BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts	Application 17-03-021 (Filed on March 30, 2017)

OPENING BRIEF OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G) IN SUPPORT OF THEIR APPLICATION FOR (A) APPROVAL OF THE FORECASTED REVENUE REQUIREMENT ASSOCIATED WITH CERTAIN PIPELINE SAFETY ENHANCEMENT PLAN PROJECTS AND ASSOCIATED RATE RECOVERY, AND (B) AUTHORITY TO MODIFY AND CREATE CERTAIN BALANCING ACCOUNTS

AVISHA A. PATEL

Attorney for

SOUTHERN CALIFORNIA GAS COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
555 West Fifth Street, GT-14E7
Los Angeles, California 90013
Telephone: (213) 244-2954
Facsimile: (213) 629-9620
E-mail: APatel@semprautilities.com

March 26, 2018

TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES iii

SUMMARY OF RECOMMENDATIONS iv

I. INTRODUCTION 1

II. PROCEDURAL BACKGROUND 4

A. The Commission Ordered a New Paradigm for Safety Enhancement. 4

B. SoCalGas and SDG&E's PSEP Was Carefully Reviewed and Adopted by the Commission. 5

C. The Commission Established a Framework for Recovery of All Reasonable PSEP Costs. 6

D. The Commission Determined Certain Costs May Not Be Recovered in Rates. 9

E. Protests, Pre-Hearing Conference, and the Scoping Memorandum and Ruling. 10

F. Hearings. 14

III. LEGAL STANDARD OF REVIEW 14

A. Ratesetting Proceeding – Just and Reasonable Standard. 14

B. Burden of Proof – Preponderance of the Evidence. 14

IV. THE RECORD ESTABLISHES BY A PREPONDERANCE OF THE EVIDENCE THAT APPLICANTS' FORECASTS ARE REASONABLE AND THE ASSOCIATED REVENUE REQUIREMENT SHOULD BE AUTHORIZED 15

A. The Twelve Projects in the Application Are Within the Scope of PSEP. 15

B. The Cost Forecasts Comply with Commission Directives and Are Reasonable. 19

1. No Commission-Ordered Disallowances Have Been Included in Applicants' Forecasts. 19

2. General Management and Administration Costs. 19

3. Company Overheads. 21

4. Phase 2 Engineering, Design, and Planning Costs. 21

C. Applicants' Forecasts Are Robust, Reasonable, and Worthy of Ratemaking. 22

1. Scope Validation and Other Cost Avoidance Efforts Have Been Undertaken. 22

2. Applicants' Forecasts Are Project-Specific, Developed by Experienced Estimating Professionals, and Based on Applicants' Actual Experience Implementing PSEP....23

3. Intervenors' Proposed Funding Levels Are Woefully Inadequate for Applicants to Complete Commission-Ordered Safety Enhancement Work....27

a. ORA's Benchmarking Analysis Is Flawed....28

b. TURN/SCGC's Comparative Analysis Is Flawed. 30

V. TWO-WAY BALANCING ACCOUNT TREATMENT COMPORTS WITH THE COMMISSION'S SAFETY ENHANCEMENT OBJECTIVES AND IS FAIR AND REASONABLE....32

VI. THE ASSOCIATED REVENUE REQUIREMENT AND COST ALLOCATION SHOULD BE AUTHORIZED....35

VII. THE PHASE 2A DECISION TREE SHOULD BE APPROVED 37

VIII. CONCLUSION 38

TABLE OF AUTHORITIES

Page

Commission Decisions
D.11-06-007 1
D.11-06-017 .... 4, 5, 16
D.13-05-010 34
D.16-06-054 34
D.16-08-003 .... 2, 3, 8, 9, 21, 22, 23, 35, 36

Commission Rulings
R.11-02-019 4

California Statutes
Pub. Util. Code §§ 451, 454 .... 13, 14
Pub. Util. Code §§ 957, 958 .... iv, 2, 3

SUMMARY OF RECOMMENDATIONS

Legal Standards

1. Apply the preponderance of the evidence standard of proof;

Compliance

2. Find that SoCalGas and SDG&E's plans to execute the twelve Phase 1B and Phase 2A safety enhancement projects presented in this Application are consistent with Decision ("D.") 14-06-007 and Public Utilities Code sections 957 and 958;

3. Find that Applicants may remediate the Line 127 project presented herein through non-destructive examination ("NDE") rather than replacement;

4. Find the disallowances previously ordered by the Commission have been properly excluded from Applicants' forecasts;

SoCalGas and SDG&E's Pipeline Safety Enhancement Plan

5. Approve Applicants' proposed Phase 2A Decision Tree as presented in the Application;

6. Find it is reasonable for Applicants to address the incidental and accelerated mileage as included within the scope of projects in this Application;

7. Approve Applicants' forecasted capital costs associated with completion of the twelve projects presented in the Application in the amount of $197.5 million;

8. Approve Applicants' forecasted operations and maintenance ("O&M") costs associated with completion of the twelve projects presented in the Application in the amount of $57 million;

Regulatory Accounting Treatment

9. Approve Applicants' request for two-way balancing accounting treatment of forecasted and actual costs associated with the twelve projects, on an aggregate basis, as presented in this Application;

10. Authorize Applicants to subdivide the existing Safety Enhancement Capital Cost Balancing Accounts ("SECCBA") accounts into the two subaccounts proposed: Phase 1A Subaccount and Phase 1B Subaccount;

11. Authorize Applicants to subdivide the existing Safety Enhancement Expense Balancing Accounts ("SEEBA") accounts into the two subaccounts proposed: Phase 1A Subaccount and Phase 1B Subaccount;

12. Authorize Applicants to create two new balancing accounts for Phase 2 – SECCBA-P2 and SEEBA-P2 – and to transfer costs tracked in the Pipeline Safety Enhancement Memorandum Accounts ("PSEPMAs") into these new balancing accounts;

13. Approve for filing with the Commission the proposed preliminary statements (appended to the prepared direct testimony of Reginal Austria) for the authorized balancing accounts;

Revenue Requirement and Cost Allocation

14. Find that Applicants' cumulative forecasted 2019 revenue requirement associated with completion of the twelve projects in the Application – approximately $44.6 million for SoCalGas and $562,000 for SDG&E – is just and reasonable;

15. Authorize Applicants to recover the cumulative forecasted 2019 revenue requirement associated with completion of the twelve projects in the Application in the amounts of approximately $44.6 million for SoCalGas and $562,000 for SDG&E;

16. Approve the proposal of SoCalGas and SDG&E to allocate costs on a functional basis such that costs functionalized as high pressure distribution are allocated using the existing marginal demand measures for high pressure distribution;

17. Authorize Applicants to implement in transportation rates the revenue requirements associated with the twelve projects proposed in the Application effective January 1 of the year following a decision on this Application via Tier 1 Advice Letter;

18. Authorize Applicants to balance, on an aggregate basis, the actual capital and O&M costs with the associated forecasted revenue requirements and to address any differences, as appropriate, in the Applicants' Annual Regulatory Account Balance Update Tier 2 Advice Letter filing with the Commission;

19. Authorize Applicants to recover the ongoing capital-related revenue requirements associated with capital expenditures approved in this proceeding through a Tier 2 Advice Letter until such costs are incorporated in base rates in connection with Applicants' next General Rate Case proceeding; and

20. Provide such other and further ratemaking relief relating to PSEP as the Commission deems necessary or appropriate.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts	Application 17-03-021 (Filed on March 30, 2017)

OPENING BRIEF OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G) IN SUPPORT OF THEIR APPLICATION FOR (A) APPROVAL OF THE FORECASTED REVENUE REQUIREMENT ASSOCIATED WITH CERTAIN PIPELINE SAFETY ENHANCEMENT PLAN PROJECTS AND ASSOCIATED RATE RECOVERY, AND (B) AUTHORITY TO MODIFY AND CREATE CERTAIN BALANCING ACCOUNTS

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), and the Scoping Memo and Ruling of Assigned Commissioner dated August 28, 2017 ("Scoping Memo"),[1] Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (jointly, "Applicants") hereby submit this Opening Brief in support of their Application for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts dated March 30, 2017 (as amended June 21, 2017, "Application").

I. INTRODUCTION

Applicants have a singular objective in this proceeding: to obtain authorization and sufficient funding to comply with the Commission's directive to execute PSEP safety enhancement projects "as soon as practicable."[2] Through this Application, SoCalGas and

---

[1] Scoping Memo and Ruling of Assigned Commissioner dated August 28, 2017 ("Scoping Memo") at p. 7.

[2] Decision ("D.") 11-06-007, mimeo., at p. 19.

SDG&E request authority to recover in rates the forecasted revenue requirement to complete twelve PSEP projects and seek a mechanism to record and balance the costs of continuing to implement the Commission-mandated pipeline safety enhancement plan ("PSEP").[3]

Applicants prepared detailed cost estimates following detailed project-specific engineering, design, and planning work – which was specifically authorized by the Commission in its decision on Application 15-06-013, and was unopposed by The Utility Reform Network ("TURN"), Southern California Generation Coalition ("SCGC"), and the Office of Ratepayer Advocates ("ORA") (TURN, SCGC, and ORA together, "Intervenors;" Intervenors and Applicants, "Parties") – for the Phase 2 safety projects included in the Application.[4] Although not required (because the Commission has already authorized Applicants to complete Phase 1 work and further authorized Applicants to record Phase 1 costs in two-way balancing accounts[5]), in response to Intervenors' prior requests,[6] Applicants included detailed project scopes and cost estimates for two Phase 1B projects in the Application to allow Intervenors an opportunity to review Applicants' plans to address these pipelines prior to completing construction.

Now, having had the opportunity to review Applicants' plans to address the twelve PSEP projects, Intervenors do not oppose the scope of work proposed by Applicants.[7] They do not oppose the engineering activities Applicants have engaged in,[8] the construction methods

---

[3] Decision ("D.") 11-06-017, mimeo., at p. 31; Pub. Util. Code §§ 957, 958.

[4] D.16-08-003, mimeo., at p. 1 ("On June 17, 2015, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (applicants) filed this application seeking authorization to proceed with Phase 2 of their Pipeline Safety Enhancement Plan (PSEP) and to establish memorandum accounts to record approximately $22 million in planning and engineering design costs." "Today's decision grants the applicants' unopposed request for memorandum accounts…."). *See also, id.*, at pp. 13 (Conclusion of Law 1), 14 (Ordering Paragraph 1).

[5] D.14-06-007, mimeo., at pp. 22, 26-27.

[6] Motion for Official Notice in Support of the Opening Brief of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) in Support of Their Application for (A) Approval of the Forecasted Revenue Requirement Associated with Certain Pipeline Safety Enhancement Plan Projects and Associated Rate Recovery, and (B) Authority to Modify and Create Certain Balancing Accounts ("MON"), Ex. A at p. 10 (A.15-06-013, Reply Comments of the Indicated Shippers, the Office of Ratepayer Advocates, the Southern California Generation Coalition, and the Utility Reform Network dated January 22, 2016).

[7] Hearing Transcript at pp. 285:12-23, 310:5-21.

