, the proposed decision tree process set forth in the Pipeline Safety Enhancement Plan considers whether a pipeline can be taken out of service with manageable customer impacts in order to determine the assignment of that pipeline to the replacement or pressure test scope.

RESPONSE SCGC-10.8.2

See Response SCGC-10.8.1.

RESPONSE SCGC-10.8.3

N/A

QUESTION SCGC-10.9

On page 23 of the CSPD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.9.1

Please identify the amount of capital and O&M expense that would be avoided if the frequency of patrols were reduced from bi-monthly to semi-annual.

SCGC-10.9.2

Please identify the revenue requirement that would be avoided if the frequency of patrols were reduced from bi-monthly to semi-annual.

RESPONSE SCGC-10.9.1

Pipeline patrols are performed concurrent with leak surveys. CPSD never suggested changing the frequency of leak surveys to semi-annual from bi-monthly. Therefore, there would still be the same number of miles covered and therefore, SoCalGas and SDG&E anticipate that no material cost savings would be realized.

RESPONSE SCGC-10.9.2

N/A

QUESTION SCGC-10.10

On page 24 of the CSPD report regarding SoCalGas/SDG&E's PSEP, it states:

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

SCGC-10.10.1

Please identify the amount of capital and O&M expense that would be associated with testing or replacing these pipelines.

SCGC-10.10.2

Please identify the revenue requirement that would be associated with testing or replacing these pipelines.

RESPONSE SCGC-10.10.1

The portion of the estimated Capital and O&M cost (pro-rated based on length) associated with Category 4 segments installed between July 1, 1961 and 1970 and proposed for pressure testing or replacement in our plan is as follows:

Estimated Replacement and Pressure Testing Costs for All Category 4 Pipeline Segments Installed Between July 1, 1961 and 1970[1]

	Replacement Capital	Pressure Test O&M
SoCalGas	$ 63.3 million	$ 3.8 million
SDG&E	$ 6.3 million	$ 0.0 million

In compiling these costs, SoCalGas and SDG&E did not conduct an analysis to determine whether or not a segment installed in the above referenced date range has documentation to show compliance with the applicable GO-112 requirements, because D.11-06-017 requires SoCalGas and SDG&E to bring all transmission pipelines into compliance with modern standards for safety and does not exempt pipeline segments that satisfy historic regulatory requirements applicable at the time of installation.

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[1] Costs estimates based on estimates of approximately 19.61 Criteria Miles and 11.26 Non-Criteria Miles.

Accordingly, SoCalGas and SDG&E disagree with the CPSD's finding that segments lacking documentation of a pressure test pursuant to GO 112 installed between 1961 and 1970 should be replaced or installed at the Companies' expense. As stated in our January 27 Comments on the Technical Report of the Consumer Protection and Safety Division:

> This requirement to either test or replace all pipeline segments that lack documentation sufficient to exceed current Federal regulations requires the testing or replacement of all pipeline segments installed between July 1961 and 1970, regardless of documentation. Thus, the question of whether existing documentation satisfies the requirements that existed between July 1961 and 1970 irrelevant. The requirement to test or replace these segments is driven entirely by the Commission's desire to exceed current Federal regulations, and therefore, the costs of such testing or replacement should be borne by our customers.

Direct Cost Summary
(in thousands of 2011 dollars)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	6,327	18,981	18,981	18,981	-	-	-	-	-	-	63,270
SoCalGas - O&M	-	762	1,016	1,016	1,016	-	-	-	-	-	-	3,811
Total SoCalGas	**-**	**7,089**	**19,997**	**19,997**	**19,997**	**-**	**-**	**-**	**-**	**-**	**-**	**67,080**
SDG&E - Capital	-	626	1,878	1,878	1,878	-	-	-	-	-	-	6,259
SDG&E - O&M	-	0	0	0	0	-	-	-	-	-	-	1
Total SDG&E	**-**	**626**	**1,878**	**1,878**	**1,878**	**-**	**-**	**-**	**-**	**-**	**-**	**6,260**

Moreover, cost estimates to test or replace these pipeline segments would not accurately reflect the cost of pressure testing a new line before it is placed in service, which would typically be less than the cost to test or replace in-service pipelines.

RESPONSE SCGC-10.10.2

The below table summarizes the loaded and escalated cost of the direct costs provided Response SCGC-10.10.1

Loaded and Escalated Cost Summary
(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas - Capital	-	6,893	21,284	21,986	22,567	-	-	-	-	-	-	72,730
SoCalGas - O&M	-	809	1,108	1,136	1,169	-	-	-	-	-	-	4,222
Total SoCalGas	**-**	**7,702**	**22,392**	**23,122**	**23,736**	**-**	**-**	**-**	**-**	**-**	**-**	**76,953**
SDG&E - Capital	-	663	2,054	2,118	2,167	-	-	-	-	-	-	7,002
SDG&E - O&M	-	0	0	0	0	-	-	-	-	-	-	1
Total SDG&E	**-**	**663**	**2,054**	**2,119**	**2,167**	**-**	**-**	**-**	**-**	**-**	**-**	**7,003**

The below table summarizes the revenue requirement of the loaded and escalated costs above.

Revenue Requirement Summary

(in thousands of dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
Total SoCalGas	-	838	2,324	5,981	9,557	11,989	11,402	11,062	10,680	10,315	9,961	9,615	131,209	224,933
Total SDG&E	-	0	117	469	809	1,158	1,103	1,071	1,036	1,002	970	938	14,293	22,966

QUESTION SCGC-10.11

Considering the CSPD report in its entirety, please identify the overall capital costs and O&M expenses associated with SoCalGas' proposed PSEP with the modifications proposed by CSPD.

RESPONSE SCGC-10.11

On page 2 of the CPSD report, the purpose of the review is explained as follows:

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

SoCalGas understands the Findings noted in the CPSD report to be comments, observations, and areas for further evaluation/investigation that will help inform the Commission as it develops the directives and legislation that will ultimately guide the execution of the PSEP. As such, SoCalGas does not interpret the CPSD report to be definitively proposing modifications to the PSEP. Moreover, we believe our comments on the Report adequately address the comments and observations by the CPSD.

QUESTION SCGC-10.12

Considering the CSPD report in its entirety, please identify the overall revenue requirement associated with SoCalGas' proposed PSEP with the modifications proposed by CSPD.

RESPONSE SCGC-10.12

See Response SCGC-10.11

OIR ON THE COMMISSION'S OWN MOTION TO ADOPT NEW SAFETY AND RELIABILITY REGULATIONS FOR NATURAL GAS TRANSMISSION AND DISTRIBUTION PIPELINES AND RELATED RATEMAKING MECHANISMS (R.11-02-019)

(DATA REQUEST FROM SCGC-10)

QUESTION SCGC-10.13

Considering the CSPD report in its entirety, please identify the overall capital costs and O&M expenses associated with SDG&E's proposed PSEP with the modifications proposed by CSPD.

RESPONSE SCGC-10.13

On page 2 of the CPSD report, the purpose of the review is explained as follows:

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

SDG&E understands the Findings noted in the CPSD report to be comments, observations, and areas for further evaluation/investigation that will help inform the Commission as it develops the directives and legislation that will ultimately guide the execution of the PSEP. As such, SDG&E does not interpret the CPSD report to be definitively proposing modifications to the PSEP. Moreover, we believe our comments on the Report adequately address the comments and observations by the CPSD.

QUESTION SCGC-10.14

Considering the CSPD report in its entirety, please identify the overall revenue requirement associated with SDG&E's proposed PSEP with the modifications proposed by CSPD.

