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) 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	Application 16-09-005 (Filed on September 2, 2016)

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

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Legal Standards

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Compliance

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4. Find SoCalGas and SDG&E calculated the system average cost of pressure testing pipelines consistent with Decision ("D.") 14-06-007;

5. Find all disallowances set forth in Decision D.14-06-007 were properly calculated by Applicants;

6. Find all disallowances were properly excluded;

7. Find SoCalGas and SDG&E properly reconciled "as-filed" mileage with actual mileage addressed in the projects that are the subject of this proceeding;

SoCalGas and SDG&E's Pipeline Safety Enhancement Plan

8. Find that SoCalGas and SDG&E implemented reasonable oversight and control of their PSEP activities;

9. Find that SoCalGas and SDG&E appropriately followed their Decision Tree process;

10. Find that SoCalGas and SDG&E's retention of external contractor personnel to augment internal company personnel was a reasonable means to complete safety enhancement as soon as practicable;

11. Find that SoCalGas and SDG&E implemented reasonable resource management (contracting and procurement) practices to promote cost-effective safety enhancement;

12. Find that SoCalGas and SDG&E's Performance Partnership Program is a reasonable means to engage construction contractors;

13. Find that SoCalGas and SDG&E implemented reasonable processes to track and verify PSEP costs;

14. Find that the Seven Stage Review Process is a reasonable means to manage PSEP projects efficiently and effectively;

15. Find that SoCalGas and SDG&E acted as reasonable managers in prudently planning and executing the twenty-six pipeline projects presented in this proceeding;

16. Find SoCalGas and SDG&E acted as reasonable managers in addressing the accelerated mileage presented in this proceeding;

17. Find SoCalGas and SDG&E acted as reasonable managers in addressing the incidental mileage presented in this proceeding;

18. Find that SoCalGas and SDG&E acted as reasonable managers in prudently planning and executing the fifteen bundled valve projects presented in this proceeding as part of the Valve Enhancement Plan;

19. Find that SoCalGas and SDG&E acted as reasonable managers in prudently planning and implementing two methane-sensing pilot projects (one for each of SoCalGas and SDG&E) as part of the Technology Plan;

Costs Recorded to Pipeline Safety and Reliability Memorandum Accounts, Safety Enhancement Expense Balancing Accounts, and Safety Enhancement Capital Cost Balancing Accounts

20. Find the safety enhancement costs presented for review in this proceeding by SoCalGas and SDG&E in Table 1 herein – in total, the fully loaded amount of $194,831,156 ($134,168,709 capital and $60,662,447 operations and maintenance) – were necessary and reasonably and prudently incurred;

21. Find reasonable the company overheads applied by SoCalGas and SDG&E to PSEP costs;

22. Find reasonable the costs incurred to obtain PSEP-specific insurance (Owner Controlled Insurance Program and Professional Liability).

23. Find reasonable the General Management and Administration costs incurred in the course of executing PSEP;

24. Find reasonable and approve for cost recovery $6,476,402 associated with the Line 1005 replacement project;

25. Find reasonable and approve for cost recovery $2,656,749 associated with the Line 1011 replacement project;

26. Find reasonable and approve for cost recovery $2,737,981 associated with the Line 1013 replacement project;

27. Find reasonable and approve for cost recovery $927,812 associated with the Line 1014 replacement project;

28. Find reasonable and approve for cost recovery $5,722,269 associated with the Line 1015 (North and South) pressure test project;

29. Find reasonable and approve for cost recovery $24,838,832 associated with the Line 2000 West Sections 1, 2, and 3 pressure test project;

30. Find reasonable and approve for cost recovery $822,206 associated with the Line 2001 West A Sections 15 and 16 replacement project;

31. Find reasonable and approve for cost recovery $13,025,271 associated with the Line 2001 West B Sections 10, 11, and 14 pressure test and replacement project;

32. Find reasonable and approve for cost recovery $9,610,893 associated with the Line 2003 Sections 1, 3, and 4 pressure test and replacement project;

33. Find reasonable and approve for cost recovery $2,050,065 associated with the Line 235 West Sawtooth Canyon replacement project;

34. Find reasonable and approve for cost recovery $7,634,170 associated with the Line 33-120 Section 2 replacement project;

35. Find reasonable and approve for cost recovery $284,661 associated with the Line 35-20-N replacement project;

36. Find reasonable and approve for cost recovery $1,202,276 associated with the Line 36-37 replacement project;

37. Find reasonable and approve for cost recovery $2,566,211 associated with the Line 36-9-09 North Section 2B pressure test project;

38. Find reasonable and approve for cost recovery $2,785,427 associated with the Line 36-9-09-North Section 6A pressure test project;

39. Find reasonable and approve for cost recovery $10,953,327 associated with the Line 36-1032 Sections 1, 2, and 3 replacement project;

40. Find reasonable and approve for cost recovery $16,915,804 associated with the Line 38-539 replacement project;

41. Find reasonable and approve for cost recovery $10,475,451 associated with the Line 406 Sections 1, 2, 2A, 4, and 5 pressure test and replacement project;

42. Find reasonable and approve for cost recovery $6,967,415 associated with the Line 407 (North and South) pressure test project;

43. Find reasonable and approve for cost recovery $483,725 associated with the Line 41-30-A replacement project;

44. Find reasonable and approve for cost recovery $6,418,206 associated with the Line 45-120 Section 1 replacement project;

45. Find reasonable and approve for cost recovery $857,395 associated with the Line 45-120XO1 replacement project;

46. Find reasonable and approve for cost recovery $5,336,370 associated with the Play Del Rey Storage Phases 4 and 5 pressure test project;

47. Find reasonable and approve for cost recovery $1,157,969 associated with the Arrow & Haven valve bundle project;

48. Find reasonable and approve for cost recovery $1,063,539 associated with the Bain Street valve bundle project;

49. Find reasonable and approve for cost recovery $295,027 associated with the Brea valve bundle project;

50. Find reasonable and approve for cost recovery $1,237,040 associated with the Chino valve bundle project;

51. Find reasonable and approve for cost recovery $805,126 associated with the Haskell valve bundle project;

52. Find reasonable and approve for cost recovery $616,166 associated with the Moreno - Large valve bundle project;

53. Find reasonable and approve for cost recovery $861,101 associated with the Moreno - Small valve bundle project;

54. Find reasonable and approve for cost recovery $1,549,003 associated with the Pixley valve bundle project;

55. Find reasonable and approve for cost recovery $1,411,385 associated with the Prado valve bundle project;

56. Find reasonable and approve for cost recovery $19,486 associated with the Puente valve bundle project;

57. Find reasonable and approve for cost recovery $813,358 associated with the Santa Fe Springs valve bundle project;

58. Find reasonable and approve for cost recovery $5,783,560 associated with the SGV Fern and Walnut valve bundle project;

59. Find reasonable and approve for cost recovery $1,734,650 associated with the Victoria valve bundle project;

60. Find reasonable and approve for cost recovery $815,990 associated with the Whitewater valve bundle project;

61. Find reasonable and approve for cost recovery $13,556,637 associated with the Palmdale with Line 235 and Supply Line 44-654 valve bundle project;

62. Find reasonable and approve for cost recovery $1,157,969 associated with the Arrow & Haven valve bundle project;

63. Find reasonable and approve for cost recovery $4,702,224 associated with the Line 49-14 replacement project;

64. Find reasonable and approve for cost recovery $5,034,329 associated with the Line 49-22 abandonment project;

65. Find reasonable and approve for cost recovery $4,393,207 associated with the Line 49-32 replacement project;

66. Find reasonable and approve for cost recovery $358,080 associated with SoCalGas' methane-sensing pilot equipment that is part of its Technology Plan;

67. Find reasonable and approve for cost recovery $5,552,621 associated with SoCalGas' facilities lease;

68. Find reasonable and approve for cost recovery $199,000 associated with descoped projects;

69. Find reasonable and approve for cost recovery $320,539 associated with post-completion adjustment costs associated with projects approved for rate recovery in D.16-12-063;

70. Find reasonable and approve for cost recovery $117,059 associated with SDG&E's methane-sensing pilot equipment that is part of its Technology Plan;

71. Find reasonable and approve for cost recovery $685,142 associated with SDG&E's facilities lease;

Revenue Requirement and Cost Allocation

72. Approve recovery of revenue requirements as follows: $67.5 million for SoCalGas and $2.6 million for SDG&E;

73. Find that SoCalGas and SDG&E correctly have allocated costs consistent with the existing cost allocation and rate design, including allocation to the backbone function;

74. Find that SoCalGas and SDG&E correctly have allocated 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;

75. Approve SoCalGas and SDG&E's request to file Tier 1 Advice Letters within thirty days from the effective date of the decision in this proceeding in order to update the revenue requirements authorized by the Commission, including regulatory account interest, and incorporate the updated revenue requirements into rates on the first day of the next month following advice letter approval or in connection with the timing of other authorized changes in Applicants' gas transportation rates; and

76. Approve SoCalGas and SDG&E's request to file Tier 2 Advice Letters to incorporate into rates future-year revenue requirements associated with reasonably incurred capital expenditures approved in this proceeding.

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Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the Amended Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling dated April 24, 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 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 September 2, 2016 ("Application").

I. INTRODUCTION.

Through this Application, SoCalGas and SDG&E seek review of costs incurred by them to prudently execute 26 pipeline projects, 15 bundled valve projects, and two methane-sensing equipment pilot projects under their Commission-approved pipeline safety enhancement plan

[1] Amended Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling dated April 24, 2017 ("Scoping Memo") at p. 7.

("PSEP"), as mandated by the Commission and the State of California.[2] This is Applicants' second after-the-fact reasonableness review application[3] and seeks cost recovery for some of the earliest projects initiated in PSEP. Each of the projects was executed with prudent oversight and management by experienced professionals; and costs were monitored, tracked, and properly recorded to the interim memorandum accounts and subsequently transferred to the balancing accounts authorized in the Commission's decision approving the PSEP.[4] "It is a matter of fundamental utility ratemaking that utilities recover all just and reasonable costs of providing utility service,"[5] and thus, recovery in rates of the following reasonably incurred safety enhancement costs should be authorized:

Table 1

	Completed Project / Cost Category	Project Type	Capital Costs (Fully Loaded)	O&M Costs (Fully Loaded)	Total Costs (Fully Loaded)
1.	Line 1005	Replace	$6,476,402		$6,476,402
2.	Line 1011	Replace	$2,656,749		$2,656,749
3.	Line 1013	Replace	$2,737,981		$2,737,981
4.	Line 1014	Replace	$927,812		$927,812
5.	Line 1015 (North and South)	Test	$480,991	$5,241,278	$5,722,269
6.	Line 2000 West Sections 1, 2, 3	Test	$8,435,767	$16,403,065	$24,838,832
7.	Line 2001 West A Sections 15, 16	Replace	$822,206		$822,206
8.	Line 2001 West B Sections 10, 11, 14	Test/Replace	$4,552,781	$8,472,490	$13,025,271
9.	Line 2003 Sections 1, 3, 4	Test/Replace	$7,018,826	$2,592,067	$9,610,893
10.	Line 235 West Sawtooth Canyon	Replace	$2,050,065		$2,050,065
11.	Line 33-120 Section 2	Replace	$7,634,170		$7,634,170
12.	Line 35-20-N	Replace	$284,661		$284,661
13.	Line 36-37	Replace	$1,202,276		$1,202,276
14.	Line 36-9-09 North Section 2B	Test		$2,566,211	$2,566,211
15.	Line 36-9-09 North Section 6A	Test		$2,785,427	$2,785,427
16.	Line 36-1032 Sections 1, 2, 3	Replace	$10,953,327		$10,953,327

[2] Decision ("D.") 11-06-017, mimeo., at p. 31; Pub. Util. Code §§ 957, 958.
[3] The Commission authorized rate recovery in the Applicants' first after-the-fact reasonableness review in D.16-12-063.
[4] Ex. SCG-10 (Pech) at p. 5; Ex. SCG-13 (Austria) at p. 1.
[5] D.16-05-024, mimeo., at p. 3, citing Pub. Util. Code § 451.

17.	Line 38-539	Replace	$16,915,804		$16,915,804
18.	Line 406 Sections 1, 2, 2A, 4, 5	Test/Replace	$7,255,313	$3,220,138	$10,475,451
19.	Line 407 (North and South)	Test	$536,711	$6,430,704	$6,967,415
20.	Line 41-30-A	Replace	$483,725		$483,725
21.	Line 45-120 Section 1	Replace	$6,418,206		$6,418,206
22.	Line 45-120XO1	Replace		$857,395	$857,395
23.	Playa Del Rey Storage Phases 4, 5	Test		$5,336,370	$5,336,370
24.	Arrow & Haven Valve Bundle	Valve	$1,157,969		$1,157,969
25.	Bain Street Valve Bundle	Valve	$1,063,539		$1,063,539
26.	Brea Valve Bundle	Valve	$295,027		$295,027
27.	Chino Valve Bundle	Valve	$1,237,040		$1,237,040
28.	Haskell Valve Bundle	Valve	$805,126		$805,126
29.	Moreno – Large Valve Bundle	Valve	$616,166		$616,166
30.	Moreno – Small Valve Bundle	Valve	$861,101		$861,101
31.	Pixley Valve Bundle	Valve	$1,549,003		$1,549,003
32.	Prado Valve Bundle	Valve	$1,411,385		$1,411,385
33.	Puente Valve Bundle	Valve	$19,486		$19,486
34.	Santa Fe Springs Valve Bundle	Valve	$813,358		$813,358
35.	SGV Fern and Walnut Valve Bundle	Valve	$5,783,560		$5,783,560
36.	Victoria Valve Bundle	Valve	$1,734,650		$1,734,650
37.	Whitewater Valve Bundle	Valve	$815,990		$815,990
38.	Palmdale with Line 235 and Supply Line 44-654 Valve Bundle	Replace/Valve	$13,556,637		$13,556,637
39.	Methane-Sensing Equipment Pilot	N/A	$358,080		$358,080
40.	Facilities Lease (SoCalGas)	N/A		$5,552,621	$5,552,621
41.	Descoped Projects	N/A		$199,000	$199,000
42.	Post-Completion Cost Adjustments	N/A		$320,539	$320,539
	SoCalGas Total		**$119,921,890**	**$59,977,305**	**$179,899,195**
1.	Line 49-14	Replace	$4,702,224		$4,702,224
2.	Line 49-22	Abandonment	$5,034,329		$5,034,329
3.	Line 49-32	Replace	$4,393,207		$4,393,207
4.	Methane-Sensing Equipment Pilot	N/A	$117,059		$117,059
5.	Facilities Lease (SDG&E)	N/A		$685,142	$685,142
	SDG&E Total		**$14,246,819**	**$685,142**	**$14,931,961**
	GRAND TOTAL		$134,168,709	$60,662,447	$194,831,156

These costs, after applicable exclusions and disallowances, result in a calculated revenue requirement of $67.5 million for SoCalGas and $2.6 million for SDG&E.

II. PROCEDURAL BACKGROUND.

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

The PSEP grew out of 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."[6] In March 2011, Assigned Commissioner Florio 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.[7]

As a result, 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.[8] The Implementation Plan was to address all natural gas transmission pipeline,[9] and was to "address retrofitting pipelines to allow for in-line inspection tools and, where appropriate, automated or remote controlled shut off valves."[10]

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[6] Rulemaking ("R.") 11-02-019, mimeo., at p. 1.
[7] 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.
[8] D.11-06-017, mimeo., at pp. 18-19.
[9] D.11-06-017, mimeo., at p. 20.
[10] D.11-06-017, mimeo., at p. 21.

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

In D.14-06-007, the Commission approved SoCalGas and SDG&E's proposed Implementation Plan – the PSEP – but did not pre-approve the costs of implementing PSEP.[11] In so doing, the Commission approved the proposed 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.[12] 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") (these are sometimes referred to as "criteria" miles).[13] Phase 1B encompasses replacement of non-piggable pipelines that were installed prior to 1946.[14] Pipeline in less populated areas are to be addressed in Phase 2.[15] Phase 2 includes pipeline in less populated areas without record of a pressure test, or without record of a pressure test to 1.25 MAOP ("Phase 2A");[16] and 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,

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[11] 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.

