

**BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF CALIFORNIA**



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Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.

Application 22-05-015  
(Filed May 16, 2022)

And Related Matter.

Application 22-05-016  
(Filed May 16, 2022)

**THE UTILITY REFORM NETWORK AND  
SOUTHERN CALIFORNIA GENERATION COALITION  
JOINT OPENING BRIEF**

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**TABLE OF CONTENTS**

**1. INTRODUCTION/SUMMARY OF RECOMMENDATIONS..... 1**

**2. PROCEDURAL BACKGROUND ..... 2**

**3. EVIDENTIARY STANDARDS AND THE BURDEN OF PROOF ..... 2**

**4. SCOPING MEMORANDUM ISSUES ..... 2**

**5. TEST YEAR FORECASTING METHODS AND GRC RATEMAKING ..... 2**

**6. POLICY OVERVIEW ..... 2**

**7. AFFORDABILITY AND CUSTOMER IMPACTS / ALTERNATIVES ..... 2**

**8. CLIMATE POLICY/SUSTAINABILITY POLICY ..... 2**

**9. RISK-INFORMED GRC OVERVIEW ..... 2**

**10. GAS DISTRIBUTION..... 2**

**11. GAS SYSTEM STAFF AND TECHNOLOGY ..... 2**

**12. GAS TRANSMISSION OPERATIONS AND CONSTRUCTION..... 2**

**13. GAS ENGINEERING ..... 2**

**13.1 SoCalGas Unreasonably Included Pre-2019 ROW Renewal Costs in the MROWMA. .... 4**

**13.1.1 The MROWMA Covers Morongo ROW Renewal Efforts During the TY 2019 GRC. .... 5**

**13.1.2 Costs Associated with Morongo ROW Renewal Activities in 2012-2018 Were Subsumed by SoCalGas’s TY 2012 and TY 2016 GRC Revenue Requirements..... 6**

**13.2 SoCalGas’s Defense is Unpersuasive..... 9**

**14. PIPELINE SAFETY ENHANCEMENT PLAN (PSEP) ..... 12**

**14.1 The Commission Has Generally Viewed Contingency Factors with Considerable Skepticism, Reasoning that Contingency Factors Reduce Incentives to Control Costs. .... 14**

**14.2 SoCalGas Is Well Positioned to Accurately Forecast PSEP Costs in This GRC..... 19**

**14.3 SoCalGas’s Criticisms of TURN-SCGC’s Recommendation Fall Flat..... 23**

**14.4 TURN-SCGC’s Adjustments Should Be Adopted..... 25**

**15. GAS INTEGRITY MANAGEMENT PROGRAMS..... 28**

<b>15.1</b>	<b>The Commission Should Reduce SoCalGas’s Test Year 2024 TIMP O&amp;M Forecast by 29 percent from \$135.4 million to \$96.1 million.....</b>	<b>30</b>
<b>15.1.1</b>	<b>SoCalGas’s Test Year 2024 A&amp;R O&amp;M Forecast of \$103.9 Million Should Be Reduced by 28.6 Percent (\$29.7 Million) to \$74.2 Million for Test Year 2024.....</b>	<b>31</b>
<b>15.1.1.1</b>	<b>SoCalGas’s Methodology for Forecasting A&amp;R ILI and ECDA O&amp;M Costs for Test Year 2024 is Based upon Unit Costs, but SoCalGas Fails to Provide any Support for the Claimed Unit Costs.....</b>	<b>32</b>
<b>15.1.1.2</b>	<b>SoCalGas Cannot Rely on the Expansion of GTSR Rule Part 1 to Cover Outside-of-HCA Assessments and Material Verification as a Reason for Increasing A&amp;R ILI and ECDA O&amp;M Forecasted Costs in Comparison to Base Year 2021 Costs.....</b>	<b>34</b>
<b>15.1.1.3</b>	<b>The Unreasonableness of SoCalGas’s A&amp;R ILI and ECDA Expense Forecasts for Test Year 2024 Is Demonstrated by the Fact that SoCalGas Substantially Increases Its A&amp;R ILI and ECDA Costs for Doing Less ILI and ECDA Assessment Activity. ....</b>	<b>36</b>
<b>15.1.1.4</b>	<b>The Dramatic Magnitude of the Increase in SoCalGas’s Forecasts of Test Year 2024 A&amp;R ILI and ECDA Unit Expense in Comparison to Recorded 2017-2021 Expense Is Further Demonstrated by a Backcast.....</b>	<b>37</b>
<b>15.1.1.5</b>	<b>The Commission Should Base the Forecast for A&amp;R ILI and ECDA O&amp;M for Test Year 2024 on the Five Year 2017-2021 Average ILI and ECDA Assessment Expenses.....</b>	<b>38</b>
<b>15.1.1.6</b>	<b>In Addition to Adopting the Five-Year Average of Recorded A&amp;R ILI and ECDA Assessment Cost of \$61.581 Million for Test Year 2024, the Commission Should Include Incremental Amounts for Material Verification and Crack Management to the A&amp;R O&amp;M Forecast.....</b>	<b>39</b>
<b>15.1.1.7</b>	<b>Conclusion: The Test Year 2024 Forecast for A&amp;R O&amp;M Should Be \$74.212 Million in 2021 Dollars. ....</b>	<b>40</b>
<b>15.1.2</b>	<b>The Remaining Four Non-A&amp;R TIMP O&amp;M Cost Categories Should Be Forecasted to Be Equal to the Five-Year 2017-2021 Average Amount in 2021 Dollars.....</b>	<b>41</b>

15.1.2.1	<b>SoCalGas’s Forecast for the Four Non-A&amp;R Categories of TIMP O&amp;M Expense Should Be Reduced to the Five-Year 2017-2021 Average of Expense for Each of the Four Non-A&amp;R Categories.....</b>	<b>41</b>
15.1.2.2	<b>SoCalGas Fails to Provide Any Evidence of a Need to Increase the Test Year Level of O&amp;M Expense for the Four Non-A&amp;R TIMP O&amp;M Categories Above the Five-Year 2017-2021 Averages.....</b>	<b>43</b>
15.1.3	<b>Conclusion: The Commission Should Authorize a Test Year 2024 Forecast for Each of the Five Categories of TIMP O&amp;M Expense that Is Based on the Five-Year 2017-2021 Average Level of Expense with Additional Increases to the A&amp;R Category of \$7.145 Million for Crack Management and \$1.136 Million for Material Verification....</b>	<b>44</b>
15.2	<b>The SoCalGas TIMP Balancing Account Should Be Converted from Being a Two-Way Balancing Account to Being a One-Way Balancing Account Combined with A Memorandum Account in Which SoCalGas Would Record on a Year-to-Year Basis for Future Reasonableness Review Any Amounts that Are in Excess of Costs Authorized for TIMP Activities in this GRC.....</b>	<b>45</b>
15.2.1	<b>SoCalGas TIMP Costs Started to Increase Precipitously in 2017.....</b>	<b>46</b>
15.2.2	<b>SoCalGas Advice Letter 6060 Seeking Recovery of a Portion of the TIMPBA Balance that is 35 Percent Above the GRC Authorized Amount Demonstrates that the SoCalGas TIMPBA Undercollections During the Test Year 2019 GRC Cycle Soared.....</b>	<b>48</b>
15.2.3	<b>The Risk Spend Efficiencies for SoCalGas Integrity Assessments and Remediations on the High Pressure System Are Low. ....</b>	<b>49</b>
15.2.4	<b>The Commission Should Replace the Two-Way TIMP Balancing Account with a One-Way Balancing Account Plus a Memorandum Account to Record Any Annual Overspending with Recovery of Overspent Amounts Being Subject to an Application Rather than an Advice Letter. ....</b>	<b>49</b>
15.2.5	<b>The Commission Has Been More Successful in Containing SoCalGas’s Pipeline Safety Enhancement Plan Project Costs than It Has Been in Containing TIMP Costs. ....</b>	<b>50</b>
15.3	<b>The Mileage Covered by the SoCalGas Integrated Safety Enhancement Plan During this GRC Cycle Should Be Significantly Reduced to Reflect Actual Regulatory Requirements. ....</b>	<b>52</b>
15.3.1	<b>In D.19-09-51, the Commission Directed SoCalGas to Identify by Class All of the SoCalGas Transmission Pipelines Which Were Tested Under the Pre-1970 American Standard Association (“ASA”) Code.</b>	<b>52</b>

15.3.2	<b>SoCalGas Should Extend the Period of Time for Completing Work on ISEP Mileage to Take Advantage of the Time Allowed Under 49 CFR § 192.624(b) and Under the “As Soon As Practicable” PSEP 2B Requirement.</b>	<b>54</b>
15.3.3	<b>The Forecast for ISEP Mileage and Capital Expenditures Presented in the TURN-SCGC Direct Testimony on the Assumption that 1,108 miles Were in the Scope of the ISEP Should Be Reduced.</b>	<b>55</b>
15.3.4	<b>If ISEP Expenditures are Excluded from Post-Test-Year Attrition Adjustments as Requested by SoCalGas, the Commission Should Adopt TURN-SCGC’s Downwardly Adjusted Forecasts for Post-Test-Year ISEP Expenditures.</b>	<b>58</b>
15.3.5	<b>Limiting SoCalGas’s ISEP Activities so that SoCalGas Complies With the Deadlines Established in 49 CFR § 192.624(b) and in Public Utilities Code § 958 Without SoCalGas Doing More than is Required to Meet the Deadlines Is Consistent with Commission Policy.</b>	<b>58</b>
15.4	<b>The Commission Should Deny SoCalGas’s Request for a New GSEP Balancing Account.</b>	<b>59</b>
15.4.1	<b>The Commission Should Deny SoCalGas’s Request to Create a New Permanent GSEP Balancing Account.</b>	<b>60</b>
15.4.1.1	<b>There Is No Statutory Requirement for the Commission to Establish the GSEPBA.</b>	<b>60</b>
15.4.1.2	<b>SoCalGas Has a Long History with the Activities for Which Costs Would Be Recorded in the New GSEPBA, so SoCalGas Does Not Need the GSEPBA.</b>	<b>61</b>
15.4.1.3	<b>SoCalGas Should Be Incentivized to Complete Projects At or Below Project Estimates Because, Particularly, Hydrotesting Has a Very Low Risk Spend Efficiency.</b>	<b>62</b>
15.4.2	<b>If the Commission Determines that SoCalGas Requires Relief for this GRC for the Cost of Hydrotesting ISEP Projects, SoCalGas Should Be Permitted to Establish the GSEP Memorandum Account to Record Overspending Forecasted ISEP Costs for this GRC Cycle Only.</b>	<b>63</b>
15.4.3	<b>The Commission Should Unequivocally Deny SoCalGas’s Request to Include Within the Scope of the GSEPBA Implementation of Future Gas Rules and Regulations.</b>	<b>64</b>
15.4.4	<b>If the Commission Permits SoCalGas to Create the GSEPBA for this 2024-2027 GRC Cycle, SoCalGas Should Not Be Permitted to Recover 35 Percent Above Authorized Expenditures Through an Advice Letter Filing.</b>	<b>64</b>

<b>16.</b>	<b>GAS STORAGE OPERATIONS AND CONSTRUCTION (SOCALGAS ONLY).</b>	<b>65</b>
16.1	The Commission Should Reject the Microgrid Portion of the Principal Component of the HRCM Project.....	66
16.1.1	The Microgrid is Not Necessary for Honor Rancho Storage Field Reliability.....	66
16.1.2	The Savings in Electricity Costs Would Not Be Sufficient to Justify the \$23 Million Expenditure on the Microgrid. ....	67
16.1.3	SoCalGas Fails to Show that the Existing Onsite Electrical Generation at Honor Rancho Would Be Insufficient to Supply Administrative and Auxiliary Load in the Event of an Electrical Outage. ....	68
16.2	The ARE Component of the HRCM Project is Outside the Scope of this Test Year 2024 GRC. ....	68
16.3	Even if SoCalGas’s ARE Component Proposals Were Within the Scope of this Proceeding, the Commission Should Reject the Proposals.....	70
<b>17.</b>	<b>PROCUREMENT</b> .....	<b>71</b>
<b>18.</b>	<b>CLEAN ENERGY INNOVATIONS</b> .....	<b>71</b>
18.1	Clean Fuels Infrastructure Development “Functions.” .....	73
18.1.1	The Business Development Function. ....	73
18.1.2	Clean Fuels Power Generation Function.....	75
18.2	Clean Fuels Infrastructure Development Programs. ....	77
18.2.1	The Clean Fuels Transportation Program. ....	77
18.2.2	CCUS FEED Study .....	78
18.2.3	Clean Fuels Operational Readiness Program. ....	79
18.3	Clean Energy Innovations Project Management Office.....	81
<b>19.</b>	<b>ELECTRIC GENERATION (SDG&amp;E ONLY)</b> .....	<b>83</b>
<b>20.</b>	<b>ELECTRIC DISTRIBUTION (SDG&amp;E ONLY)</b> .....	<b>83</b>
<b>21.</b>	<b>CUSTOMER SERVICES</b> .....	<b>83</b>
<b>22.</b>	<b>SUPPLY MANAGEMENT, LOGISTICS AND SUPPLIER DIVERSITY</b> .....	<b>83</b>
<b>23.</b>	<b>CLEAN TRANSPORTATION (SDG&amp;E ONLY)</b> .....	<b>83</b>
<b>24.</b>	<b>FLEET SERVICES</b> .....	<b>83</b>
<b>25.</b>	<b>REAL ESTATE, LAND SERVICES, AND FACILITY OPERATIONS</b> .....	<b>83</b>
<b>26.</b>	<b>ENVIRONMENTAL SERVICES</b> .....	<b>83</b>
<b>27.</b>	<b>INFORMATION TECHNOLOGY</b> .....	<b>83</b>
<b>28.</b>	<b>CYBERSECURITY</b> .....	<b>83</b>