RESPONSE SCGC-10.14

See Response SCGC-10.13

EXHIBIT E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U904G) and San Diego Gas & Electric Company (U902G) to Recover Costs Recorded in the Pipeline Safety and Reliability Memorandum Accounts, the Safety Enhancement Expense Balancing Accounts, and the Safety Enhancement Capital Cost Balancing Accounts.	A.16-09-005

SOUTHERN CALIFORNIA GENERATION COALITION PROTEST OF THE SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY APPLICATION TO RECOVER COSTS RECORDED IN THE PIPELINE SAFETY RELIABILITY MEMORANDUM ACCOUNT, THE SAFETY ENHANCEMENT EXPENSE BALANCING ACCOUNTS, AND THE SAFETY ENHANCEMENT CAPITAL COST BALANCING ACCOUNTS

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Dated: October 10, 2016

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U904G) and San Diego Gas & Electric Company (U902G) to Recover Costs Recorded in the Pipeline Safety and Reliability Memorandum Accounts, the Safety Enhancement Expense Balancing Accounts, and the Safety Enhancement Capital Cost Balancing Accounts.	A.16-09-005

SOUTHERN CALIFORNIA GENERATION COALITION
PROTEST OF THE
SOUTHERN CALIFORNIA GAS COMPANY AND
SAN DIEGO GAS & ELECTRIC COMPANY
APPLICATION TO RECOVER COSTS RECORDED IN THE PIPELINE SAFETY RELIABILITY MEMORANDUM ACCOUNT,
THE SAFETY ENHANCEMENT EXPENSE BALANCING ACCOUNTS, AND THE SAFETY ENHANCEMENT CAPITAL COST BALANCING ACCOUNTS

In accordance with Rule 2.6 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the Southern California Generation Coalition ("SCGC") respectfully protests the September 2, 2016 Application of the Southern California Gas Company ("SoCalGas") and San Diego Gas and Electric Company ("SDG&E") (jointly, "Applicants") to recover Pipeline Safety Enhancement Plan ("PSEP") costs recorded in their Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs"), their Safety Enhancement Expense Balancing Accounts ("SEEBAs"), and their Safety Enhancement Capital Cost Balancing Accounts ("SECCBAs")

As discussed below, the Application proposes the recovery of costs without an adequate showing and even proposes the recovery of costs for projects that are not authorized by the Commission. Thus, recovery of costs as proposed by the Applicants would unjustifiably raise the cost of the gas transmission service that the Applicants provide to SCGC members. Accordingly SCGC requests that the Application be set for an evidentiary hearing.

I. BACKGROUND.

Pursuant to Decision ("D") 12-04-021, the Applicants created their PSRMAs to record PSEP Operations and Maintenance ("O&M") and capital costs.[1] In the subsequent D.14-06-007 approving implementation of their PSEP in the Applicants' 2013 Triennial Cost Allocation Proceeding ("TCAP"), the Commission stated that costs accumulated in the Applicants' PSRMAs would be reviewed for reasonableness.[2] Additionally, the Commission authorized the Applicants to establish their SEEBAs and SECCBAs to record Phase 1 PSEP costs with the new accounts becoming effective on the effective date of D.14-12-007, June 12, 2016.[3]

The Applicants sought review of the reasonableness of costs recorded in their PSRMAs during the locked-in period from February 24, 2011, the effective date of Rulemaking 11-02-019, to June 12, 2014, the effective date of D.14-06-007, in Application ("A.") 14-12-016. The PSRMA reasonableness review application is currently pending before the Commission.

In their new application, the Applicants seek reasonableness review of $134 million in direct capital costs and $61 million in O&M.[4] More specifically the Applicants seek reasonableness review of the costs of 26 pipeline projects,[5] 15 bundled valve projects,[6] and two methane sensing equipment pilot projects, one for SoCalGas and another for SDG&E.[7] The Applicants' direct costs of the pipeline projects that are presented in the Application for a determination of reasonableness include $101.97 million in capital expenditures, $54.49 million in O&M expenditures, a $48,00 "capital credit," and $6.81 million in "miscellaneous other"

[1] D.12-04-021, p. 12 (April 19, 2012).

[2] D.14-06-007, p. 61, Ordering Paragraph 6 (June 12, 2014).

[3] *Ibid,* p. 60, Ordering Paragraph 4.

[4] Application, p. 1.

[5] Direct Testimony of Rick Phillips, Chapter III, p.1 (Sept. 2, 2016) ("Phillips Direct).

[6] Direct Testimony of Huge Mejia, Chapter V, pp.1, 5, Table 1 (Sept. 2, 2016) ("Mejia Direct).

O&M costs.[8] The Applicants' direct capital cost of the 15 bundled valve projects is $31.72 million.[9] The direct costs of the methane sensing pilot projects are $358,000 for SoCalGas and $117,000 for SDG&E.[10]

The revenue requirement that the Applicants seek to recover is $68.4 million for SoCalGas and $2.6 million for SDG&E.[11] The Applicants explain that in D.16-08-003 they were authorized 50 percent interim recovery of PSRMA, SEEBA, and SECCBA revenue requirements, subject to refund.[12] As a result of 50 percent interim recovery of PSRMA, SEEBA, and SECCBA revenue requirements already being incorporated into rates, the Applicants' illustrative transportation rate tables show the rate impact of incorporating the additional 50 percent of costs not yet incorporated into rates.[13]

SCGC members are electric generation ("EG") customers of SoCalGas. The Transmission Level Service ("TLS") and Backbone Transmission Service ("BTS") rates are particularly relevant to SCGC members. The TLS and BTS rates would increase by a greater percentage than the rates for any other rate class, 5.0 percent for TLS rates and 8.8 percent for BTS rates.[14]

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[7] Direct Testimony of Michael Bermel, Chapter VI, pp. 8-9, Tables 1 and 2 (Sept. 2, 2016) ("Bermel Direct).

[8] Phillips Direct, pp. 1, 14-15, Tables 5-8.

[9] Mejia Direct, pp.1, 5, Table 1 (Sept. 2, 2016).

[10] Bermel Direct, pp. 8-9.

[11] Application, p. 1; Direct Testimony of Reginald M. Austria, Chapter XI, p. 3, Table 1 (Sept. 2, 2016) ("Austria Direct)

[12] Direct Testimony of Sharim Chaudhury, Chapter XII, p. 6, footnote 7 (Sept. 2, 2016) ("Chaudhury Direct").

[13] *Ibid.*

[14] *Ibid.* p. 7, Table 8.

II. PROTEST.

As a threshold matter, the costs of projects which were not authorized in D.11-06-017 should be excluded from the scope of this proceeding.[15] Additionally, the Application should be reviewed through the evidentiary process to determine whether all costs that were disallowed for recovery in D.14-06-007 have been excluded from the Application. For projects which were authorized in D.14-06-007 subject to reasonableness review, the Application should be reviewed through the evidentiary process to determine whether the costs that are included in the Application are shown to be reasonable as required by D.14-06-007, and whether all costs that are included in the Application directly contribute to the implementation of Safety Enhancement as required by D.14-06-007. The Applicants should not be permitted to recover any costs fro projects which were not authorized by D.11-06-017, any disallowed costs, any costs which are not sufficiently shown to be reasonable, and any costs that do not directly contribute to the implementation of Safety Enhancement.

A. The Costs of Projects Which Were Not Authorized in D.11-06-017 Should Be Excluded from the Scope of this Proceeding.

As a threshold matter, the costs of projects which were not authorized to be part of the Applicants' PSEP in Decision ("D.") 11-06-017 (June 9, 2011) should be excluded from the scope of this proceeding. The Applicants propose that the scope of the PSEP Phase 2 work should expand beyond the scope permitted by D.11-06-017

The Applicants state, correctly, that in PSEP Phase 2, "PSEP Phase 2 includes pipelines without record of a pressure test or with record of a pressure test but not up to 1.25 MAOP in less populated areas…."[16] They call work on these pipelines "Phase 2A."[17] However, the

[15] D.11-06-017 (June 9, 2011).

[16] Application, p. 11.