[12] D.14-06-007, mimeo., at pp. 2-3, 14, 59 (Ordering Paragraph 1).

[13] Ex. SCG-02 (Phillips) at p. 4; Ex. SCG-03 (Phillips) at p. 6.

[14] Ex. SCG-03 (Phillips) at p. 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. R.11-02-019, Amended Pipeline Safety Enhancement Plan of Southern California Gas Company (U 904-G) and San Diego Gas & Electric Company (U 902-M) Pursuant to D.11-06-017, Requiring All California Natural Gas Transmission Operators To File a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan at p. 21.

[15] Ex. SCG-03 (Phillips) at p. 6.

[16] Ex. SCG-03 (Phillips) at p. 6.

Subpart J adopted in 1970 ("Phase 2B").[17] The Commission authorized Applicants to begin Phase 1 work as described in their PSEP and to record related costs in two-way balancing accounts subject to refund pending a subsequent reasonableness review.[18]

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."[19] 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."[20]

C. The Commission Established a Reasonableness Review Framework for Recovery of 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."[21] On May 18, 2012, the Pipeline Safety and Reliability Memorandum Accounts ("PSRMA") were created for SoCalGas and SDG&E, respectively, by Advice Letters 4359 and 2106-G.[22] Reasonable costs associated with planning and executing

[17] Ex. SCG-03 (Phillips) at p. 6.
[18] D.14-06-007, mimeo., at p. 59-60 (Ordering Paragraphs 3 and 4).
[19] D.14-06-007, mimeo., at p. 8.
[20] D.14-06-007, mimeo., at p. 8.
[21] D.12-04-021, mimeo., at p. 12 (Ordering Paragraph 3). D.12-04-021 also transferred SoCalGas and SDG&E's PSEP to the Applicants' Triennial Cost Allocation Proceeding – A.11-11-002 – and subsequently Applicants were authorized to continue to record and report on PSEP costs per the July 26, 2013 Administrative Law Judge's Ruling To Continue Tracking Interim Pipeline Safety Enhancement Plan Costs in Authorized Memorandum Accounts in A.11-11-002.
[22] *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.[23]

In D.14-06-007, rather than pre-approve cost recovery based on 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, the Commission adopted a process for reviewing and approving the reasonableness of PSEP implementation expenditures after-the-fact.[24]

To enable the after-the-fact review of PSEP costs, D.14-06-007 required SoCalGas and SDG&E to establish balancing accounts (the Safety Enhancement Expense Balancing Accounts ("SEEBA") to record Phase 1 operations and maintenance costs and the Safety Enhancement Capital Cost Balancing Accounts ("SECCBA")[25]) to record PSEP capital expenditures.[26] 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."[27]

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

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[23] D.12-04-021, mimeo., at p. 12 (Ordering Paragraph 3); D.14-06-007, mimeo., at p. 60 (Ordering Paragraph 4).

[24] D.14-06-007, mimeo., at pp. 2, 26, 60-61 (Ordering Paragraphs 5 and 6). The Commission did determine in D.14-06-007, however, that certain PSEP costs should be disallowed (*see* Section 6, "Ratemaking Principles to be Applied in Reasonableness Applications," at pp. 31-39).

[25] D.14-06-007, mimeo., at p. 60 (Ordering Paragraph 4). In A.17-03-021, Applicants' pending forecast application seeking to proceed with certain Phase 1B and Phase 2 projects, Applicants requested to sub-divide the SEEBAs and SECCBAs so as to record separately costs incurred for Phase 1A and those incurred for Phase 1B. A.17-03-021, Amended 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 at p. 14.

[26] 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.

[27] D.14-06-007, mimeo., at p. 39.

expenses were reasonable and consistent with the reasonable manager standard and granted the application.[28]

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 costs properly recorded in their respective SECCBAs, SEEBAs, and PSRMAs.[29] In addition, D.16-08-003 directed SoCalGas and SDG&E to file this Application[30] and established a framework and schedule for future reasonableness review applications.[31]

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

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;[32] (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;[33] (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

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[28] *See* D.16-12-063, granting A.14-12-016. The decision declined to authorize recovery of costs for PSEP-specific insurance (without prejudice to Applicants' ability to seek these costs in a future proceeding). *Id*. at 54.

[29] D.16-08-003, mimeo., at p. 16 (Ordering Paragraphs 2 and 3).

[30] D.16-08-003, mimeo., at p. 13 (Finding of Fact 6).

[31] In addition to the Application, D.16-08-003 also provides for an additional standalone application for after-the-fact review of the costs incurred to complete Phase 1A projects (which Applicants anticipate filing in 2018) and one forecast application for authorization to recover the costs of Phase 2 projects (A.17-03-021, which is currently pending); Phase 1A projects completed after the filing of these authorized applications, as well as remaining forecasted projects not included in the forecast application, are to be submitted for approval in the Test Year 2019 (TY 2019) and subsequent General Rate Cases.

[32] D.14-06-007, mimeo., at pp. 32-34, as modified by D.15-12-020.

[33] D.14-06-007, mimeo., at pp. 32-34, as modified by D.15-12-020.

the minimum then-applicable industry standards or regulations;[34] (d) Safety Enhancement incentive compensation for executives;[35] and (e) the cost of searching for pipeline test records.[36]

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

Protests to the Application were filed by The Utility Reform Network ("TURN"), the Office of Ratepayer Advocates ("ORA"), and Southern California Generation Coalition ("SCGC;" together with TURN and ORA, "Intervenors;" Intervenors and Applicants, together, "Parties"). As summarized in the Scoping Memo, the protests "adhered to a common theme: that the applicants have not met their burden of proving that the costs incurred are reasonable,"[37] and thus supplemental testimony should be required.

Pre-hearing conference statements were filed by Applicants and Intervenors, and a pre-hearing conference was held on February 10, 2017. At the pre-hearing conference, the Parties were ordered to meet-and-confer regarding two elements:

(i) Creation of a matrix wherein Intervenors identify the information they believe is missing from the Application and supporting testimony and workpapers; Applicants' response either identifying where the information is located or stating the information is not included; and Intervenors' reply as to why certain information that is not included is, or should be, required; and

(ii) The extent to which Phase 2B work should be considered within the scope of this proceeding.[38]

Following a meet-and-confer, the parties agreed that supplemental testimony would not be required.[39] With respect to Phase 2B, the parties agreed that cost recovery for Phase 2B work that is accelerated or incidental could be considered in this proceeding.[40]

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[34] D.14-06-007, mimeo., at p. 36, as modified by D.15-12-020.
[35] D.14-06-007, mimeo., at p. 38.
[36] D.14-06-007, mimeo., at p. 39.
[37] Scoping Memo at p. 2.
[38] *See* February 10, 2017 Pre-Hearing Conference, Transcript at pp. 28-29.
[39] Scoping Memo at p. 5.
[40] The Parties stipulated to the following:

On April 20, 2017, the assigned Commissioner, Carla J. Peterman, and assigned Administrative Law Judge ("ALJ"), Robert M. Mason III, issued a Scoping Memo and Ruling, and issued an amended Scoping Memo on April 24, 2017. In the Scoping Memo, the assigned Commissioner and ALJ agreed that supplemental testimony did not appear to be necessary[41] and set a schedule for the proceeding.[42] The proceeding was categorized as ratesetting and ALJ Robert M. Mason III was designated presiding officer.[43] The purpose of the proceeding was determined to be "whether the costs recorded in the PSRMAs, SECCBAs, and SEEBAs were

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Applicants define Phase 2B segments as "pipelines with record of a pressure test, but without record of a pressure test to modern (49 Code of Federal Regulations Part 192, Subpart J) standards." The parties disagree as to whether the work identified as Phase 2B of PSEP has been mandated by the Commission due to differing interpretations of D.11-06-017. Applicants read the decision, particularly Ordering Paragraphs 3 and 4, to require the pressure testing or replacement of segments for which Applicants have a pre-Subpart J pressure test record. Intervenors read the decision, particularly Ordering Paragraph 3, as not requiring ratepayers to pay for retesting through the Pipeline Safety Enhancement Plan (PSEP), those segments for which Applicants possess a pre-Subpart J pressure test record, provided that the test met the requirements in place when the test was conducted. The parties agree that this disagreement should be resolved in a different proceeding. Notwithstanding their different interpretations of the Commission's prior decision, the parties agree to the following:

- Accelerated miles are miles that would otherwise be addressed in a later phase of PSEP under the approved prioritization process, but are being advanced to Phase 1A to realize operating and cost efficiencies. Accelerated miles may include Phase 1B or Phase 2.
- Incidental miles are miles not scheduled to be addressed in PSEP, but are included where their inclusion is determined to improve cost and program efficiency, address implementation constraints, or facilitate continuity of testing.
- Recovering the cost of "incidental" and/or "accelerated" pressure testing or replacement of segments may be considered in this proceeding.
- Any finding in this proceeding that costs of such work may be recovered would not be precedential for the issue of whether replacement or testing of all segments with a pre-Subpart J test record has been mandated or is necessary.
- The recovery of the costs of "standalone" Phase 2B segments will be addressed in a forecast application or Applicants' General Rate Case to be filed in the future, at which time parties may assert their positions.

Scoping Memo at pp. 4-5 (footnotes omitted). In A.17-10-008, SoCalGas's general rate case filing, SoCalGas has summarized the Parties' differing interpretations and requested clarification as to whether the Commission intended to require Applicants to execute Phase 2B work.

[41] Scoping Memo at p. 9.

[42] Scoping Memo at p. 7.

[43] Scoping Memo at pp. 13-14.

prudently incurred," and the following items were designated as within the scope of the proceeding:

(1) Whether Applicants have met their burden of proving, by the preponderance of the evidence standard, that costs recorded in the PSRMAs, SECCBAs, and SEEBAs were prudently incurred and were necessary costs to properly implement SDG&E and SoCalGas' Safety Enhancement program.

(2) Whether Applicants have met their burden of proving, by the preponderance of the evidence standard, that they complied with the guidance and requirements in D.14-06-007 and all other relevant decisions addressing Safety Enhancement.

(3) Whether Applicants complied with all state and federal regulations and followed industry best practices in the Safety Enhancement activities.

(4) Whether Applicants' requested costs are reasonable when compared to the costs incurred to perform similar activities by comparable utilities.

(5) Whether Applicants have included in their request for recovery amounts that should be borne by shareholders.

(6) Whether the requested revenue requirement and cost allocation are reasonable.[44]

The Scoping Memo also required Applicants to file comments indicating which, if any, pipeline maintenance projects had been deferred due to the unavailability of the Aliso Canyon storage facility.[45]

F. Hearings Waived; Submission of Briefs.

Prior to the commencement of the scheduled hearings on this matter, the Parties jointly notified the Commission and the applicable service list that they had agreed to waive hearings and would submit the matter for Commission decision based upon written briefs. The Parties appeared before the Commission on December 8, 2017 to move exhibits into evidence, including

[44] Scoping Memo at pp. 8-9.
[45] Scoping Memo at p. 9. Applicants' comments were filed on October 20, 2017, and no reply comments were filed by any other Parties.

under seal when properly designated as confidential, and obtained leave to file briefs containing confidential information under seal.[46]

III. LEGAL STANDARD OF REVIEW AND OTHER MATTERS.

A. The Commission Applies the Reasonable Manager Standard To Determine Whether Costs Were Prudently Incurred.

As noted in the Scoping Memo,[47] rather than pre-approving forecasted costs in D.14-06-007, the Commission instead ordered an after-the-fact reasonableness review of costs incurred by Applicants in executing PSEP.[48] To assess the reasonableness of incurred costs, the Commission applies the reasonable manager standard. To meet this standard, "[t]he act of the utility should comport with what a reasonable manager of sufficient education, training, experience and skills using the tools and knowledge at his disposal would do when faced with a need to make a decision and act."[49] As explained by the Commission, "reasonable and prudent acts do not require perfect foresight or optimum outcomes, but may fall within a spectrum of possible acts consistent with utility needs, ratepayer interests, and regulatory requirements."[50] While the act of the utility should "logically be expected, at the time the decision is made, to accomplish the desired result at the lowest reasonable cost consistent with good utility practices,"[51] the Commission has been consistent that perfection and prescience are not required: "No utility manager can have perfect foresight but a prudent manager would seek flexibility to deal with unexpected conditions."[52] Thus, if the utility's "efforts [a]re within the spectrum of possible actions a prudent and reasonable manager would take under th[ose] circumstances,"[53] the utility has met the reasonable manager standard.

[46] December 8, 2017 Evidentiary Hearing, Transcript at pp. 6, 8.
[47] Scoping Memo at pp. 5-6.
[48] D.14-06-007, mimeo., at pp. 23-24, 60-61 (Ordering Paragraphs 5 and 6).
[49] D.90-09-088 at p. 16.
[50] D.97-08-055 at p. 54.
[51] D.90-09-088, mimeo., at p. 16.
[52] D.87-06-021, mimeo., at p. 23.
[53] D.87-06-021, mimeo., at p. 23.

The Commission has stressed that the utilities are held to "a standard of reasonableness *based upon the facts that are known or should be known at the time*" (emphasis added).[54] In so doing, the Commission looks to the decision-making process and information available to the manager to assess whether the course of action was within the "bounds of reasonableness, even if it turns out not to have led to the best possible outcome."[55] As explained by the Commission, this is to "avoid the application of hindsight in reviewing the reasonableness of a utility decision."[56]

The Commission has described certain indicia suggesting prudent management which would satisfy the reasonable manager standard:

> At a minimum we would expect that SDG&E and SoCalGas could document and demonstrate an overview of the management of Safety Enhancement which might include: ongoing management approved updates to the Decision Tree and ongoing updates similar to the Reconciliation. The companies should be able to show work plans, organization charts, position descriptions, Mission Statements, etc., used to effectively and efficiently manage Safety Enhancement. There would likely be records of contractor selection controls, project cost control systems and reports, engineering design and review controls, and of course proper retention of construction records, retention of pressure testing records, and retention of all other construction test and inspection records, and records of all other activities mandated to be performed and documented by state and federal regulations.[57]

When there is this type of prudent management, "the commission can find the costs incurred by the utility to be just and reasonable and therefore, they can be recovered from ratepayers."[58]

B. Standard of Proof.

The Commission determined the reasonable manager standard should be satisfied by a preponderance of the evidence.[59],[60] Preponderance of the evidence is defined "in terms of

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[54] D.90-09-088, mimeo., at p. 15 (citing D.88-03-036 at 5).
[55] D.89-02-074 at p. 169 (Conclusion of Law 3).
[56] D.90-09-088at p. 15.
[57] D.14-06-007, mimeo., at p. 37.
[58] D.14-06-007, mimeo., at p. 31.
[59] D.14-06-007, mimeo., at p. 13.
[60] Scoping Memo at p. 5.

probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[61] In other words, Applicants "must present more evidence that supports the requested result than would support an alternative outcome."[62]

C. Other Matters.

In addition to the foregoing, the Commission noted that Applicants should reconcile "as filed" mileage proposed in Applicants' filed and adopted PSEP with the mileage actually addressed.[63]

Intervenors argued in A.14-12-016 that Applicants' costs in implementing PSEP should be compared to those of other utilities,[64] but the Commission did not adopt that recommendation in its decision in that proceeding, D.16-12-063. Moreover, an after-the-fact comparison of utility costs to determine reasonableness would not be consistent with the Commission's reasonable manager standard, which, as discussed above, is a review based on what a reasonable manager knew or should have known at the time a decision was made, not an after-the-fact hindsight review. Therefore, no requirement to compare utility costs after-the-fact exists today. Nevertheless, Intervenors requested to include within the scope of this proceeding "[w]hether Applicants' requested costs are reasonable when compared to the costs incurred to perform similar activities by comparable utilities."[65] Although the Scoping Memo authorized Intervenors to address this issue here, no intervenors submitted any evidence or testimony on this issue.