29.	<b>CORPORATE CENTER – GENERAL ADMINISTRATION .....</b>	<b>83</b>
30.	<b>INSURANCE.....</b>	<b>83</b>
31.	<b>COMPENSATION AND BENEFITS .....</b>	<b>83</b>
32.	<b>PENSION AND POST-RETIREMENT BENEFITS OTHER THAN PENSIONS .</b>	<b>83</b>
33.	<b>PEOPLE AND CULTURE DEPARTMENT.....</b>	<b>83</b>
34.	<b>ADMINISTRATIVE AND GENERAL .....</b>	<b>83</b>
35.	<b>SHARED SERVICES BILLING, SHARED ASSETS BILLING, SEGMENTATION &amp; CAPITAL REASSIGNMENTS.....</b>	<b>83</b>
36.	<b>RATE BASE .....</b>	<b>83</b>
37.	<b>DEPRECIATION .....</b>	<b>83</b>
38.	<b>TAX .....</b>	<b>83</b>
39.	<b>WORKING CASH.....</b>	<b>83</b>
40.	<b>CUSTOMER FORECAST.....</b>	<b>83</b>
41.	<b>COST ESCALATION .....</b>	<b>83</b>
42.	<b>MISCELLANEOUS REVENUES.....</b>	<b>83</b>
43.	<b>REGULATORY ACCOUNTS .....</b>	<b>84</b>
44.	<b>SUMMARY OF EARNINGS/RESULTS OF OPERATIONS .....</b>	<b>84</b>
45.	<b>POST TEST YEAR RATEMAKING .....</b>	<b>84</b>
45.1	<b>Attrition Is Intended to Provide Some Reasonable Relief to Shareholders Between General Rate Cases, Not Guarantee Company Earnings.....</b>	<b>85</b>
45.2	<b>O&amp;M Attrition Should Be Based on General Inflation (CPI-U).....</b>	<b>86</b>
45.2.1	<b>Using a Broad Index for O&amp;M Escalation Reasonably Addresses Inflation-Related Cost Pressures While Providing the Utility an Incentive to Manage its Operations as Efficiently as Possible.....</b>	<b>87</b>
45.2.2	<b>The Commission Should Reject SoCalGas’s Request for Separate Medical Expense Escalation.....</b>	<b>90</b>
45.3	<b>Capital Attrition Should Be Based on Seven Years of Recorded Rate Base Additions Without Exceptions.....</b>	<b>94</b>
45.3.1	<b>Seven Years of Recorded Data Is a Very Robust Basis for Trending Capital.....</b>	<b>94</b>
45.3.2	<b>SoCalGas’s Critiques of TURN-SCGC’s Capital Attrition Mechanism Should Be Dismissed.....</b>	<b>96</b>
45.3.2.1	<b>The TURN-SCGC Model is Logically Sound. ....</b>	<b>97</b>

45.3.2.2	The TURN-SCGC Approach Reasonably Captures the Current Utility Spending Focus. ....	98
45.3.2.3	The TURN-SCGC Approach Reasonably Addresses Attrition Year Capital Costs. ....	101
45.3.3	SoCalGas Fails to Demonstrate the Reasonableness of Its Three “Exceptions” to a Trend-Based Capital Attrition Mechanism.....	102
45.3.3.1	Gas Integrity Management Programs.....	105
45.3.3.2	Honor Rancho Compressor Modernization and CIS Replacement.....	107
46.	REVENUES AND RATES.....	109
47.	AFFORDABILITY METRICS .....	109
48.	OTHER ISSUES .....	109
49.	CONCLUSION .....	109

**TABLE OF AUTHORITIES**

**Statutes**

49 CFR § 192.624..... passim  
49 CFR § 192.624(2) ..... 55  
49 CFR § 192.624(a)..... 52  
49 CFR § 192.624(b) ..... 53, 54, 55  
49 CFR § 192.624(b)(1)..... 55  
49 CFR § 192.710..... 35  
Pub. Util. Code § 958..... 58

**California Public Utilities Commission Decisions**

D.00-02-046..... 85  
D.03-12-059 (December 18, 2023)..... 19  
D.04-05-055 (May 27, 2004) ..... 85  
D.04-07-022 (July 16, 2004)..... 85, 88  
D.06-11-048 (November 30, 2006) ..... 18  
D.08-09-039 (September 18, 2008) ..... 104  
D.09-03-025 (March 12, 2009)..... 12, 86, 93  
D.10-04-027 (April 8, 2010)..... 18  
D.11-06-017 (June 9, 2011)..... 12  
D.12-11-051 (November 29, 2012) ..... 103, 104  
D.12-12-030 (December 20, 2012)..... 17  
D.13-05-010 (May 9, 2013)..... 7, 9, 90

D.16-06-054 (June 23, 2016).....	7, 8, 9, 47
D.16-08-003 (August 18, 2016).....	103
D.18-04-012 (April 26, 2018).....	8, 9, 10
D.19-03-025 (March 28, 2019).....	12, 23
D.19-05-020 (May 16, 2019).....	15, 16, 22, 23
D.19-09-051 (September 26, 2019) .....	passim
D.20-01-002 (January 16, 2020).....	87
D.21-08-036 (August 19, 2021).....	passim
D.22-01-011 (January 13, 2022).....	64
D.22-02-001 (February 2, 2022).....	3, 64
D.22-09-026 (September 15, 2022) .....	76, 108
D.22-12-055 (December 15, 2022).....	75
D.85-12-076.....	85
D.92497 (December 5, 1980).....	85

## SUMMARY OF RECOMMENDATIONS

In accordance with Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (“Commission”), The Utility Reform Network (“TURN”) and Southern California Generation Coalition (“SCGC”) jointly recommend the following:

### **Section 13 – Gas Engineering**

- The Commission should deny SoCalGas’s request to recover \$4.6 million in pre-2019 expenses incurred while pursuing renewal of the right-of-way agreements with the Morongo Band of Mission Indians (Morongo) because these activities took place prior to the creation of the Morongo Rights of Way Memorandum Account (“MROWMA”).
- The Commission should permit SoCalGas to add to 2024 ratebase the net plant-in-service balance on \$101.2 million after accumulated depreciation, not the net balance on the full \$105.8 million recorded to the MROWMA.

### **Section 14 – Pipeline Safety Enhancement Plan (PSEP)**

- The Commission should reduce the test year Operations and Maintenance (“O&M”) forecast for Pipeline Safety Enhancement Plan (“PSEP”) pressure test (hydrotest) projects to eliminate unreasonable contingency adders. The Commission should either eliminate the contingencies (a 16.44% reduction) or limit contingencies to 10 percent (a 6.45% reduction).
- The Commission should reduce the 2022-2024 capital forecast for Pipeline Safety hydrotest projects to eliminate unreasonable contingency adders. The Commission should either eliminate the contingencies (a 16.44% reduction) or limit contingencies to 10 percent (a 6.45% reduction).
- The Commission should reduce the 2022-2024 capital forecast for pipeline replacement projects to eliminate unreasonable contingency adders. The Commission should either eliminate the contingencies (a 14.94% reduction) or limit contingencies to 10 percent (a 4.95% reduction).

### **Section 15 – Gas Integrity Programs**

- The Commission should authorize a Test Year 2024 Transmission Integrity Management Program (“TIMP”) O&M expense forecast for each of the five categories of TIMP O&M expense that is based on the five-year 2017-2021 average level of expense with increases to the Assessment & Remediation category of \$7.145 million for crack management and \$1.136 million for material verification, resulting in an overall reduction of SoCalGas’s

forecasted TIMP O&M expense by 29 percent (\$39.3 million) from \$135.4 million to \$96.1 million.

- The Commission should direct SoCalGas to convert its Transmission Integrity Management Program Balancing Account (“TIMPBA”) from being a two-way balancing account to being a one-way balancing account.
  - The Commission should permit SoCalGas to record in a new memorandum account for reasonableness review in a future application proceeding amounts which result from TIMP spending on a year-to-year basis above the amount that the Commission authorizes SoCalGas to recover during each year of the Test Year 2024 GRC cycle.
  - The Commission should direct SoCalGas to eliminate from its TIMPBA the provision that permits SoCalGas to submit a Tier 3 advice letter to seek recovery of TIMP costs that result from spending 35 percent more than the total authorized TIMP O&M and capital expenditures.
- The Commission should direct SoCalGas to reconfirm 50 percent of the 550 miles of transmission pipeline for which reconfirmation is required by Pipeline and Hazardous Materials Safety Administration (“PHMSA”) regulations, leaving the remaining 50 percent of the 550 miles for reconfirmation by 2035 during the SoCalGas Test Year 2028 and Test Year 2032 GRC cycles.
  - Remaining Integrated Safety Enhancement Plan (“ISEP”) miles should be reconfirmed in accordance with SoCalGas’s PSEP Phase 2B “as soon as practicable” requirement through future GRCs.
- The Commission should deny SoCalGas’s request for a permanent new Gas Safety Enhancement Plan (“GSEP”) balancing account.
  - If the Commission is swayed by SoCalGas’s pleas that it needs relief in this GRC because it has not had time to develop ISEP estimates that are beyond Class 5 estimates, the ISEP forecasted costs should be included in base rates with SoCalGas being permitted to establish a memorandum account in which it would record any spending in excess of its forecast for this GRC 2024-2027 GRC cycle only for recovery by application in a subsequent proceeding.
  - If the Commission permits SoCalGas to create the GSEPBA for this 2024-2027 GRC cycle, the Commission nevertheless should deny SoCalGas’s request for permission to recover 35 percent above authorized expenditures through filing an advice letter for the same reasons that the Commission should direct SoCalGas to eliminate the 35 percent provision from the TIMPBA.

- The Commission should unequivocally deny SoCalGas’s request to extend GSEPBA balancing account coverage to “the implementation of future gas rules and regulations” following the precedent set in D.22-02-001.

### **Section 16 – Gas Storage Operations and Construction (SoCalGas Only)**

- The Commission should not authorize the construction of the \$23 million microgrid portion of the Honor Rancho Compressor Modernization (“HRCMM”) project.
- Insofar as there are no revenue requirements in this GRC for the Advanced Renewable Energy (“ARE”) component of the HRCM project (hydrogen production, hydrogen storage and blending, and a hydrogen fueling station), the Commission should decline to address the ARE component as outside the scope of this GRC.
  - If the Commission were to consider and approve SoCalGas’s ARE component proposals in an advisory opinion, SoCalGas would leverage the Commission’s advisory opinion to argue for recovery of ARE component expenditures in SoCalGas’s Test Year 2028 GRC.

### **Section 18 -- Clean Energy Innovations**

- The Commission should reject SoCalGas’s request for ratepayer funding of \$20.4 million in Test Year 2024 for Clean Fuels Infrastructure Development because each of the Clean Fuels Infrastructure Development “functions” or “programs” involves SoCalGas providing non-utility services to customers in the guise of promoting “clean fuels.”

### **Section 45 – Post Test Year Ratemaking**

- The Commission should adopt a post-test year ratemaking (or attrition) mechanism based on traditional policies to appropriately balance the interests of ratepayers and shareholders. The mechanism should escalate expenses based on general inflation and base the capital-related revenue requirement adjustments on a trend of capital additions determined by seven-year average of recorded additions.
- For SoCalGas, no exceptions should be made to this determination of capital additions.
- The Commission should exclude any revenue requirement for untariffed products and services and preclude any post-test year increase in the revenue requirement for untariffed products and services.

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**THE UTILITY REFORM NETWORK AND  
SOUTHERN CALIFORNIA GENERATION COALITION  
JOINT OPENING BRIEF**

**1. INTRODUCTION/SUMMARY OF RECOMMENDATIONS**

In accordance with the July 13, 2023 Ruling of Administrative Law Judge (“ALJ”) Manisha Lakhanpal, The Utility Reform Network (“TURN”) and the Southern California Generation Coalition (“SCGC”) respectfully submit this Joint Opening Brief in the captioned proceeding to address various issues raised by the Southern California Gas Company (“SoCalGas”) in its General Rate Case (“GRC”) Application (“A.”) 22-05-015. TURN is separately filing an opening brief on additional issues raised by the SoCalGas application and by San Diego Gas and Electric Company (“SDG&E”) in A.22-05-016. SCGC is not filing a separate opening brief.

In accordance with the Common Briefing Outline agreed by the parties to this proceeding, this Joint Opening Brief addresses issues under the following sections of the Common Briefing Outline:

13. Gas Engineering
14. Pipeline Safety Enhancement Plan
15. Gas Integrity Management Programs
16. Gas Storage Operations and Construction (SoCalGas only)
18. Clean Energy Innovations.
45. Post Test Year Ratemaking

TURN separately addresses additional issues that fall under those headings in the Common Briefing Outline.

For the reasons discussed in this Joint Opening Brief, TURN and SCGC respectfully request that the Commission adopt the recommendations set forth in the forgoing Summary of Recommendations.

- 2. PROCEDURAL BACKGROUND**
- 3. EVIDENTIARY STANDARDS AND THE BURDEN OF PROOF**
- 4. SCOPING MEMORANDUM ISSUES**
- 5. TEST YEAR FORECASTING METHODS AND GRC RATEMAKING**
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- 12. GAS TRANSMISSION OPERATIONS AND CONSTRUCTION**
- 13. GAS ENGINEERING**

SoCalGas operates three gas transmission lines, Lines 2000, 2001, and 5000, that run east-west from the California-Arizona border and transverse the reservation land of the Morongo

Band of Mission Indians (Morongo) near Cabazon, California.<sup>1</sup> SoCalGas seeks recovery of costs incurred through 2020 related to renegotiating the right-of-way (ROW) agreements between SoCalGas and Morongo. These costs include recovery of the outstanding revenue requirement balance of \$21.2 million in the Morongo Right of Way Memorandum Account (MROWMA), as well as an approximately \$105 million addition to plant-in-service recorded in the MROWMA.<sup>2</sup>

The MROWMA balance includes SoCalGas's payment of \$100 million during the first half of 2020 for two ROW agreements for Lines 2001 and 5000, which SoCalGas tracked as a capital expenditure.<sup>3</sup> SoCalGas also tracked an additional \$5.8 million for ROW negotiations and renewal activities that SoCalGas chose to capitalize, of which \$4.6 million is associated with direct costs incurred prior to 2019.<sup>4</sup> That \$4.6 million includes (1) \$3.930 million of direct costs from 2012-2018 for ROW renegotiation, including labor, supervision, and outside services, as well as overheads, such as property taxes, payroll taxes, and administrative costs, plus (2) an additional \$0.710 million in accrued AFUDC on the 2012-2018 costs which SoCalGas chose to capitalize.<sup>5</sup>

The Commission should only authorize SoCalGas to recover \$101.2 million recorded to the MROWMA, which includes Morongo ROW direct costs and overhead incurred during the TY 2019 GRC period and associated AFUDC. The Commission should deny recovery of the

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<sup>1</sup> Ex. SCG-07-R, p. MTM-14.

<sup>2</sup> Ex. TURN-SCGC-02, p. 2.

<sup>3</sup> Ex. TURN-SCGC-02, p. 2; Ex. SCG-07-R, p. MTM-15. The third ROW agreement for Line 2000 expired in 2020. *Id.*

<sup>4</sup> Ex. TURN-SCGC-02, p. 2.

<sup>5</sup> Ex. TURN-SCGC-02, p. 3.