[8] *Id.*

proposed by Applicants,[9] or even the inclusion of accelerated or incidental miles.[10] Rather, after agreeing that Applicants should engage in extensive engineering, design and planning work to prepare the detailed cost estimates that form the basis for Applicants' request in this proceeding,[11] Intervenors now propose to take a step backward and instead base funding for the twelve unique projects presented for review in this proceeding based on rudimentary non-project-specific cost estimates. This would require the Commission to ignore the detailed project-specific engineering, design and planning work that Applicants undertook—after receiving express authorization from the Commission to do so and receiving no opposition from Intervenors—to prepare detailed project-specific scopes of work and cost estimates for Commission and Intervenor review. To the extent Intervenors now take the position that Applicants need not have undertaken these engineering, design and planning activities to present detailed project scopes and cost estimates in this Application (under the premise their rudimentary non-project-specific cost estimates based on pipeline length and diameter are sufficient), Intervenors' failure to inform the Commission and Applicants of this position in a timely manner has unnecessarily delayed Applicants' prompt execution of PSEP Phase 2 projects. The rudimentary cost estimates proposed by Intervenors could have been submitted, reviewed, and approved by the Commission two years ago, when Applicants sought authority to prepare the detailed cost estimates that the Commission and Intervenors previously requested.[12]

Intervenors' rudimentary cost proposals, on an aggregate basis, are significantly lower than the project-specific Class 3 estimates prepared by Applicants and, moreover, are coupled with regulatory accounting treatment that would have the effect of penalizing Applicants if the reasonable costs of executing safety enhancement work for the benefit of ratepayers exceed the

[9] *Id.*
[10] ORA does not oppose the inclusion of accelerated or incidental miles and, as explained *infra* at Section IV.A, TURN/SCGC only recommend that Applicants be required to "attest that for each of the projects included in this application, any Phase 2B mileage that they recommend including in a project is included solely to minimize the cost of conducting the Phase 1B or Phase 2A pressure test, replacement, de-rate, or de-rate with abandonment project." Ex. TURN/SCGC-01 (Yap) at p. 2.
[11] D.16-08-003, mimeo., at p. 1; Ex. SCG-19-C.
[12] D.16-08-003, mimeo., at p. 1; D.14-06-007, mimeo., at pp. 25-26, 28.

rudimentary estimates proposed by Intervenors.[13] This is unreasonable and contrary to what the Commission contemplated in mandating PSEP, i.e., "to strike a fair balance between ratepayers and shareholders."[14] Applicants, consistent with Commission precedent, propose equitable regulatory accounting treatment in the form of two-way balancing accounts – which the Commission already ordered for Phase 1[15] – such that ratepayers pay no more than the actual costs of executing PSEP projects (less certain disallowances, as noted below).

II. PROCEDURAL BACKGROUND

A. The Commission Ordered a New Paradigm for Safety Enhancement.

SoCalGas and SDG&E developed the PSEP in response to Commission directives in Rulemaking ("R.") 11-02-019, initiated by the Commission *sua sponte* following a pipeline rupture and ignition in San Bruno on September 9, 2010. The Rulemaking was a "forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[16] In March 2011, the assigned Commissioner highlighted the importance of these safety efforts:

> We are dealing with dire issues here concerning our public safety and human life. As we pointed out in the rulemaking, this proceeding is not business as usual, these are extraordinary circumstances, and we need extraordinary efforts to achieve our goal – to make our natural gas pipeline infrastructure safe and reliable.[17]

To achieve this objective, in Decision ("D.") 11-06-017, the Commission required all natural gas pipeline operators to submit an Implementation Plan to pressure test or replace all transmission pipeline that either had not been tested or for which reliable documentation of a pressure test was not available.[18] The Implementation Plan was to address all natural gas

---

[13] D.11-06-017, mimeo., at p. 31; Pub. Util. Code §§ 957, 958.
[14] D.14-06-007, mimeo, at pp. 19, 22.
[15] D.14-06-007, mimeo., at pp. 22, 26-27.
[16] Rulemaking ("R.") 11-02-019, mimeo., at p. 1.
[17] R.11-02-019, March 24, 2011 Assigned Commissioner's Ruling Adding Items to Previously Scheduled Comment Cycle, Addressing Ex Parte Contacts, Scheduling Public Participation Hearings, Setting Prehearing Conference and Encouraging Participation by Pipeline Hazardous Materials Safety Administration, at p. 1.
[18] D.11-06-017, mimeo., at pp. 18-19.

transmission pipeline,[19] and was to "address retrofitting pipelines to allow for in-line inspection tools and, where appropriate, automated or remote controlled shut off valves."[20]

B. SoCalGas and SDG&E's PSEP Was Carefully Reviewed and Adopted by the Commission.

SoCalGas and SDG&E filed their proposed Implementation Plan on August 26, 2011, and the Commission approved the Implementation Plan – the PSEP – nearly three years later, in D.14-06-007.[21] In endorsing the PSEP, the Commission approved the proposed Phase 1 Decision Tree to guide whether specific segments should be pressure-tested, replaced, or abandoned, and adopted SoCalGas and SDG&E's prioritization of safety enhancement projects into three phases: 1A, 1B, and 2.[22] Phase 1A encompasses pressure testing or replacing transmission pipeline in Class 3 and 4 locations, and Class 1 and 2 locations in high consequence areas ("HCA"), that do not have sufficient documentation of a pressure test to at least 1.25 times the maximum allowable operating pressure ("MAOP").[23] Phase 1B encompasses replacement of non-piggable pipelines that were installed prior to 1946.[24] Pipeline in less populated areas are to be addressed in Phase 2.[25] Phase 2A includes pipeline in less populated areas without record of a pressure test, or without record of a pressure test to 1.25 MAOP.[26] Currently it is anticipated that Phase 2A will consist of pressure testing or replacing approximately 760 miles of pipeline.[27]

---

[19] D.11-06-017, mimeo., at p. 20.
[20] D.11-06-017, mimeo., at p. 21.
[21] D.14-06-007, mimeo., at pp. 2-3. The Commission found that the estimates prepared by Applicants in the two-and-a-half months prior to filing the Implementation Plan were "too rudimentary to preapprove" for ratemaking purposes. *Id.* at pp. 2, 25-26.
[22] D.14-06-007, mimeo., at pp. 2-3, 14, 59 (Ordering Paragraph 1).
[23] Ex. SCG-02 (Mejia) at pp. 3-4; Ex. SCG-10 at pp. WP-G-1-2.
[24] Ex. SCG-01 (Mejia) at pp. 4-6. Specifically, Phase 1B contemplates replacing non-piggable pipelines installed prior to 1946 with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards. The Commission ordered this work in directing California pipeline operators to "address retrofitting pipeline to allow for in-line inspection tools" in D.11-06-017. "Non-piggable" pipelines cannot accommodate in-line inspection tools that assess pipeline integrity. Pre-1946 pipelines were built using non-state-of-the-art construction methods (i.e., oxy-acetylene welds that inherently are brittle) and materials (i.e., pipe manufacturers used various non-state-of-the art manufacturing processes), were not designed to accommodate a post-construction pressure test, and have an increased risk of developing leaks on girth welds. *Id.* at p. 4.
[25] Ex. SCG-03 (Gonzalez) at pp. 3-4.
[26] Ex. SCG-01 (Mejia) at pp. 3-4, 8-9.
[27] Ex. SCG-01 (Mejia) at p. 9.

Phase 2B includes pipeline with record of a pressure test that was completed prior to the existence of the modern standards set forth in 49 Code of Federal Regulations Part 192, Subpart J adopted in 1970.[28] The Commission authorized Applicants to begin Phase 1 work as described in their PSEP.[29]

The Commission also approved the Valve Enhancement Plan proposed in the Implementation Plan, including "modifications to 541 valves, and the addition of 20 valves, to provide for automated shut-off capability in order to isolate, limit the flow of gas to no more than 30 minutes, and thereby facilitate timely access of 'first responders' into the area surrounding a substantial section of ruptured pipe."[30] The approved PSEP "also includes: 1) improvements to communications and data gathering to ascertain pipeline conditions; 2) installing backflow valves to prevent gas from flowing into sections intended to be isolated from other connected lines; 3) expand the coverage of SDG&E and SoCalGas' private radio networks to serve as back-up to improve system reliability; 4) installing remote leak detection equipment; and 5) increasing physical patrols and leak survey activities."[31]

C. The Commission Established a Framework for Recovery of All Reasonable PSEP Costs.

On April 19, 2012, prior to completing its review and approval of PSEP, the Commission authorized SoCalGas and SDG&E to create a "memorandum account to record for later Commission ratemaking consideration the escalated and direct and incremental overhead costs of its Pipeline Safety Enhancement Plan."[32] On May 18, 2012, the Pipeline Safety and Reliability Memorandum Accounts ("PSRMAs") were created for SoCalGas and SDG&E, respectively, by Advice Letters 4359 and 2106-G.[33] Reasonable costs associated with planning and executing

[28] Ex. SCG-03 (Gonzalez) at p. 3-4.
[29] D.14-06-007, mimeo., at p. 59-60 (Ordering Paragraphs 3 and 4).
[30] D.14-06-007, mimeo., at p. 8.
[31] D.14-06-007, mimeo., at p. 8.
[32] D.12-04-021, mimeo., at p. 12 (Ordering Paragraph 3). As the Commission explained in D.14-06-007, a memorandum account is an appropriate regulatory tool when the scope of work has not yet been defined clearly or determined to be reasonable and costs have not yet been determined to be reasonable for rate recovery. D.14-06-007, mimeo., at pp. 26-27.
[33] *See* Advice Letter 4359 filed on May 18, 2012 by Southern California Gas Company and Advice Letter 2106-G filed on May 18, 2012 by San Diego Gas & Electric Company.

PSEP projects were recorded to the PSRMAs on an interim basis, pending Commission approval of the PSEP.[34]

In D.14-06-007, the Commission authorized Applicants to record costs related to Phase 1 work in newly authorized two-way balancing accounts -- the Safety Enhancement Expense Balancing Accounts ("SEEBA") to record operations and maintenance ("O&M") costs and the Safety Enhancement Capital Cost Balancing Accounts ("SECCBA")[35] to record PSEP capital expenditures[36] -- subject to refund pending a subsequent reasonableness review.[37] The Commission adopted a process for reviewing and approving the reasonableness of PSEP implementation expenditures after-the-fact through a reasonableness review based on the finding that the preliminary cost forecasts prepared by SoCalGas and SDG&E in the two-and-a-half-month period of time allotted to prepare the PSEP were "not sufficiently detailed to justify ratemaking pre-approval at this time."[38] The Commission stated,

> Although ratepayers will bear the costs of the new and safer pipeline systems as installed, we cannot reasonably forecast and preapprove Safety Enhancement costs at this time because SDG&E and SoCalGas do not have reliable detailed cost estimates, nor can we adequately estimate the cost for testing pipelines or the remaining book value of abandoned pipelines that will be absorbed by the shareholders. This must be resolved later.[39]

In that proceeding, TURN expressed concern that the preliminary cost estimates submitted by Applicants had not been prepared by Applicants and were based on incomplete analyses of whether pipelines would be tested or replaced.[40] SCGC argued Applicants' preliminary cost estimates "lacked the necessary detail needed before the Commission could

[34] D.12-04-021, mimeo., at p. 12 (Ordering Paragraph 3); D.14-06-007, mimeo., at p. 60 (Ordering Paragraph 4).
[35] D.14-06-007, mimeo., at p. 60 (Ordering Paragraph 4).
[36] D.14-06-007, mimeo., at p. 60 (Ordering Paragraph 4). These were created for SoCalGas and SDG&E by Advice Letters 4664 and 2300-G-A, respectively.
[37] D.14-06-007, mimeo., at p. 59-60 (Ordering Paragraphs 3 and 4).
[38] D.14-06-007, mimeo., at pp. 2, 22-23, 26, 53, 60-61 (Findings of Fact 9, 10; Ordering Paragraphs 2, 5, 6).
[39] D.14-06-007, mimeo., at p. 5.
[40] D.14-06-007, mimeo., at p. 19.

adequately conduct a review of the proposed expenditures and authorize rate recovery."[41] The Commission largely agreed and opted to "take a more conservative approach [by using] balancing accounts and reasonableness reviews"[42] rather than rely on Class 5 preliminary estimates that were "rudimentary at best."[43] To recover PSEP costs in rates, SoCalGas and SDG&E were ordered to "file an application with testimony and work papers to demonstrate the reasonableness of the costs incurred which would justify rate recovery."[44] The intent, repeated twice in the decision, was "to strike a fair balance between ratepayers and shareholders."[45]

Applicants did just that. In December 2014, SoCalGas and SDG&E filed an application (A.14-12-016) requesting the Commission to find reasonable the costs incurred to execute certain early PSEP projects that were recorded in the PSRMAs, as well as the associated revenue requirement. In the decision in that proceeding, D.16-12-063, the Commission found that SoCalGas and SDG&E's actions and expenses were reasonable and consistent with the reasonable manager standard and granted the application.[46] A second reasonableness review application (A.16-09-005) was filed pursuant to D.16-08-003;[47] a proposed decision is expected in that proceeding in the coming months.