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[61] D.14-06-007 at 13 (citing Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184).
[62] *Id*.
[63] D.14-06-007, mimeo., at pp. 36-37.
[64] A.14-12-016, Ex. ORA-01 (Stannik) at p. 6.
[65] Scoping Memo at p. 9; *See also* February 10, 2017 Pre-Hearing Conference, Transcript at pp. 4, 11.

IV. THE RECORD ESTABLISHES THAT SOCALGAS AND SDG&E HAVE SATISFIED THE REASONABLE MANAGER STANDARD IN THE DEVELOPMENT, MANAGEMENT, AND EXECUTION OF PSEP.

A. Applicants Have Complied with the Commission's Mandate To Implement PSEP "As Soon As Practicable."[66]

In the wake of Commissioner Florio's March 2011 words that the new, yet-to-be-established safety enhancement efforts were not "business as usual,"[67] SoCalGas and SDG&E initiated unprecedented infrastructure enhancement efforts. On April 15, 2011, SoCalGas and SDG&E reported to the Commission that they already had begun to review their gas transmission pipeline records and were developing an action plan to address identified pipelines in populated areas.[68] On June 9, 2011 Applicants were ordered to develop the Implementation Plan and supporting cost estimates;[69] and on August 26, 2011, Applicants filed their proposed Implementation Plan. By the time the PSEP was adopted on June 12, 2014 – thirty-four months after Applicants first filed their Implementation Plan – SoCalGas and SDG&E had heeded the Commission's directive to complete pipeline safety enhancement work "as soon as practicable"[70] and had already initiated over half the Phase 1A pipeline and valve projects,[71] including all projects submitted for cost recovery in this proceeding.[72]

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[66] D.11-06-007, mimeo., at p. 19

[67] 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.

[68] R.11-02-019, April 15, 2011, *Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations*.

[69] D.11-06-017, mimeo., at pp. 18-19.

[70] D.11-06-007, mimeo., at p. 19.

[71] Ex. SCG-01 (Buczkowski) at p. 1. Indeed, SoCalGas and SDG&E initiated work in furtherance of their proposed Implementation Plan in May 2012. *Id.*

[72] Ex. SCG-02 (Phillips) at p. 3.

B. Applicants Were Reasonable Managers in Establishing a New Program – the PSEP – with Prudent Governance and Oversight.

PSEP is the largest natural gas infrastructure safety enhancement program in SoCalGas and SDG&E's operational history.[73] SoCalGas and SDG&E were tasked with developing and implementing PSEP in addition to continuing to operate their system and providing safe and reliable service. The work scheduled is extensive, both in terms of the volume of projects and the time necessary to complete each project.[74] At any given time, 15-30 PSEP projects are in construction, each of which presents unique attributes and challenges.[75] This requires the simultaneous execution of projects by hundreds of trained company and contractor personnel.[76]

The project execution process requires orchestral coordination to align the many items needed before beginning construction: excavation permits; traffic control permits; environmental permits; specialty permits (e.g., Caltrans); temporary land rights for laydown yards; permanent easements when the footprint of the new pipeline alignment is different than the existing; material deliveries (particularly specialty materials and equipment); availability of the system to take an outage on the pipeline system to test or replace; and availability of local operations personnel to provide standby services, to disconnect the various taps of a pipeline, and to perform a tie-in.[77]

It is important to note that prior to implementing PSEP, Applicants were not accustomed to addressing the activities within the scope of PSEP at the volume and pace required by PSEP. In order to execute the Commission-ordered PSEP, a new program had to be established by the Applicants, which they did by leveraging decades of professional expertise and their institutional knowledge of their pipeline system.

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[73] Ex. SCG-02 (Phillips) at p. 2.
[74] Ex. SCG-02 (Phillips) at p. 5.
[75] Ex. SCG-04 (Phillips) at p. 3.
[76] Ex. SCG-04 (Phillips) at p. 4.
[77] Ex. SCG-04 (Phillips) at p. 5.

1. The PSEP Organization Is Subject to Prudent Governance and Oversight by a Program Management Office.

A PSEP organization was created within SoCalGas to oversee PSEP project execution, provide project and process controls during the lifecycle of each project, assess each project's budget and schedule, and communicate progress to stakeholders.[78] Separate PSEP departments were formed with distinct roles and functional responsibilities to effectively and efficiently manage PSEP.[79] Although PSEP is an independent organization within SoCalGas, to assure prudent decision-making and promote both cost and organizational efficiencies, PSEP personnel continuously collaborate with other knowledgeable groups within SoCalGas and SDG&E (*e.g.*, Region Operations, Engineering, Gas Transmission Planning, Gas Control, Public Affairs, etc.) to route, design, and schedule pipeline and valve work.[80]

Ultimate governance and oversight of PSEP is conducted by the PSEP Project Management Office ("PMO").[81] The PMO provides oversight of PSEP at the organizational level, develops PSEP policies, promotes oversight and accountability, and develops metrics to keep management apprised of progress.[82] In 2011, CPSD predicted that "the PMO will be critical to the proper execution of PSEP," and this has proven to be true.[83] The PMO provides structure, guidance, and oversight regarding design and construction; develops standards and procedures that promote consistency across PSEP projects; and develops and reports key performance indicators/metrics that are reviewed by management in order to measure accomplishments, note constraints, and identify opportunities for improvement.[84]

In addition to these and many other activities, the PMO confirms compliance with Commission guidance and decisions, applicable laws and regulations, and SoCalGas and

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[78] Ex. SCG-02 (Phillips) at p. 5.
[79] Ex. SCG-02 (Phillips) at p. 5. The nine specific groups are: (1) Program Management Office ("PMO"); (2) Construction; (3) Engineering; (4) Environmental; (5) Supply Management; (6) Gas Control; (7) Non-PMO General Administration; (8) Communication and Outreach; and (9) Training. *See id*. Each of the nine groups oversees critical aspects of PSEP.
[80] Ex. SCG-02 (Phillips) at p. 8.
[81] Ex. SCG-02 (Phillips) at p. 6.
[82] Ex. SCG-02 (Phillips) at pp. 6-7.
[83] Ex. SCG-02 (Phillips) at p. 6.
[84] Ex. SCG-02 (Phillips) at p. 6.

SDG&E's respective Gas Standards.[85] Gas Standards comprise the policy and procedures that govern all aspects of the design, construction, operations, and maintenance of the utilities' transmission and distribution systems.[86] They are regularly updated by the utilities and reviewed by the Commission's SED to promote compliance with federal and State regulations and incorporate industry best practices.[87] They are referenced in all stages of PSEP planning and govern design analysis, materials purchased, and construction practices.[88]

Throughout the PSEP execution process, SED has overseen the successful execution of PSEP projects and SoCalGas and SDG&E have fully cooperated in the regulatory oversight process.[89] SED personnel have been onsite at PSEP construction projects routinely to monitor compliance with applicable regulations and have particularly focused on overseeing construction activities and recordkeeping.[90] SED feedback has been instrumental in confirming for Applicants that their PSEP efforts remain in line with the Commission's safety goals and directives.

2. SoCalGas and SDG&E Developed and Implemented a Seven Stage Review Process To Prudently Manage PSEP Projects.

For projects included in this proceeding that were commenced in 2013 and thereafter, PSEP developed and implemented a Seven Stage Review Process to promote efficient project execution and prudent project management.[91] The Seven Stage Review Process sequences and schedules PSEP project workflow deliverables as follows: (Stage One) Project Initiation; (Stage Two) Test or Replace Analysis; (Stage Three) Begin Detailed Planning; (Stage Four) Detailed

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85 Ex. SCG-02 (Phillips) at p. 12.
86 Ex. SCG-02 (Phillips) at p. 12.
87 Ex. SCG-02 (Phillips) at pp. 12-13. The Gas Standards incorporate applicable federal and state regulations.
88 Ex. SCG-02 (Phillips) at pp. 12-13.
89 Ex. SCG-02 (Phillips) at pp. 13-14.
90 Ex. SCG-02 (Phillips) at pp. 13-14. In D.14-06-007, the Commission delegated to SED specific authority (in addition to its existing broad authority) "to directly observe and inspect the testing, maintenance and construction, and all other technical aspects of Safety Enhancement to ensure public safety both during the immediate maintenance or construction activity and to ensure that the pipeline system and related equipment will be able to operate safely and efficiently for their service lives." D.14-06-007, mimeo., at p. 29. *See also id.* at pp. 30-31.
91 Ex. SCG-02 (Phillips) at p. 8.

Design/Procurement; (Stage Five) Construction; (Stage Six) Place into Service; and (Stage Seven) Closeout.[92] Each stage includes specific objectives and an evaluation "gate" at the end of each stage to verify that objectives have been met before proceeding to the next stage.[93] In this way, projects are properly expedited and management is kept informed.

3. Prudent Tracking, Controls, and Management Practices Were Implemented To Manage Project Costs.

Practices were implemented to properly track and manage costs. Project-specific costs are tracked to their respective project accounts; and costs that cannot be attributed to a specific PSEP project are tracked to a PSEP General Management and Administration ("GMA") account based on the related activity and support function.[94]

a. Project-Specific Costs

Project-specific costs are tracked by a Work Order Authorization ("WOA") that is issued for each PSEP project.[95] To allocate costs properly, cost categories are assigned a unique internal order number.[96] Applicants have also implemented procedures to verify the accuracy of costs invoiced: billing rates are reconciled, and time sheets and other supporting documentation are reviewed.[97] Only after the information is verified, is the invoice forwarded to project managers to confirm accuracy.[98] In this way, Applicants are able to accurately track and record costs.

Project-specific costs include, but are not limited to, those associated with the following project support activities and personnel:

- Project Manager who has overall responsibility to manage the scope, cost, and schedule for all assigned projects;

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[92] Ex. SCG-02 (Phillips) at pp. 8-10.
[93] Ex. SCG-02 (Phillips) at pp. 8-9. The Seven Stage Review Process for the Valve Enhancement Plan includes an additional two scoping stages that are necessary to determine how effectively to achieve the valve isolation objectives: Stage 0 (which involves valve scope assessment) and Stage .5 (which entails updating and refining the valve scope analysis based on new data sets). Ex. SCG-05 (Bermel) at pp. 8-9.
[94] Ex. SCG-02 (Phillips) at p. 25.
[95] Ex. SCG-02 (Phillips) at p. 25.
[96] Ex. SCG-02 (Phillips) at p. 25.
[97] Ex. SCG-02 (Phillips) at p. 25.
[98] Ex. SCG-02 (Phillips) at pp. 25-26.

- Project Engineers who are responsible for engineering and design efforts for the project;
- Designers who are responsible for developing detailed drawings;
- Project schedulers who regularly update detailed project schedules;
- Cost engineers who monitor costs and provide project forecasts and outlook to the PMO;
- Business Analysts who provide project support in evaluating the accuracy of invoices and charges to each project;
- Permitting and Land Services Representatives who support the project team by obtaining the required permits and land easements;
- Environmental representatives who have overall responsibility for environmental compliance for a project, including water management;
- Material Coordinators who are responsible for requesting and tracking materials;
- Construction Teams who are responsible for reviewing designs for constructability and manage construction activities;
- Community Outreach Liaisons who are responsible for working with impacted communities; and
- Project and Document Control personnel.[99]

b. General Management and Administration Costs

GMA costs are those incurred at the program level and support cost minimization, maximize the effectiveness of the safety investment, improve organizational and project execution efficiency, and provide consistency in the implementation of PSEP projects.[100] These costs are not attributed to individual PSEP projects but are necessary for the cost-effective and successful execution of PSEP.[101] The GMA captures functional supporting costs for the PSEP

[99] Ex. SCG-08 (Mejia) at pp. 10-11.
[100] Ex. SCG-08 (Mejia) at p. 1.
[101] Ex. SCG-08 (Mejia) at p. 1.

organization that are not captured in non-incremental overheads typically charged to projects.[102] This type of allocation is standard in the industry.[103]

Applicants track GMA costs by utilizing internal orders ("IOs")[104] based on the following functional groups and their activities:

- PMO: This category includes costs reasonably incurred to promote management and oversight of the numerous disparate and unique projects undertaken by PSEP at any given time.[105] The PMO has established processes and procedures for managing day-to-day PSEP operations, including developing a document management system that enables access to project documentation throughout the project life cycle and the process for transferring data from this PSEP data repository to Applicants' usual document management system, and developing a Management of Change process that enables tracking and managing change orders to project scope, cost, or schedule and allows for easy review thereof.[106]
- Construction: This category includes costs reasonably incurred for the direct management of construction-related activities during execution of PSEP projects.[107] Construction management expertise is centralized in this group, which achieves consistency across pipeline and valve automation work.[108] This group also manages construction documentation. In furtherance of this, the group launched a program that utilizes computer tablets to capture data and inspection information in the field.[109] This has resulted in greater consistency in inspections, accelerated project closeout, and decreased administrative time.[110]

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[102] Ex. SCG-08 (Mejia) at p. 11.
[103] Ex. SCG-08 (Mejia) at p. 11.
[104] Ex. SCG-10 (Pech) at p. 5.
[105] Ex. SCG-08 (Mejia) at p. 2.
[106] Ex. SCG-08 (Mejia) at p. 2.
[107] Ex. SCG-08 (Mejia) at p. 3.
[108] Ex. SCG-08 (Mejia) at p. 3.
[109] Ex. SCG-08 (Mejia) at p. 3.
[110] Ex. SCG-08 (Mejia) at p. 3.

- Engineering: This category includes the costs of project planning, engineering, and execution.[111] This group manages execution oversight across all PSEP projects from initiation through closeout, and developed a comprehensive program to manage surveying, mapping, potholing, and subsurface utility activities.[112] Costs to develop, manage, and improve the PSEP estimating tool are tracked under this cost category, as are costs incurred by Land Services.[113]
- Environmental: This category includes costs incurred in supporting PSEP's environmental strategy and compliance oversight, which may include field work during the construction phase.[114]
- Supply Management: This category of costs includes those incurred in managing procurement procedures and identifying long lead and critical path equipment and materials.[115]
- Gas Control: This category includes costs incurred in gas control support, which entails various activities including managing and scheduling transmission pipeline shutdowns to support pipeline and valve work and assists in scheduling tie-ins.[116] This group also assists in tracking customer and system impacts and thus is an integral component of PSEP.[117]
- Non-PMO General Administration: This category includes costs associated with program-wide support from Project Controls, Quality Assurance/Quality Control, and documentation control.[118] This group provides project control oversight and reporting, works to develop and update project schedules and costs and maintains

[111] Ex. SCG-08 (Mejia) at p. 3.
[112] Ex. SCG-08 (Mejia) at p. 3.
[113] Ex. SCG-08 (Mejia) at p. 4.
[114] Ex. SCG-08 (Mejia) at pp. 5-6.
[115] Ex. SCG-08 (Mejia) at p. 6.
[116] Ex. SCG-08 (Mejia) at p. 7.
[117] Ex. SCG-08 (Mejia) at p. 7.
[118] Ex. SCG-08 (Mejia) at p. 8.

the master project schedule.[119] Costs of the PSEP Quality Plan are charged to this GMA.[120]

- Communication and Outreach: This category includes costs incurred in developing internal and external communications of PSEP status to key stakeholders, including local elected and government officials and affected commercial entities and residents.[121]
- Training: This category of costs includes those for developing and implementing onboarding training and field training.[122] Training improves both safety and efficiency by promoting consistency across projects and supports compliance with applicable laws, regulations, policies, and procedures.[123]

All of the foregoing categories include both labor and non-labor costs.[124]

Before GMA costs are allocated to projects on a percentage basis,[125] they are subject to review and approval processes from the GMA department heads on a monthly basis.[126] Any mischarges identified are reported to the PMO Business and Administration group for correction.[127] 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;[128] and (ii) a weekly report indicating hours charged by external vendors.[129] Only after hours are approved by department heads, are vendors authorized to invoice and bill

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[119] Ex. SCG-08 (Mejia) at p. 8.
[120] Ex. SCG-08 (Mejia) at p. 8.
[121] Ex. SCG-08 (Mejia) at p. 9.
[122] Ex. SCG-08 (Mejia) at p. 9.
[123] Ex. SCG-08 (Mejia) at p. 9.
[124] Ex. SCG-10 (Pech) at pp. 2-4.
[125] Ex. SCG-08 (Mejia) at p. 11.
[126] Ex. SCG-10 (Pech) at p. 5.
[127] Ex. SCG-10 (Pech) at p. 5.
[128] Ex. SCG-10 (Pech) at p. 6.
[129] Ex. SCG-10 (Pech) at p. 6.