[17] *Ibid.*

Applicants go on to state, incorrectly, that PSEP Phase 2 would also encompass "pipelines with record of a pressure test, but without record of a pressure test to modern (Subpart J) standards….."[18] The Applicants call this work "Phase 2B."[19] The Applicants' witness Phillips makes the same claim that PSEP Phase 2 has two sub-phases.[20] The Applicants argue in their Application and in their testimony:

> Current pressure test standards were developed and issued as part of Part 192, 49 CFR Subpart J – recognized as the modern standard for pressure testing. D.11-06-017 requires in-service natural gas transmission pipeline in California to have been pressure tested in accordance with modern standards for safety (*see* D.11-06-017, mimeo., at 18). 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.[21]

Expanding PSEP Phase 2 beyond pipelines in less populated areas that lack sufficient documentation of pressure testing to pipelines that do have documentation of pressure testing, albeit not up to the standards of Subpart J, would expand PSEP Phase 2 enormously. While the Applicants have 660 miles of pipeline in less populated areas that lack sufficient documentation of pressure testing, they have approximately 1,200 miles of pipeline segments that have documentation of pressure testing, but the pressure testing was conducted prior to the adoption of Part 192 of Title 49 of the Code of Federal Regulations on November 12, 1970.[22]

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[18] *Ibid.*

[19] *Ibid.*

[20] Phillips Direct, p, 6

[21] Application, footnote 40; Direct Testimony of Jimmie Cho, p. 4, footnote 8 (Sept. 2, 2016) ("Cho Direct"); Phillips Direct, p. 6, footnote 24.

[22] A.15-06-013, Prepared Direct Testimony of Rick Phillips, p. RP-3 (June 17, 2015); D.16-08-003, p. 8 (Aug. 18, 2016).

The so-called Phase 2B costs appear in this Application in the form of "accelerated miles." The Applicants includes both "accelerated miles" and "incidental miles" in their Application[23] The Applicants' witness Phillips defines "accelerated miles" as follows:

> Accelerated miles are miles that would otherwise be addressed in a later phase of PSEP under the approved prioritization process, but are being advanced to Phase 1A to realize operating and cost efficiencies. Accelerated miles may include Phase 1B or Phase 2. Phase 1B includes pipelines installed before 1946 that are unpiggable. Phase 2 includes pipelines without sufficient record of a pressure test in less populated areas (Phase 2A) or pipelines with record of a pressure test, but without record of a pressure test to modern – Subpart J – standards (Phase 2B).[24]

Witness Phillips describes "incidental miles" as follows: "Incidental miles are miles not scheduled to be addressed in PSEP, but are included where their inclusion is determined to improve cost and program efficiency, address implementation constraints, or facilitate continuity of testing."[25]

The accelerated and incidental miles the Applicants expect to undertake in PSEP Phase 1A, the PSEP Phase that was designed to address the most densely populated areas,[26] is substantial. The Applicants' witness Phillips says that the Applicants currently anticipate pressure testing or replacing 175 miles of pipeline in Phase 1A, with 80 miles, 46 percent, being accelerated and incidental miles.[27]

Any Commission decision addressing the Application in this proceeding should be narrowly crafted to explicitly avoid being construed to constitute approval of expanding PSEP Phase 2 to encompass what the Applicants call "Phase 2B," pressure testing or replacing pipeline

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[23] Phillips Direct, pp. 12-13.

[24] *Ibid*, p. 13.

[25] *Ibid.*

[26] Prepared Direct Testimony of Rick Phillips, Chapter II, p. 4 (Sept. 2, 2016).

[27] *Ibid.*

segments that have adequate documentation of pressure testing prior to implementation of Part 192 but not fully up to Part 192 standards. D.11-06-017 Ordering Paragraph 3 does not require retesting or replacement of pre-1971 pipelines that have adequate documentation of pressure testing as long as the pressure test records include "all elements required by the regulations in effect when the test was conducted" and the pressure test had a duration of at least one hour.[28]

Mandating retesting or replacement of all pre-1971 pipeline segments that have adequate documentation of a pressure test that meets the requirements of D.11-06-017 Ordering Paragraph 3 would constitute a major expansion of the Pipeline Safety Enhancement Plans of the California gas utilities without any demonstration of safety benefits that could plausibly justify the potentially enormous cost of the retesting or replacement. In any decision in this proceeding, the Commission should explicitly reject any aspect of the Application that could be construed to seek authorization of a plan for retesting or replacement of pre-1971 pipeline segments that have adequate documentation of pressure testing as "required by the regulations in effect when the test was conducted" where the pressure test was for at least one hour as described in D.11-06-017 Ordering Paragraph 3.

If Phase 2 accelerated miles are considered in this Application, the accelerated miles should be limited to what the Applicants call "Phase 2A" miles. This was the approach the Commission took in A.15-06-013, which the Commission addressed in D.16-08-003. The Applicants limited their request in A.15-06-013 to what they now call "Phase 2A" miles: "This Application <u>solely</u> addresses the planning and engineering design costs associated with developing detailed cost estimates for the approximately 660 mile of pipeline that do not have sufficient documentation of a pressure test to at least 1.25 time MAOP."[29] The Commission

[28] D.11-06-017, p. 31, Ordering Paragraph 3 (June 9, 2011).

[29] A.15-06-013, p. 4 (June 17, 2015) (emphasis added, footnotes deleted).

noted the limited scope of A.15-06-013 in D.16-08-003: "Only planning and engineering costs associated with the 660 miles of untested pipeline are included in the request for memorandum account treatment. The applicants stated that the cost of testing or replacing the other 1,200 miles of pipeline will be addressed in separate applications."[30] The scope of this proceeding should be similarly limited.

B. The Application Should Be Reviewed Through the Evidentiary Process to Determine Whether the Applicants Excluded All Costs that Were Disallowed for Recovery in D.14-06-007.

The Application should be reviewed to determine whether the Applicants have properly excluded all costs which the Commission found to be ineligible for recovery from ratepayers in D.14-06-007 as subsequently modified by D.5-06-020. The Applicants recognize that the Commission disallowed costs that were relevant to projects presented for review in this proceeding.[31] The Applicants' determination of the disallowances should be examined through the evidentiary process. For example, the Applicants determine a $1.7 million system average cost to pressure test pipelines and multiply that average cost by the length of pipe that is subject to a disallowance.[32] The proposed $1.7 million system average cost should be examined.

C. The Application Should Be Reviewed Through the Evidentiary Process to Determine Whether the Costs that Are Included in the Application Are Shown to Be Reasonable as Required by D.14-06-007.

After excluding costs of projects that were not authorized by the Commission and removing disallowed costs, the remaining costs presented for review in the Application should be reviewed for reasonableness. In D.14-06-007, the Commission stated that the Applicants would be permitted to recover the costs recorded in their PSRMA only to the extent to which the costs were reasonably incurred: "That is, the costs must have been prudently incurred by competent

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[30] D.16-08-003, p. 8 (Aug. 18, 2016).

[31] Phillips Direct, pp. 2-8.

management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who are performing their jobs properly."[33] The Commission explained, further, that "where imprudent actions by the gas system operator have led to unreasonable costs, we will assign those costs to shareholders."[34] The Commission identified the minimum filing requirements for the Applicants' Safety Enhancement reasonableness applications:

> When SDG&E and SoCalGas file applications to demonstrate the reasonableness of Safety Enhancement they will bear the burden of proof that the companies used industry best practices and that their actions were prudent. This is not a "perfection" standard: it is a standard of care that demonstrates all actions were well planned, properly supervised and all necessary records are retained. At a minimum we would expect that SDG&E and SoCalGas could document and demonstrate an overview of the management of Safety Enhancement which might include: ongoing management approved updates to the Decision Tree and ongoing updates similar to the Reconciliation. The companies should be able to show work plans, organization charts, position descriptions, Mission Statements, etc., used to effectively and efficiently manage Safety Enhancement. There would likely be records of contractor selection controls, project cost control systems and reports, engineering design and review controls, and of course proper retention of constructions records, retention of pressure testing records, and retention of all other construction test and inspection records, and records of all other activities mandated to be performed and documented by state or federal regulations.[35]

In many instances, the Applicants describe what they did and identify the associated costs, but they either do not present a showing of reasonableness at all or they summarily state that what they did was reasonable without going into the depth required by D.14-06-007. For example,

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[32] *Ibid,* p. 7.