To address the Commission's concern that Applicants' Phase 1 cost estimates were too rudimentary, and Intervenors' arguments that ratemaking should only be approved based on better estimates following detailed engineering and design work, Applicants filed the application underlying D.16-08-003 (A.15-06-003) "seeking authorization to proceed with Phase 2 of their Pipeline Safety Enhancement Plan (PSEP) and to establish memorandum accounts to record approximately $22 million in planning and engineering design costs."[48] The first sentence of

---

[41] D.14-06-007, mimeo., at p. 23.
[42] D.14-06-007, mimeo., at p. 22.
[43] D.14-06-007, mimeo., at pp. 25-26.
[44] D.14-06-007, mimeo., at p. 39.
[45] D.14-06-007, mimeo, at pp. 19, 22.
[46] *See* D.16-12-063, granting A.14-12-016. The decision declined to authorize recovery of costs for PSEP-specific insurance based on insufficient evidence (without prejudice to Applicants' ability to seek these costs in a future proceeding). *Id*. at 54.
[47] D.16-08-003, mimeo., at p. 13 (Finding of Fact 6).
[48] D.16-08-003, mimeo., at p. 1. The application describes the request as follows: "SoCalGas and SDG&E request authorization to begin with the planning and engineering design analysis necessary to

D.16-08-003 states, "[t]oday's decision grants the applicants' *unopposed* request for memorandum accounts and adopts Staff's proposal for an interim rate increase subject to refund" (emphasis added).[49] Accordingly, the Pipeline Safety Enhancement Memorandum Accounts ("PSEPMAs") were created for Applicants to record costs associated with detailed engineering and design activities for Phase 2 PSEP projects.[50]

Also in D.16-08-003, the Commission authorized SoCalGas and SDG&E to recover in rates, subject to refund, fifty percent of the revenue requirements associated with actual PSEP Phase 1 costs properly recorded in their respective SECCBAs, SEEBAs, and PSRMAs.[51] In this way, Applicants would not have to wait years, pending a final decision following a lengthy reasonableness review process, to recover in rates costs incurred in executing PSEP.

In addition, D.16-08-003 established a framework and schedule for future cost recovery for PSEP work. Applicants were directed to file reasonableness review applications in 2016 and 2018, and this forecast Application "as soon as possible."[52] Beginning with Applicants' 2019 General Rate Case ("GRC"), PSEP is to be integrated into Applicants' future GRCs until implementation of PSEP is complete.[53]

D. The Commission Determined Certain Costs May Not Be Recovered in Rates.

---

develop detailed cost estimates for Phase 2 projects and to record the planning and engineering design costs in memorandum accounts. The objective is to develop more detailed and accurate project estimates to be presented in subsequent Phase 2 applications for review and approval by the Commission. This approach will enhance transparency by providing the Commission and interested parties with more detailed and accurate planning and engineering design information and cost estimates prior to the commencement of construction. Through this process, SoCalGas and SDG&E can avoid presenting Phase 2 cost estimates for Commission consideration that are "too rudimentary to preapprove" [footnote omitted] and enhance transparency by providing the Commission and interested parties with more detailed scope and cost information prior to initiating construction on Phase 2 projects" (footnote omitted). MON, Ex. E at p. 7 (A.15-06-013, Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) to Proceed with Phase 2 of Their Pipeline Safety Enhancement Plan and Establish Memorandum Accounts to Record Phase 2 Costs).

[49] D.16-08-003, mimeo., at p. 1.

[50] SoCalGas Advice Letter 5017-A and SDG&E Advice Letter 2506-G-A established the PSEP-Phase 2 Memorandum Accounts.

[51] D.16-08-003, mimeo., at p. 16 (Ordering Paragraphs 2-4).

[52] D.16-08-003, mimeo., at Attachment A, pp. 1-2.

[53] D.16-08-003, mimeo., at Attachment A, p. 2. *See* A.17-10-008, SCG-15, Testimony of Rick Phillips (request for funds in general rate case for PSEP).

D.14-06-007 disallowed recovery in rates of certain costs, including: (a) the cost of pressure testing pipeline installed after January 1, 1956 that lacks sufficient record of a pressure test record that comports with the minimum then-applicable industry standards or regulations;[54] (b) a portion of pipeline replacement costs equivalent to the system-average cost of pressure testing pipeline, for pipelines installed after January 1, 1956 that lack sufficient record of a pressure test that comports with the minimum then-applicable industry standards or regulations;[55] (c) the remaining undepreciated book value for abandoned or replaced pipeline installed after January 1, 1956 that lacks sufficient record of a pressure test that comports with the minimum then-applicable industry standards or regulations;[56] (d) Safety Enhancement incentive compensation for executives;[57] and (e) the cost of searching for pipeline test records.[58]

E. Protests, Pre-Hearing Conference, and the Scoping Memorandum and Ruling.

Protests to the Application were filed by TURN, SCGC, and ORA, and a response was filed by Shell Energy North America (US), L.P. ("Shell").[59] A joint pre-hearing conference statement was filed by Applicants, Intervenors, and Shell, and a pre-hearing conference was held on June 5, 2017.

On August 28, 2017, the assigned Commissioner, Clifford Rechtschaffen, and assigned Administrative Law Judge ("ALJ"), Adeniyi Ayoade, issued a Scoping Memo and Ruling of Assigned Commissioner ("Scoping Memo") setting a schedule for the proceeding.[60] The proceeding was categorized as ratesetting and ALJ Adeniyi Ayoade was designated presiding officer.[61] The following items were identified as within the scope of the proceeding:

---

[54] D.14-06-007, mimeo., at pp. 32-34, as modified by D.15-12-020.
[55] D.14-06-007, mimeo., at pp. 32-34, as modified by D.15-12-020.
[56] D.14-06-007, mimeo., at p. 36, as modified by D.15-12-020.
[57] D.14-06-007, mimeo., at p. 38.
[58] D.14-06-007, mimeo., at p. 39.
[59] Scoping Memo and Ruling of Assigned Commissioner dated August 28, 2017 ("Scoping Memo") at p. 4.
[60] Scoping Memo at p. 8.
[61] Scoping Memo at p. 15.

(1) Whether Applicants' application of the Commission-approved Decision Tree to Phase 2A of PSEP is appropriate;

(2) Whether Applicants' forecasts of costs associated with the completion of the nine Phase 1B projects presented in the Application are reasonable;

(3) Whether Applicants' forecasts of costs associated with the completion of the three Phase 2A projects presented in the Application are reasonable;

(4) Whether Applicants should be permitted to conduct non-destructive examination of a segment of Line 127 rather than replacing it as provided in the Decision Tree;

(5) Whether the forecasted revenue requirement associated with the twelve projects in the Application are just and reasonable and may be recovered by Applicants in rates;

(6) Whether Applicants' proposed regulatory accounting treatment of forecasted and actual costs, on an aggregate basis, associated with the twelve projects in the Application is appropriate;

(7) Whether Applicants may file the proposed preliminary statements submitted with the Application to create certain balancing accounts;

(8) Whether Applicants may subdivide the existing SECCBA accounts into the two subaccounts proposed in the Application;

(9) Whether Applicants may subdivide the existing SEEBA accounts into the two subaccounts proposed in the Application;

(10) Whether Applicants may create two new balancing accounts for Phase 2 as proposed in the Application, and transfer costs tracked in the PSEPMAs into these new balancing accounts;

(11) Whether Applicants' proposal in the Application for allocating the revenue requirement by functional area is consistent with prior Commission directive;

(12) Whether Applicants may implement in transportation rates, through a Tier 1 Advice Letter, the revenue requirements associated with the twelve projects

proposed in this Application effective January 1 of the year following a decision on the Application;

(13) Whether Applicants may balance, on an aggregate basis, the actual capital and O&M costs with the associated forecasted revenue requirements, and whether they may address differences in the Applicants' Annual Regulatory Account Balance Update Tier 2 Advice Letter filing with the Commission;

(14) Whether Applicants may recover the ongoing capital-related revenue requirements associated with the capital expenditures approved in this proceeding through a Tier 2 Advice Letter until such costs are incorporated in base rates in connection with Applicants' next general rate case;

(15) Whether the information provided by Applicants adequately supports the inclusion of accelerated and incidental miles in the forecast;

(16) Whether Applicants should be required to provide specific cost information (e.g., inputs and outputs of the estimating tools, assumptions, and other methods of forecasting costs) in support of the requested funding and/or forecasted costs for its projects;

(17) Whether Applicants should be required to provide cost comparisons of similar or previous work done by Applicants or other utilities, in order to determine whether Applicants based cost estimates for the PSEP projects upon similar work in the industry; and

(18) Whether Applicants should proceed with the execution of nine Phase 1B projects previously approved by the Commission and three Phase 2A projects in compliance with Decision 11-06-017, and recover the total associated revenue requirement ($197.5 million in capital-related costs and $57 million in operations and maintenance costs) in customer rates.[62]

[62] Scoping Memo at pp. 5-7.

Although the Parties have not formally stipulated to any issues within the scope of this proceeding,[63] it appears that many of the foregoing issues may be undisputed because no controverting evidence has been admitted into the record.

No Intervenor has suggested Applicants' Phase 2A Decision Tree should not be approved (Issue 1). TURN/SCGC support the non-destructive examination option for Line 127, and ORA has not indicated to the contrary (Issue 4). Intervenors also have not commented on Applicant's proposal to allocate the revenue requirement by functional area, consistent with the Commission's decision in D.16-12-063 (Issue 11), nor whether Applicants may implement the revenue requirement in transportation rates through a Tier 1 advice letter, which is standard practice (Issue 12). To this extent, Applicants do not address these issues at length in this Opening Brief.