Applicants.[130] For the first reasonableness review, ORA performed an audit of certain PSEP costs and supporting documentation and found no inconsistencies.[131]

GMA costs are distinct from the incremental company-wide overheads applied to PSEP.[132]

c. 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.[133] 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.[134]

PSEP also obtained PSEP-specific insurance, an Owner Controlled Insurance Program ("OCIP") and Professional Liability insurance to cover Phase 1A projects.[135] In this Application, SoCalGas and SDG&E present for review the pro-rated amounts of $1.9 million and $.24 million, respectively, in PSEP-specific insurance costs.[136] The benefits of the OCIP are myriad: it helped to optimize competition for construction efforts, enhance supplier diversity, and promote competitiveness of costs.[137] Moreover, purchasing PSEP-specific insurance increased the number of contractors potentially available to bid on PSEP projects as, generally, only larger construction and service-based contractors have the ability to purchase significant insurance

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[130] Ex. SCG-10 (Pech) at p. 6.
[131] A.14-12-016, Ex. ORA-01 (Stannik) at p. 7.
[132] Ex. SCG-10 (Pech) at pp. 6-7. 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 GMA categories described herein apply to PSEP. *Id.*
[133] Ex. SCG-11 (Gonzalez) at p. 1.
[134] Ex. SCG-11 (Gonzalez) at p. 2.
[135] PSEP-specific insurance provides coverage that is not provided by Company public liability/properly damage insurance, and thus there is no duplication of coverage. Similarly, there is no commingling of costs because each of the insurance overheads allocated to PSEP projects is accounted for separately in specific cost pools. Ex. SCG-11 (Gonzalez) at pp. 3-4; Ex. SCG-10 (Cayabyab) at pp. 4-5.
[136] Ex. SCG-12 (Cayabyab) at p. 1.
[137] Ex. SCG-12 (Cayabyab) at pp. 2-4.

limits. Removing this potential bid barrier helped to increase contractor competition, provide dedicated insurance limits, and improved insurance coverage — all of which are for the overall benefit of ratepayers.[138] The OCIP also mitigated the negative impact of market conditions that saw increased premiums and decreased coverage.[139] Finally, the OCIP also reduced administrative burdens.[140]

The OCIP was obtained through competitive sourcing through a broker who marketed the program to global insurance markets, supported Applicants' supplier diversity goals, and provided ancillary administrative services which in turn minimized costs and improved coverage terms.[141] The OCIP policy provides ten-year coverage of $300 million in commercial general liability, with a $165 million sublimit for fires.[142]

The company overheads represent the indirect components of executing PSEP. They have been incurred, calculated, and allocated with prudent oversight and management and therefore should be recovered in rates.

4. Prudent Community Outreach Activities Were Implemented.

A proactive community outreach effort was determined to be prudent, particularly because Phase 1A projects are located in populated areas.[143] Community outreach efforts kept customers, elected officials, and government entities informed about projects taking place in their communities.[144] Meetings were held with elected officials and municipal agencies in order to provide advance notice and updates regarding projects.[145] For the projects included in this proceeding alone, approximately 6,000 customer notification letters and 4,000 door hangers were delivered to customers.[146] In addition, PSEP established an internet webpage to provide

[138] Ex. SCG-12 (Cayabyab) at pp. 1-4.
[139] Ex. SCG-12 (Cayabyab) at pp. 1-3.
[140] Ex. SCG-12 (Cayabyab) at pp. 2-3.
[141] Ex. SCG-12 (Cayabyab) at pp. 2-3.
[142] Ex. SCG-12 (Cayabyab) at p. 2.
[143] Ex. SCG-02 (Phillips) at p. 11.
[144] Ex. SCG-02 (Phillips) at pp. 11-12.
[145] Ex. SCG-02 (Phillips) at pp. 11-12.
[146] Ex. SCG-02 (Phillips) at pp. 11-12.

background, construction activity, and project status information to give customers and other stakeholders easy access to information that may affect them.[147]

These community outreach efforts were instrumental in avoiding project delays and, in some instances, resulted in less onerous permit conditions being imposed on Applicants.[148] For example, ongoing communications with the City of Arroyo Grande helped ensure permits for the Line 36-9-09 North project were issued on schedule.[149] This, in turn, helped to minimize project costs.[150]

5. SoCalGas and SDG&E Prudently Staffed the PSEP Organization.

Because PSEP is an incremental program, SoCalGas and SDG&E did not have sufficient employees to transition to the PSEP organization without impacting their core business of maintaining safe and reliable service to customers.[151] Rather than source and hire sufficient personnel to staff the PSEP organization – which might have been an impossible task, would have impeded Applicants' ability to move expeditiously in compliance with the Commission's directive to execute PSEP "as soon as practicable,"[152] and would have created personnel abundance problems when PSEP eventually came to an end. Applicants augmented their internal resources by engaging experienced contractors who quickly could be added to or removed from PSEP, depending on program needs.[153] Applicants also hired additional internal resources for both engineering and non-engineering positions.[154] These trained and/or experienced personnel perform a wide range of PSEP activities.[155] Applicants reasonably determined this to be a cost-

[147] Ex. SCG-02 (Phillips) at p. 12.
[148] Ex. SCG-02 (Phillips) at p. 12.
[149] Ex. SCG-02 (Phillips) at p. 12.
[150] Ex. SCG-02 (Phillips) at p. 12. In addition, in response to an inquiry by an SED inspector, the city praised SoCalGas for its proactive community outreach efforts. *Id.*
[151] Ex. SCG-02 (Phillips) at pp. 14-15.
[152] D.11-06-007, mimeo., at p. 19.
[153] Ex. SCG-02 (Phillips) at p. 15.
[154] Ex. SCG-02 (Phillips) at p. 16.
[155] Ex. SCG-02 (Phillips) at p. 16.

effective means to achieve the Commission's goals of speedy execution of this large-scale safety enhancement program.[156]

Applicants' employees who are external to the PSEP organization also provide support on an as-needed basis, subject to prudent oversight.[157] Management positions authorized to charge their time to PSEP are approved by both PSEP and the appropriate operating department's leadership[158] and are required to account for the nature of their billed hours in documentation reviewed by PSEP management.[159]

6. SoCalGas and SDG&E Undertook Specific Cost Reduction Activities To Achieve their Objective To Maximize the Cost Effectiveness of System Enhancement Investments.

As described earlier, an overarching objective of PSEP is to maximize the cost effectiveness of investments in the SoCalGas/SDG&E transmission system. In addition to establishing a program that capitalizes on collaboration and promotes efficiencies, SoCalGas and SDG&E undertake the following activities in support of reducing costs to ratepayers.

a. Scope Validation Efforts.

One of the first steps in the Seven Stage Review Process is proactively conducting due diligence to validate the scope of projects as listed in Applicants' original Implementation Plan.[160] The PSEP team compares data from the as-filed PSEP to internal data bases to validate project mileage.[161] A mileage reduction may result from the critical assessment of records, reduction in MAOP, or abandonment of lines that no longer are required from an overall gas operating system perspective.[162]

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156 Ex. SCG-02 (Phillips) at p. 18.
157 Ex. SCG-02 (Phillips) at p. 17.
158 Ex. SCG-02 (Phillips) at p. 17.
159 Ex. SCG-02 (Phillips) at p. 18.
160 Ex. SCG-02 (Phillips) at p. 10.
161 Ex. SCG-02 (Phillips) at p. 10.
162 Ex. SCG-02 (Phillips) at p. 10.

Scope validation has produced tangible cost savings. The as-filed scope of Phase 1A was 355 Category 4 miles.[163] Through scope validation activities, SoCalGas and SDG&E successfully reduced the scope of Phase 1A by approximately 260 miles, to approximately 95 Category 4 miles.[164] This achieved an estimated cost savings of *over $500 million* for customers.[165]

b. Resource Management

Approximately 75% of PSEP costs are for purchased services and materials.[166] Thus, an important aspect of cost management is retaining capable contractors and vendors at reasonable rates.[167] PSEP implements proven supply management techniques and practices to acquire materials and services at reasonable and market-based cost.[168] This is done by using reasonable selection processes, creating reasonable incentives, and imposing cost controls.[169]

i. Competitive Sourcing

Applicants' objective has been to achieve market-based rates by utilizing competitive bidding, which the Commission has expressly identified as a factor evidencing the reasonableness of costs.[170] Indeed, the majority of PSEP agreements for materials and services either have been competitively bid or were set at market-based rates stemming from recent previous competitive solicitations.[171] Thus, in addition to conducting individual bidding events, SoCalGas and SDG&E leverage terms, conditions, and rates from existing agreements when doing so may reduce costs for customers.[172] In this way, PSEP benefits from using previously

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[163] Ex. SCG-02 (Phillips) at p. 11. Category 4 includes pipelines that lack sufficient documentation of a post-construction strength test to 1.25 time MAOP. All Category 4 pipeline segments were prioritized for further analysis and action. *See* Ex. SCG-16 (Amended Workpapers) at p. WP-G-2.
[164] Ex. SCG-02 (Phillips) at p. 11. Thirty-two Phase 1A projects were eliminated altogether. *See id.*
[165] Ex. SCG-02 (Phillips) at p. 11.
[166] Ex. SCG-02 (Phillips) at p. 18.
[167] Ex. SCG-02 (Phillips) at p. 18.
[168] Ex. SCG-02 (Phillips) at p. 18.
[169] Ex. SCG-02 (Phillips) at p. 18.
[170] D.16-12-063, mimeo., at p. 58 (Conclusion of Law 2).
[171] Ex. SCG-02 (Phillips) at pp. 18-19.
[172] Ex. SCG-02 (Phillips) at p. 19.

negotiated rates and minimizes administrative costs and delays.[173] Approximately 98% of PSEP agreements with contractors and vendors are either competitively bid or based on agreements that use market-based rates based on a recent competitive sourcing event.[174]

The PSEP organization also takes advantage of changing market conditions in order to achieve cost savings. In the year prior to filing the Application, the PSEP organization re-bid or re-negotiated contracts with inspectors, engineering design providers, surveyors, environmental service providers, and warehouse lessors based on changed market conditions (*e.g.*, a slowdown in nationwide construction activity) and the utilization of tailored procurement strategies (*e.g.*, not-to-exceed bids for certain categories of work) to further reduce costs for customers.[175]

ii. Materials

While materials may be acquired for PSEP projects using various strategies that suit the project and need, generally, materials are purchased by Applicants' authorized agents and payment is made through existing SoCalGas and SDG&E systems.[176] Efforts are made to utilize vendors from Applicants' Approved Manufacturers List because of the additional comfort that they have been engaged and/or previously vetted.[177] Material bids are designed to obtain multiple quotes for the best pricing options, promote work with select vetted firms for efficiency of process, and to encourage the development of local resources and sourcing.[178]

When possible, material needs are aggregated across projects in order to obtain favorable pricing and reduce administrative burden.[179] On occasion, specific design parameters may require project-specific buys. When these are required, multiple buys are executed at each major design phase to address time constraints and to reduce costs.[180] Long lead times, for example, are identified early for sourcing. When there are nevertheless delays, if possible and appropriate,

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[173] Ex. SCG-02 (Phillips) at p. 19.
[174] Ex. SCG-02 (Phillips) at p. 19.
[175] Ex. SCG-02 (Phillips) at p. 24.
[176] Ex. SCG-02 (Phillips) at pp. 22-23.
[177] Ex. SCG-02 (Phillips) at pp. 22-23.
[178] Ex. SCG-02 (Phillips) at p. 23.
[179] Ex. SCG-02 (Phillips) at p. 23.
[180] Ex. SCG-02 (Phillips) at p. 23.

items may be transferred between projects to reduce last-minute buys and shipping costs and maintain the construction schedule.[181]

Due to the sheer volume of projects that are underway at the same time, and efforts to realize cost savings with bulk orders, PSEP requires significant incremental warehouse space to store materials.[182] To meet these requirements, two centralized material yards were established in Fontana and Bakersfield to serve as receipt points for shipments and staging areas for project materials.[183]

iii. Construction Contractor Costs – the Performance Partnership Program

The Performance Partnership program was developed by Applicants after SoCalGas and SDG&E determined the increase in Phase 1A work could be completed most cost-effectively by having bundles of construction work bid competitively.[184] The Performance Partnership Program allows "Performance Partners" to enter into competitive bidding for batches of projects rather than bidding one project at a time.[185] This provides numerous benefits for SoCalGas and SDG&E: providing competitive market prices, avoiding administrative costs for individual bids, engaging construction contractors in longer-term agreements for numerous projects (which also lowers costs by maintaining a sustained workforce with less downtime and allowing contractors to work with the same internal engineering teams for a more collaborative effort), and providing contractors incentive to agree to additional cost control mechanisms (since a winning bidder is awarded more than just one project).[186] Of course, the PSEP organization retains the discretion to use or not use the Performance Partnership Program and instead competitively or single-source contractors when deemed more beneficial to do so.[187]

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[181] Ex. SCG-02 (Phillips) at p. 23.
[182] Ex. SCG-02 (Phillips) at p. 23.
[183] Ex. SCG-02 (Phillips) at p. 23.
[184] Ex. SCG-02 (Phillips) at p. 20.
[185] Ex. SCG-02 (Phillips) at p. 20.
[186] Ex. SCG-02 (Phillips) at pp. 20-21.
[187] Ex. SCG-02 (Phillips) at p. 21.

The Performance Partnership Program employs a risk/reward mechanism — a target price. Under this contracting method, the Performance Partner shares in both reduced and excess costs to incentivize contractors to perform cost-efficiently.[188] The target price is mutually agreed to by Applicants and the Performance Partner in advance, and the Performance Partner is not entitled to any profits if costs exceed twenty percent of the target price.[189]

The Performance Partnership Program has achieved significant cost savings for customers: seventeen pipeline projects and three bundled valve projects submitted herein for cost recovery utilized the Performance Partnership Program, and approximately $3.9 million in cost savings were realized.[190] SoCalGas and SDG&E were able to negotiate additional incentive mechanisms to further reduce costs: caps on Performance Partner overheads; individual profit caps; annual profit caps (which resulted in approximately $950,000 in rebates to Applicants after the first year of utilizing Performance Partner contracts); caps on mark-up from third-party contractors utilized by Performance Partners; and audit rights.[191]

To obtain additional confidence that the Performance Partnership Program resulted in actual savings to ratepayers, SoCalGas and SDG&E engaged an independent consulting firm to evaluate the program.[192] The independent firm's analysis concluded that the Performance Partnership Program resulted in greater customer benefits through reduced costs.[193]

iv. Other Cost Avoidance Efforts

The PSEP organization consistently prioritized achievement of cost savings. In addition to the foregoing, during the Seven Stage Review Process project teams negotiated with permit agencies and land owners to avoid costly permit conditions or unreasonable land acquisition

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188 Ex. SCG-02 (Phillips) at p. 21.
189 Ex. SCG-02 (Phillips) at p. 21.
190 This amount is the difference between the negotiated target price and the final actual cost to SoCalGas and SDG&E for pipeline projects. SCG-02, Phillips Testimony at p. 21. *See also, Id.* at Attachment A. It is not inclusive of the valve projects and peripheral related cost savings such as reduced administrative costs, etc. Ex. SCG-07 (Mejia) at pp. 5-7.
191 Ex. SCG-02 (Phillips) at p. 22.
192 Ex. SCG-02 (Phillips) at p. 22.
193 Ex. SCG-02 (Phillips) at Attachment B, PSEP Pipeline Construction Contractor Profit Analysis.

costs and mitigated the effects of unforeseen conditions that arise during construction by minimizing the cost impact of design conflicts and scope changes.[194]

Additionally, in order to realize cost savings, the PSEP organization placed PSEP Professional Liability insurance itself, thereby reducing the Professional Liability insurance placement by nearly $2 million (as compared to having a project management firm place it).[195] Even more cost savings were achieved when the PSEP organization re-negotiated the price for the insurance with the insurer after the mileage scope was reduced through records review efforts.[196]

With respect to contractor selection for the bundled valve projects before the Performance Partnership Program was initiated, electrical contractors were competitively bid.[197] This allowed SoCalGas and SDG&E to work with dedicated construction crews and resulted in workflow management and cost efficiencies.[198]

c. *Cost Drivers Were Managed Reasonably*.