\$4.6 million in direct costs incurred prior to 2019 and associated AFUDC.<sup>6</sup> Furthermore, the Commission should permit SoCalGas to add to 2024 ratebase the net plant-in-service balance on \$101.2 million after accumulated depreciation, not the net balance on the full \$105.8 million.<sup>7</sup>

As explained further below, the Commission should deny recovery of direct costs incurred prior to the establishment of the MROWMA on January 1, 2019 for labor, supervision, and outside services, as well as overheads, such as property taxes, payroll taxes, and administrative costs. SoCalGas did not have Commission authorization to track ROW renewal costs for potential recovery over GRC authorized levels from 2012-2018. SoCalGas already recovered these direct Morongo ROW costs and overheads as O&M through its TY 2012 and TY 2016 GRC revenue requirements. Absent explicit Commission authority to track Morongo ROW renewal direct costs in 2012-2018, ratepayers should not be asked to provide a rate of return on O&M costs already covered in the TY 2012 and TY 2016 revenue requirements.

### **13.1 SoCalGas Unreasonably Included Pre-2019 ROW Renewal Costs in the MROWMA.**

SoCalGas erred in tracking costs associated with pre-2019 ROW renewal efforts in the MROWMA for two reasons. First, the Commission authorized SoCalGas to track costs incurred during renewal discussions with Morongo during the TY 2019 GRC cycle but not before. Second, the labor, supervision, travel costs, and outside services, as well as overheads, such as property taxes, payroll taxes, and administrative costs, associated with SoCalGas's ROW renewal efforts pre-2019 were funded through the TY 2012 and TY 2016 GRCs.

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<sup>6</sup> See Ex. TURN-SCGC-02, p. 9.

<sup>7</sup> Ex. TURN-SCGC-02, p. 4.

### **13.1.1 The MROWMA Covers Morongo ROW Renewal Efforts During the TY 2019 GRC.**

In D.19-09-051, the Commission authorized SoCalGas to establish the MROWMA for the TY 2019 GRC period, which commenced January 1, 2019. SoCalGas had requested authority to create the MROWMA to record “pre-construction costs associated with the possible relocation of gas transmission pipelines to bypass” land held by the Morongo, which would be necessary if SoCalGas was ultimately unable to obtain ROW renewals.<sup>8</sup> SoCalGas specifically excluded such costs from its TY 2019 GRC forecast.<sup>9</sup> The Commission granted SoCalGas’s request to track these pre-construction costs in the new MROWMA. These costs are not at issue between TURN-SCGC and SoCalGas, as SoCalGas excluded from the MROWMA all direct costs for pre-construction activities prior to 2019, including the associated capital-related costs (depreciation, return, taxes) for those pre-2019 activities through 2019.<sup>10</sup>

The Commission in D.19-09-051 also denied SoCalGas’s request to establish a second account, the Morongo Right of Way Balancing Account (MROWBA), to record and recover costs associated with renewal of the three expiring ROW agreements.<sup>11</sup> SoCalGas had proposed to recover through the MROWBA (1) payments for the renewal of the ROW, (2) infrastructure and pre-construction costs incurred in conjunction with a long-term renewal of the ROW (as opposed to in furtherance of a complete relocation); and (3) costs incurred during renewal discussions with Morongo.<sup>12</sup> SoCalGas specifically excluded these costs from its GRC

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<sup>8</sup> D.19-09-051, p. 135; Ex. TURN-400, A.17-10-007 et al., SCG-09-R (Haines), pp. DRH-19 – 20.

<sup>9</sup> D.19-09-051, p. 140.

<sup>10</sup> Ex. TURN-400, TURN-SCGC-036, Q. 36.1 – 36.3.

<sup>11</sup> D.19-09-051, p. 141.

<sup>12</sup> Ex. TURN-400, A.17-10-007 et al., SCG-09-R (Haines), pp. DRH-20 – 21.

forecast.<sup>13</sup> While rejecting the MROWBA, the Commission authorized SoCalGas to track these costs in the new MROWMA for future reasonableness review.<sup>14</sup> The dispute between TURN-SCGC and SoCalGas involves the third category of costs, those associated with Morongo ROW renewal efforts undertaken in 2012-2018.

In the TY 2019 GRC, SoCalGas described the “renewal effort costs” it sought to recover through the (rejected) MROWBA as “[c]osts incurred *during* renewal discussions with Morongo.”<sup>15</sup> SoCalGas pointed to “internal labor, consulting and legal fees, professional services, and Tribal member education and communications in support of renewal,” as examples of the costs “associated with its renewal effort as of the beginning of the test year.”<sup>16</sup> As explained above, the Commission directed SoCalGas to instead track these costs in the MROWMA.

SoCalGas tracked direct costs for labor, consulting and legal fees, travel, professional services, and A&G overheads, etc., incurred during renewal efforts with Morongo that took place prior to 2019 (from 2012-2018).<sup>17</sup> Such costs do not belong in the MROWMA.

### **13.1.2 Costs Associated with Morongo ROW Renewal Activities in 2012-2018 Were Subsumed by SoCalGas’s TY 2012 and TY 2016 GRC Revenue Requirements.**

Prior to the establishment of the MROWMA for the TY 2019 GRC period, SoCalGas’s management of the Morongo ROW was funded through GRC rates covering ongoing gas

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<sup>13</sup> D.19-09-051, p. 140.

<sup>14</sup> D.19-09-051, p. 141.

<sup>15</sup> Ex. TURN-400, A.17-10-007 et al., SCG-09-R (Haines), p. DRH-21 (emphasis added).

<sup>16</sup> Ex. TURN-400, A.17-10-007 et al., SCG-09-R (Haines), p. DRH-21.

<sup>17</sup> Ex. TURN-SCGC-02, p. 3, Table 1.

transmission operations. Pertinent here are the TY 2012 and TY 2016 GRC decisions, as they funded GRC operations from 2012-2015 and 2016-2018.<sup>18</sup>

In the TY 2012 GRC, SoCalGas requested O&M expenses to maintain and manage ROW in its Gas Transmission testimony, and SoCalGas also mentioned ROW activities in its Gas Engineering testimony.<sup>19</sup> In D.13-05-010, the Commission authorized TY 2012 GRC forecasts for SoCalGas’s Gas Transmission and Gas Engineering activities, including ROW costs, without contemplating any exceptions for ROW costs beyond the GRC.<sup>20</sup> SoCalGas’s TY 2012 GRC revenue requirement also included funding for other functions related to negotiating Morongo ROW renewal, including the SoCalGas Legal Department, the SoCalGas External Affairs - Community Relations group, and the Corporate Center’s Legal Department, which offers “services in the areas of ... environmental, and commercial and corporate, including real estate, ... matters” to all Sempra Energy companies.<sup>21</sup> Similarly, SoCalGas recovered overheads, such as property taxes, payroll taxes, and administrative costs.<sup>22</sup> During the TY 2012 GRC, SoCalGas commissioned an independent appraisal of the value of the Morongo ROW, completed in March 2015, as part of its ongoing transmission ROW management activities.<sup>23</sup> There is no doubt that

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<sup>18</sup> D.13-05-010, p. 2 (authorizing revenue requirements for TY 2012 and post-test years 2013-2015); D.16-06-054, p. 325, Ordering Paragraph 1.

<sup>19</sup> Ex. TURN-SCGC-02, p. 7.

<sup>20</sup> See, e.g., D.13-05-010, p. 362 (adopting SoCalGas’s forecast for Gas Transmission - Technical Services O&M of \$2.379 million addressing right-of-way management activities); pp. 443, 446 (adopting SoCalGas’s forecast for Gas Engineering – Gas Transmission – Pipeline Land Rights); See also D.13-05-010, Sections 8.3 (Gas Transmission - SoCalGas), 9.3.3 (Gas Engineering – SoCalGas), 23 (Regulatory Accounts).

<sup>21</sup> D.13-05-010, p. 786 (External Affairs – Community Relations group); p. 786 (Legal Department, with, in pertinent part, commercial and environmental practice areas); p. 790 (funding for SoCalGas’s Legal and External Affairs departments); p. 813 (Corporate Center’s Legal Department), p. 817 (funding for Corporate Center Legal Department).

<sup>22</sup> Ex. TURN-SCGC-02, p. 7.

<sup>23</sup> Ex. TURN-SCGC-02, p. 7.

SoCalGas knew that the Morongo ROW agreements were due to expire in 2018 (Lines 2000 and 5000) and 2020 (Line 2001).<sup>24</sup>

Likewise, in D.16-06-054, the Commission adopted a revenue requirement for SoCalGas for the TY 2016 GRC period that “provide[d] the necessary funds to allow SoCalGas to operate its natural gas transmission, gas distribution, and gas storage systems safely and reliably at reasonable rates.”<sup>25</sup> In that decision, the Commission adopted a series of proposed settlement agreements covering SoCalGas’s TY 2016 revenue requirement and attrition year adjustments (among other things).<sup>26</sup> The TY 2016 revenue requirement authorized for SoCalGas included funding amounts for each general area of SoCalGas’s operations, including in pertinent part, the gas transmission and gas engineering departments, and administrative and general costs, including Legal and External Affairs expenses.<sup>27</sup> The Commission did not contemplate any exceptions for ROW costs beyond the GRC in D.16-06-054.

The types of costs SoCalGas includes in Morongo ROW renewal efforts are consistent with the categories of costs funded through the TY 2012 and TY 2016 GRC decisions. It does not matter whether SoCalGas explicitly included costs for Morongo ROW renewal in those GRCs.<sup>28</sup> Unless expressly stated otherwise, the Commission expects the utility’s GRC forecasts

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<sup>24</sup> D.18-04-012, p. 11 (“It is also clear that SoCalGas was well aware that the first three ROWS were set to expire during the period covered by the 2016 GRC” and complications during the renewal negotiation process “were not unforeseeable” as of 2015). *See also* Ex. TURN-SCGC-02, p. 7; Ex. SCG-07, p. MTM-14.

<sup>25</sup> D.16-06-054, p. 5.

<sup>26</sup> D.16-06-054, p. 3.

<sup>27</sup> D.16-06-054, pp. 29-30 (scope of Settlement agreement); pp. 265-266 (A&G costs).

<sup>28</sup> *See* D.18-04-012, pp. 11-12 (rejecting SoCalGas’s argument that because it did not specifically identify pre-construction costs relating to the Morongo ROW renewals in the TY 2016 GRC, those costs were not covered by the settlement agreements and GRC revenue requirement adopted in D.16-06-054, and explaining that there was no indication that settling parties or the Commission had reason to believe that SoCalGas excluded GRC-type costs from the GRC).

to “cover all of the activities and associated costs of providing service during the period covered by the forecasts.”<sup>29</sup>

SoCalGas has recognized that costs associated with the Morongo ROW renewal are “more akin to the routine types of costs that would be in a rate case application, under ordinary circumstances” [than pre-construction costs] and withdrew its request in Application (A.) 16-12-011 to track such costs in a memorandum account during the TY 2016 GRC cycle.<sup>30</sup> In D.18-04-012, the Commission addressed SoCalGas’s remaining request in A.16-12-011 to track pre-construction costs in a memorandum account. The Commission found that such costs “are GRC-costs that should have been raised and are deemed included in SoCalGas’s 2016 GRC.”<sup>31</sup>

In sum, the Commission should find that the direct costs SoCalGas incurred for Morongo ROW renewal efforts during the TY 2012 GRC period and TY 2016 periods (2012-2018) were subsumed within the forecasts authorized by the Commission in D.13-05-010 and D.16-06-054.

### **13.2 SoCalGas’s Defense is Unpersuasive.**

SoCalGas offers two arguments in defense of its request to recover capital-related revenue requirement on ROW renewal direct costs incurred in 2012-2018 for labor, supervision, travel, outside services, and overheads, and then capitalized by SoCalGas.

First, SoCalGas draws a distinction between pre-construction expenses, addressed by the Commission in D.18-04-012, and pre-2019 expenses associated with renewal efforts.<sup>32</sup>

SoCalGas explains that it excluded pre-construction costs incurred in 2018 and 2019 from the

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<sup>29</sup> D.18-04-012, p. 12.

<sup>30</sup> Ex. TURN-400, SCG Response to TURN/ORR/SCGC Motion to Dismiss Application, A.16-12-011, p. 3-4; D.18-04-012, pp. 3-4 (recounting SoCalGas’s withdrawal of its request in A.16-12-011 to track the costs incurred in negotiations with Morongo, payment to Morongo for ROW renewal, and costs incurred during the renewal process, following the motion to dismiss).

<sup>31</sup> D.18-04-012, p. 15.

<sup>32</sup> Ex. SCG-238, pp. RMY-12 – 13.

MROWMA “in recognition of D.18-04-012.”<sup>33</sup> SoCalGas excluded these pre-construction costs from the MROWMA “since these costs were recovered during the 2016 GRC cycle.”<sup>34</sup> Unlike SoCalGas’s treatment of ROW renewal costs, SoCalGas did not record to the MROWMA any capital-related costs (e.g., depreciation, return, and taxes) in 2019 or later that were associated with direct costs that it excluded from the MROWMA in recognition of D.18-04-012.<sup>35</sup>

The Commission should reject the premise underlying SoCalGas’s argument: that SoCalGas may now recover direct costs associated with Morongo ROW renewal efforts prior to the TY 2019 GRC cycle because the Commission has not explicitly considered and prohibited this recovery. It is important to bear in mind that in A.16-12-011, SoCalGas sought a change in the status quo – an opportunity to track costs associated with the Morongo ROWs in a memorandum account during the TY 2016 GRC (and beyond).<sup>36</sup> As noted above, SoCalGas initially sought to track both ROW renewal costs and pre-construction costs in a memorandum account but ultimately withdrew the request to track renewal costs in response to a motion to dismiss filed by TURN, SCGC, and the Public Advocates Office (then called the Office of Ratepayer Advocates).<sup>37</sup> The Commission declined the utility’s remaining request to track pre-construction costs in D.18-04-012.<sup>38</sup> SoCalGas now argues that the activities it undertook prior to the effective date of the MROWMA for ROW renewal efforts are different than pre-2019 pre-

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<sup>33</sup> Ex. SCG-207, p. MTM-10 (“In anticipation of the expiring rights-of-way, SoCalGas completed pre-construction activities and recorded costs in separate internal orders, including removal of equipment within the Morongo reservation which were excluded from the MROWMA in recognition of D.18-04-012, ruling to not include pre-construction activity [sic.]”); Ex. TURN-400, TURN-SCGC-036, Q. 36.2 (excluded costs were incurred in 2018 and 2019).

<sup>34</sup> Ex. TURN-400, TURN-SCGC-036, Q. 36.1.