Although Issues 16 and 17 above are within the scope of this proceeding, they are mooted by the facts that Applicants' detailed cost estimates have been admitted into the record in this proceeding[64] and ORA obtained, and based its forecast recommendations on, cost information obtained by it from other utilities.[65] Thus, the Commission need not determine whether Applicants should be directed to provide this information in this proceeding – it is already in the record in this proceeding.[66]

Issue 15 pertains to whether Applicants have presented sufficient evidence to support their inclusion of accelerated and incidental miles. Applicants have substantiated their requests to include accelerated and incidental miles in the workpapers for each project, as applicable.[67] None of the Intervenors have introduced evidence into the record on this issue; however, TURN/SCGC's witness recommends that the Commission require Applicants to attest that any Phase 2B mileage included in this proceeding is included solely to minimize the cost of

---

[63] Applicants provided a list of the issues within the scope of this proceeding, having marked those to which they would stipulate, to Intervenors by email on March 16, 2018. Intervenors were requested to mark the issues to which they would stipulate. Not a single one of Intervenors responded.
[64] See Ex. SCG-19-C.
[65] Ex. ORA-06-C-A at pp. 5-6.
[66] *See* Exs. SCG-19-C, ORA-06-C-A, and ORA-09-C-A.
[67] Ex. SCG-10 at pp. WP-II-A11, WP-II-A20, WP-II-A29, WP-II-A40, WP-II-A50, WP-II-A59, WP-II-A69, WP-II-A80, WP-II-A90, WP-II-A99, WP-II-A110.

conducting the Phase 1B or Phase 2A pressure test, replacement, de-rate, or de-rate and abandon projects.[68] Thus, it appears any dispute among the parties regarding Issue 15 is limited to justification for the inclusion of Phase 2B accelerated miles.

The remaining issues (2, 3, 5-7, 8-9, 10, 13-14, and 18) are dependent on the following two questions:

i. What amount should Applicants be authorized to recover in rates for executing the twelve PSEP projects in the Application; and

ii. What regulatory accounting treatment should be accorded to costs incurred in executing the twelve PSEP projects in this Application?

F. Hearings.

Evidentiary hearings were held before ALJ Ayoade on February 26 and 28, 2018.

III. LEGAL STANDARD OF REVIEW

A. Ratesetting Proceeding – Just and Reasonable Standard.

This is a ratesetting proceeding.[69] Applicants bear the burden of establishing affirmatively the reasonableness of all aspects of their requests herein.[70] Pursuant to Public Utilities Code sections 451 and 454, all rates and charges collected by a utility must be "just and reasonable," and a public utility may not charge any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified."[71] Thus, the Commission requires that Applicants demonstrate that the revenue requirement proposed herein for executing the twelve PSEP projects is just and reasonable.[72]

B. Burden of Proof – Preponderance of the Evidence.

The standard of proof applicable to a ratesetting proceeding is preponderance of the evidence.[73] Preponderance of the evidence is defined "in terms of probability of truth, e.g., 'such

---

[68] Ex. TURN/SCGC-01 (Yap) at p. 4.
[69] Scoping Memo at p. 15.
[70] D.14-06-007, mimeo., at pp. 12, 55 (Conclusion of Law 3).
[71] Pub. Util. Code §§ 451, 454.
[72] D.14-06-007, mimeo., at p. 12; Pub. Util. Code § 451.
[73] D.14-06-007, mimeo., at pp. 13, 55 (Conclusion of Law 4).

evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[74] In other words, Applicants "must present more evidence that supports the requested result than would support an alternative outcome."[75]

IV. THE RECORD ESTABLISHES BY A PREPONDERANCE OF THE EVIDENCE THAT APPLICANTS' FORECASTS ARE REASONABLE AND THE ASSOCIATED REVENUE REQUIREMENT SHOULD BE AUTHORIZED

A. The Twelve Projects in the Application Are Within the Scope of PSEP.

The twelve projects proposed in the Application are PSEP projects, and no Intervenor has contested this. Phase 1B has already been approved for execution by the Commission and is subject to two-way balancing account treatment.[76] Nevertheless, because Intervenors repeatedly requested an opportunity to review Applicants' plans for executing Phase 1B work,[77] Applicants included nine Phase 1B projects in this proceeding. No Intervenor has entered evidence into the record in this proceeding contesting or otherwise disagreeing with the scope of work for any of the twelve projects.

With respect to the Line 127 Phase 1B project,[78] TURN/SCGC support the non-destructive examination option presented by Applicants,[79] and ORA has not opined either way. To that extent, Applicants believe this issue is uncontested.

---

[74] D.14-07-007, mimeo., at p. 13; D.08-12-058 citing Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.
[75] D.14-07-007, mimeo., at p. 13.
[76] D.14-06-007, mimeo, at p. 60 (Ordering Paragraph 4).
[77] *See, e.g.,* MON, Ex. A at p. 10 (A.15-06-013, Reply Comments of the Indicated Shippers, the Office of Ratepayer Advocates, the Southern California Generation Coalition, and the Utility Reform Network dated January 22, 2016).
[78] Applicants propose non-destructive examination of Line 127 rather than replacing the segment as called for by the Decision Tree. This proposal is based on the specific pipeline characteristics and documentation pertaining to this segment. Those characteristics include: (a) the pipe is seamless; (b) the segment is approximately 15 feet; (c) the segment has a record of a pressure test performed in 1968; (d) the segment is located before a pig launcher; and € the segment is located where Line 127 starts within SoCalGas' La Goleta storage facility. Because of where the segment is located, the segment is more easily observed and examined, and replacement of this segment will not enhance system piggability. Ex. SCG-03 (Gonzalez) at pp. 11-12; Ex. SCG-10 at pp. WP-II-A119-A125.
[79] Ex. TURN/SCGC-01 (Yap) at p. 8. ("I believe that the Applicants have made a good case for relying on NDE rather than replacement.")

Applicants have established by a preponderance of the evidence that "incidental" and "accelerated" miles are reasonably included in the twelve projects. Applicants include incidental and accelerated miles within the scope of projects that are already planned to be addressed in accordance with the Commission-approved prioritization process in order to comply with the Commission's directive to obtain "the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[80] Accelerated miles are miles that otherwise would be addressed in a later phase of PSEP under the Decision Tree prioritization process but are advanced to realize operating and cost efficiencies.[81] Incidental miles are those which are not scheduled to be addressed as part of PSEP, but are included when it is determined that addressing them improves cost and program efficiency, addresses implementation constraints, or facilitates continuity of testing.[82] Both incidental and accelerated miles are included (1) to minimize customer impacts, (2) in response to operational constraints, or (3) because of the cost and operational efficiencies gained by incorporating them into the project scope rather than executing a project circumventing them.[83]

Incidental and accelerated miles account for approximately 1.9% of total replacement project miles (.425/22.546 miles[84]) and approximately 1% of total pressure test project miles (.385/36.981 miles[85]). The following Table 1 depicts the accelerated and incidental mileage that will be addressed in the twelve projects in this proceeding.

Table 1 – Incidental and Accelerated Mileage

Project	Project Length	Accelerated Miles	Incidental Miles	Reason for Inclusion
Line 127	15 Feet	0	0	N/A
Line 7043	7.5 Feet	0	2 Feet	Constructability
Line 36-37 Section 11	7.635 Miles	264 Feet	0	Constructability

[80] D.11-06-017, mimeo., at p. 22.
[81] Ex. SCG-03 (Gonzalez) at p. 3.
[82] Ex. SCG-03 (Gonzalez) at p. 4.
[83] Ex. SCG-03 (Gonzalez) at pp. 3-4.
[84] Ex. SCG-10, Workpaper Summary (immediately prior to p. WP-II-A1.)
[85] Ex. SCG-10, Workpaper Summary (immediately prior to p. WP-II-A1.)

Line 36-1001/45-1001	1.579 Miles	0	.35 Miles	Re-route to avoid mountainous terrain and environmentally sensitive habitats
Line 38-514	1.387 Miles	0	26 Feet	Constructability
Line 38-960	6.112 Miles	21 Feet	0	Constructability
Line 43-121	.258 Miles	0	48 Feet	Constructability
Line 38-556	5.571 Miles	0	37 Feet	Constructability
Total Replacement	**22.546 Miles**	**285 Feet**	**1,961 Feet**	
Line 36-37 Section 12	30.916 Miles	5.708 Miles	4.574 Miles	Necessary in order to de-rate/abandon the entire section
Line 36-1002	16.683 Miles	6.797 Miles	8.116 Miles	Necessary in order to de-rate/abandon the entire section
Total De-Rate / Abandon	**47.599 Miles**	**12.505 Miles**	**12.69**	
Line 2000 C	22. 910 Miles	0	174 Feet	Constructability
Line 2000 D	14.038 Miles	.352 Miles	0	Constructability
Total Pressure Test	**36.948 Miles**	**.352 Miles**	**174 Feet**	

Ninety-four percent (1,848 feet of 1,951 feet) of incidental miles included in replacement projects are included in the Line 36-1001/45-1001 replacement project based on re-routing of the project to avoid mountainous terrain and environmentally sensitive habitats.[86] The remaining 113 feet of incidental mileage was included in four replacement projects (Lines 7043, 38-514, 43-121, 38-556) for constructability purposes.[87] Likewise, the 174 feet of incidental mileage that were included in the Line 2000-C pressure test project were included for constructability reasons.[88]

Similarly, the reason for including Phase 2B miles has been justified. The Line 36-37 Section 12 project includes 4.574 incidental miles and 5.708 accelerated Phase 2B miles that are located between Phase 1B segments.[89] These miles are included for constructability and practical purposes: it would be impractical to de-rate or abandon only the Phase 1B segments of this pipeline and circumvent the adjoining incidental and accelerated segments.[90] Moreover,

[86] Ex. SCG-03 (Gonzalez) at p. 13.
[87] Ex. SCG-10 at pp. WP-II-A11, WP-II-A-40, WP-II-A-59, WP-II-A-69.
[88] Ex. SCG-10 at p. WP-II-A99.
[89] Ex. SCG-02 (Mejia) at pp. 3-4; Ex. SCG-10 at p. WP-II-A80.
[90] Ex. SCG-02 (Mejia) at p. 4.

non-contiguous abandonment is illogical and would require additional equipment and cost to keep those segments operating at the higher MAOP.[91]

The Line 36-1002 project entails de-rating 16.683 miles, 1.77 of which are Phase 1B, and 4.987 are Phase 2A.[92] The incidental and accelerated mileage are included here for the same reasons they are included for Line 36-37 Section 12: it is impractical and illogical to abandon just the non-contiguous segments and not the adjoining segments.[93] Phase 2B miles are included for constructability purposes; their inclusion eliminates additional cost and unnecessary equipment to keep those segments operating at the higher MAOP.[94]

Three test or replacement projects also include Phase 2B mileage. Line 36-37 Section 11 includes 264 feet of Phase 2B pipe that appears in seven segments along the pipeline, mostly located between Phase 1B segments.[95] Phase 2B mileage is included in order to realize construction efficiencies: replacing the short segments allows the construction team to conduct post-replacement pressure testing in continuous sections of pipe before tying the line in for service, which in turn minimizes system impacts and enhances pipeline safety.[96]

Line 38-960 is a 6.112-mile replacement project that includes 21 feet of Phase 2B accelerated pipe that sits between Phase 2B mileage; it is included for constructability purposes and to allow for one continuous pressure test and eliminate the need for additional tie-in activities and associated costs.[97]

The 14.038-mile Line 2000-D pressure test project includes .352 miles of accelerated Phase 2B pipe made up of eight separate segments that are located between the Phase 2A pipe subject to testing.[98] It is cost-effective to include the Phase 2B segments as opposed to