The Commission has acknowledged that even a reasonable manager will encounter unexpected situations in the course of prudent management; what matters is that the reasonable manager retains the flexibility to deal with the situation.[199] PSEP has managed the unexpected situations that have caused delays with deftness and, moreover, has implemented process improvements based on learnings therefrom.[200]

Construction start dates are largely determined by things that are not within the PSEP organization's control. For example, permits or land rights must be acquired; materials must have been delivered; and contractors and inspectors have to be available at the same time, along with construction oversight and regional operations personnel.[201] The following is a non-

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[194] Ex. SCG-02 (Phillips) at p. 24.
[195] Ex. SCG-02 (Phillips) at p. 24.
[196] Ex. SCG-02 (Phillips) at pp. 24-25.
[197] Ex. SCG-07 (Mejia) at pp. 7-9.
[198] Ex. SCG-07 (Mejia) at pp. 7-9.
[199] "No utility manager can have perfect foresight but a prudent manager would seek flexibility to deal with unexpected conditions." D.87-06-021, mimeo., at p. 23.
[200] *See, infra*, Section IV, D.
[201] Ex. SCG-02 (Phillips) at pp. 26-30.

exhaustive list of events that drive costs and delays and have affected at least one project included in this proceeding for cost recovery.

- Pipeline and valve projects are linear and are located in rights of way and on private and federal land. This requires, at a minimum, that permits must be obtained. Approximately 140 permits and 90 land use agreements were obtained for the 41 projects submitted herein for review.
- A project in two different jurisdictions may have two different sets of rules regarding work times, dates, holiday moratoriums, etc.[202] These must be reconciled.
- Conditions are frequently placed on permits which require scope changes (e.g., specialized paving) or confine active construction area such that it is overly congested and decreases expected productivity.[203]
- Both temporary and permanent private land agreements must be negotiated with numerous individual entities.[204]
- Unknown substructures that are not identified on maps or records are encountered during construction which may require pipeline route changes.[205]
- Unanticipated soil changes may require a change in excavating or shoring method.[206]
- Coordination with other utilities may be required (for example, valve projects may require new communications or electricity lines, and other utilities may not be available to complete the work on schedule).[207]
- Due to an overall increase in demand for materials (since PSEP is an incremental program), materials may not be available in a timely manner, or specialty

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[202] Ex. SCG-02 (Phillips) at pp. 26-30.
[203] Ex. SCG-02 (Phillips) at pp. 26-30.
[204] Ex. SCG-02 (Phillips) at pp. 29-30.
[205] Ex. SCG-02 (Phillips) at p. 30.
[206] Ex. SCG-02 (Phillips) at pp. 30-31.
[207] Ex. SCG-02 (Phillips) at p. 31.

materials must be made, modified, and/or inspected to assure conformance to Company specifications.[208]

- There may be a change in circumstances requiring mitigation between the time when customer and capacity impacts are reviewed to when construction begins.[209]

These challenges are not unique to PSEP or to SoCalGas and SDG&E. Indeed, as reported by the independent consulting firm retained by Applicants, they are in line with the experiences of other public and private global organizations that manage large construction projects.[210] As such, their mere occurrence does not suggest imprudence; indeed, the fact that the challenges were overcome and the projects were completed suggests reasonable and prudent management by SoCalGas and SDG&E.

7. Environmental Considerations Were Managed Effectively.

Environmental issues were considered and well managed in implementing PSEP. The PSEP organization's Environmental Group worked closely with project teams to identify potential environmental issues early in the planning process and develop mitigating strategies.[211] Coordinated efforts also resulted in minimizing waste.[212] Notably, none of the 41 projects included in this proceeding for cost recovery received noticed of violations or had fines issued against them.[213]

8. PSEP Prioritized Safety, as Evidenced by its Outstanding Safety Record.

PSEP has an Occupational and Safety Health Administration ("OSHA") incident rate of 0.47, which is well below the industry average of 1.2.[214] This can be attributed to thorough training and stringent safety procedures that are applicable to both Applicants' employees and

[208] Ex. SCG-02 (Phillips) at p. 31.
[209] Ex. SCG-02 (Phillips) at pp. 31-32.
[210] Ex. SCG-02 (Phillips) at Attachment C.
[211] Ex. SCG-02 (Phillips) p. 14.
[212] For example, SoCalGas and SDG&E shared and transferred water used in pressure testing for reuse in multiple projects. This effort reduced the dependency on potable water (particularly important given the drought conditions in Southern California) and also minimized waste. *See* Ex. SCG-02 (Phillips) at p. 14.
[213] Ex. SCG-02 (Phillips) at p. 14.
[214] Ex. SCG-02 (Phillips) at p. 14.

PSEP contractors.[215] This record shines a spotlight on the PSEP organization's prudent management of program execution.

9. Actual versus "As-Filed" Mileage Reconciliation

In compliance with the Commission's directive, the PSEP organization reconciled the mileage of projects actually completed and submitted herein for cost recovery with the "as-filed" mileage anticipated in the Implementation Plan. The following are the results for the projects included in this proceeding.[216]

Table 2 - SoCalGas Pipeline Projects

Line	As Filed (Miles)	Included In This Proceeding (Miles)
1005	3.5	0.029 (151 ft.)
1011	5.14	0.077 (405 ft.)
1013	3.5	0.027 (140 ft.)
1014	0.003	0.003 (16 ft.)
1015 (North & South)	7.85	0.409 (2,161 ft.)
2000 West Sec (1,2,3)[217]	117.6	14.571
2001 West[218]	64.1	
2001 West A Sec (15,16)		0.006 (31 ft.)
2001 West B Sec (10,11,14)		2.939
2003 Sec (1,3,4)[219]	26.5	0.249 (1,315 ft.)
235 West Sawtooth Canyon	-[220]	0.324 (1,710 ft.)
235 West/44-654/235-335 Palmdale[221]		
235 West	3.1	0.031 (164 ft.)

[215] Ex. SCG-02 (Phillips) at p. 14.
[216] Ex. SCG-03 (Phillips) at pp. 2-3. The "as filed" mileage is consistent with that contained in the workpapers included with the SoCalGas and SDG&E Amended PSEP Application, filed in December of 2011.
[217] Line 2000, because of its length, will be remediated in four phases: 2000-A, 2000-Bridge, 2000-C, and 2000 West. 2000-C has been regrouped with 2001-West-C and will be executed as one project under "2000-C/2001W-C Desert Bundle."
[218] Line 2001-West will be remediated as three projects: 2001 West-A, 2001 West-B, and 2001 West-C. This pipeline has been broken up into section to report schedule progress. 2001 West-C has been regrouped with 2000-C and will be executed as one project under "2000-C/2001W-C Desert Bundle."
[219] Line 2003 has been broken up into two separate projects for reporting schedule progress, Line 2003 Section 1, 3, 4 and Line 2003 Section 2.
[220] Filing mileage included in the 3.1 miles indicated for 235 West below.
[221] The 235 West/44-654/235-335 Palmdale Project is addressed in Chapter V (Mejia).

44-654	0.01	0.047 (246 ft.)
235-335 Palmdale	-	-
33-120 Section 2[222]	1.25	0.279
35-20-N	0.01	0.013 (69 ft.)
36-37	0.02	0.012 (62 ft.)
36-9-09 North[223]	16.02	
36-9-09 North Section 2B		2.155
36-9-09 North Section 6A		0.916
36-1032 Sec (1,2,3)	1.54	0.653 (3,449 ft.)
38-539	12.08	2.613
406 Sec (1,2,2A,4,5)[224]	20.7	1.166
407 (North & South)	6.3	2.997
41-30-A	0.26	0.020 (107 ft.)
45-120 Section 1[225]	4.30	0.553
45-120X01	0.01	0.011 (57 ft.)
PDR Storage Phase 4 and 5[226]	1.92	0.269 (1,418 ft.)
TOTAL	**295.713**	**30.369 miles[227]**

Table 3 - SDG&E Pipeline Projects

Line	As Filed (Miles)	Included in This Filing (Miles)
49-14	2.45	0.032 (167 ft.)
49-22[228]	4.04	4.046
49-32	0.06	0.063 (332 ft.)
TOTAL	**6.55**	**4.141**

The scope reduction shown above is primarily the result of the scope validation of records or reductions in MAOP. Additionally, as indicated, some of the projects have been split

[222] Line 33-120 is being addressed under three separate projects.
[223] At the time of filing, the scope of the Line 36-9-09 North project was 16.01 miles, covering several non-contiguous segments crossing different jurisdictional boundaries. Therefore, Line 36-9-09 North is being addressed in ten different sections, two of which (2B and 6A) are included in this Application.
[224] Line 406 is being addressed under two separate projects.
[225] Line 45-120 is being addressed under two separate projects.
[226] Playa del Rey is being addressed under two separate projects.
[227] Values may not add to total due to rounding.
[228] Line 49-22 includes Section 1, National City and Section 2, Chula Vista.

into sections and were either included in A.14-12-016 or will be included in future applications.[229]

C. SoCalGas and SDG&E Prudently Executed PSEP.

The primary objective of PSEP is to: (1) enhance public safety; (2) comply with Commission directives and applicable regulations; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.[230] As directed by the Commission, the SoCalGas and SDG&E PSEP includes a risk-based methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas, and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels.[231] To implement this prioritization process, the PSEP is divided into two Phases, Phase 1 and Phase 2, and these two phases are further divided into two parts, Phases 1A and 1B, and Phases 2A and 2B.[232] This proceeding seeks reasonableness review of certain Phase 1A projects.[233]

1. <u>SoCalGas and SDG&E Have Acted as Reasonable Managers in Applying the Commission-Approved Decision Tree to Phase 1A Projects</u>.

Phase 1A encompasses pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in high consequence areas[234] that do not have sufficient documentation of a pressure test to at least 1.25 times the MAOP. In order to determine whether Phase 1A pipeline should be

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[229] Ex. SCG-3 (Phillips) at p. 3.
[230] Ex. SCG-02 (Phillips) at p. 3.
[231] Ex. SCG-03 (Phillips) at p. 13; D.14-06-007, mimeo., at pp. 10-11.
[232] Ex. SCG-02 (Phillips) at p. 6.
[233] Ex. SCG-02 (Phillips) at pp. 4-5. As indicated *infra* at Section III, D, review is also sought of certain portions of projects that were accelerated from Phase 1B and Phase 2B in order to realize efficiencies. *See also* Ex. SCG-02 (Phillips) at p. 5.
[234] The term "high consequence areas" refers to Class Locations as defined in Part 192.5 of Title 49 of the Code of Federal Regulations.

tested or replaced, Applicants follow the Commission-approved Decision Tree.[235], [236] Table 1, *supra*, sets forth the Decision Tree outcome for each of the projects included in this proceeding.

The Decision Tree uses a step-by-step analysis of pipeline segments to allocate the segments into the following categories: (1) pipeline segments that are 1,000 feet or less in length; (2) pipeline segments greater than 1,000 feet in length that can be removed from service for pressure testing; and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing without significantly impacting customers.[237] These pipeline categories are then further analyzed to identify other factors that may impact a determination of whether to pressure test or replace the segment.

The additional analysis is based on the following principles used to guide the test-versus-replace decision: (1) SoCalGas and SDG&E will not interrupt service to their core customers in order to pressure test a pipeline; (2) SoCalGas and SDG&E will work with noncore customers to determine if an extended outage is possible; (3) SoCalGas and SDG&E will, where necessary, temporarily interrupt noncore customers as provided for in their tariffs; (4) SoCalGas and SDG&E will work with noncore customers to plan, where possible, service interruptions during scheduled maintenance, down time or off-peak seasons; and (5) SoCalGas and SDG&E will consider cost and engineering factors along with the improvement of the pipeline asset.[238] These principles were explained in SoCalGas and SDG&E's amended PSEP and during evidentiary hearings in A.11-11-002. 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. Because of the need to

[235] D.14-06-007, mimeo., at p. 59 (Ordering Paragraph 1).

[236] SoCalGas and SDG&E also proposed the formation of an Engineering Advisory Board to provide an extra level of comfort that SoCalGas and SDG&E decisions to test, replace, or abandon were sound (A.11-11-002: Rebuttal Testimony of Rick Phillips at 14). The Engineering Advisory Board was to be a four-member board made up of a company representative, a representative of the Commission's Safety and Enforcement Division, a representative of the Commission's Energy Division, and an outside pipeline integrity expert to be mutually agreed upon by the first three (A.11-11-002: Rebuttal Testimony of Rick Phillips at 15). D.14-06-007, however, did not adopt the advisory board concept proposed by SoCalGas and SDG&E. D.14-06-007, mimeo., at p. 28.

[237] Ex. SCG-03 (Phillips) at p. 10.

[238] Ex. SCG-03 (Phillips) at p. 11.

apply engineering expertise and consider how the pipelines operate within the overall pipeline system, pipeline operators make this determination on a project-by-project basis.[239]

a. Segments Less than 1,000 Feet

Generally, pipeline segments that are less than 1,000 feet in length are identified for replacement under the Decision Tree because it is usually more cost-effective to replace these short segments.[240] SoCalGas and SDG&E may, however, engage in further review during the early planning stage to determine the most appropriate action for a specific segment.[241] For example, costs and other engineering factors may be considered, depending on the unique attributes of each pipeline segment and its situation (*e.g.*, the short segment is located on a bridge or under a freeway, making it impractical to replace due to heightened complexity). This approach was endorsed by the Commission in D.14-06-007 where, in denying SoCalGas and SDG&E's proposal to create an Engineering Advisory Board, the Commission determined it "see[s] no benefit to creating any oversight or advisory board to muddle the clear line of responsibility that rests solely with SDG&E and SoCalGas to competently manage and maintain the pipeline system."[242]

An additional implicit consideration is that installing new pipe — manufactured to modern standards — further enhances the safety of the entire pipeline system.[243]

b. Segments Greater than 1,000 Feet

The decision to pressure test or replace pipeline segments greater than 1,000 feet is based on an assessment of potential customer impacts and an engineering and cost analysis that seeks to minimize customer impacts while maximizing safety and cost-effectiveness.[244] Per the Decision Tree, pipeline segments greater than 1,000 feet that can be removed from service are generally pressure tested unless the segment was installed prior to 1946 and is non-piggable, or

[239] Ex. SCG-03 (Phillips) at p. 11.
[240] Ex. SCG-03 (Phillips) at p. 11.
[241] Ex. SCG-03 (Phillips) at p. 12.
[242] D.14-06-007, mimeo., at p. 28.
[243] Ex. SCG-03 (Phillips) at p. 12.
[244] Ex. SCG-03 (Phillips) at p. 12.

other factors indicate replacement should occur.[245] Also per the Decision Tree, pipeline segments that are greater than 1,000 feet in length that cannot be removed from service are replaced.[246]

2. SoCalGas and SDG&E Acted as Prudent and Reasonable Managers in Addressing Accelerated and Incidental Mileage in Planned Projects.