<sup>35</sup> Ex. TURN-400, TURN-SCGC-036, Q. 36.3.

<sup>36</sup> D.18-04-012, pp. 3-4.

<sup>37</sup> Ex. TURN-400, SCG Response to TURN/ORR/SCGC Motion to Dismiss Application, A.16-12-011, p. 3-4; D.18-04-012, pp. 3-4.

<sup>38</sup> D.18-04-012, p. 2.

construction activities simply because the Commission’s decision in A.16-12-011 only reached the merits of SoCalGas’s memorandum request for pre-construction costs.

SoCalGas’s position should be rejected as it implies that utilities may seek to recover GRC costs beyond the authorized GRC revenue requirement *unless* the Commission specifically finds that the specific costs at issue were already funded in the GRC. To the contrary, the GRC revenue requirement is intended to cover “all of the activities and associated costs of providing service during the period covered by the [GRC] forecasts,” unless the Commission authorizes a different procedure.<sup>39</sup>

Second, SoCalGas defends its choice to capitalize pre-2019 ROW renewal direct and overhead expenses, which created a stream of capital-related revenue requirements during the 2019 GRC period to record.<sup>40</sup> SoCalGas claims: “It is standard practice to capitalize all costs related to supporting and obtaining the resulting asset since all of these costs were required in obtaining the asset. In this specific case, SoCalGas is seeking recovery for all costs related to the renegotiation of the Transmission Right-of-Way agreements.”<sup>41</sup> But SoCalGas does not assert that capitalization of these pre-2019 costs is required.<sup>42</sup> The problem with selecting capitalization in this instance is that SoCalGas already recovered O&M and A&G costs related to gas transmission rights-of-way through the TY 2012 and TY 2016 GRCs. SoCalGas’s approach would allow it to earn a return on the O&M and overhead costs that it already collected in rates. This is unfair to ratepayers.

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<sup>39</sup> D.18-04-012, p. 12.

<sup>40</sup> Ex. SCG-238, p. RMY-13.

<sup>41</sup> Ex. TURN-SCGC-02, Attachment D, TURN-SCGC-024, Q.23.3.

<sup>42</sup> Ex. TURN-400, TURN-SCGC-036, Q. 36.3.2 (labor, supervision, travel costs, outside services, and overheads “are the types of costs which *are allowed* to be capitalized in obtaining the Land Rights”).

As such, the Commission should deny recovery of the \$4.6 million in direct costs and overheads incurred prior to 2019 and associated AFUDC.<sup>43</sup> Excluding this amount leaves \$101.2 million for recovery, which TURN-SCGC do not oppose. For the same reason, the Commission should permit SoCalGas to add to 2024 rate base the net plant-in-service balance on \$101.2 million after accumulated depreciation, not the net balance on the full \$105.8 million.<sup>44</sup>

#### **14. PIPELINE SAFETY ENHANCEMENT PLAN (PSEP)**

Twelve years ago, in D.11-06-017, the Commission required natural gas pipeline operators to submit a comprehensive implementation plan to replace or pressure test all natural gas transmission pipeline in California that has yet to be tested or for which reliable records are unavailable.<sup>45</sup> The Commission authorized SoCalGas's and SDG&E's Pipeline Safety Enhancement Plan (PSEP), which includes four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B, in D.14-06-007 and directed both utilities to begin implementation.<sup>46</sup> Cost recovery for PSEP projects initially occurred through after-the-fact reasonableness reviews. The TY 2019 GRC was the first GRC to include PSEP forecasts.<sup>47</sup> In that case, SoCalGas developed a forecast for 11 Phase 2A pressure test projects and 11 replacement projects, including 10 Phase 1B and 1 Phase 2A projects.<sup>48</sup>

In this GRC, SoCalGas prepared cost estimates for a “portfolio” of 33 PSEP projects that are “candidates for execution within this GRC period” and proposes to “establish a revenue

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<sup>43</sup> See Ex. TURN-SCGC-02, p. 9.

<sup>44</sup> Ex. TURN-SCGC-02, p. 4.

<sup>45</sup> D.19-09-051, p. 196 (citing D.11-06-017, pp. 23-24). This directive stemmed from the catastrophic rupture of PG&E's transmission pipeline in San Bruno on September 9, 2010. *Id.*

<sup>46</sup> See D.19-09-051, pp. 197-198.

<sup>47</sup> D.19-09-051, p. 197. Before that, the Commission approved PSEP forecasts for SoCalGas and SDG&E outside of a GRC in D.19-03-025. Ex. SCG-08, p. BGK-10.

<sup>48</sup> D.19-09-051, pp. 200 (pressure test projects), 210-211 (replacement projects).

requirement based on an anticipated level of executable spending” from this portfolio.<sup>49</sup> As in the TY 2019 GRC, all of the pressure test projects are Phase 2A projects, while the replacement projects are a mix of Phase 2A and Phase 1B projects.<sup>50</sup> SoCalGas’s total forecast for the 33-project portfolio is \$295 for O&M and \$570 for capital.<sup>51</sup> SoCalGas used a zero-based approach to develop the PSEP forecasts on a project-by-project basis, based on preliminary engineering and project planning analyses.<sup>52</sup> SoCalGas prepared its forecasts primarily based on Class 3 estimates using the Association for the Advancement of Cost Engineering (ACEE) standard classification system. Consistent with AACE standards, SoCalGas includes a contingency factor, also referred to as “risk assessment” amounts, as part of its cost estimate for each project.<sup>53</sup>

SoCalGas’s request in this GRC is for 17 percent of the total O&M portfolio forecast for TY 2024 and 56 percent of the total capital portfolio forecast for 2022-2024, rather than for specific projects within the portfolio.<sup>54</sup> SoCalGas requests the flexibility to determine which specific projects in the portfolio it will undertake during this time based on pipeline system operational requirements and project execution schedule changes.<sup>55</sup> SoCalGas’s specific GRC forecast includes \$54.214 million in O&M for pressure test projects and \$141.509 million, \$101.920 million, and \$73.810 million, respectively, for 2022-2024 capital pipeline replacement projects and the capital components of hydrotests (a total of \$317.239 million).<sup>56</sup>

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<sup>49</sup> Ex. SCG-08, pp. BGK-19, BGK-38.

<sup>50</sup> Ex. TURN-SCGC-03, pp. 5 (Table 1), 7 (Table 3).

<sup>51</sup> Ex. SCG-08, p. BGK-19, fn. 38.

<sup>52</sup> Ex. SCG-08, p. BGK-19.

<sup>53</sup> Ex. TURN-SCGC-03, p. 2.

<sup>54</sup> Ex. SCG-08, p. BGK-19, fn. 38.

<sup>55</sup> Ex. SCG-08, pp. BGK-19 – 20.

<sup>56</sup> Ex. SCG-208, p. BGK-1; Ex. SCG-08, pp. BGK-25, BGK-37.

TURN-SCGC recommend a reduction to SoCalGas's forecasts for pressure test and pipeline replacement projects to remove all contingency factors, or at least remove contingency factors in excess of 10 percent. As demonstrated below, removing or reducing contingencies is appropriate because the Commission has hesitated to include contingencies in forecasts without good cause, and SoCalGas is well-positioned to accurately forecast PSEP costs in this GRC. The forecast adjustments resulting from this change to contingencies are presented in Section 14.4 below.

**14.1 The Commission Has Generally Viewed Contingency Factors with Considerable Skepticism, Reasoning that Contingency Factors Reduce Incentives to Control Costs.**

A "contingency," according to the Association for the Advancement of Cost Engineering (ACEE), is included in a cost estimate "to cover the probability of unforeseeable events" that, if they occur, "will likely result in additional costs within the defined project scope."<sup>57</sup> The Commission has considered utility requests for contingencies in cost forecasts in a number of proceedings over time and has generally reviewed contingencies with skepticism because they reduce utility incentives to control costs.

Most recently in D.21-08-036, issued in Southern California Edison Company's (SCE's) TY 2021 GRC, the Commission considered SCE's request for contingency factors in the Seismic Assessment and Mitigation Program, which includes assessment of SCE's electric and non-electric facilities, generation infrastructure, and telecommunications/IT infrastructure to identify necessary seismic mitigations, followed by implementation of necessary retrofits and

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<sup>57</sup> Ex. TURN-SCGC-03, p. 2 (quoting AACE International Transactions RISK 08 2009 Report, Defining Risk and Contingency for Pipeline Projects at RISK.08.7).

improvements.<sup>58</sup> SCE’s forecast included, in pertinent part, a 35 percent contingency for the assessment and retrofit of 16 “Mechanical Electrical Equipment Rooms” within the Transmission Substation Mitigation category and a 1.5 percent contingency rate for the Non-Electric Facilities category.<sup>59</sup> The Commission rejected contingencies for these projects, despite SCE’s claim that use of contingency factors “is an industry standard practice to account for unknown or unforeseen conditions,” as well as SCE’s suggestion that the proposed seismic mitigation projects at transmission substations carry a particular risk of unforeseen field conditions during the construction phase.<sup>60</sup> The Commission reasoned:

As explained in D.19-05-020, budgeting for contingencies is not necessarily appropriate in the context of a general rate case, where the utility must demonstrate the reasonableness of every dollar in its forecasted revenue requirement. Since contingency allowances are, by SCE’s own admission, intended to cover “unforeseen conditions,” these amounts are also unpredictable, and therefore, we find that SCE has not established these costs to be reasonable.<sup>61</sup>

The Commission further emphasized that disallowing all of SCE’s requested contingencies – including the 35 percent and 1.5 percent contingencies – “should motivate SCE to remain within its forecast budgets for these projects.<sup>62</sup> Finally, the Commission noted, “If additional funds become necessary SCE may seek to establish that necessity in the next GRC.”<sup>63</sup>

Likewise in D.19-05-020, issued in SCE’s TY 2018 GRC, the Commission considered, and rejected, SCE’s request for a range of contingencies for Capitalized Software projects. The Commission looked beyond SCE’s claims that inclusion of contingencies in project cost

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<sup>58</sup> D.21-08-036, pp. 325-326.

<sup>59</sup> D.21-08-036, pp. 327-328 (discussing Cal Advocates’ and TURN’s objections to SCE’s requests for contingencies).

<sup>60</sup> D.21-08-036, pp. 330-331.

<sup>61</sup> D.21-08-036, p. 331.

<sup>62</sup> *Id.*

<sup>63</sup> *Id.*

estimates for IT is routine and in line with industry standards, focusing instead on whether contingencies are appropriate in general rate cases. The Commission considered SCE's responsibility to "demonstrate the reasonableness of every dollar in its revenue requirement" in a GRC, a showing absent given SCE's justification that "contingencies are necessary for the 'uncertainties and variables that are unknown'."<sup>64</sup> The Commission further considered the balance of ratepayer and shareholder interests in the GRC framework, where "any savings the utility can generate between general rate cases belong to the shareholders," and "in exchange for this opportunity, the shareholders take on the burden of added expenses it may incur during a rate case cycle."<sup>65</sup> The Commission explained why requiring SCE to "forecast what it projects to be a reasonable expense" balances the interests of ratepayer and shareholders in the GRC framework.<sup>66</sup> The Commission then concluded, "Consistent with ratemaking policy, disallowing these contingencies should motivate SCE to remain within its forecast budgets for these projects. If additional funds become necessary, SCE may seek to establish that necessity in the next GRC."<sup>67</sup>

Similarly in D.19-09-025, issued in Pacific Gas and Electric Company's (PG&E's) 2019 Gas Transmission and Storage rate case, the Commission rejected PG&E's request for a contingency factor in its forecast for the Right-of-Way Maintenance program for gas transmission system pipeline facilities. TURN had opposed PG&E's contingency request because "ratepayers should not be required to fund expenses which PG&E has not supported."<sup>68</sup>

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<sup>64</sup> D.19-05-020, p. 150.

<sup>65</sup> D.19-05-020, p. 151.

<sup>66</sup> D.19-05-020, pp. 151-152.

<sup>67</sup> D.19-05-020, p. 152.

<sup>68</sup> D.19-09-025, p. 229.

TURN also noted that if PG&E does not incur authorized O&M costs, those funds will flow through to shareholders.<sup>69</sup> The Commission agreed with TURN and removed all of PG&E's requested contingency.<sup>70</sup>

On the other hand, the Commission has authorized contingencies under certain circumstances. In D.19-09-051, the Commission limited SoCalGas's request for PSEP project contingencies to an average of 15 percent, which is at the higher end of the range of contingency factors that have been allowed previously for other projects.<sup>71</sup> The Commission rejected the utility's request for higher contingencies, averaging 26% for hydrotest projects and 25% for replacement projects,<sup>72</sup> for two reasons. As the Commission noted, the proposed pressure test projects and replacement projects were "subject to a lesser degree of unpredictable variables relative to the earlier Phase 1A projects," and SoCalGas had "more data from the earlier PSEP projects within which to make more informed and more detailed forecasts."<sup>73</sup>

The Commission has not always granted utility requests for contingencies in PSEP cost forecasts. In D.12-12-030 the Commission denied PG&E's requested PSEP project risk contingency percentages ranging from 10 percent to 28 percent, with an average of 21 percent.<sup>74</sup> The Commission found that PG&E's forecast costs were already considerably higher than the forecasts presented by other parties even without the contingency factor.<sup>75</sup> Thus, the Commission determined that it made sense to authorize PG&E's forecast costs excluding the contingency factor as a middle ground.<sup>76</sup>

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<sup>69</sup> *Id.*

<sup>70</sup> D.19-09-025, pp. 229-230.

<sup>71</sup> *See* D.19-09-051, pp. 205 (hydrotest projects), 215 (capital PSEP projects).

<sup>72</sup> D.19-09-051, p. 205.

<sup>73</sup> D.19-09-051, p. 205.

<sup>74</sup> D.12-12-030, p. 97.

<sup>75</sup> *Id.* at 98.

<sup>76</sup> *Id.*

Historically, the Commission has considered the appropriateness of contingency factors in proceedings addressing other high cost capital projects, such as the SoCalGas Advanced Metering Infrastructure (“AMI”) proceeding. In that case, SoCalGas requested that the Commission authorize a 10 percent contingency on the cost of the AMI system, which the Commission denied.<sup>77</sup> Instead, the Commission authorized a balancing account reflecting the fact that AMI was something completely outside the utility’s normal operating experience. The Commission also placed a “hard cap” on the authorized cost, with shareholders placed at risk for 50 percent of any cost overruns up to \$100 million above the budgeted amount.<sup>78</sup>

In D.10-02-032, the Commission granted PG&E a 7.9 percent contingency on its AMI system and a 12.9 percent contingency on its Smart Meter upgrade project, but refused any contingency amount for PG&E’s Dynamic Pricing programming project.<sup>79</sup> Then in D.14-08-032, PG&E’s TY 2014 GRC, the Commission denied PG&E’s requests for two contingency factors: a \$7.2 million contingency for constructing training facilities and an 18 percent contingency factor for its proposed Electric Distribution (Electric and Gas) and Workforce Mobilization and Scheduling project.<sup>80</sup>

The Commission has also considered contingency factors in the context of powerplant construction for PG&E and SCE. In D.06-11-048, the Commission granted a five percent contingency factor for PG&E on total project cost for the Humboldt powerplant.<sup>81</sup> Similarly, the

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<sup>77</sup> D.10-04-027, Finding of Fact 9.