[91] Ex. SCG-02 (Mejia) at p. 4.
[92] Ex. SCG-02 (Mejia) at p. 4; Ex. SCG-10 at p. WP-II-A90.
[93] Ex. SCG-02 (Mejia) at p. 4.
[94] Ex. SCG-02 (Mejia) at p. 4.
[95] Ex. SCG-02 (Mejia) at pp. 4-5; Ex. SCG-10 at p. WP-II-A20.
[96] Ex. SCG-02 (Mejia) at pp. 4-5.
[97] Ex. SCG-02 (Mejia) at p. 5; Ex. SCG-10 at pp. WP-II-A49-50.
[98] Ex. SCG-02 (Mejia) at p. 5; Ex. SCG-10 at p. WP-II-A110.

circumventing them because it allows for continuous pressure tests which, in turn, save costs.[99] Their inclusion also minimizes customer impacts.[100]

B. The Cost Forecasts Comply with Commission Directives and Are Reasonable.

1. No Commission-Ordered Disallowances Have Been Included in Applicants' Forecasts.

As noted in Section II.D, the Commission has determined that Applicants may not recover in rates certain categories of costs. In accordance with this directive, Applicants do not include executive incentive compensation costs in their forecasts, nor do they include costs associated with searching for pipeline testing records.[101] Moreover, disallowances that pertain to post-1955 vintage pipe that is tested or replaced as part of PSEP have not been implicated by the twelve projects in the Application; accordingly, they do not factor into Applicants' forecasts.[102]

2. General Management and Administration Costs.

In addition to costs associated with the project-specific variables discussed in Section IV.C below, Applicants' forecasts include General Management and Administration ("GMA") costs estimated, based on Applicants' prior experience, to be approximately ten percent (10%) of total project forecasted costs.[103]

GMA costs are those incurred at the program level and support cost minimization, maximize the effectiveness of safety investments, improve organizational and project execution efficiency, and provide consistency in the implementation of PSEP projects.[104] These costs are necessary for the cost-effective and successful execution of PSEP.[105] The GMA captures functional supporting costs for the PSEP organization that are not captured in non-incremental

[99] Ex. SCG-02 (Mejia) at p. 5.
[100] Ex. SCG-02 (Mejia) at p. 5.
[101] Ex. SCG-03 (Gonzalez) at pp. 2-3.
[102] Ex. SCG-03 (Gonzalez) at p. 2.
[103] Ex. SCG-05 (Pech) at p. 6. The expected allocation per GMA category, based on Applicants' prior experience with PSEP, is set forth at Ex. SCG-05 (Pech) at p. 2.
[104] Ex. SCG-05 (Pech) at pp. 1-6.
[105] Ex. SCG-05 (Pech) at pp. 1-2.

overheads typically charged to projects.[106] This type of activity and associated allocation has been included in both of Applicants' prior reasonableness reviews.[107]

Applicants track GMA costs by utilizing internal orders ("IOs")[108] based on functional groups and their activities.[109] Before GMA costs are allocated to projects on a percentage basis,[110] they are subject to review and approval processes from the GMA department heads on a monthly basis.[111] Any mischarges identified are reported to the PMO Business and Administration group for correction.[112] Among other things, department heads review and approve or correct the following reports: (i) a monthly report which identifies all IO numbers charging to each GMA department;[113] and (ii) a weekly report indicating hours charged by external vendors.[114] Only after hours are approved by department heads are vendors authorized to invoice and bill Applicants.[115] For the first PSEP reasonableness review, ORA performed an audit of certain PSEP costs and supporting documentation and found no inconsistencies.[116]

GMA costs are distinct from the incremental company-wide overheads applied to PSEP.[117] No Intervenor has opposed Applicants' GMA forecasts.

---

[106] Ex. SCG-05 (Pech) at pp. 8, 10. The nine GMA categories are as follows: Program Management Office, Construction, Engineering, Environmental, Supply Management, Gas Control, Non-PMO General Administration, Communication and Outreach, and Training. *Id.* at pp. 2-6.
[107] D.16-12-063, mimeo., at p. 14; MON, Ex. B at pp. 19-24 (A. 16-09-005, Opening Brief of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) in Support of Their Application 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 dated January 19, 2018).
[108] Ex. SCG-05 (Pech) at pp. 7-8.
[109] Ex. SCG-05 (Pech) at pp. 6-7.
[110] Ex. SCG-05 (Pech) at pp. 7-8.
[111] Ex. SCG-05 (Pech) at p. 7-8.
[112] Ex. SCG-05 (Pech) at p. 7-8.
[113] Ex. SCG-05 (Pech) at pp. 7-8.
[114] Ex. SCG-05 (Pech) at pp. 7-8.
[115] Ex. SCG-05 (Pech) at p. 8.
[116] MON, Ex. C at pp. 1-3 (A.14-12-016, Ex. ORA-02 (J. Lee) Prepared Testimony on Southern California Gas Company and San Diego Gas & Electric Company Application for Pipeline Safety and Reliability Memorandum Account (PSRMA) Cost Recovery, ORA Audit Report, dated August 7, 2015).
[117] Ex. SCG-05 (Pech) at pp. 8-9. The following are non-incremental overheads which are not charged to PSEP: Warehouse, Fleet Distribution, Fleet Transmission, Shop OH, Small Tools, Exempt MPM, Engineering/S&E Distribution, Engineering/S&E Transmission, and DOH Replacement. Instead, the nine identified GMA categories (Program Management Office, Construction, Engineering,

3. Company Overheads.

Whereas GMAs are "direct" charges to PSEP (because they can be traced directly to PSEP), company overheads or "indirect" charges are associated with direct costs that benefit a project, but are not directly charged.[118] Company overheads are reflected in Applicants' fully loaded costs and include the following incremental loaders: Payroll Tax, Vacation and Sick time, Benefits (non-balanced only), Workers' Compensation, Public Liability/Property Damage, Incentive Compensation Plan, Purchasing, Administrative and General, and Insurance.[119] Company overheads were included in the prior reasonableness review applications.[120]

The company overheads represent the indirect cost components of executing PSEP. The forecasted company overheads included in Applicants' forecasts are based on actual company overheads that were incurred, calculated, and allocated with prudent oversight and management, and therefore, should be authorized to be recovered in rates, subject to balancing in accordance with Applicants' requested regulatory accounting treatment. No Intervenor has opposed Applicants' forecast of company overhead costs.

4. Phase 2 Engineering, Design, and Planning Costs.

Applicants' forecasts for the projects proposed herein include the planning and engineering design costs for Phase 2, which were authorized in D.16-08-003 and have been recorded to the PSEPMAs.[121] It is consistent with Applicants' prior cost recovery applications that the costs of discrete projects be considered together, as a whole, rather than piecemeal.[122] Applicants therefore seek authority from the Commission to transfer costs currently recorded to the PSEPMAs to the appropriate balancing accounts for Phase 2 PSEP work. If the Commission adopts Applicants' proposal, these costs should be transferred to the newly created SEEBA-P2 and SECCBA-P2, as discussed in Section V below.

Environmental, Supply Management, Gas Control, Non-PMO General Administration, Communication and Outreach, and Training) apply to PSEP. *Id.* at pp. 2-6.

[118] Ex. SCG-06 (Chan) at p. 1; Ex. SCG-05 (Pech) at pp. 8-9.

[119] Ex. SCG-05 (Pech) at pp. 8-9; Ex. SCG-06 (Chan) at 1 and WP-1-1.

[120] D.16-12-063, mimeo., at pp. 12-14.

[121] Ex. SCG-03 (Gonzalez) at pp. 5-6.

[122] D.15-12-020 at pp. 4-5, 25 (Ordering Paragraph 3); Ex. SCG-07 (Austria) at p. 4.

Although Intervenors oppose the forecasted cost estimates prepared by Applicants' based on the detailed Phase 2 engineering, design and planning work, no Intervenor has opposed the work as unreasonable (indeed, Intervenors had an opportunity to oppose Applicants' proposal to engage in Phase 2 engineering, design and planning work but, notably, did not[123]).

C. Applicants' Forecasts Are Robust, Reasonable, and Worthy of Ratemaking.

1. Scope Validation and Other Cost Avoidance Efforts Have Been Undertaken.

Applicants engage in scope validation efforts in order to reduce the scope of PSEP.[124] For example, Applicants have been able to reduce the scope of Phase 1B by approximately 38 miles – saving customers approximately $250 million – by de-rating or abandoning pipeline.[125] Pipeline is only descoped from PSEP after a thorough review of the ability of adjoining lines to meet current and future load requirements and verification that there will be no anticipated customer impacts or system constraints.[126]

Where Phase 1B pipe segments have a record of a pressure test and have records that demonstrate the presence of seamless pipe, Applicants also consider alternatives to replacement, such as direct assessment.[127] Following this review process, Applicants determined to recommend non-destructive examination for Line 127 (which recommendation is unopposed by Intervenors).[128]

Applicants have developed numerous other practices to manage costs and implement prudent oversight and, consistent with their ongoing commitment to continuous improvement, Applicants will continue to improve upon these practices so as to manage costs to the benefit of ratepayers.[129]

---

[123] D.16-08-003, mimeo., at p. 1.
[124] Ex. SCG-01 (Mejia) at p. 6.
[125] Ex. SCG-01 (Mejia) at pp. 6-7. "As-filed" Phase 1B mileage has been reconciled with that currently in scope. Ex. SCG-01 (Mejia) at Attachment A.
[126] Ex. SCG-01 (Mejia) at p. 7.
[127] Ex. SCG-01 (Mejia) at p. 8.
[128] Ex. SCG-01 (Mejia) at p. 8.
[129] MON, Ex. B at pp. 17, 55 (A. 16-09-005, Opening Brief of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) in Support of Their Application to Recover Costs Recorded in the Pipeline Safety and Reliability Memorandum Accounts, the Safety Enhancement

2. Applicants' Forecasts Are Project-Specific, Developed by Experienced Estimating Professionals, and Based on Applicants' Actual Experience Implementing PSEP.

In D.14-06-007, the Commission stated, "It is only fair that ratepayers should have the benefit of detailed plans for this Commission to consider before authorizing or preapproving the expenditure of many hundreds of millions of dollars."[130] Heeding the Commission's directive, Applicants sought and obtained authority to incur and record the costs of completing engineering, design and planning activities to prepare detailed, Class 3 estimates of the costs to complete Phase 2 work.[131]

For each of the twelve projects in this Application, Applicants prepared detailed workpapers that describe, *inter alia*: (a) the project; (b) alternatives considered; (c) forecast methodology utilized; (d) project schedule; (e) costs of materials, construction, environmental requirements, land and right-of-way rights, labor, GMA, etc.; (f) assumptions (such as pricing based on project location, permit requirements, traffic control, etc.); and (g) project-specific maps, including elevation profile where it affects the scope of work or costs. The detailed cost estimates[132] admitted into the record in this proceeding have even more information regarding the components that make up the estimate for each project. Applicants' estimates account for project-specific characteristics, such as the number of laydown yards that are required for a project,[133] whether nighttime permit conditions impact labor,[134] site facility costs,[135] whether electrolysis test stations are required to be installed,[136] and how many Baker Tanks are required.[137] The estimates incorporate Applicants' unique knowledge as experienced operators of their system. For example, Applicants anticipate, based on their prior experience, that three of

---

Expense Balancing Accounts, and the Safety Enhancement Capital Cost Balancing Accounts dated January 19, 2018).