The Commission directed the utilities to develop plans that "provide for testing or replacing all [segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test] *as soon as practicable*" (emphasis added)[247] and that address "all natural gas transmission pipeline…even low priority segments,"[248] while also "[o]btaining the greatest amount of safety value, i.e., reducing safety risk, for ratepayer expenditures."[249] The inclusion of "accelerated" and "incidental" miles, defined below, is driven by efforts to achieve these goals while also adhering to the objective of minimizing customer impacts.[250]

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.[251]

Incidental miles are those which are not required to be addressed as part of PSEP, but are included when it is determined that doing so minimizes customer impacts, improves cost and program efficiency, addresses implementation constraints, or facilitates continuity of testing.[252]

245 Ex. SCG-03 (Phillips) at p. 12.
246 Ex. SCG-03 (Phillips) at p. 12.
247 D.11-06-007, mimeo., at p. 19.
248 D.11-06-007, mimeo., at p. 19.
249 D.11-06-007, mimeo., at p. 20.
250 Ex. SCG-03 (Phillips) at pp. 12-13.
251 Ex. SCG-03 (Phillips) at p. 13.
252 Ex. SCG-03 (Phillips) at p. 13. An additional benefit of including incidental mileage is to further confirm the integrity of the pipeline.

Operational and cost efficiencies frequently can be realized by including “non-criteria” miles within a project scope rather than executing a project around them.[253], [254]

For certain of the Phase 1A projects included in this Application, segments were accelerated from Phase 1B and Phase 2 in order to realize cost and program efficiencies.[255] Phase 2B miles were accelerated only when they minimized customer impacts, improved cost and program efficiency, addressed implementation constraints, or facilitated the continuity of testing.[256], [257] The Line 2000 West Section 1 hydrotest project is an example of a project wherein cost and program efficiency were improved by accelerating Phase 2B mileage. This project includes 417 feet of Category 4 Criteria miles and 4.102 miles accelerated from Phase 2B. The test scope was planned to combine multiple proximate non-contiguous Category 4 segments into one hydrotest in order to realize cost savings and efficiencies. As a result, construction time in the field is minimized, mobilization and demobilization costs are reduced, and impacts to the community are lessened – all while addressing pipe that was within the scope of PSEP, albeit a later phase.[258]

3. <u>SoCalGas and SDG&E Acted as Prudent Managers in Executing Bundled Valve Projects</u>.

In D.11-06-017, the Commission also directed pipeline operators to address the installation of “automated or remote-controlled shut-off valves” in their proposed implementation plans.[259] In response to this directive, SoCalGas and SDG&E submitted a Valve Enhancement Plan which was reviewed favorably by the Consumer Protection and Safety Division (“CPSD,” now called Safety and Enforcement Division [“SED”]) of the CPUC in

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[253] Ex. SCG-03 (Phillips) at p. 13.
[254] “Criteria miles” refers to segments located in Class 3 and 4 locations and Class 1 and 2 High Consequence Areas.
[255] Ex. SCG-03 (Phillips) at p. 13.
[256] Ex. SCG-03 (Phillips) at pp. 12-13.
[257] Incidental and accelerated miles may be included in a pressure test or replacement project but are significantly more likely to occur with a pressure test project because of the efficiencies realized by pressure testing longer segments of pipeline.
[258] Ex. SCG-16 at pp. 79, 85.
[259] D.11-06-017 at 21, 30 (Conclusion of Law Paragraph 9), and 32 (Ordering Paragraph 80).

2012[260] and approved as part of their PSEP in D.14-06-007.[261] The Valve Enhancement Plan works in concert with PSEP's pipeline testing and replacement plan to enhance system safety by augmenting existing valve infrastructure to accelerate SoCalGas and SDG&E's ability to identify, isolate and contain escaping gas in the event of a pipeline rupture.

The Valve Enhancement Plan focuses on the enhancement of valve infrastructure to isolate transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs. To maximize the cost effectiveness of this investment in valve infrastructure, SoCalGas and SDG&E's Valve Enhancement Plan enhances public safety through the following activities in support of an overall objective to achieve isolation of identified pipeline segments in 30-minutes or less:

- Installation of Automatic Shutoff Valve ("ASV")/Remote Control Valve ("RCV") capability at intervals of approximately eight miles or less on pipelines that are twenty inches or greater in diameter;
- Installation of ASV/RCV capability at intervals of approximately eight miles or less on pipelines twelve inches or greater in diameter that operate at a hoop stress of 30% or more of SMYS; and
- Installation of ASV/RCV capability at shorter interval spacing (one-half to one mile) on up to twenty pipeline segments that meet the above criteria and also cross a known geologic threat (*e.g.*, earthquake faults, landslide areas, washout areas, and other potential geologic or man-made hazards).[262]

In an effort to achieve the isolation objective, the Valve Enhancement Plan that was approved by the Commission has continued to be refined as Applicants conducted additional diligence.[263] Multiple main pipeline valves may be required to isolate a section of pipeline, and mitigating the loss of service to customers requires a refined control strategy and several assets.[264] Refinement in the field is necessary because the most current configuration of the

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[260] Ex. SCG-06 (Bermel) at p. 4.
[261] D.14-06-007, mimeo., at pp. 8, 59 (Ordering Paragraph 2).
[262] Ex. SCG-05 (Bermel) at pp. 1-2.
[263] Ex. SCG-05 (Bermel) at pp. 5-7.
[264] Ex. SCG-05 (Bermel) at p. 7.

pipeline system must be taken into consideration in order to best achieve SoCalGas and SDG&E's 30-minutes or less isolation objective.[265]

Activities on the bundled valve projects submitted for review in this proceeding have included valve installations and enhancements, communication equipment installation, backflow prevention valve installation, and expansion of the Applicants' private radio network coverage.[266]

In an effort to create efficiencies and reduce costs, individual valve projects were "bundled" in order to allow management of several projects as one combined design with related construction activities.[267]

4. <u>SoCalGas and SDG&E Acted as Reasonable Managers by Employing a Measured Approach in Implementing the Technology Pilot Program</u>.

As part of PSEP, Applicants' proposed, and the Commission approved, a Technology Plan.[268] The objectives of the approved PSEP Technology Plan are threefold: (a) to provide more timely information about pipeline and pipeline route and right-of-way status; (b) to enable more timely responses to incidents; and (c) to equip operators with additional data to help manage situations following an emergency.[269] In furtherance of these objectives, Applicants proposed installation of the following:

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[265] Ex. SCG-05 (Bermel) at pp. 5-7.
[266] Ex. SCG-05 (Bermel) at p. 5.
[267] Ex. SCG-07 (Mejia) at p. 4.
[268] The Commission determined in D.14-06-007 that "Safety Enhancement includes… improvements to communications and data gathering to ascertain pipeline conditions; … [and] installing remote leak detection equipment."[268] CPSD concurred that there were safety benefits to methane sensing detectors and fiber optic monitoring systems. D.14-06-007, mimeo., at p. 8; Ex. SCG-06 (Bermel) at pp. 2-3. "The Companies should continue evaluating next generation methane detection technologies. Any technology that shows promise in regard to accuracy, reliability, maintenance needs, and cost should be tested through a pilot program through which the units are evaluated in actual, varying, field conditions, to support wide scale deployment throughout the system." R.11-02-019, January 17, 2012 *Technical Report of CPSD Regarding the SoCalGas and SDG&E PSEP*, at p. 22. Further, it stated "CPSD believes that work and materials related to the installation of fiber-optic sensors and the DCMS may have value. The greatest cost of placement of fiber-optic cable, which must be buried slightly above the pipeline, is the cost of excavation itself. The costs for material and installation justify placing the cable in the ground even if it is not connected to monitors right away." *Id.*
[269] Ex. SCG-06 (Bermel) at pp. 1-2.

- Above-ground, near real-time methane sensors to provide continuous leak detection where a pipeline is routed near facilities that pose special evacuation consideration or other special commerce implications;
- Fiber-optic cabling along pipeline segments to allow for monitoring when pipelines experience non-native movement, vibration, or temperature gradients, or acoustic signatures indicative of a leak;[270] and
- A back-office computer monitoring and communication system to collect and manage routine fiber and methane sensor data, acquire and manage alarms, and provide information and processing of data.[271]

Consistent with their approved Technology Plan, SoCalGas and SDG&E have been pursuing remote methane sensing system development and advancements with their respective Advanced Meter business partners since 2011.[272] These efforts have led to the production of proprietary remote field site methane sensing systems capable of utilizing the advance metering network communications favored by the Commission and CPSD.[273]

As prudent managers, SoCalGas and SDG&E opted to take a measured approach to implementing the Technology Plan in an effort to gain confidence that the concepts they were developing would serve to achieve the Commission's, CPSD's, and their safety enhancement objectives. The general pilot work conducted will enable SoCalGas and SDG&E to leverage future advances in commercial methane sensors as the technology itself continues to make progress in sensing accuracy, reliability, and cost.[274] In addition to the activities undertaken by each utility as described below, Applicants incurred reasonable costs in: developing and producing advanced meter-compatible gas modules which can interface with commercially

[270] Applicants do not seek recovery of costs associated with fiber optic installation in this proceeding. Company procedures now prescribe that all new and replacement pipelines of 12"-diameter or greater and over 1-mile in contiguous length shall be co-equipped with fiber-optic sensing cabling during construction. Thus far these costs have been incurred only outside of PSEP. Ex. SCG-06 (Bermel) at pp. 3-4.

[271] Ex. SCG-06 (Bermel) at p. 2.

[272] Ex. SCG-06 (Bermel) at p. 4.

[273] Ex. SCG-06 (Bermel) at pp. 2-3.

[274] Ex. SCG-06 (Bermel) at p. 7.

available methane sensors; the purchase of methane sensors, fabricating and installing remote methane-sensing stations; configuring the existing advanced meter radio system to collect information and route them into a data management and alarming system; and developing and deploying a computerized base hosted data management system, alarm processing, and reporting system.[275]

Because the radio infrastructure for each utility's advanced meter system is proprietary to the providers, it was reasonable to sole-source the work on the Technology Pilot Programs to each utility's advanced meter system provider.[276]

Each of the pilot programs installed currently are under testing and evaluation.[277]

a. SoCalGas's Technology Pilot Program

SoCalGas developed and deployed ten solar-powered, remote, continuous methane monitoring systems along transmission lines at or near facilities with special evacuation considerations in the event of a pipeline gas release.[278] SoCalGas and its advanced meter supplier and system provider undertook the following activities: design, fabrication, and installation of the base remote monitoring stations; integration of the remote monitoring stations with SoCalGas' Advanced Metering System so as to read and process data from the field devices; and implementation of data management and alarm processing host system to read the methane sensor data, register and process alarms, and to provide for daily system integrity checks of the base units.[279] An advance meter system radio module was also developed which can interface with commercially-available methane sensors to provide for near-real-time measurement of methane concentrations in air.[280]

The fully-loaded, reasonably incurred cost associated with SoCalGas's Technology Pilot Program is $358,080.

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[275] Ex. SCG-06 (Bermel) at pp. 7-9.
[276] Ex. SCG-06 (Bermel) at pp. 5-6.
[277] Ex. SCG-06 (Bermel) at pp. 5-6.
[278] Ex. SCG-06 (Bermel) at p. 4.
[279] Ex. SCG-06 (Bermel) at pp. 4-5.
[280] Ex. SCG-06 (Bermel) at p. 5.

b. SDG&E's Technology Pilot Program

SDG&E deployed 15 self-contained, battery-powered remote continuous methane monitoring systems along its transmission Line 3010 at or near facilities with special evacuation considerations in the event of a pipeline gas release.[281] In support of this deployment, base remote methane monitoring sensors and integrated advanced material radio system compatible modules were specified, developed, purchased, and installed.[282] Remote monitoring stations that were compatible with SDG&E's advanced meter system were integrated in order to enable reading and processing data from the field devices, and a data management and alarm processing host system was implemented.[283]

Applicants also worked with SDG&E's advanced meter system supplier in order to develop a compatible radio module containing an integral methane sensor in a single small package that could be pole-mounted easily.[284]

The fully loaded, reasonably incurred cost associated with SDG&E's Technology Pilot Program is $117,059.

V. IN MANAGING AND EXECUTING PSEP AS REASONABLE MANAGERS, THE COSTS INCURRED BY SOCALGAS AND SDG&E IN EXECUTING PSEP ARE JUST AND REASONABLE AND THUS SHOULD BE RECOVERED IN RATES.

A. Reasonable Costs Were Properly Recorded to the PSRMAs, SEEBAs, and SECCBAs.

1. <u>All Reasonable Costs Were Properly Recorded to the Appropriate Accounts</u>.

Costs associated with the foregoing reasonable and prudent activities were recorded appropriately to the PSRMAs, SEEBAs, and SECCBAs in accordance with the Commission directive. Table 1 on pages 3-4 shows the requested costs – exclusive of disallowances -- associated with each of the projects and other cost categories.

[281] Ex. SCG-06 (Bermel) at p. 5.
[282] Ex. SCG-06 (Bermel) at p. 5.
[283] Ex. SCG-06 (Bermel) at pp. 5-6.
[284] Ex. SCG-06 (Bermel) at p. 6.

2. Miscellaneous Costs.

As shown in Table 1, in addition to the costs associated with each of the projects set forth therein, the following additional costs were recorded to the PSRMAs, SEEBAs, and SECCBAs.

a. Facilities Lease Expense

As PSEP is an incremental program that required retaining internal and external personnel, there were no existing facilities to house the additional personnel.[285] SoCalGas and SDG&E leased additional facilities — two adjacent floors at the Gas Company tower in Los Angeles and one space in San Diego[286] — to accommodate the PSEP organization.[287]

Applicants have been prudent in their acquisition and use of additional space. Various departments and personnel were co-located so as to maximize communication and collaboration and minimize idle waiting time.[288] The space planning strategy considered which PSEP groups interact frequently so both formal and informal meetings and interactions could occur fluidly.[289] Seating capacity was also maximized through the use of shared offices and smaller touchdown workstations.[290] Obtaining the additional space was prudent and reasonable.

b. Descoped Projects

Descoped projects are those for which planning was underway when Applicants determined they could bring the project outside the scope of PSEP through ongoing records review or by lowering the MAOP.[291] As a result of their efforts to minimize PSEP costs, SoCalGas and SDG&E were able to remove the following pipeline projects from within the scope of PSEP: Line 35-20-A; Line 38-523; Line 41-6045; and Line 41-80.[292] Applicants seek

[285] Ex. SCG-03 (Phillips) at p. 16.
[286] The space leased in San Diego was the second-lowest priced of eleven options presented to Applicants, required no tenant improvements, and was available for immediate occupancy so as to allow the execution of PSEP to proceed expeditiously. Ex. SCG-03 (Phillips) at p. 18.
[287] Ex. SCG-03 (Phillips) at p. 16. Before the two floors at the Gas Company Tower became available for lease, a short-term lease for a portion of a floor at the Gas Company Tower was obtained. *Id.* Also, a portion of a classroom was leased to accommodate technical training for field personnel. *Id.*
[288] Ex. SCG-03 (Phillips) at p. 16.
[289] Ex. SCG-03 (Phillips) at p. 16.
[290] Ex. SCG-03 (Phillips) at p. 17.
[291] Ex. SCG-03 (Phillips) at p. 18.
[292] Ex. SCG-03 (Phillips) at p. 18.

cost recovery of $199,000 associated with descoped projects.[293] This amount is exclusive of disallowances (i.e., the costs pertain to pre-1956 vintage pipeline and do not include the costs of searching for records pertaining to these de-scoped projects).[294] These costs were prudently incurred by reasonable managers expeditiously proceeding with PSEP and ultimately resulted in cost savings (because the projects were not required to be executed), and thus should be recovered by Applicants.

c. Post-Completion Adjustments

Applicants hereby seek cost recovery of $320,000 associated with projects (including descoped projects) and facilities build-out that were presented in the first PSEP reasonableness review, A.14-12-016.[295] Post-completion adjustments occur when invoices or accounting adjustments are received after the application for an after-the-fact reasonableness review is filed.[296] Despite best efforts by Applicants to capture all costs during the close-out process — including initiating processes to validate invoices are received and paid prior Stage 7 Closeout — such adjustments do occur.[297] The primary categories of post-completion adjustments in this case are contractor invoices, accrual reversals, and company labor hour/journal entry adjustments.[298] As they are costs that have been prudently incurred by Applicants in executing PSEP, they should be recovered.