<sup>78</sup> *Id.* at Ordering Paragraph 2.

<sup>79</sup> D.10-02-032, pp. 128-129.

<sup>80</sup> D.14-08-032, pp. 130, 135-136.

<sup>81</sup> D.06-11-048, pp. 21-22.

Commission authorized a five percent contingency factor for SCE on total project cost for the Mountainview powerplant.<sup>82</sup>

In sum, where stakeholders have challenged utility requests for contingencies, the Commission's approach has been one of caution. The Commission has properly sought to avoid disturbing the balance of interests between shareholders and ratepayers embedded in cost of service ratemaking. This same balance should guide the Commission here in considering SoCalGas's proposed PSEP contingencies. With PSEP forecasts included in GRC base rates, the larger the contingency factor, the less risk to the shareholders because the ratepayers are covering more of the identified uncertainties. Shifting more risk to ratepayers reduces the utility's incentive to control costs.

#### **14.2 SoCalGas Is Well Positioned to Accurately Forecast PSEP Costs in This GRC.**

In this case, the Commission should conclude that contingencies are unreasonable at the levels included in SoCalGas's cost estimates. According to SoCalGas, the contingency percentages included in its Class 3 estimates vary from 12 to 20 percent, but TURN-SCGC note that contingencies for 9 projects within the SoCalGas "portfolio" are larger than 20 percent, with some much larger.<sup>83</sup> As TURN-SCGC witness Catherine Yap explains:

These contingency factors, which are also referred to as "risk assessment" amounts, are added to the cost estimates after the analyst has done very detailed cost projections. Detailed cost projections are provided for construction contractor costs, engineering costs, SoCalGas labor costs, and land, environmental, permitting, and materials costs, which are each assigned a risk assessment amount. The costs and risk assessment amounts are summarized at the project level to make up the total risk-adjusted direct costs. SoCalGas

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<sup>82</sup> D.03-12-059, p. 49.

<sup>83</sup> Ex. SCG-208, p. BGK-9; Ex. TURN-SCGC-03 – Attachment B (CONFIDENTIAL), p. 3.

calculates a percentage comparing the total risk-adjusted direct costs to the unadjusted direct costs.<sup>84</sup>

As explained below, the Commission could reasonably reject any contingency factors for these projects, given SoCalGas's even greater experience with implementing PSEP replacement projects than in the TY 2019 GRC, as well as the Commission's reasoning for rejecting contingencies for other utilities in recent GRCs.

At this point, SoCalGas has nearly a decade of experience implementing PSEP projects. As noted above, the Commission approved SoCalGas's PSEP in 2014. SoCalGas recounts the history of the program since then in its direct testimony. In A.14-12-016, SoCalGas sought cost recovery of the first batch of PSEP projects completed before June 12, 2014.<sup>85</sup> In A.16-09-005, SoCalGas requested a reasonableness review and cost recovery for 26 pipeline projects and 15 valve projects.<sup>86</sup> In A.18-11-010, SoCalGas requested a reasonableness review and cost recovery for another 44 pipeline projects and 39 valve projects.<sup>87</sup> In A.17-03-021, SoCalGas presented its first PSEP forecast covering 12 pipeline projects, including 9 Phase 1B and 3 Phase 2A projects, which the Commission authorized.<sup>88</sup> SoCalGas presented its second PSEP forecast in its TY 2019 GRC, covering 22 Phase 2A and Phase 1B pipeline projects and 284 valve projects, and the Commission authorized the revenue requirement for all but 3 of the pipeline projects.<sup>89</sup> The sum of PSEP pipeline projects included in this history exceeds 100.

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<sup>84</sup> Ex. TURN-SCGC-03, p. 2.

<sup>85</sup> Ex. SCG-08, p. BGK-10.

<sup>86</sup> Ex. SCG-08, p. BGK-10.

<sup>87</sup> Ex. SCG-08, p. BGK-10.

<sup>88</sup> Ex. SCG-08, pp. BGK-10 - 11.

<sup>89</sup> Ex. SCG-08, p. BGK-11.

Moreover, SoCalGas has a demonstrated track record of managing PSEP project costs to meet or beat SoCalGas’s forecasts. In this GRC, SoCalGas has presented 21 pipeline projects for reasonableness review and cost recovery, including projects completed primarily between December 2015 and December 2020, representing 80 miles of transmission pipeline.<sup>90</sup> In 16 of those 21 pipeline projects, SoCalGas came in under budget.<sup>91</sup> For the total portfolio, SoCalGas’s recorded costs were 10 percent lower than forecast.<sup>92</sup> All of these projects were Phase 1A projects, which the Commission has viewed as subject to a greater degree of unpredictable variables than Phase 1B and Phase 2A projects.<sup>93</sup>

When SoCalGas prepared its forecasts in 2017 for the TY 2019 GRC (filed in October 2017), SoCalGas had the benefit of data from the earlier PSEP projects; the Commission recognized this fact in reducing the utility’s requested contingencies.<sup>94</sup> The Commission also noted that the Phase 2A and Phase 1B projects forecasted in that proceeding “are subject to a lesser degree of unpredictable variables relative to earlier Phase 1A projects.”<sup>95</sup> By the time SoCalGas submitted its TY 2024 GRC in 2022, SoCalGas had 5 additional years of experience with PSEP projects to inform its forecasts. And like the TY 2019 GRC, SoCalGas’s proposed “portfolio” of PSEP projects here are all Phase 1B and Phase 2A projects.<sup>96</sup>

Moreover, SoCalGas maintains that its estimating process has improved since the time that it submitted its TY 2019 GRC application, thanks to “lessons learned from estimating and

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<sup>90</sup> Ex. SCG-08, p. BGK-48.

<sup>91</sup> Ex. TURN-SCGC-03, p. 6, Table 2.

<sup>92</sup> Ex. TURN-SCGC-03, p. 6, Table 2.

<sup>93</sup> Ex. SCG-08, p. BGK-v; D.19-09-051, p. 205.

<sup>94</sup> D.19-09-051, p. 205.

<sup>95</sup> D.19-09-051, p. 205.

<sup>96</sup> Ex. SCG-08, pp. BGK-26 - 27 (Table BK-12); BGK-38 (Table BK-32).

executing the Phase 1B and Phase 2A projects included in A.17-10-008.”<sup>97</sup> SoCalGas has worked to continuously improve its estimating process, the result of which is a “higher confidence level in the base estimates” for the projects included in this GRC than in the last GRC.<sup>98</sup> SoCalGas highlights this positive evolution in its estimating process:

These continuous improvements, which are managed and implemented by a dedicated estimating department, are evidenced by the incorporation of “actual costs...as they are incurred in the field” into the estimating tool, and the engagement of subject matter experts that “use their expertise and professional experience to provide estimate assumptions for their areas that form the basis of each estimate.”<sup>99</sup>

The resulting base cost estimates carefully prepared by SoCalGas for this proceeding are clearly grounded in the utility’s extensive experience with PSEP project implementation and sophisticated ability to anticipate a wide range of foreseeable events.

For all of these reasons, the Commission should conclude that SoCalGas is well positioned to accurately forecast PSEP costs in this GRC. The Commission should accordingly hold SoCalGas to its burden of demonstrating the reasonableness of every dollar requested in a GRC and find that its requested contingencies, intended to cover unforeseeable events that might increase costs, are excessive. Rejecting SoCalGas’s requested contingencies will strike a fair balance between the interests of ratepayers in avoiding excessive costs and of shareholders in having a reasonable opportunity to benefit during the rate case cycle if “the company’s management can ‘do it for less’.”<sup>100</sup>

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<sup>97</sup> Ex. SCG-208, p. BGK-9.

<sup>98</sup> Ex. SCG-208, pp. BGK-2, BGK-9; Ex. SCG-08, p. BGK-20.

<sup>99</sup> Ex. SCG-208, p. BGK-10, fn. 40 (referencing Ex. SCG-08, p. BGK-20).

<sup>100</sup> D.19-05-020, p. 152 (discussing the Commission’s intentions with cost of service GRC ratemaking in the context of disallowing SCE’s request for capitalized software project contingencies).

### 14.3 SoCalGas’s Criticisms of TURN-SCGC’s Recommendation Fall Flat.

SoCalGas opposes TURN-SCGC’s recommendation regarding PSEP contingencies on four grounds, none of which demonstrate the superiority of the utility’s approach. First, SoCalGas argues that its use of contingencies is consistent with industry standards.<sup>101</sup> This may be the case, but as the Commission made clear in D.21-08-036 and D.19-05-020, it does not establish that budgeting for contingencies is necessarily appropriate in a general rate case, where the utility must demonstrate the reasonableness of every dollar in its forecasted revenue requirement.<sup>102</sup> Under cost of service ratemaking, authorized GRC costs will be charged to ratepayers regardless of the amount the utility actually spends. For this reason, the Commission must protect ratepayers from costs that the utility has not established are foreseeable and reasonable.<sup>103</sup>

Second, SoCalGas points to the Commission’s previous authorization of PSEP forecasts including contingencies. SoCalGas discusses the TY 2019 GRC decision, D.19-09-051, which reflected the Commission’s consideration of SoCalGas’s experience with forecasting PSEP projects in 2017, five years before it prepared its GRC request at issue here. TURN-SCGC demonstrate why the Commission should reach a different outcome here in Section 14.2 above. SoCalGas also points to D.19-03-025, which authorized SoCalGas’s first PSEP forecast “based on the same estimation methodology at issue here.”<sup>104</sup> However in that case, the Commission also adopted a one-way balancing account to protect ratepayers from overestimates.<sup>105</sup> Here, in

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<sup>101</sup> Ex. SCG-208, pp. BGK-7, BGK-12 – 13.

<sup>102</sup> D.21-08-036, p. 331 and Conclusion of Law 155; D.19-05-020, p. 150.

<sup>103</sup> See D.21-08-036, p. 331 (“Since contingency allowances are ... intended to cover “unforeseen conditions,” these amounts are also unpredictable, and therefore, we find that SCE has not established these costs to be reasonable.”).

<sup>104</sup> Ex. SCG-208, p. BGK-8, fn. 31.

<sup>105</sup> D.19-03-025, p. 61.

contrast, SoCalGas has proposed to extend through the TY 2024 GRC cycle the PSEP Memorandum Account (PSEPMA) established in D.19-09-051 to track cost overruns in excess of the amounts authorized in that decision.<sup>106</sup> No party has proposed a one-way balancing account to protect ratepayers from an excessive forecast.

Third, SoCalGas posits that “applying [a 10 percent contingency] cap would be arbitrary.”<sup>107</sup> TURN-SCGC’s position is that contingencies are unnecessary at this point in PSEP’s evolution, but that if the Commission authorizes contingencies, they should at least be significantly lower than those authorized in the TY 2019 GRC.<sup>108</sup> A cap of 10 percent achieves that objective. SoCalGas also misunderstands the relevance of TURN-SCGC’s discussion of the fact that SoCalGas implemented the PSEP projects subject to reasonableness review in this GRC ten percent under budget.<sup>109</sup> That 10 percent cost underrun is not the basis for a specific contingency cap of 10 percent, but rather supports the notion that SoCalGas has managed PSEP costs effectively, including the unforeseeable circumstances that may have arisen with the 21 completed projects presented in this GRC.<sup>110</sup>

Finally, SoCalGas suggests that “imposing a cap on contingency at the portfolio level effectively negates the extensive work” SoCalGas undertook to provide specific estimates for each project, based on “each project’s risk profile.”<sup>111</sup> But SoCalGas’s own GRC forecast is already somewhat disconnected from the work it conducted to develop detailed, project-specific

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<sup>106</sup> Ex. SCG-38-R-E, p. RMY-18.

<sup>107</sup> Ex. SCG-208, p. BGK-12.

<sup>108</sup> Ex. TURN-SCGC-03, p. 6.

<sup>109</sup> See Ex. SCG-208, p. 12 (“Therefore, it is erroneous to conclude that a 10 percent contingency should apply due to a 10 percent aggregate cost underrun for a limited, defined list of projects.”).

<sup>110</sup> Ex. TURN-SCGC-03, p. 6 (noting, in discussing Table 2 on that page, that “SoCalGas has been successful on average in meeting or even beating its PSEP budgets.”).

<sup>111</sup> Ex. SCG-208, p. BGK-13.

cost estimates for the 33-project “portfolio.” SoCalGas asks the Commission to authorize revenue requirements covering an “executable” level of work from that portfolio, including 17 percent of the portfolio O&M budget and 56 percent of the capital budget, rather than authorize revenue requirements for specific projects.<sup>112</sup> Given the wide range of contingencies included in SoCalGas’s cost estimates for the 33-project portfolio,<sup>113</sup> it is entirely possible that the utility might choose to implement projects with less than average cost risk, or more, creating a mismatch between revenue requirements and project-specific cost estimates.

#### **14.4 TURN-SCGC’s Adjustments Should Be Adopted.**

For the foregoing reasons, the Commission should conclude that SoCalGas’s contingencies for PSEP projects are excessive. As a matter of fairness to ratepayers, the Commission should either limit contingencies for hydrotest projects and capital pipeline replacement projects to 10% or remove all contingencies. Either would be a reasonable outcome under the circumstances. The Commission can effectuate these options using the methodologies explained below.

##### Limiting Contingencies to 10 Percent

Because SoCalGas has designated as confidential the contingencies included in its forecasts, TURN-SCGC witness Catherine Yap presented the total forecast adjustment for the portfolio of pressure test projects and the portfolio of pipeline projects that results from limiting the contingencies for each project in the “portfolio” to 10 percent. The reduction to SoCalGas’s portfolio of capital pipeline replacement projects resulting from limiting contingencies to 10 percent is \$20.405 million, which is 4.95 percent of SoCalGas’s total portfolio forecast for

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<sup>112</sup> Ex. SCG-208, p. BGK-6; Ex. SCG-208, p. BGK-19, fn. 38.