[33] D.14-06-007, *ibid,* p. 31

[34] *Ibid.*

[35] *Ibid,* pp. 36-37.

regarding descoped projects, the Applicants' witness Phillips says: "The descoped projects directly contributed towards the implementation of projects prior to cancellation and were prudently and reasonably incurred."[36] The Application should be set for hearing to determine whether the Applicants make a showing beyond conclusory statements which meets the standards set in D.14-07-007. As discussed below regarding schedule, it would be expeditious to require the Applicants to make a specific showing of reasonableness for all of the costs presented in the Application, including the cost of each of the 26 pipeline projects, 15 bundled valve projects, and two methane sensing equipment pilot projects for which the Applicants seek a reasonableness determination. The Application should also be examined to determine whether the Applicants were prudent in deciding to replace rather than pressure test segments.

III. SCHEDULE AND CATEGORIZATION.

The Applicants propose that their Application be categorized as "Ratesetting" because of the potential impact on the Applicants' rates,[37] and SCGC concurs. However, SCGC does not concur with the Applicants' proposed schedule.

Applicants propose that intervenor testimony be submitted by March 3, 2017.[38] Given the Applicants' sparse showing, multiple rounds of discovery will be necessary on various issues for intervenors to obtain sufficient information to enable submission of an informed reasonableness recommendation. Additional time may be needed for the submission of intervenor testimony.

A preferable course would be for the Commission to require the Applicants to submit supplemental testimony to demonstrate the reasonableness of their claimed costs. Supplemental

[36] Phillips Direct, p. 18.

[37] Application, p. 19.

[38] *Ibid.*

testimony was required in A.14-12-016,[39] and supplemental testimony should similarly be required in this proceeding.

Furthermore, the supplemental testimony should contain the level of detail that the Applicants finally presented in their rebuttal testimony in the PSRMA reasonableness review proceeding, A.14-12-016. If, instead, the Applicants wait until rebuttal testimony to submit a sufficient detail as they finally did in A.14-12-016, intervenors should be allowed to submit sur-rebuttal testimony.

IV. CONCLUSION.

For the reasons set forth above, SCGC respectfully protests the Application and requests that the Application be set for evidentiary hearing.

Respectfully submitted,

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Dated: October 10, 2016

[39] Scoping Memo and Ruling, A.14-12-016 p. 5 (April 1, 2015).

EXHIBIT F

FILED
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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application 17-10-007 (Filed October 6, 2017)
Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application 17-10-008 (Filed October 6, 2017)

PROTEST OF THE UTILITY REFORM NETWORK

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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November 17, 2017

PROTEST OF THE UTILITY REFORM NETWORK

I. Introduction

On October 6, 2017, San Diego Gas & Electric Company (SDG&E) filed Application (A.) 17-10-007, its Test Year 2019 General Rate Case (GRC), seeking to increase its electric and gas revenue requirement and base rates effective on January 1, 2019 and increase its revenue requirement in each of the following three years, 2020-2022. On the same day, Southern California Gas Company (SoCalGas) filed A.17-10-008, its Test Year 2019 GRC, seeking to increase its gas revenue requirement and base rates effective on January 1, 2019 and increase its revenue requirement in each of the following three years, 2020-2022. Because SDG&E and SoCalGas are affiliated companies owned by Sempra Energy and their applications involve related questions of law and fact, similar issues, and have common witnesses, the Commission consolidated these two applications on November 8, 2017.[1]

Pursuant to Rule 2.6 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure, The Utility Reform Network (TURN) submits this protest to the applications of SDG&E and SoCalGas (collectively, the Sempra Utilities). Rule 2.6 requires that protests be filed within 30 days of the date the notice of the filing of the application first appeared in the Commission's Daily Calendar. Notice of the instant applications first appeared on October 18, 2017. TURN's protest is thus timely filed.

II. Overview of GRC Requests and The Broader Context in Which They Occur

SDG&E's and SoCalGas's applications request remarkable revenue requirement

[1] *Administrative Law Judge's Ruling Consolidating Applications*, issued Nov. 8, 2017, pp. 1-2.

increases. The following tables summarize the utilities' requests.[2]

SDG&E Test Year 2019 GRC Request (2019-2022 Cycle)

Year	Increase ($000)	GRC Rev. Req. ($000)	% Increase
2018 (As-Expected Authorized)		$1,981,000	
2019	$218,000	$2,199,000	11.00%
2020	$159,900	$2,358,900	7.27%
2021	$122,700	$2,481,600	5.20%
2022	$126,000	$2,607,600	5.08%
Sum of 2019-2022 Increases	$626,600		
% Increase by 2022 (over 2018)	31.63%		
Cumulative Increase in Revenues	$1,723,100		

SoCalGas Test Year 2019 GRC Request (2019-2022 Cycle)

Year	Increase ($000)	GRC Rev. Req. ($000)	% Increase
2018 (As-Expected Authorized)		$2,509,000	
2019	$480,000	$2,989,000	19.13%
2020	$255,400	$3,244,400	8.54%
2021	$200,800	$3,445,200	6.19%
2022	$212,800	$3,658,000	6.18%
Sum of 2019-2022 Increases	$1,149,000		
% Increase by 2022 (over 2018)	45.80%		
Cumulative Increase in Revenues	$3,300,600		

The Commission must keep in mind that customers would experience these increases *in combination with* revenue requirement and rate increases associated with

[2] These increase amounts presented by the utilities are likely to be understated. Each utility also has memorandum and balancing account proposals that could assign to ratepayers amounts in excess of the forecast, thus causing the increases to be even higher than the stated figures. For example, SoCalGas proposes a Morongo Rights-of-Way memorandum account and balancing account, for which the forecasted amount is zero. Ex. SCG-09, p. 21. Thus, if SoCalGas records any costs of extending the expiring rights-of-way, or in furtherance of a relocation of the associated pipelines, that amount would be an increment above the utility's forecasted GRC increase. Similarly, both SoCalGas and SDG&E propose a Liability Insurance Premium Balancing Account that would amortize any above-forecasts expenses through the annual regulatory account update advice letter filing. Ex. SCG-42, p. 19 and Ex. SDG&E-41, p. 13.

other non-GRC programs and projects. The following list includes examples of pending requests from SDG&E and SoCalGas that would impact rates during the proposed 2019-2022 GRC cycle and is not intended to be exhaustive:

- In A.15-09-013, SDG&E and SoCalGas have requested authorization to construct a new 36-inch gas transmission pipeline in SDG&E's service territory, Line 3602, at a construction cost of $595 million.[3]
- In A.16-09-005, a Pipeline Safety Enhancement Program (PSEP) reasonableness review proceeding, SoCalGas has requested a revenue requirement increase of $65 million, with a much smaller increase of $2.6 million requested by SDG&E.[4]
- In A.17-01-020, SDG&E has requested approval of its proposed SB 350 Transportation Electrification Proposals, including "priority review projects" and the "Residential Charging Program." SDG&E estimates the revenue requirements associated with the priority review projects as $29.4 million from 2018-2025 plus $38.6 million from 2026-2050; and with the Residential Charging Program as approximately $201.5 million from 2019-2025 plus $504.5 million from 2026-2050.[5]
- In A.17-03-021, SoCalGas and SDG&E have requested, respectively, revenue requirement increases of $44.6 million and $0.500 million for PSEP Phase 1B and 2A projects, based on forecasted costs of $197.5 million in capital and

[3] A.15-09-013, p. 24 (referencing the cost estimate provided in Proponent's Environmental Assessment, Table 3-7 at p. 3-67).