130 D.14-06-007, mimeo., at p. 23.
131 D.16-08-003 at p.1.
132 Ex. SCG-19-C.
133 Ex. SCG-10 at p. WP-II-A61.
134 Hearing Transcript at pp. 80:7-27,109:9-27.
135 Ex. SCG-10 at p. WP-II-A71.
136 Ex. SCG-10 at p. WP-II-A32.
137 Ex. SCG-10 at p. WP-I-A22.

the twelve projects in this proceeding will have sugar sand conditions that will slow down productivity.[138]

The information that goes into the cost estimates has been derived by Applicants after assessing and confirming project parameters, undertaking site visits, developing preliminary designs for Geographic Information System ("GIS") alignment sheets, identification of special crossings, survey and preparation of base maps, analysis of environmental restrictions to work locations and seasonal restrictions, identification of valve sites, identification of access roads, identification of workspaces (including potential material staging areas), review of feature studies (which depict and describe all the physical components of a pipeline and all the attributes associated with those components), and coordinating with Gas Engineering and Pipeline Integrity to identify repairs/cut-outs for anomalies and in-line inspection compatibility.[139] The resulting estimates are from a construction standpoint, i.e., what it takes to construct the projects.[140]

Applicants' project estimation practices and tool have evolved over time.[141] The tool used in 2011 to prepare the initial PSEP estimate (which the Commission and Intervenors found too "rudimentary"[142]) was improved upon in 2013 to increase the number of factors considered in deriving the estimate.[143] There are, and continue to be, ongoing efforts to enhance estimate accuracy by incorporating actual costs incurred in executing PSEP as they are incurred in the field.[144] A dedicated and experienced centralized estimating team was assembled in-house.[145] Subject matter experts for each of the following functional areas use their professional expertise and experience to provide estimate assumptions that form the basis for each project estimate:

- Project Execution: analyze alternatives to Decision Tree outcome for remediation; manage customer impacts; validate appropriate replacement diameter; identify taps

[138] Hearing Transcript at pp. 81:6-24, 104:18 – 105:11.
[139] Ex. SCG-03 (Gonzalez) at pp. 5-6.
[140] Hearing Transcript at pp. 104:18 – 105:11.
[141] Ex. SCG-03 (Gonzalez) at pp. 4-10.
[142] D.14-06-007, mimeo., at p. 2.
[143] Ex. SCG-03 (Gonzalez) at p. 5.
[144] Ex. SCG-03 (Gonzalez) at p. 5.
[145] Ex. SCG-03 (Gonzalez) at p. 5.

and laterals within segments; assess potential customer impacts and develop mitigation strategies; develop pipeline features to be cut out prior to pressure test; identify potential valve additions; review and approve scope of work; and review and approve project-specific pressure test procedures, when applicable.[146]

- Engineering Design: perform planning and engineering design work to develop a scope of work with sufficient detail to develop robust cost estimates; assess and validate project parameters; visit job site; develop preliminary design; develop pipeline profile; identify pressure test segments based on the minimum and maximum allowable test pressures; identify special pipeline crossings for replacement projects; and develop preliminary designs for each section.[147]
- Construction: provide construction contractors with knowledge of PSEP work in the scoping process; collaborate in field investigation; assess potential constructability issues based on project scope and prior job knowledge; review engineering design package to determine construction assumptions; and provide input into the development of each construction estimate.[148]
- Environmental: prepare detailed analysis of recommended project routing to minimize environmental construction impacts and associated costs; identify permit conditions and estimate associated costs; determine water treatment costs, as applicable; quantify water transportation costs, as appropriate; and develop cost estimates for construction monitoring, sampling/laboratory analysis, abatement, and hazardous material management and disposal, as implicated.[149]
- Land Services: determine municipal permit requirements and associated costs; identify potential laydown/staging yards required and communicate with land owners

[146] Ex. SCG-03 (Gonzalez) at p. 7.
[147] Ex. SCG-03 (Gonzalez) at pp. 7-8.
[148] Ex. SCG-03 (Gonzalez) at p. 8.
[149] Ex. SCG-03 (Gonzalez) at pp. 8-9.

to determine availability; and develop cost estimates associated with temporary construction easements, appraisals, title reports, etc.[150]

- Compressed Natural Gas/Liquefied Natural Gas Team: provides analyses regarding impacts on customer natural gas loads to develop optimal process for keeping customers online as required by tariffs; and develop cost estimates for the provision of CNG/LNG.[151]
- Supply Management: provides material and logistics-related cost estimates based on a preliminary bill of material developed by each project team.

All of the foregoing enhancements made since 2011 are incorporated into the Class 3 estimates upon which Applicants based their forecasts in this proceeding. Whereas in D.14-06-007 the Commission declined to authorize ratemaking on a forecast basis based on the 2011 Class 5 estimates,[152] these Class 3 estimates are based upon detailed project-specific engineering, design and planning work and are reasonable and worthy of ratemaking. In order to confirm the foregoing, Applicants engaged KPMG to assess their estimating practices, and KPMG determined that Applicants' "estimating procedures are consistent with industry practice for developing an AACEi 56R-08, Class 3 Estimate" and the "estimating process and methods… are consistent with industry practice."[153] KPMG further noted that Applicants' estimating process had improved from that used for Phase 1A[154] in that it "utilizes a bottoms-up approach

[150] Ex. SCG-03 (Gonzalez) at p. 9.
[151] Ex. SCG-03 (Gonzalez) at p. 9.
[152] D.14-06-007, mimeo., at pp. 25-26. The Commission stated, "The witness clearly showed that SDG&E and SoCalGas at best a 'level [sic] 5' budget in a system where a level [sic] 5 budget is extremely preliminary, in fact rudimentary, and then only after careful planning and design does the budget progressively improve to levels [sic] 4, 3, 2, and finally level 1which is the most complete and advanced level of budgetary planning. [Footnote 17:] 'Class 5 or slightly better' characterization is based on a 'recommended practice' produced by the Association for the Advancement of Cost Engineering." *Id.*
[153] Ex. SCG-04 (Gonzalez) at Attachment A, p. 1. As noted, KPMG reviewed 11 Phase 1B estimates prepared by Applicants.
[154] Ex. SCG-04 (Gonzalez) at Attachment A, p. 1. KPMG notes that the "estimating process for Phase 1A projects utilized a parametric type estimating tool to produce a percentage based estimate." Intervenors' propose forecasts based on parametric type estimating tools. Ex. SCG-04 (Gonzalez) at p. 1.

with input and deliverables provided from various project stakeholders… and a centralized group of professional cost estimators."[155]

That being said, even the best estimates are just that – an informed, detailed, best approximation that nevertheless may deviate from the actual outcome – and thus, in fairness to both ratepayers and Applicants, must be coupled with the regulatory accounting treatment described in Section V below.

3. Intervenors' Proposed Funding Levels Are Woefully Inadequate for Applicants to Complete Commission-Ordered Safety Enhancement Work.

Although Intervenors (ORA, on the one hand, and TURN/SCGC, on the other) use different methodologies for arriving at their proposed authorized funding levels for the twelve projects in this proceeding, both result in forecasts similar to the ones Applicants proposed in 2011 and the Commission rejected as "rudimentary."[156] They do not offer the "detailed plans" the Commission ordered to be provided in order to approve ratemaking.[157] This alone is sufficient basis for Intervenors' proposals to be rejected.

Applicants have established by a preponderance of the evidence that their proposed forecasts are just and reasonable: Applicants examined the unique attributes of each project, engaged in extensive engineering, design and planning work, and assigned costs to the various attributes of each project based on their knowledge as pipeline operators and actual experience executing PSEP. In contrast, Intervenors did not evaluate the various components of each project and, as a result, their forecasts are less likely to reflect the costs to be incurred in executing the twelve projects than the forecasts proposed by Applicants. Applicants have met their burden of proof by "present[ing] more evidence that supports the requested result than would support an alternative outcome."[158]

The following are additional reasons why Intervenors' proposed authorized funding levels are insufficient to support ratemaking.

---

[155] Ex. SCG-04 (Gonzalez) at Attachment A, p. 1.
[156] D.14-06-007, mimeo., at p. 2.
[157] D.14-06-007, mimeo., at p. 23.
[158] D.14-07-007, mimeo., at p. 13.

a. ORA's Benchmarking Analysis Is Flawed.

ORA proposes different methods to compute its proposed authorized funding levels for replacement projects and pressure test projects. ORA does not propose any funding level for the de-rate and de-rate and abandon projects (Line 36-37 Section 12 and Line 36-1002).[159] Moreover, ORA's proposed funding levels have not been escalated to reflect future costs, nor are they fully loaded with indirect costs; thus, they necessarily cannot be accepted or used as a basis for determining an authorized funding level.[160]

ORA assembled a database comprised primarily of projects executed by Pacific Gas and Electric Company ("PG&E") (90%), and some projects executed by Applicants (8%) and Southwest Gas (2%).[161] For replacement projects (the costs of which are primarily capital expenditures), ORA determined the "predicted cost" of a project based solely on two attributes: pipeline length and diameter.[162] ORA then determined an 80% prediction interval.[163] For hydrotest projects (the costs of which are primarily O&M expenditures), ORA calculated a cost-per-mile of hydrotesting, but only after excluding 119 pressure tests under 3 miles in length.[164] Notably, ORA did not exclude PG&E's hydrotest projects (which constitute 220 projects in ORA's database, whereas only 14 are those of Applicants), even though they do not include the capital costs of hydrotesting,[165] and thus cannot be compared, apples-to-apples, to Applicants' hydrotest costs, which do include capital costs.[166]

---

[159] Hearing Transcript at p. 309:18-21.
[160] Ex. ORA-02 (Molla) at pp. 1-3. As the projects used by ORA in its database go back five years and they have not even been escalated to present day, ORA's predicted costs for the projects to be executed in the future are significantly understated.
[161] Ex. ORA-02 (Molla) at p. 3; Ex. SCG-04 (Gonzalez) at p. 4.
[162] Ex. ORA-01 (Stannik) at p. 4.
[163] Ex. ORA-02 (Molla) at pp. 9-10.
[164] Ex. ORA-04 (Stannik) at pp. 3-4; Hearing Transcript at pp. 266:15 – 269:28. This is important to note given that the vast majority of segments in the two hydrotest projects in this proceeding are well under 3 miles in length. Ex. SCG-10 at pp. WP-II-A97- WP-II-A98, WP-II-A108 – WP-II-A109.
[165] Ex. SCG-11 (ORA Response to SCG-SDGE DR-01) at pp. 9 – 10.
[166] Indeed, it is unclear whether any of the test or replacement costs in ORA's database can truly be considered apples to Applicants' apples. Ex. SCG-04 (Gonzalez) at pp. 11-13.