<sup>113</sup> Ex. TURN-SCGC-03 – Attachment B (CONFIDENTIAL), p. 3.

capital pipeline projects of \$415.196 million.<sup>114</sup> For hydrotest projects, this limit reduces the total portfolio forecast by \$28.5 million, a 6.45 percent adjustment to SoCalGas’s total hydrotest portfolio forecast of \$441.457 million.<sup>115</sup>

In rebuttal testimony, SoCalGas proposed a method for approximating the value of TURN-SCGC’s adjustments applied to SoCalGas’s GRC forecasts (which contemplate the implementation of a subset of the projects included in the portfolio). SoCalGas applied the TURN-SCGC percentage reduction for all hydrotests (6.45%) to SoCalGas’s GRC O&M forecast and the percentage reduction for all capital pipeline projects (4.95%) to its GRC capital forecasts.<sup>116</sup> For purposes of the Joint Comparison Exhibit, SoCalGas revised this method to more accurately reflect the capital component of hydrotest projects, applying the TURN-SCGC 6.45% reduction instead of the 4.95% reduction for pipeline replacement projects.<sup>117</sup> TURN-SCGC accept this method as reasonable given that SoCalGas does not request approval of specific projects within the “portfolio.” TURN-SCGC incorporate the resulting adjustments shown in the Joint Comparison Exhibit to SoCalGas’s GRC forecasts in the table below.

#### Eliminating Contingencies

TURN-SCGC witness Catherine Yap did not calculate the adjustment resulting from eliminating all contingencies in her testimony, but those values can be calculated from the same data she used to calculate adjustments associated with capping contingencies at 10%. This data

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<sup>114</sup> Ex. TURN-SCGC-03, p. 5, Table 1; Ex. SCG-08, p. BGK-26 – 27. TURN-SCGC’s Table 1 and SCG’s Table BK-12 include slightly different forecasts for Project 44-306/44-307, differing by about \$2.3 million, which impacts the total portfolio forecast.

<sup>115</sup> Ex. TURN-SCGC-03, p. 7, Table 3; Ex. SCG-08, p. BGK-38. Both tables combine O&M and capital costs for hydrotest projects.

<sup>116</sup> Ex. SCG-208, p. BGK-5, fn. 14; p. BGK-15, fn. 61.

<sup>117</sup> Joint Comparison Exhibit – SoCalGas, p. 334.

is included in the record in Ex. TURN-SCGC-03 – Attachment B (CONFIDENTIAL). In preparing this brief, TURN-SCGC used data contained in Ex. TURN-SCGC-03 – Attachment B (CONFIDENTIAL) to calculate the adjustment to SoCalGas’s forecasts that would result from eliminating all contingencies.<sup>118</sup> The adjustment factors that result are approximately 14.94% for pipeline replacement projects and 16.44% for hydrotest projects.<sup>119</sup>

The results of both of these adjustments are shown in the following table, which presents SoCalGas’s forecasts for the various PSEP activities in the same format as in the Joint Comparison Exhibit.

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<sup>118</sup> See, e.g., Ex. TURN-SCGC-03 – Attachment B (CONFIDENTIAL), p. 3. This page provides the contingency factor included (but not revealed) in SoCalGas’s cost estimate for each Capital Pipeline project shown in Ex. SCG-08 Table BK-12 and each Hydrotest project shown in Ex. SCG-08 Table BK-32.

<sup>119</sup> To calculate the adjustment factor that results from removing all contingencies from the portfolio of Capital Pipeline projects based on Ex. TURN-SCGC-03 – Attachment B (CONFIDENTIAL), p. 3, TURN-SCGC (1) multiplied the SoCalGas cost estimate for each project by the contingency factor for that project to produce contingency amounts; (2) calculated the sum of the contingency amounts included in the Capital Pipeline project cost estimates; and (3) divided the sum of the contingency amounts by SoCalGas’s total cost estimate for the portfolio of Capital Pipeline projects. To calculate the adjustment factor that results from removing all contingencies from the portfolio of Hydrotest projects, TURN-SCGC similarly (1) multiplied the SoCalGas cost estimate for each project by the contingency factor for that project to produce contingency amounts; (2) calculated the sum of the contingency amounts included in the Hydrotest project cost estimates; and (3) divided the sum of the contingency amounts by SoCalGas’s total cost estimate for the portfolio of Hydrotest projects.

PSEP Projects	Type	Phase	SoCalGas (\$000)		
			2022	2023	2024
<b>Hydrotest (JCE, p. 320)</b>	<b>O&amp;M</b>	<b>2A</b>			<b>\$ 50,682</b>
			TURN-SCGC Adjustments		
Adjustment Factor (Contingencies > 10%)					-6.45%
Remove Contingencies > 10%					\$ (3,269)
<i>Adjustment Factor (All Contingencies)</i>					-16.44%
<i>Remove All Contingencies</i>					\$ (8,332)
<b>Hydrotest (JCE, p. 334)</b>	<b>Capital</b>	<b>2A</b>	<b>\$ 17,077</b>	<b>\$ 13,711</b>	<b>\$ 22,223</b>
			TURN-SCGC Adjustments		
Adjustment Factor (Contingencies > 10%)			-6.45%	-6.45%	-6.45%
Remove Contingencies > 10%			\$ (1,101)	\$ (884)	\$ (1,433)
<i>Adjustment Factor (All Contingencies)</i>			-16.44%	-16.44%	-16.44%
<i>Remove All Contingencies</i>			\$ (2,807)	\$ (2,254)	\$ (3,653)
<b>Replacements (JCE, p. 332)</b>	<b>Capital</b>	<b>2A</b>	<b>\$ 14,258</b>	<b>\$ 2,268</b>	<b>\$ 22,980</b>
			TURN-SCGC Adjustments		
Adjustment Factor (Contingencies > 10%)			-4.95%	-4.95%	-4.95%
Remove Contingencies > 10%			\$ (706)	\$ (112)	\$ (1,138)
<i>Adjustment Factor (All Contingencies)</i>			-14.94%	-14.94%	-14.94%
<i>Remove All Contingencies</i>			\$ (2,130)	\$ (339)	\$ (3,433)
<b>Replacements (JCE, p. 336)</b>	<b>Capital</b>	<b>1B</b>	<b>\$ 37,814</b>	<b>\$ 52,377</b>	<b>\$ 19,943</b>
			TURN-SCGC Adjustments		
Adjustment Factor (Contingencies > 10%)			-4.95%	-4.95%	-4.95%
Remove Contingencies > 10%			\$ (1,872)	\$ (2,593)	\$ (987)
<i>Adjustment Factor (All Contingencies)</i>			-14.94%	-14.94%	-14.94%
<i>Remove All Contingencies</i>			\$ (5,649)	\$ (7,825)	\$ (2,979)

## 15. GAS INTEGRITY MANAGEMENT PROGRAMS

For the reasons discussed in Subsection 15.1 of this Joint Opening Brief, TURN and SCGC recommend that the Commission reduce the SoCalGas Test Year 2024 Transmission Integrity Management Program (“TIMP”) Operations and Maintenance (“O&M”) forecasted costs by 29 percent (\$39.3 million) from \$135.4 million to \$96.1 million.

For the reasons discussed in Subsection 15.2 of this Joint Opening Brief, TURN and SCGC recommend that the Commission direct SoCalGas to convert its Transmission Integrity

Management Program Balancing Account (“TIMPBA”) from being a two-way balancing account to being a one-way balancing account. Additionally, TURN and SCGC recommend that SoCalGas be permitted to record in a new memorandum account amounts which result from TIMP spending on a year-to-year basis above the amount that the Commission authorizes SoCalGas to recover during each year of the Test Year 2024 GRC cycle. TURN and SCGC further recommend that the Commission direct SoCalGas to eliminate from its TIMPBA the provision that permits SoCalGas to submit a Tier 3 advice letter to seek recovery of TIMP costs that result from spending up to 35 percent more than the total authorized TIMP Operations and Maintenance (“O&M”) and capital expenditures.

For the reasons discussed in Subsection 15.3 below, TURN and SCGC recommend that the Commission direct SoCalGas to reconfirm 50 percent of the 550 miles of transmission pipeline for which reconfirmation is required by Pipeline and Hazardous Materials Safety Administration (“PHMSA”) regulations, leaving the remaining 50 percent of the 550 miles for reconfirmation by 2035 during the SoCalGas Test Year 2028 and Test Year 2032 GRC cycles. Remaining Integrated Safety Enhancement Plan (“ISEP”) miles should be reconfirmed in accordance with SoCalGas’s PSEP Phase 2B “as soon as practicable” requirement through future GRCs.

As discussed in Subsection 15.4 below, TURN and SCGC recommend that the Commission deny SoCalGas’s request for a new Gas Safety Enhancement Plan (“GSEP”) balancing account.

**15.1 The Commission Should Reduce SoCalGas’s Test Year 2024 TIMP O&M Forecast by 29 percent from \$135.4 million to \$96.1 million.**

SoCalGas proposes to increase its TIMP O&M spending in Test Year 2024 by 62 percent over its 2017-2021 average and by 31 percent over its Base Year 2021 spending.<sup>120</sup> The O&M spending falls under five categories:

- Assessment & Remediation,
- Preventative & Mitigative Measures,
- Data & GIS,
- Program Management & Support,
- Risk & Threat.<sup>121</sup>

The increase (in thousands) and the percentage increase relative to recorded years 2017-2021 and relative to Base Year 2021 for each of the five categories and for total TIMP O&M are shown in the following table:

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<sup>120</sup> Exhibit (“Ex.”) TURN-SCGC-04-E, p. 2.

<sup>121</sup> *Id.*

**Table 1<sup>1</sup>**

TIMP O&M Costs by Category						
constant \$2021 (000s)	Assessment & Remediation	Preventative & Mitigative Measures	Data & GIS	Program Management & Support	Risk & Threat	Total
<i>Recorded</i> 2017	32,892	8,372	3,720	3,190	1,760	49,934
<i>Recorded</i> 2018	49,057	6,192	8,146	5,220	2,538	71,153
<i>Recorded</i> 2019	59,207	4,936	11,480	3,485	2,199	81,307
<i>Recorded</i> 2020	87,050	4,198	13,719	4,742	1,695	111,404
<i>Recorded</i> 2021	79,697	4,619	10,880	6,081	2,380	103,657
<i>Average</i> 2017-2021	61,581	5,663	9,589	4,544	2,114	83,491
<i>Forecasted</i> 2024	103,896	6,842	11,972	10,308	2,415	135,433
<i>increase relative to 2017-2021 avg</i>	69%	21%	25%	127%	14%	62%
<i>increase relative to 2021</i>	30%	48%	10%	70%	1%	31%

122

As shown in the table above, the bulk (76.7 percent) of the proposed increase in O&M expense is in the A&R category. However, the reasons discussed below, the SoCalGas forecast for all five categories of TIMP expense should be reduced. The reductions result in the total forecast for TIMP O&M being reduced by 29 percent (\$39.3 million).

**15.1.1 SoCalGas’s Test Year 2024 A&R O&M Forecast of \$103.9 Million Should Be Reduced by 28.6 Percent (\$29.7 Million) to \$74.2 Million for Test Year 2024.**

The SoCalGas forecast of \$103.9 million in TIMP O&M expense for Assessment & Remediation (“A&R”) in Test Year 2024 should be reduced by \$29.7 million (28.6 percent) to \$74.2 million. SoCalGas uses a model that is “fundamentally rooted in average unit costs” for the two types of A&R inspections, but SoCalGas fails to provide any support for the unit costs. SoCalGas’s unsupported unit costs are far in excess of historical unit costs.

<sup>122</sup> Ex. TURN-SCGC-04-E, p. 3.

Instead of relying on SoCalGas’s model, the Commission should base the Test Year 2024 forecast of A&R O&M on five years of historical A&R costs with two adjustments, one for increased Material Verification and Crack Management Tool Run costs and another for an incremental number of validation digs in Test Year 2024 in comparison to Base Year 2021.

**15.1.1.1 SoCalGas’s Methodology for Forecasting A&R ILI and ECDA O&M Costs for Test Year 2024 is Based upon Unit Costs, but SoCalGas Fails to Provide any Support for the Claimed Unit Costs.**

SoCalGas uses the following model for developing its Test Year 2024 forecasts of A&R O&M expense:

Table 2<sup>123</sup>

	<u>Tools/Materials/Surveys</u>			<u>Validation Digs</u>			TOTAL
	Assessment Units	# of Units	Unit Cost	Assessment Units	# of Units	Unit Cost	
ILI	# of Assessments	20	\$1,420	# of Assessments	20	\$2,500	<b>\$78,400</b>
ECDA	# of Miles	22.1	\$55	# of Assessments	16	\$1,000	<b>\$17,216</b>
Material verification		130	\$3	Fixed cost		\$717	<b>\$1,136</b>
Crack Management Tool Runs		147	\$48				<b>\$7,145</b>
							<b>\$103,897</b>

As shown in Table 2, first SoCalGas calculates its projected In-Line Inspection (“ILI”) A&R expense by multiplying a unit cost per assessment (\$1.42 million) times the number of assessments (20). SoCalGas then multiplies a unit cost for assessment validation digs (\$2.5 million) by the number of assessments (20). The sum of the two products is the forecast \$78.4 million for A&R ILI O&M expense.

Second, SoCalGas produces a forecast of External Corrosion Direct Assessment (“ECDA”) by multiplying the assessment cost per mile (\$55,000) times the number of ECDA assessment miles (22.1). SoCalGas multiplies the validation dig unit cost for ECDA (\$1.0

<sup>123</sup> Ex. TURN-SCGC-04-E, p. 3.

million) times the number of ECDA assessments (16). The total of these two products is the forecast, \$17.216 million for A&R ECDA expense.

SoCalGas then adds to the total amounts for ILA and ECDA the amounts for the last two categories, Material Verification (\$1.136 million) and Crack Management Tool Runs (\$7.145 million), to derive a total \$103.896 million forecast for 2024 A&R O&M expenses.

If SoCalGas is going to rely upon the unit cost per assessment or the unit cost per assessment validation dig, SoCalGas should provide at least some evidentiary support for the purported unit costs. SoCalGas adamantly refused to provide any support. TURN and SCGC asked SoCalGas to “show a derivation of the ILI unit assessment costs....”<sup>124</sup> SoCalGas refused to provide the derivation. SoCalGas said, in response, “There is variability in assessment costs since costs are driven by several wide ranging factors including ILI tool performance which drives the need for validation digs, logistics related to field environment, and pipe condition which drives the need for repair.”<sup>125</sup> SoCalGas adds, “To account for this variability, historical ILI project costs were averaged to derive a typical ILI project costs of \$3.92 million.”<sup>126</sup>

Pressing SoCalGas for more details, TURN and SCGC asked, “Please provide a project by project listing of each of the ILI assessments and associated validation digs that was used as part of the base year data supporting the 2024 unit costs.”<sup>127</sup> TURN and SCGC also asked for “project name, project costs, year completed, location, run mileage, run type” and other information.<sup>128</sup> SoCalGas simply refused to provide any further information.<sup>129</sup>

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<sup>124</sup> Ex. TURN-SCGC-04-E, Attachment, p. 203.