[4] A.16-09-005, pp. 13-15.

[5] A.17-01-020, SDG&E Testimony, Chapter 6, Appendix A.

$57 million in O&M.[6]

- In A.17-04-016, SDG&E has requested a $48 million revenue requirement increase in 2018 for forecasted procurement and GHG-related costs.[7]
- In A.17-04-027, SDG&E has requested authorization to implement the Customer Information System Replacement Program and forecasts a one-time expenditure of $253.6 for implementation, and a "total cost of ownership" revenue requirement of $996.6 million (including implementation costs, ongoing support costs for the 15-year asset life, loaders and escalation).[8]
- In A.17-05-007, SoCalGas has requested authorization to expand its Mobilehome Park (MHP) Utility Upgrade Program to include an additional 26,000 MHP spaces and to record the associated costs to the existing memorandum account for the MHP Utility Upgrade for future reasonableness review in a GRC.[9] Based on SoCalGas's average recorded program costs to date, SoCalGas forecasts total costs (including capital, O&M, and other costs) of $272.2 million from 2018-2024 to convert these MHP spaces.[10] SoCalGas estimates the revenue requirements associated with these expenditures as approximately $114 million from 2018-2023 plus $398.3 million from 2024-2092.[11]
- In A.17-05-008, SDG&E has requested authorization to expand its MHP

[6] A.17-03-021, p. 11.

[7] A.17-04-016, p. 4.

[8] A.17-04-021, p. 2.

[9] A.17-05-007, p. 4.

[10] A.17-05-007, SoCalGas Testimony, Chapter 3, pp. HSM-1 – HSM-3.

[11] A.17-05-007, SoCalGas Testimony, Chapter 5, p. KCC & RG-3.

Utility Upgrade Program to include an additional 6,600 MHP spaces and to record the associated costs to the existing memorandum account for the MHP Utility Upgrade for future reasonableness review in a GRC.[12] Based on SDG&E's average recorded program costs to date, SDG&E forecasts total costs (including capital, O&M, and other costs) of $203.5 million from 2018-2023 to convert these MHP spaces ($97.6 million for gas and $105.9 million for electric).[13] SDG&E estimates the revenue requirements associated with these expenditures as approximately $81 million from 2018-2023 plus $426.8 million from 2024-2092.[14]

Meanwhile, as the Commission considers these various proposed rate increases, including the instant GRC requests, the residential customers of both utilities are increasingly facing disconnection for non-payment. The following tables provide annual disconnection data for each utility from 2010-2016.[15]

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[12] A.17-05-008, p. 4.

[13] A.17-05-008, SDG&E Testimony, Chapter 3, pp. HSM-1 – HSM-3.

[14] A.17-05-007, SDG&E Testimony, Chapter 5, p. WV-3.

[15] These tables also provide 2017 data to-date (through Sept.), but it is not yet possible to determine whether disconnections will be higher in 2017 than 2016.

SDG&E Residential Disconnections for Non-Payment[16]

Year	Average Customer Accounts in IOU Territory	Unique Customers Disconnected for Non-Payment	Unique Customer Disconnection Rate	Total Disconnects*	Total Disconnect Rate
2010	1,243,206	17,892	1.4%		
2011	1,252,446	16,664	1.3%	20,690	1.7%
2012	1,263,459	17,195	1.4%	21,691	1.7%
2013	1,276,571	18,531	1.5%	26,627	2.1%
2014	1,296,816	21,975	1.7%	28,933	2.2%
2015	1,323,318	19,409	1.5%	35,899	2.7%
2016	1,350,527	24,585	1.8%	40,067	3.0%
2017 to-date (through 9/17)				33,937	

* accounts for multiple disconnections of the same customers

SoCalGas Residential Disconnections for Non-Payment[17]

Year	Average Customer Accounts in IOU Territory	Unique Customers Disconnected for Non-Payment	Unique Customer Disconnection Rate	Total Disconnects*	Total Disconnect Rate
2010	5,309,229	123,220	2.3%		
2011	5,342,947	100,131	1.9%	112,009	2.1%
2012	5,370,778	96,971	1.8%	106,797	2.0%
2013	5,413,885	92,493	1.7%	101,373	1.9%
2014	5,433,053	88,105	1.6%	94,342	1.7%
2015	5,461,904	103,617	1.9%	110,357	2.0%
2016	5,496,386	119,905	2.2%	129,545	2.4%
2017 to-date (through 9/17)				91,872	

* accounts for multiple disconnections of the same customers

SDG&E and SoCalGas have historically disconnected significantly fewer customers than Pacific Gas and Electric Company and Southern California Edison

[16] Source: SDG&E Disconnection Settlement Quarterly Report (Oct. 25, 2017), filed in R.10-02-005.

[17] Source: SoCalGas Disconnection Settlement Quarterly Report (Oct. 25, 2017), filed in R.10-02-005; SoCalGas Disconnection Settlement Quarterly Reports (Jan. 25, 2017, Jan. 27, 2016, Jan. 26, 2015, Jan. 28, 2014, Jan. 25, 2013, Jan. 25, 2012).

Company – and continue to do so. Even so, the increase in disconnections over the past few years suggests, at least in part, that their customers are struggling more to keep up with bills. Additional rate increases, such as the substantial increases proposed in these GRCs, will only make bills less affordable, all else being equal.

III. Grounds for Protest

The Commission must ensure that the rates charged by SDG&E and SoCalGas are just and reasonable. As the Commission explained in D.01-10-031:

> We have a regulatory responsibility to ensure [SDG&E/SoCalGas] provides adequate service at just and reasonable rates, and we must view the facts accordingly. Our legislative mandate encompasses promoting the "safety, health, comfort, and convenience of [SDG&E's/SoCalGas's] patrons, employees, and the public." *See* §451.[18]

TURN protests SDG&E's and SoCalGas's request for authorization to increase their revenue requirements as presented in their respective applications, as SDG&E's and SoCalGas's requests are without sufficient support. As the applicants, SDG&E and SoCalGas bear the burden of proving that they are entitled to the relief being sought here and must affirmatively establish the reasonableness of each and every proposal within their applications.[19] Moreover, the starting point for the Commission's analysis must be that existing rates are reasonable unless a party meets its burden of proving that they are not.[20]

While TURN is still in the preliminary stage of our investigation, we expect to present evidence in our prepared testimony and through evidentiary hearings showing

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[18] D.01-10-031, *Order Granting Rehearing of and Modifying Decision 00-02-046*, p. 5.

[19] *See, i.e.,* D.09-03-025, p. 8 (discussing SCE's burden of proof in its Test Year 2009 General Rate Case, A.07-11-011).

[20] "[The utility] has the burden of proving that its current authorized revenues are unreasonable and should be adjusted." D.00-02-046, Conclusion of Law 3.

that SDG&E and SoCalGas have failed to meet their burdens of demonstrating the reasonableness of many aspects of their showings, including but not limited to certain proposals regarding electric and gas distribution costs, gas transmission costs, electric generation costs, customer service costs, administrative and general expenses, shared services and other support costs, rate base, and post-test year ratemaking. Thus far, we have identified the following specific issue that warrant close scrutiny.

Safety/Risk

With respect to GRC projects and programs justified on the basis of safety, the Sempra Utilities' request needs scrutiny in several respects, including:

- Whether the utilities have adequately prioritized their safety risks and provided a transparent and reliable methodology for such prioritization;
- Whether the utilities have explained how they prioritized safety mitigation projects and programs in this rate case in relation to cost-effectiveness or some other measure and, if so, whether such explanation is adequate and reasonable;
- Whether the utilities have explained how they decided on the particular portfolios of safety mitigations proposed in this rate case and how their chosen portfolios take into account constraints such as affordability impacts, utility financial constraints, and execution feasibility. If so, the Commission should examine whether the utility explanations are adequate and reasonable.
- Whether and how the utilities took into account the issues and concerns raised by the Safety and Enforcement Division and the parties in the Risk Assessment and Mitigation Phase (RAMP) proceeding, I.16-10-015/I.16-10-016, and whether the utilities' responses are reasonable.