ORA's methods are a form of parametric estimating.[167] Parametric estimating uses a dataset of historical projects and averages a cost per unit to predict cost.[168] While parametric estimating may be useful for high-level scoping decisions, it is not appropriate to determine the forecasted cost of a specific pipeline project for ratemaking purposes.[169] Even in assessing Applicants' estimating practices, KPMG determined that the current bottoms-up approach Applicants use is superior to the parametric estimating Applicants conducted for Phase 1A projects.[170] Specific projects have myriad features that are unique to that framework which should be examined and accounted for in an estimate – this is the process of bottoms-up estimating.[171]

Not only are ORA's methods inferior to a bottoms-up estimating process for estimating costs; on top of that, ORA also undercuts its own position by proposing that, when Applicants' bottoms-up approach produces a lower estimated cost than ORA's, Applicants' estimate – not ORA's – should form the basis for authorized funding.[172]

ORA further undercuts the credibility of its position by proposing a cost-per-mile for hydrotesting that is 34% lower than that proposed by ORA in Applicants' reasonableness review proceeding.[173] In that proceeding, ORA's cost-per-mile calculation was based on Applicants' actual costs of hydrotesting.[174] It appears ORA is not committed to any particular methodology at all, implying its objective is to impose the lowest possible funding on Applicants. While reducing costs is a worthy goal (and one which Applicants also share), it is unreasonable to

---

[167] Ex. SCG-04 (Gonzalez) at p. 3.
[168] Ex. SCG-04 (Gonzalez) at p. 3.
[169] Ex. SCG-04 (Gonzalez) at p. 3.
[170] Ex. SCG-04 (Gonzalez) at Attachment A, p. 1.
[171] Ex. SCG-04 (Gonzalez) at pp. 3, 5, 20, Attachment A at p. 1.
[172] Ex. ORA-03 (Yunge) at p. 6; Hearing Transcript at p. 292:4-12.
[173] MON, Ex. D at pp. 2-4 (A.16-09-005, Ex. ORA-02 (N. Stannik) ORA Prepared Testimony Regarding System-Wide Average Hydrotesting Costs). ORA proposes a cap of $1.216 million/mile, but in A.16-09-005, Applicants' second PSEP reasonableness review, ORA proposed a system average cost of hydrotesting – based on its calculation of Applicants' actual costs of hydrotesting – of $1.85 million/mile. *Id.*
[174] *Id.* at p. 2.

achieve that objective by depriving Applicants of the ability to recover the reasonable costs of executing Commission-mandated safety enhancement work.

b. TURN/SCGC's Comparative Analysis Is Flawed.

In TURN/SCGC's analysis of replacement projects, Ms. Yap considers pipeline diameter;[175] length;[176] geographic terrain;[177] and urban versus rural, or mixed urban-and-rural (as allowed by her limited database of twenty-nine projects[178]).[179] For her analysis of hydrotest projects, she does not make any of the foregoing distinctions and furthermore excludes the projects that are most like the Line 2000-C and 2000-D projects in this proceeding and include capital costs for replacement work.[180]

Although TURN/SCGC's witness considers more than a mere two attributes, her methodology is flawed. For example, Ms. Yap uses two projects (Line 235 Sawtooth Canyon and Line 1011) as comparisons for the Line 36-1001/45-1001 replacement project in this proceeding. However, no engineering or design comparison was done among the projects to determine whether they are reasonable comparisons to the subject project.[181] In fact, these are not suitable projects for comparison. The Line 235 Sawtooth Canyon project did not have the construction challenges that the Line 36-1001/45-1001 project is expected to face due to its topography,[182] and the Line 1011 project is a mere 405 feet and thus, is not representative of the approximately 1.6-mile subject project.[183] Moreover, even the comparison projects used by Ms. Yap show a wide disparity of costs, ranging from $5.8 million to $14.3 million.[184] There are

[175] Ex. TURN/SCGC-01 (Yap) at p. 7. Hearing Transcript at p. 135: 7 – 15.
[176] Ex. TURN/SCGC-01 (Yap) at pp. 6-7.
[177] Ex. TURN/SCGC-01 (Yap) at p. 7.
[178] Ex. TURN/SCGC-01 (Yap) at p. 6. Although there are 29 projects in her database, Ms. Yap uses only 1-5 projects to compare to each project in this proceeding. Ex. TURN/SCGC-01 (Yap) at pp. 10-17; Ex. SCG-04 (Gonzalez) at p. 18.
[179] Ex. TURN/SCGC-01 (Yap) at pp. 8-11.
[180] Ex. TURN/SCGC-01 (Yap) at p. 14. In this respect, the projects in Ms. Yap's hydrotest database are similar to the PG&E projects in ORA's database, i.e., sufficiently different by excluding capital costs so as to prevent an apples-to-apples comparison with Applicants' projects which have capital components. Ex. SCG-10 at pp. WP-II-A98, WP-II-A109.
[181] Ex. SCG-04 (Gonzalez) at p. 6.
[182] Ex. SCG-04 (Gonzalez) at p. 6.
[183] Ex. SCG-04 (Gonzalez) at p. 6.
[184] Ex. TURN/SCGC-01, Attachments B-G at pp. 26-28.

countless other variables that were not considered by Ms. Yap. In any event, Applicants maintain that comparisons between projects should not be made because it would be impossible to match up all the different variables to yield a result sufficient for ratemaking purposes.[185]

Cost drivers are not limited to pipeline diameter, length, urban versus rural environment, and geographic terrain. They come in many forms: soil conditions,[186] installation requirements (the means and methods of installation details),[187] permitting conditions,[188] environmental consideration and mitigation,[189] and underground facility density.[190] Construction duration typically has the largest impact on overall project cost, and even projects of similar lengths and diameter can have drastically different construction durations depending on factors such as population density, permitting conditions, etc.[191] These and many other factors were considered by Applicants and were assigned costs by experienced professionals in the detailed cost estimates prepared by Applicants.[192] Neither TURN/SCGC nor ORA considered these factors. Recognizing the unique attributes individually, for each specific project, is more likely to result in a robust estimate than relying on a small set of completed projects that share two-to-four similar attributes.

In tying their proposed funding levels to historical projects, both ORA and TURN/SCGC fail to account for the fact that a project can be very unlike the projects that came before it. This is illustrated in Ms. Yap's analysis of the two hydrotest projects, Lines 2000-C and 2000-D. She compares them to a 14.571-mile project tested in three segments; a 2.998-mile project tested in two segments; and a 15.195-mile project tested in ten segments.[193] These are not comparable to the Line 2000-C project (22.943 miles tested in 16 segments coupled with replacement work)[194] or the Line 2000-D project (14.038 miles tested in 15 segments coupled with replacement

---

[185] Ex. SCG-04 (Gonzalez) at p. 6.
[186] Ex. SCG-04 (Gonzalez) at pp. 7-8.
[187] Ex. SCG-04 (Gonzalez) at p. 8.
[188] Ex. SCG-04 (Gonzalez) at pp. 8-9.
[189] Ex. SCG-04 (Gonzalez) at p. 9.
[190] Ex. SCG-04 (Gonzalez) at pp. 9-10.
[191] Ex. SCG-04 (Gonzalez) at p. 21.
[192] Ex. SCG-19-C.
[193] Ex. TURN/SCGC-01 (Yap) at p. 16.
[194] Ex. SCG-10 at p. WP-II-A97.

work).[195] If anything, the two hydrotest projects in this proceeding are more similar to each other; yet even their costs per mile vary significantly: Line 2000-D amounts to $2.5MM/mile while Line 2000-C amounts to $1.4MM/mile. Attributes other than length drive costs and, moreover, it has been demonstrated that length is *not* necessarily correlated to cost.[196]

V. TWO-WAY BALANCING ACCOUNT TREATMENT COMPORTS WITH THE COMMISSION'S SAFETY ENHANCEMENT OBJECTIVES AND IS FAIR AND REASONABLE

Applicants seek two-way balancing account treatment, on an aggregate basis, for costs incurred in executing the twelve projects in the Application. This is consistent with the Commission's decision to order two-way balancing account treatment of costs incurred in executing Phase 1.[197] The Commission implemented balancing account treatment in order "to strike a fair balance between ratepayers and shareholders."[198] While the Commission ordered certain disallowances – activities and items for which Applicants would bear costs rather than ratepayers[199] – the Commission was clear that ratepayers should bear the reasonable costs of implementing PSEP that have not been disallowed:

> *This decision does not propose or adopt any penalty for SDG&E or SoCalGas*. We do however identify certain costs that should be absorbed by shareholders instead of ratepayers. Consistent with long-standing ratemaking principles, ratepayers will generally bear the reasonable costs for a safe and reliable natural gas transmission system.[200]

ORA does not oppose balancing account treatment for capital costs or the costs associated with the replacement, de-rate, or abandonment projects in this proceeding.[201] This is consistent with the reasonable position stated by ORA's expert, Mr. Stannik:

> As far as what the projects will ultimately cost, no one knows for certain what those will cost, not me, not anyone here. It won't be 100 percent certain until those are

---

[195] Ex. SCG-10 at p. WP-II-A108.
[196] Ex. SCG-04 (Gonzalez) at pp. 15-16; s*ee also* Ex. SCG-19-C.
[197] D.14-06-007, mimeo., at p. 60 (Ordering Paragraph 4).
[198] D.14-06-007, mimeo, at pp. 19, 22.
[199] D.14-06-007, mimeo., at pp. 32-34, as modified by D.15-12-020.
[200] D.14-06-007, mimeo., at p. 31.
[201] Hearing Transcript at pp. 308:22 – 309:20.

> done. So I wouldn't want to say I know for sure or I can even be quite sure exactly what those are going to cost when they're completed because no one can.[202]

ORA's request for a one-way downward balancing account for the O&M costs of hydrotesting is inconsistent with this testimony by ORA's own witness.[203] Indeed, no one can know what the actual costs of the twelve projects will be; therefore, the only way to implement the Commission's intent for ratepayers to "bear the reasonable costs for a safe and reliable natural gas transmission system"[204] is to allow two-way balancing account treatment.

Both ORA's proposal for a one-way downward balancing account and TURN/SCGC's proposal for no regulatory accounting treatment whatsoever are contrary to the Commission's prior PSEP decision in that they act as a penalty against Applicants and do not allow for reasonable costs of implementing PSEP to be paid by ratepayers. The need for and fairness of balancing account treatment is best illustrated by a scenario currently pending on a project included in this proceeding. The permitting agency, Caltrans, has informed Applicants that it will require a change in scope on the Line 36-37 Section 11 project.[205] Caltrans determined that the planned method for replacement – the standard practice of laying the replacement line parallel to the existing line and subsequently abandoning the old line in place – would not be permitted, and instead the old line would need to be excavated and removed completely.[206] Although Applicants will negotiate this permit condition, if they are not successful and must implement Caltrans' scope of work, the cost of this project is anticipated to increase by approximately $8 million.[207] Although aware of this pending scenario, no Intervenor has offered a proposal for dealing with this type of unexpected cost increase. Without a two-way balancing account, Applicants would have to absorb this cost – effectively a penalty, which the Commission explicitly stated was not intended.[208]

---

[202] Hearing Transcript at pp. 328:26 – 329:5.
[203] Hearing Transcript at pp. 308:22 – 309:20.
[204] D.14-06-007, mimeo., at p. 31.
[205] Ex. SCG-04 (Gonzalez) at p. 22.
[206] Ex. SCG-04 (Gonzalez) at p. 22.
[207] Ex. SCG-04 (Gonzalez) at p. 22.
[208] D.14-06-007 at p. 31.

Moreover, even if Intervenors' assertion that Applicants' forecasted costs are unreasonable were to be accepted, under such a scenario the Commission authorizes two-way balancing accounting treatment. In D.14-06-007, the Commission stated:

> A balancing account is an appropriate regulatory tool where the scope of work is known and accepted as is here, Safety Enhancement as described by the Decision Tree and elsewhere in testimony by SDG&E and SoCalGas, etc., and we find it to be a sufficient project scope; but there is not a reasonable forecast of cost.[209]

There is no support for Intervenors' proposals to deviate so significantly from the Commission's prior PSEP decisions.[210]

To the extent certain Intervenors have concerns that a two-way balancing account constitutes a "blank check,"[211] there is an oversight mechanism available that the Commission previously has approved in connection with Applicants' safety and integrity management programs:[212] two-way balancing account treatment of all costs incurred, and costs exceeding the Commission-authorized level may be recovered only after they are reviewed for reasonableness through an advice letter filing. In this way, Intervenors (and any other interested party) may review costs exceeding authorized levels and state their objections, if any; and Applicants have an opportunity to recover their actual costs in executing Commission-mandated safety enhancement work.