<sup>125</sup> *Id.*

<sup>126</sup> *Id.*

<sup>127</sup> *Id.*, p. 204.

<sup>128</sup> *Id.*

<sup>129</sup> *Id.*

SoCalGas’s musing about how there is “variability in assessment cost” and claims about averaging costs does not make up for SoCalGas’s obstinate refusal to provide any information about what the unit costs actually are. SoCalGas fails to provide evidentiary support for the assessment unit costs used in SoCalGas’s methodology for forecasting A&R O&M for Test Year 2024, sapping the forecast from having any evidentiary value.

**15.1.1.2 SoCalGas Cannot Rely on the Expansion of GTSR Rule Part 1 to Cover Outside-of-HCA Assessments and Material Verification as a Reason for Increasing A&R ILI and ECDA O&M Forecasted Costs in Comparison to Base Year 2021 Costs.**

SoCalGas points to PHMSA’s Gas Transmission and Storage Rule (“GTSR”) Part 1<sup>130</sup> “expansion of scope” of A&R ILI and ECDA activity to material verification and to areas outside of High Consequence Areas (“HCAs”).<sup>131</sup> However, the expansion of GTSR Part 1 to material verification and to outside-of-HCA assessments can justify the unsupported projection of unit ILI and ECDA costs in the SoCalGas A&R forecasting methodology.

As for material verification and another new area under GTSR Part 1, crack management, SoCalGas forecasts separate amounts of \$1.136 million and \$7.145 million, respectively, and adds these amounts to A&R O&M costs. Thus, material verification and crack management costs are forecasted independently from the forecast of A&R ILI and ECDA unit costs and cannot be claimed as a justification for the claimed unit A&R ILI and ECDA costs. As discussed below, TURN and SCGC do not contest SoCalGas’s proposed additions to the A&R O&M Test Year 2024 costs for material verification and for crack management.

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<sup>130</sup> 84 Fed. Reg. 52180 (October 1, 2019).

<sup>131</sup> Ex. SCG-09-E. p. AK-TS-35.

GTSR Part 1 expands to TIMP assessments areas outside of HCAs. Under GTSR Part 1, 49 CFR § 192.710, TIMP now covers transmission lines that are located outside of HCAs that have a Maximum Allowable Operating Pressure (“MAOP”) of 30 percent of Specified Minimum Yield Strength (“SMYS”) which are located in Class 3 or Class 4 locations or are located in a Moderate Consequence Area.<sup>132</sup> However, the expansion of TIMP coverage would not affect the unit cost of assessment that SoCalGas claims in its forecast of A&R ILI and ECDA costs. The expansion of TIMP assessment requirements under 49 CFR § 192.710 would affect the number of units to assess rather than the unit cost per assessment.

Further, the expanded TIMP coverage does not significantly affect the number of units that are assessed. SoCalGas already assesses far more pipeline mileage than it is required to assess under PHMSA rules. Thus, the GTSR Part 1 expansion of assessment requirements under 49 CFR § 192.710 to certain transmission lines outside of HCAs would not significantly affect the number of SoCalGas assessments. SoCalGas has already completed base line assessments and several repeat assessments for 56 of the 60 miles that SoCalGas identifies as requiring assessment under the new 49 CFR § 192.710.<sup>133</sup> The 56 miles were assessed prior to 2020 with reassessments due in 2021-2027.<sup>134</sup> Thus, the expansion of PHMSA TIMP assessment requirements to certain areas outside of HCAs would not make a meaningful difference in the number of TIMP assessments performed by SoCalGas.

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<sup>132</sup> Provided these lines are ILI enabled.

<sup>133</sup> Ex. TURN-SCGC-04-E, p. 8.

<sup>134</sup> *Id.*

**15.1.1.3 The Unreasonableness of SoCalGas’s A&R ILI and ECDA Expense Forecasts for Test Year 2024 Is Demonstrated by the Fact that SoCalGas Substantially Increases Its A&R ILI and ECDA Costs for Doing Less ILI and ECDA Assessment Activity.**

The unreasonableness of SoCalGas’s A&R ILI and ECDA unit costs for Test Year 2024 is demonstrated by the fact that SoCalGas forecasts a 69 percent increase in A&R O&M expense, mostly due to ILI and ECDA, over Base Year 2021 recorded expense for doing substantially fewer assessments than in Base Year 2021.<sup>135</sup> There were 54 ILI and ECDA projects (27 ILI projects and 27 ECDA projects) conducted in 2021, but SoCalGas plans only 36 projects (20 ILI projects and 16 ECDA projects) for 2024, a 33 percent decline in the number of projects from 2021 to 2024.<sup>136</sup>

Furthermore, SoCalGas projects that it will complete 22 miles of ECDA in 2024, which is less than half of the ECDA mileage that was completed in 2021 (50 miles).<sup>137</sup> SoCalGas projects that in 2024 it will complete only 59 percent of the 27 ECDA projects performed in 2021 for more than three times the cost.<sup>138</sup> Likewise, SoCalGas projects that it will spend six percent more to complete 26 percent fewer ILI projects in 2024 compared to 2021.<sup>139</sup> Thus, SoCalGas projects increased A&R ILI and ECDA expense for doing substantially fewer assessments.<sup>140</sup>

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<sup>135</sup> Ex. TURN-SCGC-04-E, p. 11.

<sup>136</sup> *Id.*, p. 12.

<sup>137</sup> *Id.*

<sup>138</sup> *Id.*

<sup>139</sup> *Id.*

<sup>140</sup> *Id.*

**15.1.1.4 The Dramatic Magnitude of the Increase in SoCalGas’s Forecasts of Test Year 2024 A&R ILI and ECDA Unit Expense in Comparison to Recorded 2017-2021 Expense Is Further Demonstrated by a Backcast.**

The dramatic magnitude of the increase in SoCalGas’s forecasted unit cost of ILI and ECDA assessments is further demonstrated by a backcast. A backcast multiplies the recorded number of ILI and ECDA assessments that were completed in the years 2017-2021 by SoCalGas’s proposed 2024 unit costs (in 2021 dollars) for ILI and ECDA assessments.<sup>141</sup> That backcast methodology results in the following table showing recorded costs in comparison to the backcasted costs for each year. The table demonstrates the degree to which SoCalGas’s claimed but unsupported ILI and ECDA unit costs are excessive:

Table 3<sup>142</sup>

\$000 in 2021 dollars	2017	2018	2019	2020	2021
Cost of ILI runs plus verification digs	\$62,720	\$101,920	\$137,200	\$82,320	\$105,840
ECDA cost including verification digs	\$14,375	\$9,935	\$28,303	\$9,045	\$29,750
Total Estimated with SoCalGas Cost Model	\$77,095	\$111,855	\$165,503	\$91,365	\$135,590
Recorded	32,892	49,057	59,207	87,050	79,697
SoCalGas Cost Model Produces Excess Cost	\$44,203	\$62,798	\$106,296	\$4,315	\$55,893

<sup>141</sup> *Id.*, p. 14.

<sup>142</sup> *Id.*

The table shows that SoCalGas's claimed Test Year 2024 A&R ILI and ECDA unit costs produce backcasted ILI and ECDA costs for 2017-2021 that are far in excess of the actually recorded costs.

**15.1.1.5 The Commission Should Base the Forecast for A&R ILI and ECDA O&M for Test Year 2024 on the Five Year 2017-2021 Average ILI and ECDA Assessment Expenses.**

Both the comparison of SoCalGas's forecasted Test Year 2024 A&R expense for ILI and ECDA to recorded expense and the backcast applying SoCalGas's proposed 2024 unit costs to the number of ILI and ECDA assessments done in 2017-2021 demonstrate that SoCalGas has developed an excessive Test Year 2024 A&R O&M forecast by using its unsupported but nevertheless proposed unit costs for ILI and ECDA. On a per mile basis, the 2024 ILI forecasted cost is more than twice (114 percent) the 2017-2021 average, and the 2024 ECDA forecasted cost is significantly more than twice (153 percent) the 2017-2021 average.<sup>143</sup> On a per project basis the 2024 ILI forecasted cost is more than 70 percent higher than the 2017-2021 average, and the ECDA forecasted cost is well over twice (144 percent) the 2017-2021 average.<sup>144</sup> There is no reason why the cost of running ILI operations and performing ILI digs should deviate so substantially from the five year average, and there is no reason why the costs of ECDA assessments should more than double.

Given the seven-year reassessment interval required under the PHMSA TMIP regulation, the pipeline mileage assessed in 2017 will be assessed again seven years later in 2024.<sup>145</sup> Similarly, the pipeline mileage assessed in 2018 will be assessed again in 2025, and so on.<sup>146</sup>

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<sup>143</sup> Ex. TURN-SCGC-04-E, p. 14.

<sup>144</sup> *Id.*

<sup>145</sup> *Id.*, p. 12

<sup>146</sup> *Id.*

However, there are swings in the number of projects and the number of miles assessed each year, so it makes sense to utilize five years, 2017-2021, of recorded data to determine the Test Year 2024 A&R ILI and ECDA cost.<sup>147</sup> As shown in Table 1 above, the five year average of recorded 2017-2021 A&R ILI and ECDA expense is \$61.581 million in 2021 dollars.<sup>148</sup>

**15.1.1.6 In Addition to Adopting the Five-Year Average of Recorded A&R ILI and ECDA Assessment Cost of \$61.581 Million for Test Year 2024, the Commission Should Include Incremental Amounts for Material Verification and Crack Management to the A&R O&M Forecast.**

In addition to the five-year average recorded A&R assessment expense of \$61.581 million, the Commission should add amounts to account for the new GTSR Part 1 regulations requiring material verification and crack management tool runs as shown in Table 2 above. SoCalGas forecasts that material verification will cost \$1.136 million in Test Year 2024 and that crack management tool runs will cost \$7.145 million in Test Year 2024 totaling \$8.281 million.

There should also be an allowance for additional validation digs in Test Year 2024. SoCalGas projects 132 post-assessment validation digs in Test Year 2024, which is 17 digs higher than the five year 2017-2021 average of 115 validation digs.<sup>149</sup> Additional validation digs are plausible because the new PHMSA regulations require additional electromagnetic acoustic transducer (“EMAT”) assessments, which may reveal additional anomalies that will require validation digs.<sup>150</sup>

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<sup>147</sup> *Id.*

<sup>148</sup> *Id.*, p. 15.

<sup>149</sup> Ex. TURN-SCGC-04-E, p. 15.

<sup>150</sup> Ex. TURN-SCGC-04-E, p. 15.

However, the Test Year 2024 forecast for validation digs should be reduced from the \$500,000 per dig forecasted by SoCalGas.<sup>151</sup> That estimated cost per dig is excessive. In its Test Year 2023 GRC, A.21-06-021, Pacific Gas and Electric Company (“PG&E”) forecasted a cost of about \$240,000 per validation dig, less than half of SoCalGas’s \$500,000 cost.<sup>152</sup> The degree of excess in SoCalGas’s forecasted \$500,000 cost per validation dig is consistent with the degree of excess in SoCalGas’s forecast of ILI assessment expense, which is 72 percent above the five-year average, and the degree of excess in SoCalGas’s forecast of ECDA expense, which is 144 percent above the five-year average.<sup>153</sup> To be consistent with SCGC’s recommended reduction in SoCalGas’s Test Year 2024 forecasts for A&R ILI and ECDA assessments, the expense per validation dig should be reduced by half to \$250,000 per dig, which is in line with the PG&E average cost per dig.<sup>154</sup>

**15.1.1.7 Conclusion: The Test Year 2024 Forecast for A&R O&M Should Be \$74.212 Million in 2021 Dollars.**

The total Test Year 2024 forecast for A&R O&M should be \$74.212 million in 2021 dollars, a reduction of \$29.7 million (28.6 percent) from SoCalGas’s forecasted \$103.896 million.<sup>155</sup> The total forecast for A&R O&M for Test Year 2024 in 2021 dollars should be a combination of \$61.581 million to reflect five-year recorded 2017-2021 average costs of ILI and ECDA assessment plus \$8.281 million that SoCalGas forecasts it will incur due to new PHMSA requirements for material verification and crack management tool runs and another \$4.35 million

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<sup>151</sup> Ex. TURN-SCGC-04-E, Attachment J, p. 204.

<sup>152</sup> *Id.*, p. 16.

<sup>153</sup> Ex. TURN-SCGC-04-E, p. 16.

<sup>154</sup> *Id.*

<sup>155</sup> *Id.*, p. 16.

to account for SoCalGas's forecast of an additional 17 validation digs at the cost of \$250,000 per dig in Test Year 2024.<sup>156</sup>

**15.1.2 The Remaining Four Non-A&R TIMP O&M Cost Categories Should Be Forecasted to Be Equal to the Five-Year 2017-2021 Average Amount in 2021 Dollars.**

Although A&R O&M costs are the largest single category of the forecasted Test Year 2024 TIMP O&M, SoCalGas projects significant increases for the remaining four categories of forecasted TIMP O&M costs, Preventative and Mitigative Measures, Data & GIS, Program Management & Support, and Risk & Threat.<sup>157</sup>

**15.1.2.1 SoCalGas's Forecast for the Four Non-A&R Categories of TIMP O&M Expense Should Be Reduced to the Five-Year 2017-2021 Average of Expense for Each of the Four Non-A&R Categories.**

SoCalGas's forecast for the four non-A&R categories of TIMP O&M expense should be reduced to the five-year 2017-2021 average of expense for each of the categories.

The Program Management category represents the biggest percentage increase above the five-year 2017-2021 historical average, a 127 percent increase from \$4.544 million to \$10.38 million.<sup>158</sup> Such an excessive increase in Program Management O&M is unjustifiable. SoCalGas has been conducting TIMP assessments of its high pressure transmission pipelines for nearly two decades.<sup>159</sup> It should not need to increase its Program Management O&M by 127 percent with no demonstration of any safety enhancement. SoCalGas should be allowed the

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<sup>156</sup> *Id.*

<sup>157</sup> *Id.*, pp. 2, 18.

<sup>158</sup> *Id.*, p. 16.