Pipeline Safety Enhancement Plan (PSEP) Costs

SoCalGas seeks authorization to continue its PSEP activities, including pressure test projects, pipeline replacement projects, and valve projects. SoCalGas forecasts the cost of these activities that will be completed during the three-year GRC cycle (2019-2021), including other "miscellaneous costs," as $898.8 million, consisting of $249 million in O&M from 2019-2021, plus $649 million in capital from 2017-2021.[21] If the Commission authorizes a third attrition year, SoCalGas forecasts another $56 million in O&M in 2022 and $116 million in capital.[22] TURN intends to investigate the reasonableness of SoCalGas's forecasts.

SoCalGas also seeks to record and balance PSEP O&M and capital expenses in a two-way PSEP Balancing Account (PSEPBA) for true-up through an advice letter process. SoCalGas seeks to recover any net undercollection at the end of the GRC cycle, due to project spending exceeding authorized O&M and/or capital expenses, through a Tier 3 advice letter process.[23] While SoCalGas's testimony claims this process is appropriate because "it would allow the Commission to review the reasonableness of costs incurred," SoCalGas asserted at the November 14 "Breakout Session" workshop on PSEP that it is by no means proposing a reasonableness review associated with the PSEPBA.[24] TURN intends to address the reasonableness of the utility's requested

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[21] SCG-15, pp. RDP-iii, RDP-A-22. SoCalGas forecasts $53.2 million ($15.6 million in O&M an $37.6 million in capital) in miscellaneous costs including an allowance for pipeline failures, implementation continuity costs, and Program Management Office costs. SCE-15, p. RDP-A-34.

[22] PowerPoint Presentation from the November 14, 2017 workshop held in this proceeding, titled "SoCalGas and SDG&E 2019 General Rate Cases Breakout Session," slide 18; SCG-15, Section X ("Fourth-Year Projects").

[23] SCG-15, p. RDP-A-22; SCG-42, pp. RQY-16 – RQY-17.

[24] SCG-42, p. RQY-17.

approach.

Clarification of PSEP Requirements

SoCalGas seeks Commission clarification in this proceeding regarding the Commission's requirements for "Phase 2B" pipelines, which include pipelines in the SoCalGas transmission system that have documentation of a pressure test that predates the adoption of federal pressure testing regulations in 1970 in Title 49 of the Code of Federal Regulations, Part 192, Subpart J (herein after, Subpart J).[25] SoCalGas states that is has approximately 1,200 miles of such pipeline in its system.[26] The question is whether the Commission in D.11-06-017 required gas utilities to validate that all in-service natural gas transmission pipelines in California have been pressure tested to the Subpart J standard, or whether the Commission excluded from PSEP those pipeline segments for which the utility possesses a pre-Subpart J pressure test record, provided that the test met the requirements in place when the test was conducted and was at least one hour in duration. SoCalGas explains that parties in prior PSEP proceedings have expressed different interpretations of the D.11-06-017 requirements, but the Commission has yet to resolve this question.[27]

TURN supports SoCalGas's call for Commission resolution of this dispute. We are among the several parties to have argued in other proceedings, including the PSEP reasonableness review, A.16-09-005, that D.11-06-017 does not require ratepayers to pay for retesting through PSEP those pipeline segments for which the utility possesses a pre-Subpart J pressure test record, provided that the test met the requirements in place when

[25] SCG-15, p. RDP-A-57.

[26] SCG-15, p. RDP-A-12.

[27] SCG-15, p. RDP-A-57.

the test was conducted and was at least one hour in duration. The Commission does not intend to resolve this issue in A.16-09-005.[28]

TURN recommends that the Commission address this issue on an expedited track, apart from the many other issues presented by the Sempra Utilities' GRC applications, so that the Commission's clarification can inform current and future PSEP activities, as well as funding requests. Whether this issue should be briefed on an expedited track in this proceeding, or through a different procedural mechanism in another docket (such as through a petition for modification of D.11-06-017 in R.11-02-019, which has general applicability to all California natural gas transmission system operators), is a question worth exploring.

Post-Test Year Proposals

SDG&E and SoCalGas propose to extend the 2019 GRC cycle for four years, from 2019 until 2022, rather than the three-year cycle currently required by the Commission.[29] They argue that a four-year cycle is consistent with the approach authorized by the Commission in their 2004, 2008, and 2012 GRC proceedings.[30] SDG&E and SoCalGas also acknowledge that the issue of the length of the GRC cycle in the Rate Case Plan is currently under consideration in R.13-11-006.[31]

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[28] *Amended Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling*, issued in A.16-09-005 on April 24, 2017, pp. 3-5 (identifying this dispute between parties but noting that parties agreed that the Commission should resolve this disagreement in a different proceeding, specifically in a forecast application or a General Rate Case).

[29] *See* D.14-12-025, p. 40 (maintaining the historic three-year GRC cycle in the Rate Case Plan, but noting that the Commission might need to revisit the need for a four-year cycle if integrating the S-MAP and RAMP processes posed scheduling conflicts with GRCs); D.16-06-005, pp. 5-6 (denying the Petition for Modification of D.14-12-025 filed by the Sempra Utilities and the Office of Ratepayer Advocates to change the length of the GRC cycle from three to four years).

[30] SoCalGas Application, pp. 6-7; SDG&E Application, p. 7.

[31] SoCalGas Application, p. 7, fn. 7; SDG&E Application, p. 7, fn. 9.

In D.16-06-005, issued in R.13-11-006, the Commission directed Energy Division to hold a workshop to address the pros and cons of moving to a longer GRC cycle and "to provide a workshop report on whether a longer GRC cycle is worth pursuing."[32] Energy Division held this workshop on January 11, 2017, and the workshop report is forthcoming.[33] Following the issuance of the workshop report, parties will have an opportunity to file comments, after which the Commission intends to issue a proposed decision that addresses the GRC cycle length, as well as other issues pending in that proceeding.[34]

In D.17-05-013, issued in Pacific Gas and Electric Company's Test Year 2017 GRC, the Commission declined to change the term of PG&E's GRC from three years to four years, pointing to the process underway in R.13-11-006 to evaluate the merits of moving to a longer GRC cycle.[35] The Commission concluded that it should not prejudge the outcome of that process.[36] For the same reason, TURN protests this aspect of the Sempra Utilities' post-test year proposal. If the Commission has yet to issue the anticipated decision in R.13-11-006 before testimony is due in this proceeding, TURN will address the merits of the Sempra Utilities' proposal as well as the procedural deficiencies.

SDG&E and SoCalGas propose to continue their currently authorized Z-factor mechanism, and also propose a new post-test year ratemaking mechanism that would

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[32] D.16-06-005, p. 6.

[33] *Second Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, issued in R.13-11-006 on Mar. 17, 2017, p. 3.

[34] *Id.*, p. 4.

[35] D.17-05-013, pp. 197-198.

[36] *Id.,* p. 198.

adjust authorized revenue requirements for operating and capital-related expenditures. They propose to adjust labor and non-labor costs based on IHS Markit Global Insight's forecast, medical costs based on Willis Towers Watson's forecast, and capital investments based on an escalated 5-year average of capital additions.[37] SoCalGas would additionally include a forecast for PSEP capital additions beyond Test Year 2019.[38] This ratemaking methodology would result in attrition year revenue requirement increases in 2020, 2021, and 2022 of roughly 8.5%, 6%, and 6%, respectively, for SoCalGas, and 7%, 5% and 5%, respectively, for SDG&E.[39] TURN protests the Sempra Utilities' proposed post-test year ratemaking methodology and may propose an alternative methodology for the Commission's consideration.