In order to implement two-way balancing account treatment for the twelve projects in this Application on an aggregate basis, and to appropriately track the revenue requirement associated with the costs of executing the twelve Phase 1B and Phase 2A projects separately, Applicants propose the following for each of SoCalGas and SDG&E:

---

[209] D.14-06-007, mimeo., at pp. 26-27.

[210] Moreover, if Intervenors want to modify the Commission's prior grant of two-way balancing account treatment for Phase 1, the appropriate procedural mechanism for doing so is a Petition for Modification pursuant to Rule 16.3 of the Commission's Rules of Practice and Procedure.

[211] Hearing Transcript at p. 180:10-20.

[212] In a decision on Applicants' general rate case, the Commission ordered two-way balancing account treatment for the Transmission Pipeline Integrity Program and Distribution Pipeline Integrity Management Program and required costs incurred in excess of the authorized amounts to be subject to recovery through the advice letter process. D.13-05-010, mimeo., at pp. 1053-1057. TURN agreed to the same treatment (in a settlement) in the next GRC, and the Commission so ordered. D.16-06-054, mimeo., at pp. 26, 95-96, 293 (Findings of Fact 59, 60), 310 (Finding of Fact 196), 324 (Conclusion of Law 76).

- subdivide the existing SECCBA accounts into two subaccounts so as to track costs for Phases 1A and 1B separately: SECCBA Phase 1A Subaccount and SECCBA Phase 1B Subaccount;[213]
- subdivide the existing SEEBA accounts into the two subaccounts so as to track costs for Phases 1A and 1B separately: SEEBA Phase 1A Subaccount and SEEBA Phase 1B Subaccount;[214] and
- create two new balancing accounts for Phase 2 – SECCBA-P2 and SEEBA-P2.[215]

Costs currently tracked in the PSEPMAs (i.e., the costs associated with Phase 2 planning, engineering, and design work that were authorized to be tracked in the memorandum accounts) should be transferred into the latter new balancing accounts.[216]

VI. THE ASSOCIATED REVENUE REQUIREMENT AND COST ALLOCATION SHOULD BE AUTHORIZED

The cumulative forecasted 2019 revenue requirement associated with completion of the twelve projects in the Application is approximately $44.6 million for SoCalGas and $562,000 for SDG&E.[217] The capital and O&M costs forecasted include GMAs (as described further in Section IV.B.2), overhead (indirect costs), escalation, and other necessary costs to support the investment during construction and over its useful life.[218] Overhead costs are costs that indirectly support the business operations of SoCalGas and SDG&E and are included for cost recovery.[219] The revenue requirement calculation assumes all capital costs, including direct costs, overhead, escalation, and Allowance for Funds Used during Construction ("AFUDC"), are recovered through depreciation over the current authorized book-life of the assets.[220] In addition to all incremental capital and O&M expenditures, the total revenue requirement for the twelve

[213] Ex. SCG-07 (Austria) at pp. 1-2.
[214] Ex. SCG-07 (Austria) at pp. 1-2.
[215] Ex. SCG-07 (Austria) at pp. 2-3.
[216] Ex. SCG-07 (Austria) at p. 3; D.16-08-003 at p. 14 (Ordering Paragraph 1).
[217] These amounts exclude franchise fees and uncollectibles.
[218] Ex. SCG-06 (Chan) at pp. 1-3.
[219] Ex. SCG-06 (Chan) at pp. 1-3.
[220] Ex. SCG-06 (Chan) at pp. 1-3.

projects includes other costs required to support the investment, such as the authorized return on investment, taxes, and franchise fees and uncollectibles.[221]

Since the balancing accounts would record the forecasted revenue requirements adopted in the Commission's decision in this proceeding, the accounts would reflect a credit for the forecasted revenue requirements.[222], [223]

A true-up of balances would be addressed in Applicants' annual regulatory account balance update advice letter filing for gas transportation rates effective January 1 of the following year.[224] Any over and under-collections in these balancing accounts that are permanent differences are incorporated in the following year's gas transportation rates. If there are any over- or under-collections in these balancing accounts that are attributable to timing differences rather than permanent differences, the balances would be carried over to the following year and not incorporated in the following year's gas transportation rates.[225] For the capital cost related PSEP balancing accounts (i.e., Phase 1B Subaccounts of the SECCBAs and the SECCBA-P2 accounts), these accounts will continue to balance, on an aggregate project basis, the difference between actual and forecasted capital-related revenue requirements until the Phase 1B and Phase 2 PSEP assets are rolled into authorized rate base in connection with the Applicants' next General Rate Case.[226]

In accordance with D.14-06-007, PSEP costs are to be allocated consistent with the existing cost allocation and rate design for SoCalGas and SDG&E, including allocation to the backbone function.[227] In D.16-12-063, the decision on the first PSEP reasonableness review

---

[221] Ex. SCG-06 (Chan) at pp. 1-3. The fully loaded and escalated costs, as well as the forecasted revenue requirement, are shown at Tables 1 and 2. Id.
[222] Ex. SCG-07 (Austria) at p. 3.
[223] For Phase 1B projects, to the extent any planning and engineering design costs were previously incurred or the 50% interim cost recover authorized by D.16-08-003 was realized and recorded to the existing SEEBAs and SECCBAs, these costs and revenues would be properly allocated to the new Phase 1A and Phase 1B Subaccounts. Unlike the Phase 1A Subaccounts, the Phase 1B Subaccounts would reflect a credit for the forecasted revenue requirements associated with the Phase 1B projects, less any amounts already collected. Ex. SCG-07 (Austria) at p. 3.
[224] Ex. SCG-07 (Austria) at p. 6.
[225] Ex. SCG-07 (Austria) at p. 6.
[226] Ex. SCG-07 (Austria) at p. 6.
[227] D.14-06-007, mimeo., at p. 50 (Ordering Paragraph 9).

filed by Applicants, the Commission clarified that PSEP costs functionalized as high pressure distribution should be allocated using the existing marginal demand measures for high pressure distribution costs.[228] As such, SoCalGas and SDG&E propose to allocate the account balances on a functional basis.

Once the Commission authorizes rate recovery in a decision, SoCalGas and SDG&E will file preliminary statements to modify and create the regulatory accounts proposed by them.[229]

Applicants propose to file Tier 1 Advice Letters within 30 days of the effective date of the decision to update the revenue requirements authorized by the Commission, including the effects of the Tax Cuts and Jobs Act ("Tax Act") and Cost of Capital Update, and incorporate the first year's annual updated revenue requirement into rates on the first day of the month following advice letter approval or in connection with the timing of other authorized changes in the utilities' gas transportation rates.[230] If rates are implemented on a date other than January 1st of the year, the annual revenue requirement incorporated in rates will be grossed-up to ensure recovery of the first year's authorized amount by the end of the year. The annual revenue requirements for subsequent years will be incorporated in rates in connection with SoCalGas and SDG&E's consolidated rate update filing for rates effective January 1st of each year until such revenue requirements are incorporated in SoCalGas and SDG&E's next general rate case proceeding.

VII. THE PHASE 2A DECISION TREE SHOULD BE APPROVED

Applicants seek approval of their Phase 2A Decision Tree,[231] which follows the logic of the Decision Tree principles previously approved by the Commission for Phase 1 in D.14-06-007.[232] The Phase 2A Decision Tree uses a step-by-step analysis to determine whether pipeline segments should be tested or replaced. First, pipeline segments are allocated into three

---

[228] D.16-12-063, mimeo., at p. 59 (Conclusion of Law 24).
[229] Ex. SCG-07 (Austria) at pp. 6-7.
[230] On December 22, 2017, President Trump signed the Tax Act into law, which became effective on January 1, 2018. SoCalGas and SDG&E's cost of capital was updated and authorized by D.17-07-005 effective January 1, 2018.
[231] Ex. SCG-01 (Mejia) at pp. 10-13.
[232] D.14-06-007, mimeo., at p. 59 (Ordering Paragraph 1).

categories: (1) 1,000 feet or less; (2) greater than 1,000 which can be removed from service for pressure testing; and (3) greater than 1,000 which cannot be removed from service for pressure testing without significantly impacting customers.[233] Then segments are further analyzed to identify other factors that may impact a determination of whether to pressure test or replace the segment.[234]

The Phase 2A Decision Tree analysis is based on certain principles used to guide the test-versus-replace decision: SoCalGas and SDG&E will not interrupt service to their core customers in order to pressure test a pipeline; SoCalGas and SDG&E will work with noncore customers to determine if an extended outage is possible; SoCalGas and SDG&E will, where necessary, temporarily interrupt noncore customers as provided for in their tariffs; SoCalGas and SDG&E will work with noncore customers to plan, where possible, service interruptions during scheduled maintenance, down time or off-peak seasons; and SoCalGas and SDG&E will consider cost and engineering factors along with the improvement of the pipeline asset.[235] It is important to note that no industry-wide standard exists that balances the risk of a pipeline failure with the cost of testing or replacing.[236] Because of their engineering expertise and knowledge of the pipelines they operate, the utilities are in the best position to make this determination on a project-by-project basis.[237] Moreover, Intervenors have been afforded an opportunity to review the Phase 2A Decision Tree and SoCalGas and SDG&E's application of the Phase 2A Decision Tree principles to the projects in this proceeding and have objected to neither.

VIII. CONCLUSION

The record establishes by a preponderance of the evidence that SoCalGas and SDG&E's requested revenue requirement is based on reasonable cost forecasts derived from detailed project-specific engineering, design and planning activities, and founded upon their knowledge and experience in implementing PSEP. The Commission expressly determined Applicants

[233] Ex. SCG-01 (Mejia) at p. 11.
[234] Ex. SCG-01 (Mejia) at p. 11-13.
[235] Ex. SCG-01 (Mejia) at p. 12.
[236] Ex. SCG-01 (Mejia) at p. 12.
[237] Ex. SCG-01 (Mejia) at p. 12.

should be authorized to recover the reasonable costs incurred to implement the safety enhancement work ordered by the Commission (less certain Commission-ordered disallowances). Furthermore, because there are always unknowns in construction, it is both fair and reasonable to both ratepayers and Applicants to authorize balancing account treatment of Phase 2 PSEP costs so that ratepayers pay no more than the actual costs of implementing the PSEP projects, and Applicants are able to recover the reasonable costs incurred to complete safety enhancement work. Intervenors' proposals to deprive Applicants of the ability to seek recovery of the full costs of safety enhancement work, no matter how reasonable those costs may be, are inconsistent with the Commission's safety enhancement objectives and unreasonable. Based on the foregoing, the Commission should grant the relief and recovery set forth herein and in the Summary of Recommendations.

Respectfully submitted on behalf of SoCalGas and SDG&E,

By: *<u>/s/ Avisha A. Patel</u>*
Avisha A. Patel

AVISHA A. PATEL

Attorney for:
SOUTHERN CALIFORNIA GAS COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
555 West Fifth Street, GT-14E7
Los Angeles, California 90013
Telephone: (213) 244-2954
Facsimile: (213) 629-9620
E-mail: APatel@semprautilities.com

March 26, 2018