3. Disallowances Have Been Calculated and Excluded.

As noted in Section II, D, *supra*, the Commission has ordered certain disallowances. The following PSEP costs have been excluded by SoCalGas and SDG&E in compliance with the Commission's directive. They total $7.18 million in this proceeding and, combined with the disallowances excluded from the prior PSEP reasonableness review, have totaled approximately $25 million.

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[293] Ex. SCG-03 (Phillips) at p. 18.
[294] Ex. SCG-03 (Phillips) at p. 18.
[295] Ex. SCG-03 (Phillips) at p. 18.
[296] Ex. SCG-03 (Phillips) at p. 19.
[297] Ex. SCG-03 (Phillips) at p. 19.
[298] Ex. SCG-03 (Phillips) at p. 19.

a. Records Search.

SoCalGas and SDG&E tracked the costs associated with their search for pressure test records.[299] Certain of these costs were acknowledged as disallowed in the prior reasonableness review, A.14-12-016.[300] Additional disallowances in the amount of $187,000 are acknowledged herein.[301] These costs are not included in the costs presented to the Commission for review.

b. Post-1955 Vintage Pipeline Projects.

This category combines two categories of disallowances ordered by the Commission: disallowances for post-July 1961 vintage pipeline and the later-ordered post-1955 vintage pipeline.[302] Post-1955 vintage pipeline disallowances are calculated and excluded as follows.

i. Hydrotest Projects

For hydrotest projects, in order to calculate the amount of the disallowance in accordance with the Commission's directive, Applicants first calculate the percentage of pipe in the project that does not have sufficient[303] record of a pressure test.[304] That percentage is then used to determine the costs subject to disallowance (i.e., the percent of length of disallowed pipe is the same percent used to calculate the cost disallowance).[305]

When incidental mileage is included in order to facilitate the constructability of post-1955 vintage pipeline hydrotest projects, Applicants include this mileage in calculating the disallowance.[306] When accelerated mileage is included in a post-1955 vintage pipeline hydrotest

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[299] Ex. SCG-03 (Phillips) at p. 8.
[300] Ex. SCG-03 (Phillips) at p. 8.
[301] Ex. SCG-03 (Phillips) at p. 4.
[302] *See* Section II, D *supra*.
[303] For purposes of determining disallowance, Applicants define "sufficient" to mean a record that provides the minimum information to demonstrate consistency with then-applicable industry standards and recordkeeping requirements regarding strength testing. Ex. SCG-03 (Phillips) at p. 6.
[304] Ex. SCG-03 (Phillips) at p. 6.
[305] Ex. SCG-03 (Phillips) at p. 6.
[306] Ex. SCG-03 (Phillips) at p. 6. Although the Commission's orders in D.14-06-007 and D.15-12-020 only expressly require SoCalGas and SDG&E's shareholders to absorb the costs of pressure testing pipelines installed after 1956 that do not have records of a pressure test that comply with then-applicable industry standards or regulations, in implementing the Commission's order, SoCalGas and SDG&E also applied this disallowance to incidental pipeline footages when doing so implements what SoCalGas and SDG&E believe was the Commission's intent in D.14-06-007 and D.15-12-020—to hold shareholders responsible for the costs associated with completing a scope of work attributable to a lack of pressure test

project, that mileage is included for review and cost recovery because it otherwise would be addressed at a later stage in PSEP and would be subject to cost recovery then.[307]

ii. Replacement Projects

For replacement projects, when post-1955 vintage pipeline does not have sufficient record of a pressure test, in accordance with the Commission directive, Applicants calculate the disallowance based on their system-average cost to pressure test.[308] The system average is multiplied by the length of the pipe that is subject to disallowance.[309] In this way, as the Commission directed, a disallowance is assessed, but the customers bear the revenue requirement of the net replacement costs as they "benefit from having a new safe and reliable pipeline."[310]

SoCalGas and SDG&E's combined system average cost to pressure test PSEP projects, calculated as of June 2015 — the time when the projects included in this proceeding for cost recovery were completed — is $1.792 million per mile.[311]

Incidental and accelerated mileage are not included in determining the capital disallowance. Accelerated mileage is not included in the disallowance calculation because it would need to be addressed in a later phase of PSEP were it not addressed in conjunction with a project in execution.[312] Incidental mileage is not included in the disallowance calculation because it has a record of a pressure test and, unlike with the pressure test disallowance, SoCalGas and SDG&E are absorbing undepreciated book value for the *entire* project.[313] In other words, there is already an apportioning of costs as customers receive the benefit of a new pipe and SoCalGas and SDG&E's shareholders absorb the remaining book value of the incidental and accelerated pipeline.[314]

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records that should have been retained under then-applicable regulations or industry standards. Ex. SCG-15 (Ng) at p. 9.

307 Ex. SCG-03 (Phillips) at p. 6.

308 Ex. SCG-03 (Phillips) at p. 7.

309 Ex. SCG-03 (Phillips) at p. 7.

310 Ex. SCG-03 (Phillips) at p. 7.

311 Ex. SCG-03 (Phillips) at p. 7.

312 Ex. SCG-03 (Phillips) at p. 7.

313 Ex. SCG-03 (Phillips) at p. 7.

314 Ex. SCG-03 (Phillips) at p. 7.

iii. Undepreciated Book Value for Post-1955 Vintage Replacement or Abandonment Projects

For replacement and abandonment projects of post-1955 vintage pipeline that do not have a sufficient record of a pressure test but have remaining book value, SoCalGas and SDG&E have acknowledged a reduction to ratebase in an amount equal to the undepreciated book value of the entire replacement or abandonment project.[315] $231,000 in undepreciated book balances pertaining to the 41 projects has been excluded from the costs presented in this proceeding for review.

c. Executive Incentive Compensation.

Although SoCalGas and SDG&E management maintain oversight of PSEP, in order to comply with the Commission's directive to exclude executive incentive compensation costs from cost recovery, as a matter of protocol SoCalGas and SDG&E do not include executive compensation costs for recovery.[316] This alleviates the need to track such costs separately.[317]

In assessing the costs presented for review in this proceeding, Applicants found one instance of embedded executive incentive compensation charges and thus manually removed the full amount — totaling $189 — so it would not be included for in the total presented for review in this proceeding.[318] For sake of clarity, no executive incentive compensation has been included in the amounts presented in this proceeding for review.

B. Intervenors' Recommended Disallowances Are Not Consistent with Commission Guidance and Should Be Rejected.

1. <u>Intervenors Disallowance Recommendations Purportedly Based upon the Reasonable Manager Standard are Inconsistent with the Commission's Reasonable Manager Standard and Should Not Be Adopted</u>.

TURN and SCGC have proposed that certain costs be disallowed because they are not consistent with the reasonable manager standard.[319] While purporting to apply the reasonable

[315] Ex. SCG-03 (Phillips) at p. 8.
[316] Ex. SCG-03 (Phillips) at p. 8. Generally, executive time is not charged to PSEP.
[317] Ex. SCG-03 (Phillips) at p. 8.
[318] Ex. SCG-03 (Phillips) at pp. 4, 8.
[319] Ex. TURN/SCGC-01 (Yap) at pp. 10, 23, 31, 37, 41, 43.

manager standard to conclude that Applicants' actions have failed to comport with the reasonable manager standard, TURN and SCGC do not actually apply the reasonable manager standard; instead, they apply a perfection standard which the Commission has explicitly disavowed.[320] Contrary to TURN and SCGC's position, the Commission has acknowledged that the existence of unexpected occurrences does not fail the reasonable manager standard; maintaining the flexibility to prudently address unexpected occurrences satisfies the standard.[321]

Under the guise of applying the reasonable manager standard, TURN and SCGC propose disallowances for costs associated with construction delays, no matter the reason for the delay. TURN and SCGC have proposed disallowances for the Line 2001 West B Sections 10, 11, and 14 and Line 38-539 projects in the amount of $694,880 based on the contention it was unreasonable to engage in construction during the winter and Tule fog seasons.[322] This ignores the facts that it would be both impractical and imprudent to schedule construction projects only when the weather is expected to be temperate, and also that planning jobs only in the Spring and Fall seasons would result in higher overall program costs and longer durations to complete critical safety work that was ordered to be executed "as soon as practicable."[323]

TURN and SCGC have also proposed disallowances of $1,639,943 for costs associated with construction delays due to delayed materials for the Line 1005, Line 36-1032, Line 38-539, and Line 44-654/Line 235 West/Palmdale Valve Bundle projects. Again, TURN and SCGC engage in an after-the-fact, hindsight review of "how the decision holds up in light of future

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[320] The Commission articulated that SoCalGas and SDG&E are not expected to make the optimal decision every time, stating "[t]his is not a 'perfection' standard: it is a standard of care that demonstrates all actions were well planned, properly supervised and all necessary records are retained." D.14-06-007 at 36.

[321] D.87-06-021, mimeo., at p. 23.

[322] Ex. TURN/SCGC-01 (Yap) at pp. 25, 32-37.

[323] D.11-06-007, mimeo., at p. 19. Ex. SCG-04 (Phillips) at pp. 11-13. PSEP company personnel are not "seasonal" in nature, and idling contractor personnel would likely result in the loss of skilled and experienced PSEP contractors as those contractors would move on to more steady work assignments, which in turn would result in additional costs and inefficiencies to hire new contractors. Moreover, SoCalGas and SDG&E's negotiated construction contractor rates are based on contractors working at a high load factor throughout the year, amortizing their fixed costs over more billable work. *Id.*

developments"[324] that is explicitly antithetical to the reasonable manager standard. SoCalGas and SDG&E sequence construction projects to keep schedules proceeding because, at any given time, there are 15-30 PSEP projects in construction.[325] Reasonable efforts are undertaken to obtain required items in time for when they are needed during construction (*e.g.*, permits, land rights, materials, etc.). [326] In the vast majority of instances, all these various components come together in time to support the construction schedule.[327] Occasionally things do not go as planned. These few delays, however, do not support TURN and SCGC's argument that construction should not commence before all materials, permits, land rights, etc., are obtained. To maintain a default position that no construction project should proceed until all known variables are resolved — in this case, until all construction materials are received — would reduce efficiencies and increase costs.[328] Generally, it is more efficient to initiate construction of a PSEP project before all items (i.e., materials, permits, land rights, etc.) are in hand. SoCalGas and SDG&E's execution and management teams balance competing risks when authorizing a project team to mobilize for construction.[329] These decisions are based on the information available at the time to experienced management[330] -- which is the vantage point for the reasonable manager standard.[331]

The perfection standard that TURN and SCGC apply to Applicants' activities, and the shortsightedness of their disallowance request based thereupon, is best embodied in their request for a disallowance on the Line 2003 project based on a contractor's error in a drawing.[332] This is merely one inadvertent error among thousands of surveys that have been prepared for PSEP,[333] and TURN and SCGC propose a $100,409 disallowance (allegedly reflecting the cost of the

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[324] Scoping Memo at 5 n. 5, citing D.02-08-064 at 5 and 6, and D.88-02-036.
[325] Ex. SCG-04 (Phillips) at p. 3.
[326] Ex. SCG-04 (Phillips) at p. 5.
[327] Ex. SCG-04 (Phillips) at p. 5.
[328] Ex. SCG-04 (Phillips) at p. 6.
[329] Ex. SCG-04 (Phillips) at p. 5.
[330] Ex. SCG-04 (Phillips) at p. 5.
[331] D.14-06-007, mimeo., at pp. 36-37.
[332] Ex. TURN/SCGC-01 (Yap) at pp. 25-26.
[333] Ex. SCG-04 (Phillips) at p. 15.

delay attributable to the drawing error),[334] although the contractor who prepared the drawing was paid only $13,800 for the job.[335] The record demonstrates there are many reasons why this proposed disallowance is inconsistent with the reasonable manager standard and should be rejected;[336] in addition to those reasons, it is worth noting that assessing this perfection-standard-based disallowance now is likely to increase overall PSEP implementation costs for customers to a far greater extent than the $100,409 proposed to be disallowed. Shifting contractual liability to firms to pick up large construction costs is likely to have two impacts, each of which ultimately will increase costs: competition may be decreased because contractors will be less willing to take on such risk and/or contractors will account for these risks by increasing their rates.[337] This would not benefit ratepayers.

Finally, TURN and SCGC seek to disallow all costs incurred by Applicants in the Line 45-120XO1 replacement project ($857,395) because, as part of a subsequent project, a route was re-designed so as to abandon the replaced portion of this project.[338] The actions taken by SoCalGas and SDG&E in the execution of this early project, which was completed in October 2013, were reasonable based on the information known at the time and existing circumstances.[339] The confluence of three projects — one of which was part of Phase 1B, which Applicants have not yet begun to execute as standalone projects — led to the abandonment of this portion of pipe.[340] The second project implicated here – Line 45-120 — did not even go into detailed design until after Line 45-120XO1 was completed.[341] In any event, Applicants enhanced the safety of their system in executing this early project in PSEP and subsequently in abandoning it. If SoCalGas and SDG&E had prioritized not abandoning any of the recently-installed Line 45-120XO1 crossover segment, an alternative design could have been made such that no Line 45-

[334] Ex. TURN/SCGC-01 (Yap) at p. 26.
[335] Ex. SCG-04 (Phillips) at p. 15.
[336] These myriad reasons are stated in the record at Ex. SCG-04 (Phillips) at pp. 14-15.
[337] Ex. SCG-04 (Phillips) at pp. 14-15. Furthermore, such liability shifting particularly could adversely impact small businesses and diverse business enterprises. *Id.*
[338] Ex. TURN/SCGC-01 (Yap) at pp. 38-41.
[339] Ex. SCG-04 (Phillips) at pp. 19-23.
[340] Ex. SCG-04 (Phillips) at pp. 18-21.
[341] Ex. SCG-04 (Phillips) at pp. 20-21.

120XO1 piping was removed.[342] This less efficient design would not have been in the best interest of customers. It would have led to higher construction costs due to a greater amount of construction work in the street and future safety risks for operations personnel.[343] SoCalGas and SDG&E acted reasonably and prudently based on the information known at the time. In keeping with the Commission's directive on the application of the reasonable manager standard, retrospective critique does not warrant disallowances.

Although not relevant in assessing whether Applicants have satisfied the reasonable manager standard, it is worth noting that, as Applicants learn from implementing PSEP, they implement process improvements that achieve greater and greater cost reductions and efficiencies over time. The projects presented for review in this proceeding were executed at least two-to-four years ago, when PSEP was a nascent program, still ramping up.[344] The PSEP PMO prudently develops and reports metrics in part to identify opportunities for improvement.[345] Many improvements have been made in the supply chain process (including, but not limited to, adding expeditors, analyzing and tracking lead times, placing bulk orders)[346] and, as a result, *no* demobilizations have occurred due to material delivery delays since January 2015.[347] Applicants' construction readiness review process was also made more robust in order to obtain the same benefit.[348]

2. SoCalGas and SDG&E Determination To Accelerate Certain Phase 2B Mileage Comports with the Commission's Decision To Bring All Transmission Pipelines into Compliance with the Federal Regulations Adopted in 1970; Associated Costs Should Not Be Disallowed.

TURN and SCGC recommend a disallowance of associated costs totaling $7,434,752 when SoCalGas and SDG&E accelerated Phase 2B mileage and addressed it in conjunction with

[342] Ex. SCG-04 (Phillips) at pp. 22-23.
[343] Ex. SCG-04 (Phillips) at pp. 22-23.
[344] Ex. SCG-04 (Phillips) at p. 10.
[345] Ex. SCG-04 (Phillips) at p. 25.
[346] Ex. SCG-04 (Phillips) at pp. 8-10.
[347] Ex. SCG-04 (Phillips) at p. 10.
[348] Ex. SCG-04 (Phillips) at pp. 10-11.

an adjacent project in this proceeding in order to avoid a proximate project in the future.[349] This proposal would affect the cost recovery sought by Applicants for the following projects: Line 1005; Line 1014; Line 2000 West; Line 2003; and Line 49-14. Since this proposal is in direct contravention of the Commission's decisions, it should be rejected.