Administrative and General (A&G) Costs

SDG&E is proposing a $108 million increase to A&G costs in 2019 over 2016 recorded, making this by far the largest driver of its requested GRC increase on the O&M side.[40] SoCalGas's requested increase for A&G of $195 million similarly drives its GRC O&M increase, with the next largest increase, $78 million for PSEP, at less than half that amount.[41] The largest component of these increases stems from the Sempra Utilities' proposal to change the methodology for recovering pension costs, which results in a test year increase of $64 million for SDG&E and $132 million for SoCalGas.[42] TURN at this

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[37] SDG&E-43, p. KJD-ii.

[38] SCG-44, p. JAM-ii.

[39] SCG-44, p. JAM-ii; SDG&E-43, p. KJD-ii.

[40] PowerPoint Presentation from the November 1, 2017 workshop held in this proceeding, titled "SDG&E and SoCalGas 2019 General Rate Case Overview," slide 11.

[41] PowerPoint Presentation from the November 1, 2017 workshop held in this proceeding, titled "SDG&E and SoCalGas 2019 General Rate Case Overview," slide 14.

[42] SDG&E-29/SCG-31, pp. DSR-1 – DSR-3.

time takes no position on whether the utilities' proposed new methodology is reasonable, but we expect to investigate it.

Morongo Rights-of-Way Memorandum Account

SoCalGas proposes to establish a Morongo Rights-of-Way Memorandum Account (MROWMA) that, other than the effective date, is in all ways identical to the memorandum account the utility has requested in A.16-12-011.[43] SoCalGas candidly describes its request as being "contingent upon the outcome of A.16-12-011." That is, if the Commission rejects its request in that proceeding, the utility will use the GRC to renew its request. The Commission should reject this proposal as a transparent attempt to gain an inappropriate second bite at the apple.

SDG&E's Electric Distribution Capital Showing

SDG&E's Electric Capital Distribution showing is inadequately supported for a number of spending proposals. The utility has stated that it used a "zero-based" forecast method for a number of the proposals. For each proposal, the testimony contains similar if not identical boiler-plate language describing the forecast method.[44] The workpapers include similar boiler-plate language.[45] There are numerous and, in at least one case, very numerous pages of workpapers associated with a particular project that is the subject of a

[43] Ex. SCG-42, p. 17.

[44] Ex. SDG&E-14, pp. 143-144 (for the Cleveland National Forest Power Line Replacement Projects, "The forecast method used is zero-based. The forecast is based on detailed cost estimates that were developed based on the specific scope of work for the project. SDG&E develops detailed cost estimates based on current construction labor rates, material costs, overhead rates, contract pricing/quotes, and other project specific details. When projects are completed, actual costs are compared to the estimate to verify the estimates are accurate. Any significant variances between the estimated cost for a project and the actual costs are scrutinized to determine whether cost estimate inputs need to be adjusted for future projects.").

[45] Ex. SDG&E-14-CWP, p. 909, where identical language appears to describe the forecast methodology for labor and non-labor costs associated with the Cleveland National Forest Power Line Replacement Project.

zero-based forecast. But the workpapers contain nothing that would adequately substantiate or even support the basis for the forecast, such as a description of the scope of work, the detailed cost estimates, other project specific details, the number of units of work the utility expects to complete, or really anything that might permit the Commission to determine the reasonableness of the forecast.[46] The Commission should direct SDG&E (and SoCalGas, to the extent similar practices appear in its showing) to supplement the showing made in support of such capital spending proposals. It would be inappropriate to require intervenors to attempt to flesh out an adequate showing through discovery.

Potential Acquisition of Oncor Electric Delivery by Sempra Energy

Sempra Energy, the holding company of both SoCalGas and SDG&E, is pursuing the purchase of Oncor Electric Delivery, a transmission and distribution utility in Texas with ten million customers, with a reported offer of nearly $10 billion.[47] If the purchase is approved and consummated, this will likely have a material impact on the allocation of corporate center costs among SoCalGas, SDG&E, and the unregulated entities within Sempra Energy. The utilities' forecasts for 2019 do not reflect this transaction. The Commission should direct the utilities to supplement their showing to address the impact this purchase would have on their allocation, assuming the purchase is consummated before January 1, 2019.

[46] For example, workpapers for the Cleveland National Forest Power Line Replacement Method comprise approximately 30 pages of the 1000-plus pages of workpapers for Electric Distribution Capital (Ex. SDG&E-14-CWP, pp. 907-937). But other than a single page with extremely abbreviated descriptions of the "business purpose," "physical description" and "project justification" that add very little to the descriptions contained in the prepared testimony, nothing in those 30 pages of workpapers provides anything other than unexplained numbers.

[47] http://www.sandiegouniontribune.com/business/sd-fi-sempra-oncor-20171004-story.html

IV. Effect of the Application on the Protestant

TURN is a non-profit consumer advocacy organization, and has a long history of representing the interests of residential and small commercial customers of California's utility companies before this Commission. TURN's articles of incorporation specifically authorize our representation of the interests of residential customers. The instant application harms the interests of SDG&E’s and SoCalGas’s residential ratepayers, whose interests TURN represents, by seeking authorization to collect from ratepayers charges that are unjust and unreasonable for the provision of electric and gas utility service (in the case of SDG&E) and gas utility service (in the case of SoCalGas) during the years 2019, 2020, 2021, and 2022.

V. Categorization and Need for Evidentiary Hearings

In Resolution ALJ 176-3407 (Oct. 26, 2017), the Commission preliminarily determined that this proceeding should be categorized at “ratesetting” and that evidentiary hearings will be necessary. TURN concurs with this assessment. SDG&E and SoCalGas have requested substantial rate increases, and the Commission’s disposition of their applications will require the resolution of numerous disputed issues of material fact, including the reasonableness of SDG&E’s and SoCalGas’s forecasts of test year costs throughout their showings, the reasonableness of their proposed post-test year ratemaking mechanism, as well as the reasonableness of SDG&E’s and SoCalGas’s various ratemaking proposals. TURN intends to actively participate in evidentiary hearings, to the extent necessary to support our recommendations regarding the issues in this proceeding.

VI. Scope of Issues to Be Considered

A. Issues Proposed By SDG&E and SoCalGas

SDG&E and SoCalGas identify the "principal issues" to be considered in this proceeding as follows: (1) Whether each utility's proposed Test Year (TY) 2019 revenue requirement is just and reasonable, and should be adopted by the Commission and reflected in rates; (2) Whether each utility's proposed post-test year ratemaking mechanism is just and reasonable; and (3) Whether each utility's regulatory accounts proposals are just and reasonable.[48] Each utility also suggests, "With respect to safety considerations, the issues above will be considered within the context of the Commission's new risk-informed GRC framework, as discussed above. The focus on safety and risk mitigation and how RAMP was integrated into the GRC will be major components of this GRC proceeding."[49] TURN generally agrees with the very short and very broad list of issues identified by SDG&E and SoCalGas, if supplemented with the issues required by SB 598 (2017, Hueso) as discussed below, as the list would seem to encompass issues regarding costs and services even where such matters are not clearly identified in the utility applications or supporting testimony.

Historically, it was customary for the Commission to issue an Order Instituting Investigation (OII) and open a companion docket to the utility's general rate case application. As the Commission explained when it opened I.06-03-003, the companion investigation to A.05-12-002, PG&E's 2007 General Rate Case:

> The purpose of this investigation is to allow the Commission to consider proposals other than PG&E's, and to enable the Commission to enter orders on matters for which the utility may not be the proponent. This

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[48] SDG&E Application, p. 10; SoCalGas Application, p. 10.

[49] *Id.*

> companion investigation will also afford parties an opportunity and forum to provide evidence on issues of interest to the Commission. These issues may result in directives to PG&E that serve the public interest and that result in just and reasonable rates, services, and facilities.[50]

More recently, the Commission has declined to open a companion investigation in general rate cases, instead finding that such a proceeding would be unnecessary to allow the Commission to address affirmative recommendations of parties on subjects relevant to GRCs but not covered by the utilities' applications or testimony.[51] This is the approach taken in the last two SDG&E/SoCalGas GRCs.[52]

In this case, TURN requests that the Commission either open a companion investigation to SDG&E's and SoCalGas's 2019 General Rate Cases or clarify that the Commission will entertain herein the affirmative proposals of parties other than SDG&E and SoCalGas, even where such proposals are not covered by SDG&E's or SoCalGas's application or testimony, as long as parties' proposals address issues properly within the scope of a general rate case. Either of these approaches would avoid an overly restrictive construction of the matters the Commission may consider in this docket as it evaluates how best to serve the public interest.

B. Issues Required by SB 598 (2017, Hueso)

In September of this year, the California Legislature enacted Senate Bill (SB) 598 out of a concern for rising utility disconnections and the adverse impacts of

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[50] Order Instituting Investigation 06-03-003, issued March 7, 2006, p. 1.

[51] *See, e.g., Scoping Memo and Ruling of Assigned Commissioner*, issued Mar. 1, 2011 in A.10-11-015 (SCE 2012 GRC), p. 26.

[52] *Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling*, issued Mar. 2, 2011 in A.10-12-005 / A.10-12-006 (SDG&E/SoCalGas 2012 GRC), p. 12; and *Assigned Commissioner's Scoping Memo and Ruling*, issued Feb. 5, 2015 in A.14-11-003 / A.14-11-004 (SDG&E/SoCalGas 2016 GRC), p. 6.

disconnections on the health and welfare of Californians.[53] Among other things, SB 598 added Section 718 to the California Public Utilities Code, which requires, in pertinent part, as follows:

> In each gas and electrical corporation general rate case, the commission shall do both of the following:
>
> (A) Designate the impact of any proposed increase in rates on disconnections for nonpayment as an issue in the scope of the proceeding.
>
> (B) Conduct an assessment of and properly identify the impact of any proposed increase in rates on disconnections for nonpayment, which shall be included in the record of the proceeding.
>
> The commission shall adopt residential utility disconnections for nonpayment as a metric and incorporate the metric into each gas and electrical corporation general rate case.[54]

The instant GRCs are the first to be filed after the enactment of SB 598.

Consistent with the requirements of SB 598, the Commission should designate as issues within the scope of this proceeding (1) the impact of SDG&E's proposed GRC rate increase – including test year and post-test year increases – on disconnections of its customers for nonpayment, and (2) the impact of SoCalGas's proposed GRC rate increase – including test year and post-test year increases – on disconnections of its customers for nonpayment. Additionally, the Commission should indicate that it will conduct the assessment required by SB 598 for inclusion in the record of this proceeding. Finally, the Commission should clarify that it intends to adopt residential utility

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[53] SB 598, Section 1 (finding that "Gas and electric service shutoffs threaten the health of two million people annually with significant impact on infants, children, the elderly, low-income families, communities of color, people for whom English is a second language, physically disabled persons, and persons with life-threatening medical conditions," and "The loss of basic gas or electric service causes tremendous hardship and undue stress, including increased health risks to vulnerable populations, as well as overreliance on emergency services and underutilization of preventive programs.").

[54] Cal. Pub. Util. Code Sec. 718 (b)(1)-(2).

disconnections for nonpayment as a GRC metric and require SDG&E and SoCalGas to track and report on that metric in this proceeding and in subsequent GRCs.

VII. Proposed Schedule

SDG&E and SoCalGas propose a schedule for this proceeding with testimony from the Office of Ratepayer Advocates (ORA) on April 13, 2018, other inventor testimony on May 4, 2018, public participation hearings in April/May 2018, concurrent rebuttal testimony on June 18, 2018, evidentiary hearings in July/August 2018, and briefs in September/October 2018, which would result in a final decision in December 2018.[55] TURN does not object to this schedule.

VIII. Other Matters

A. The Role of 2017 Recorded Expenditure Data

SDG&E and SoCalGas have prepared their GRC applications based on Base Year (BY) 2016 recorded expenditures, consistent with the Rate Case Plan. During their GRC overview workshop, held on November 1, 2017, they provided general information about the forecasting methods they used in preparing their test year requests. As they explain, their forecasting entails reviewing, and adjusting as needed, historical costs; selecting a forecast methodology (such as averages, linear trends, using the base year, or "zero-based"); and adjusting the resultant forecast to account for known changes to programs or activities.[56] The utilities then forecast 2017, 2018, and 2019 capital for their applications, and for O&M, they "[f]orecast 2017 and 2018 as a means to demonstrate revenue needs

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[55] SDG&E Application, pp. 10-11; SoCalGas Application, pp. 10-11.

[56] PowerPoint Presentation from the November 1, 2017 workshop held in this proceeding, titled "SDG&E and SoCalGas 2019 General Rate Case Overview," slides 16-17.

in the Test Year 2019."[57]

The Commission has previously determined that actual recorded expenditures (both O&M and capital) from the year after the base year (BY+1) can be informative in a GRC.[58] Indeed, such data can serve as a check on the reasonableness of the utility's Test Year forecast. For instance, if it turns out in this case that SDG&E's or SoCalGas's 2017 recorded costs are significantly lower or higher than the utility's 2017 forecasts, this may indicate that 2017 data should be included in a historical forecast, trend line, or base year forecasting methodology to improve the accuracy of the forecast.

In D.13-05-010, issued in the SDG&E/SoCalGas 2012 GRC, the Commission concluded that it was appropriate to consider BY+1 recorded data (2010 data in that case) in determining which methodology should be adopted for individual cost forecasts. As the Commission explained, "Our picking and choosing of what the appropriate methodology to use for the cost forecasts will allow us to develop cost forecasts that we believe are reasonable to both ratepayers and the Applicants, and are as accurate as they can be within our GRC ratemaking framework."[59] More recently, in D.16-06-054, issued in the SDG&E/SoCalGas 2016 GRC, the Commission relied on BY+1 recorded data (2014 data in that case) to assess the reasonableness of certain forecasts included in the proposed settlement agreement.[60]

To ensure that the Commission and parties have timely access to the most recent

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[57] *Id.,* slide 17.

[58] D.12-11-051, p. 13 (addressing the use of 2010 recorded data in SCE's Test Year 2012 GRC, which had a Base Year of 2009).

[59] D.13-05-010, p. 20.

[60] *See, e.g.,* D.16-06-054, p. 62 ("Based on the testimony of SDG&E and ORA, and the 2014 recorded expenses, the agreed upon amount of $0.400 million for the O&M costs associated with Technology Innovation and Development is reasonable and should be adopted.").

recorded data to use in evaluating SDG&E's and SoCalGas's GRC requests, TURN recommends that these utilities make available to parties their 2017 recorded cost data (O&M and capital) as early as practicable. TURN requests that the utilities indicate in their reply to protests (or at the Prehearing Conference) approximately when parties should look forward to receiving this data so that we may plan accordingly.

IX. Conclusion

For the reasons set forth herein, TURN protests the Test Year 2019 GRC Applications of SDG&E and SoCalGas. TURN additionally agrees that evidentiary hearings will be necessary; asks the Commission to incorporate the issues required by SB 598 and clarify that affirmative recommendations of parties on subjects relevant to GRCs but not covered by the utilities' applications or testimony are within the scope; and supports the proposed schedule. Finally, TURN advocates the timely delivery of recorded 2017 expenditures to interested parties by SDG&E and SoCalGas.

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Respectfully submitted,

By: __________/s/______________

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