Applicants' PSEP was prepared in response to the Commission's directive in D.11-06-017 that all California pipeline operators "must file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)."[350] The Commission issued this order after concluding that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety. Historic exemptions must come to an end with an orderly and cost-conscience implementation plan."[351]

In issuing this mandate, the Commission expressly found that pipeline operators should be required to replace or pressure test all pipelines not tested in accordance with federal regulations adopted in 1970:

> Natural gas transmission pipelines placed in service prior to 1970 were not required to be pressure tested, and were exempted from then-new federal regulations requiring such tests. These regulations allowed operators to operate a segment at the highest actual operating pressure of the segment during the five-year period between July 1, 1965 and June 30, 1970.[352] Natural gas transmission pipeline operators should be required to replace or pressure test all transmission pipeline <u>that has not been so tested</u>.[353]

In seeking to disallow accelerated Phase 2B costs, TURN and SCGC argue that SoCalGas and SDG&E are not required to comply with these Commission directives that define the scope of Applicants' PSEP. Until the Commission modifies the language in prior decisions

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[349] Ex. TURN/SCGC-01 (Yap) at p. 7. TURN and SCGC do not seek to disallow Phase 2B costs when their acceleration served to reduce overall project costs. Ex. SCG-15 (Ng) at pp. 4-5.
[350] D.11-06-017 at 29 (Conclusion of Law 4) and at 31 (Ordering Paragraph 4).
[351] *Id*. at 18.
[352] *Id*. at 28 (Finding of Fact 6).
[353] *Id*. at 28 (Finding of Fact 7) (emphasis added).

directing all California pipeline operators to bring the State's transmission pipelines into compliance with modern standards, and also modifies the language that expressly requires pipeline operators to pressure test or replace all transmission pipelines that have not been tested to post-1970 pressure test standards, SoCalGas and SDG&E must comply with these Commission directives.

By accelerating Phase 2B mileage and addressing it as part of a project already in execution, Applicants are able to reduce overall costs for customers and reduce community impacts by avoiding executing another project in the same or proximate location in the future.[354] As such, it was reasonable and prudent for SoCalGas to include adjacent Phase 2B pipeline segments within the scope of Phase 1 projects, and associated costs should be recovered in rates.

3. TURN and SCGC's Proposals for Disallowance Calculations for Projects Including Incidental Pipe Are Inconsistent with Commission Decisions.

a. Pressure Test Projects

TURN and SCGC propose that the calculation of the disallowance percentage for test projects involving incidental pipe should only include Phase 1A mileage in the denominator.[355] This proposal is lacking in that it fails to consider whether the incidental footage is included within the scope of the project for purposes of facilitating the constructability of pipeline that is or is not subject to disallowance.[356]

Although not explicitly required to include incidental mileage in its disallowance calculation, SoCalGas and SDG&E implement a three-step process to determine whether incidental pipe should be categorized as disallowed footage.[357] First, SoCalGas and SDG&E determine whether the incidental footage was included within the scope of the project to facilitate construction of the portion of pipe that is subject to disallowance. If the incidental footage was included to facilitate construction of pipe that is subject to disallowance, then

[354] Ex. SCG-03 (Phillips) at p. 9, n. 30; Ex. SCG-26 at pp. 1-2.
[355] Ex. TURN/SCGC-01 (Yap) at p. 17.
[356] Ex. SCG-15 (Ng) at p. 10.
[357] Ex. SCG-15 (Ng) at p. 9.

SoCalGas and SDG&E consider the incidental footage to be disallowed footage for purposes of performing a disallowance calculation.[358] If, on the other hand, the incidental footage was included to facilitate construction of pipe that is not subject to disallowance, then SoCalGas and SDG&E do not treat the incidental pipe as disallowed footage for purposes of performing a disallowance calculation.[359] If incidental pipe footage was included to facilitate construction of both disallowed pipe and recoverable pipe, the incremental pipe is allocated to both the disallowed and allowed pipe footage on a pro rata basis.[360]

Second, once the analysis of incidental footage described above is complete and the total amount of disallowed footage is calculated, SoCalGas and SDG&E perform the following pipeline footage calculation:

Disallowed Footage (Category 4 Footage + Disallowed Incidental Footage) /
Total Project Footage (Category 4 Footage + Accelerated Footage + All Incidental Footage) =
Disallowed Percentage

Finally, the Disallowed Percentage is applied to the total project costs to derive the total costs subject to disallowance for that project. This is consistent with the Commission's directive regarding the allocation of costs between ratepayers and shareholders.[361]

Since TURN and SCGC have offered no justification for deviating from the Commission's decisions, and SoCalGas and SDG&E's calculation methodology is consistent with the Commission's decisions, TURN and SCGC's proposal should be rejected.

b. Replacement Projects

For replacement projects, TURN and SCGC propose that costs associated with incidental footage should be disallowed altogether under the premise that it would not have been replaced absent a project replacing Phase 1A mileage.[362] In some instances, this recommendation could lead to the entire replaced footage of a project being subject to disallowance, even though

[358] Ex. SCG-15 (Ng) at p. 9.
[359] Ex. SCG-15 (Ng) at pp. 9-10.
[360] Ex. SCG-15 (Ng) at p. 10.
[361] D.14-06-007, mimeo, at pp. 34-35; D.15-12-020, mimeo., at pp. 23 (Conclusions of Law 7-8).
[362] Ex. TURN/SCGC-01 (Yap) at pp. 14, 15, 16, 30 and 44.

SoCalGas and SDG&E have sufficient record of a pressure test for portions of the pipeline.[363] This contradicts the Commission's guidance regarding disallowances for replacement projects.[364] To comply with the Commission's disallowance directives, SoCalGas and SDG&E identify the pipeline footage within a replacement project associated with post-1955 mileage without sufficient record of a pressure test.[365] SoCalGas and SDG&E then multiply the identified disallowed footage by the system average cost to pressure test[366] as follows:

Disallowed Footage * System Average Pressure Test Cost = Disallowed Replacement Cost[367]

The resulting amount is expensed as a capital disallowance.[368] In this way, a disallowance is assessed, but customers bear the revenue requirement of the net replacement costs, since, as the Commission explained, they "benefit from having a new safe and reliable pipeline."[369]

For replacement projects, accelerated and incidental mileage is not incorporated into the disallowance calculation. This is because SoCalGas and SDG&E have sufficient records of pressure tests of these segments, and included the segments in the project scope to realize efficiencies or improve constructability. In other words, shareholders bear the costs of remedial pressure testing (where there is not sufficient record of a pressure test) and customers bear all other costs of replacing the pipeline, as expressly ordered by the Commission: "In this way shareholders bear the costs of remedial pressure tests and ratepayers pay for all other costs of testing or replacing a pipeline."[370]

TURN and SCGC's proposal to disallow costs associated with footages of pipe with sufficient pressure test records that were replaced as part of certain PSEP replacement projects to

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[363] Ex. SCG-15 (Ng) at p. 12.
[364] D.14-06-007 at pp. 34-35.
[365] Ex. SCG-15 (Ng) at p. 13.
[366] As of June 2015, when the projects presented in this Application completed construction, the system average cost of pressure testing was ~$1.7 million per mile.
[367] Ex. SCG-15 (Ng) at 13.
[368] Ex. SCG-15 (Ng) at 13.
[369] D.14-06-007 at p. 36.
[370] D.14-06-007 at p. 35.

realize efficiencies or improve constructability is inconsistent with the Commission's decisions and unfounded, and thus should be rejected.

4. ORA's System Average Calculation Proposals Are Unreasonable and Inconsistent with Commission Decisions.

ORA proposes selectively both to include and exclude certain projects from the system average calculation that is used to determine the amount of disallowances. ORA's proposals would affect the calculation of disallowances on the following projects: Line 1005; Line 1013; Line 1014; Line 1015; Line 2000 West; Line 2001 West B; Line 2003; Line 33-120; Line 35-20N; Line 407; Line 49-14; Line 49-22; Line 49-32; Line 36-37; and the Palmdale Valves.[371] As ORA's proposals are inconsistent, arbitrary and unworkable, they should be rejected.

a. The Calculation of System Average Pressure Testing Costs Should Occur at a Reasonable Point in Time and Not be Recalculated Indefinitely.

Although Applicants are still in the process of executing PSEP projects, the projects presented for review in this proceeding completed construction by June 2015.[372] Accordingly, SoCalGas and SDG&E calculated the system average cost of pressure testing as of June 30, 2015 — resulting in a calculation of $1.792 million per mile — to determine the amount of project disallowances associated with replacement projects presented in this proceeding.[373], [374]

ORA, however, proposes to adjust the calculation of the system average cost of pressure testing presented in this Application to include projects that completed construction after June 2015. This proposal should not be adopted by the Commission as it is unworkable, administratively burdensome, and unreasonable for several reasons. First, logic dictates that the

[371] Ex. SCG-15 (Ng) at p. 3.
[372] Ex. SCG-15 (Ng) at p. 15.
[373] Ex. SCG-15 (Ng) at p. 15.
[374] ORA identified one project that completed construction by June 2015 that inadvertently had been omitted from SoCalGas and SDG&E's original system average pressure testing cost calculation. SoCalGas and SDG&E do not oppose ORA's recommendation to include this project. Inclusion of that project results in an adjusted system average cost of pressure testing of $1.792 million per mile. Ex. SCG-15 (Ng) at p. 15, n. 27. The cost recovery amounts set forth in this brief account for this revised figure.

system average cost calculation called for in the Commission's decision should generally occur around the time the projects complete construction and are placed into service. Otherwise, the disallowances would continuously require adjustment as the system average constantly changes as the implementation of PSEP moves forward.[375] Second, ORA does not identify a cut-off for calculating the system average; ORA's apparent proposal to include projects that complete construction up to the day an application is filed is unreasonable and unworkable. Third, once a project completes construction, costs continue to accrue as invoices trail in and are booked to the proper utility tracking accounts.[376] Under ORA's proposal, the costs of the various projects used to calculate the system average pressure testing costs would continue to adjust over time. This could result in inadvertent inaccuracies in the amounts presented to the Commission for review because the actual system average might differ from the amount presented in a reasonableness review application. Given the arbitrariness of ORA's proposal and its administrative burdens that result in no concomitant safety or ratepayer benefit, the proposal should be rejected.

b. ORA's Proposal To Omit Certain Projects from the System Average Cost of Pressure Testing To Increase the Average Should be Rejected.

Whereas the aforementioned proposal by ORA seeks to include projects outside the scope of the matters presented, ORA's second proposal regarding calculation of the system average seeks to omit the post-construction pressure testing costs associated with installation of new pipe.[377]

ORA's proposal is inconsistent with the very rationale for disallowing these costs in the first place. In determining that SoCalGas and SDG&E's shareholders should be responsible for these costs, the Commission explained that its decision did "not impose or adopt any penalty for SDG&E or SoCalGas."[378] Rather, the Commission "endeavor[ed] to strike a fair balance between ratepayers and shareholders" by compensating ratepayers for previously incurred

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[375] Further, while the current proposal by ORA would lead to a slightly higher system average calculation today, SoCalGas and SDG&E anticipate the average will reduce over time as SoCalGas and SDG&E execute longer pressure test projects in less populated areas in Phase 2. Ex. SCG-15 (Ng) at pp. 15-16.
[376] Ex. SCG-15 (Ng) at p. 16.
[377] Ex. ORA-02 (Stannik) at pp. 3-4.
[378] D.14-06-007 at 31.

pressure testing costs where SoCalGas and SDG&E failed to maintain a record of such testing. Indeed, the express intent of the disallowance is to ensure customers are not paying twice for pressure testing these pipelines:

> Ratepayers should not pay twice to have a properly installed system in place, therefore, the cost of such tests for facilities installed after July 1, 1961, must be absorbed by the shareholders of SDG&E and SoCalGas in situations where the company has failed to maintain records of strength testing required at the time of installation of the pipeline.[379]

This was reaffirmed by the Commission in D.15-12-020:

> Due to the determinations that SDG&E's and SoCalGas' practice was to pressure test pipeline prior to placing it in service during 1956 to 1961 and seek and obtain cost recovery from ratepayers, shareholders should cover the cost to pressure test pipeline installed between 1956-1961 and for which pressure test records are not available.[380]

Given that the very rationale for disallowing an amount equivalent to the system average cost of pressure testing is that: (1) the Commission determined it was SoCalGas and SDG&E's practice to pressure test newly installed pipelines prior to placing them in service between 1956 and 1961; (2) customers would have paid the costs to pressure test new pipelines prior to placing them in service between 1956 and 1970; and (3) customers should not be required to pay twice for such post-construction pressure testing, ORA's proposal to now exclude from the calculation of the system average costs of pressure testing costs associated with post-construction pressure tests appears to serve no purpose other than to try to artificially inflate the system average cost of pressure testing. Given that the proposal is arbitrary and inconsistent with the Commission's decisions on this issue, the proposal should be rejected.

c. ORA's Post-1955 Pipe Calculations Are Incorrect.

ORA proposes a disallowance of $695,457 based on the assertion that certain accelerated pipe segments that were installed after 1955 and have pressure test records should be considered compliant with modern (49 Code of Federal Regulations Part 192, Subpart J) standards, and thus

379 D.14-06-007 at 4.
380 D.15-12-020 at 23 (Conclusion of Law 7).

the costs of retesting such segments should be borne by shareholders.[381] However, ORA's argument is premised on the false assumption – and no evidence – that the pressure test records satisfy the modern standards embodied in 49 Code of Federal Regulations Part 192, Subpart J.[382] As ORA has entered no evidence into the record indicating that the pressure test records do in fact satisfy the aforementioned modern standards, ORA's proposed disallowance should be rejected.

VI. THE REVENUE REQUIREMENT AND COST ALLOCATION.

The revenue requirements for the costs presented in this proceeding for recovery are \$67.5 million for SoCalGas and \$2.6 million for SDG&E. If the associated cost recovery is approved, these revenue requirements will be updated for the ongoing capital revenue requirements through the date the revenue requirements are incorporated in gas transportation rates. These updated revenue requirements will be allocated to the functional areas and amortized over a 12-month period.[383]

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.[384] In D.16-12-063, the decision on the first PSEP reasonableness review 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.[385] 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 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 regulatory account interest, and incorporate the updated revenue requirements into rates on the first day of the

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[381] Ex. ORA-01(Yunge) at p. 7.
[382] Ex. SCG-09 (Mejia) at pp. 7-8.
[383] Ex. SCG-13 (Austria) at p. 1; Ex. SCG-14 (Chaudhury) at p. 1.
[384] D.14-06-007, mimeo., at p. 50 (Ordering Paragraph 9).
[385] D.16-12-063, mimeo., at p. 59 (Conclusion of Law 24).

month following advice letter approval or in connection with the timing of other authorized changes in the utilities' gas transportation rates. If rates are implemented on a date other than January 1st of the year, the revenue requirements incorporated in rates will be grossed up to ensure recovery of the authorized amounts by the end of the year.

Additionally, the ongoing capital-related revenue equirements associated with reasonably incurred capital expenditures approved in this proceeding will continue to be recorded in the SECCBA. Because this revenue requirement is associated with capital assets already found reasonable by the Commission, SoCalGas and SDG&E propose filing a Tier 2 Advice Letter to incorporate future year revenue requirements into rates until such costs are incorporated into base rates in connection with the utilities' next general rate case proceeding.

VII. CONCLUSION.

The record establishes that SoCalGas and SDG&E have satisfied the reasonable manager standard in incurring the PSEP costs presented for review in this proceeding. 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,

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