<sup>159</sup> *Id.*, p. 16.

five-year 2017-2021 average of \$4.544 million in 2021 dollars for Program Management O&M, a reduction of \$5.764 million from SoCalGas's requested \$10.308 million.<sup>160</sup>

Likewise, for the remaining three categories of TIMP O&M expense, the Commission should authorize only the five-year 2017-2021 average level of expense for Test Year 2024. SoCalGas has been implementing TIMP for the same amount of transmission pipeline mileage for nearly two decades and presents no compelling reason for increasing the forecasted cost for the Data & GIS, Preventative & Mitigative Measures, and Risk & Threat categories.<sup>161</sup>

The Commission should authorize the five-year 2017-2021 average level of expense for the Data & GIS category in the amount of \$9.589 million in 2021 dollars, a reduction of \$2.38 million (20 percent), from SoCalGas's request of \$11.972 million.<sup>162</sup>

The Commission should authorize the five-year average level of expense for the Preventative & Mitigative Measures category in the amount of \$5.663 million in 2021 dollars, a reduction of \$1.179 million (17 percent), from SoCalGas's requested \$6.482 million.<sup>163</sup>

Lastly, the Commission should authorize the five-year average level of expense for the Risk & Threat category in the amount of \$2.114 million, a reduction of \$0.301 million (12.5 percent), from SoCalGas's requested \$2.415 million.<sup>164</sup>

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<sup>160</sup> *Id.*, p. 17.

<sup>161</sup> *Id.*

<sup>162</sup> *Id.*, p. 18.

<sup>163</sup> *Id.*

<sup>164</sup> *Id.*, p. 18.

**15.1.2.2 SoCalGas Fails to Provide Any Evidence of a Need to Increase the Test Year Level of O&M Expense for the Four Non-A&R TIMP O&M Categories Above the Five-Year 2017-2021 Averages.**

In its rebuttal testimony, SoCalGas argued that its proposed increases in costs in each of the four non-A&R TIMP O&M categories (Preventative & Mitigative Measures, Data & GIS Program Management & Support, and Risk & Threat) are not “driven solely by the number of miles to be assessed.”<sup>165</sup> SoCalGas says that it “anticipates” that it will have more data to evaluate, resulting in more prevention and mitigation activities.<sup>166</sup> SoCalGas argues that the funding required to manage projects, integrate data, analyze risks and threats, and determine risk mitigation actions increases regardless of whether the number of in-scope miles increase.<sup>167</sup>

SoCalGas’s expression of expectations and anticipations only demonstrates that SoCalGas has expectations and anticipations. Expressions of expectations and anticipations do not constitute evidence of a need to increase forecasted TIMP O&M for the four non-A&R TIMP O&M categories.

If SoCalGas can present an actual example of a new requirement that would cause the incurrence of increased O&M expense in Test Year 2024 in comparison to the five historical years 2017-2021, then it would be valid for the Commission to consider the allegation of increased O&M expense. In its rebuttal testimony SoCalGas can muster only one example, “The new requirements regarding the use of Stress Corrosion Cracking Direct Assessment (SCCDA) [that] prescribe the development of a threat identification and risk assessment process for evaluating segments in the SoCalGas pipeline system.”<sup>168</sup>

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<sup>165</sup> Ex. SCG-209, p. TS-AR-11.

<sup>166</sup> *Id.*

<sup>167</sup> *Id.*

<sup>168</sup> *Id.*

However, SoCalGas proposed to increase the A&R category of Test Year 2024 TIMP O&M expense by \$7.145 million for crack management and by \$1.136 million for new GTSR Part 1 materials verification.<sup>169</sup> TURN and SCGC recognized the potential for increased Test Year 2024 O&M expense for crack management and materials verification. Accordingly, TURN and SCGC stated, “It is plausible that SoCalGas could incur additional costs because of the emphasis of the GTSR Part 1 regulations on addressing cracks, particularly stress corrosion cracking, which may increase SoCalGas’s use of EMAT technology in its assessments.”<sup>170</sup> TURN and SCGC also agreed to add \$1.136 million for Material Verification to A&R O&M expense for Test Year 2024.<sup>171</sup>

Consequently, as discussed above, TURN-SCGC’s recommended 2024 A&R O&M expense of \$74.212 million already includes SoCalGas’s requested amounts to cover increased Test Year 2024 O&M expense due to crack management and material verification. It would be double counting to further increase the Test Year 2024 O&M expense for the non-A&R TIMP O&M categories when amounts are already included in the A&R TIMP O&M expense category.

**15.1.3 Conclusion: The Commission Should Authorize a Test Year 2024 Forecast for Each of the Five Categories of TIMP O&M Expense that Is Based on the Five-Year 2017-2021 Average Level of Expense with Additional Increases to the A&R Category of \$7.145 Million for Crack Management and \$1.136 Million for Material Verification.**

The Commission should authorize a Test Year 2024 forecast for each of the five categories of TIMP O&M expense that is based on the five-year 2017-2021 average level of expense with additional increases to the A&R category of \$7.145 million for crack management and \$1.136 million for material verification. SoCalGas’s proposed Test Year 2024 amounts for

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<sup>169</sup> Ex. TURN-SCGC-04-E, p.3

<sup>170</sup> *Id.*, p. 15.

<sup>171</sup> *Id.*

each of the five categories of O&M expense for Test Year 2024 with the TURN-SCGC recommended amounts and the difference between SoCalGas and TURN-SCGC are shown in the following Table 4:

Table 4<sup>172</sup>

Recommended Adjustments to TIMP O&M Costs by Category						
constant \$2021 (000s)	Assessment & Remediation	Preventative & Mitigative Measures	Data & GIS	Program Management & Support	Risk & Threat	Total
SoCalGas Proposed 2024	103,896	6,842	11,972	10,308	2,415	135,433
TURN-SCGC Recommended 2024	74,212	5,663	9,589	4,544	2,114	96,122
Difference	29,684	1,179	2,383	5,764	301	39,311

**15.2 The SoCalGas TIMP Balancing Account Should Be Converted from Being a Two-Way Balancing Account to Being a One-Way Balancing Account Combined with A Memorandum Account in Which SoCalGas Would Record on a Year-to-Year Basis for Future Reasonableness Review Any Amounts that Are in Excess of Costs Authorized for TIMP Activities in this GRC.**

The Commission should require that SoCalGas convert its current Transmission Integrity Management Plan Balancing Account (“TIMPBA”) from being a two-way balancing account to being a one-way balancing account. Additionally, the Commission should authorize a memorandum account in which SoCalGas would be permitted to record on a year-to-year basis amounts in excess of amounts authorized in this GRC for recovery after a reasonableness review by application in a future proceeding.

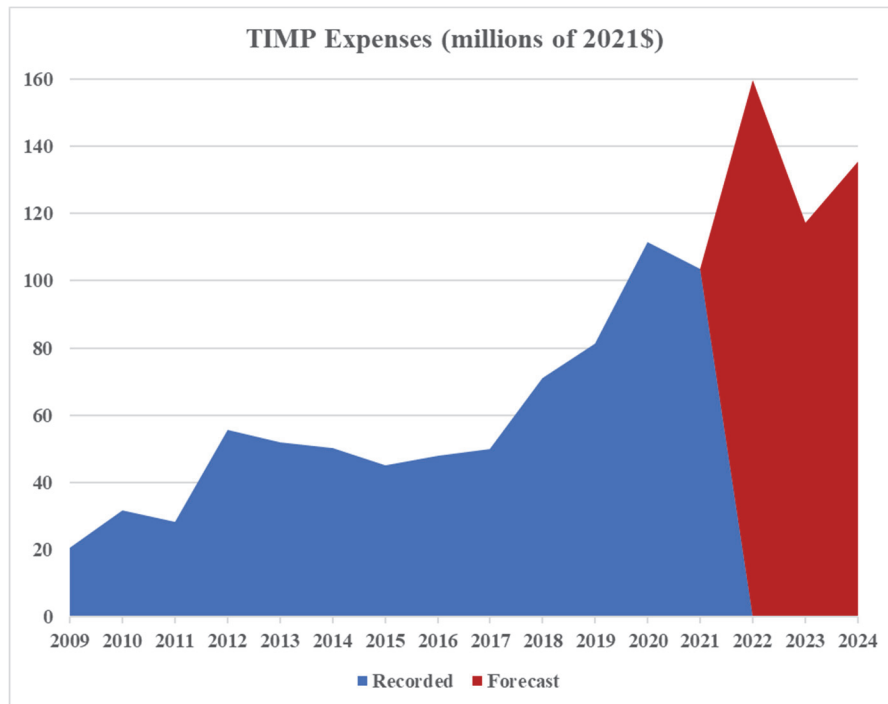
The current two-way balancing account treatment for TIMP costs has failed to protect ratepayers adequately. A one-way balancing account with a memorandum account for recording TIMP costs in excess of authorized amounts with a subsequent reasonableness review through

<sup>172</sup> Ex. TURN-SCGC-04-E, p. 18.

the application process would enhance protection for ratepayers by incenting SoCalGas to improve its TIMP forecasting as it has improved its forecasting for PSEP projects.

### 15.2.1 SoCalGas TIMP Costs Started to Increase Precipitously in 2017.

SoCalGas TIMP costs started a precipitous increase in 2017, as shown by the following graph:<sup>173</sup>



SoCalGas started conducting TIMP activities in 2004, beginning with baseline assessments for pipelines within HCAs.<sup>174</sup> SoCalGas is required to reassess its pipelines every seven years.<sup>175</sup> SoCalGas began reassessments in 2009.<sup>176</sup> Thus, the figure above starts in 2009 when baseline assessments were still ongoing but reassessments had begun.

<sup>173</sup> Ex. TURN-SCGC-04-E, p. 19.

<sup>174</sup> *Id.*, p. 18.

<sup>175</sup> *Id.*

<sup>176</sup> Ex. TURN-SCGC-04-E, Attachment Q, A.10-12-005, Ex. SGC-05, p. RKS-27.

In 2013, the Commission adopted a two-way balancing account in which SoCalGas was permitted to record TAMP O&M and capital costs.<sup>177</sup> The Commission provided for Tier 3 advice letter treatment for amounts in excess of authorized amounts: “Any costs in excess of the O&M costs and capital expenditure authorized for these TAMP costs shall be subject to recovery through a Tier 3 advice letter process.”<sup>178</sup> Additionally, the Commission said, “We will also allow the year-end balance in that two-way balancing account to be carried forward into the following year.”<sup>179</sup>

In the SoCalGas Test Year 2016 GRC, the Commission modified its treatment of amounts in excess of authorized TAMP expenditures. In D.16-06-054, the Commission said, “The advice letter process for recovery of any TAMP or DIMP undercollections will be limited to undercollection amounts up to 35% of the 2016 GRC cycle total revenue requirement for that program and will require Tier 3 advice letter. Any amounts above 35% will be subject to a separate application procedure.”<sup>180</sup> Even though D.16-06-054 tightened the review process for expenditures above authorized amounts by requiring an application for undercollected amounts above the 35 percent in 2017, TAMP expenditures started a relentless climb from around \$45 million dollars per year to amounts consistently exceeding \$100 million dollars per year as shown in the figure above.

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<sup>177</sup> D.13-05-010, p. 421 (May 9, 2013).

<sup>178</sup> *Id.*, pp. 421-422.

<sup>179</sup> *Id.*

<sup>180</sup> D.16-06-054, p. 27 (June 23, 2016).

**15.2.2 SoCalGas Advice Letter 6060 Seeking Recovery of a Portion of the TIMPBA Balance that is 35 Percent Above the GRC Authorized Amount Demonstrates that the SoCalGas TIMPBA Undercollections During the Test Year 2019 GRC Cycle Soared.**

On November 23, 2022, SoCalGas filed Advice Letter 6060 to recover through the advice letter process the portion of the TIMPBA balance that was 35 percent above the TIMP expenditures that were authorized in D.19-09-051 for the SoCalGas Test Year 2019 GRC cycle.<sup>181</sup> Insofar as the Test Year 2019 cycle extends through 2023, the cycle covers five years 2019-2023. SoCalGas TIMP Test Year 2019 GRC cycle expenditures exceeded authorized amounts by over 35 percent by 2022. The amount of annual expenditures in excess of authorized expenditures on a year-by-year basis for the each of the five years in the Test Year five-year cycle show that for both O&M expense and for capital expenditures the actual expenditures recorded each year in the TIMPBA soared above the authorized annual amounts as shown in the following table:<sup>182</sup>

	O&M Expense			Capital Expenditure		
	Authorized	Actual	Actual/Recd	Authorized	Actual	Actual/Recd
2019	47,817	75,952	159%	62,233	106,467	171%
2020	49,080	104,648	213%	55,190	76,583	139%
2021	50,258	103,839	207%	56,063	112,503	201%
2022	51,231	95,344	186%	56,724	67,881	120%
2023	<u>52,409</u>			<u>57,934</u>		
	250,795	379,783		288,144	363,434	

For 2022, the table shows that actual TIMP O&M expense was 186 percent of authorized O&M expense for 2022, and TIMP capital expenditures were 120 percent of the authorized amount for

<sup>181</sup> Advice Letter 6060 (November 2, 2022).

<sup>182</sup> Ex. TURN-SCGC-04-E, p. 22.

2022. Worse yet, 2022 recorded figures include only nine months of data, not full year 2022 data.<sup>183</sup>

Based on SoCalGas's forecasts for 2022 and 2023 O&M expense and capital expenditures, SoCalGas's additional recorded spend on TIMP activities, combined O&M and capital expenditures, during the remainder of 2022 and the calendar year of 2023 could exceed \$326 million.<sup>184</sup>

### **15.2.3 The Risk Spend Efficiencies for SoCalGas Integrity Assessments and Remediations on the High Pressure System Are Low.**

Even though SoCalGas TIMP costs have soared during the Test Year 2019 GRC cycle, the Risk Spend Efficiency ("RSE") of the SoCalGas TIMP program is very low. The RSE for Integrity Assessments and Remediations on the SoCalGas High Pressure System are in the bottom 39<sup>th</sup> percentile of safety activities for pipelines in High Consequence Areas and are in the bottom 30<sup>th</sup> percentile for pipelines outside of HCAs.<sup>185</sup> SoCalGas's program has a benefit to cost ratio of only 0.1, which means that for every dollar spent on the program, only 10 cents in risk reduction benefit are obtained.<sup>186</sup>

### **15.2.4 The Commission Should Replace the Two-Way TIMP Balancing Account with a One-Way Balancing Account Plus a Memorandum Account to Record Any Annual Overspending with Recovery of Overspent Amounts Being Subject to an Application Rather than an Advice Letter.**

The tremendous run-up of TIMP costs that began 2017 in combination with the low RSE of SoCalGas TIMP activities demonstrate that it is imperative that the Commission take action

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<sup>183</sup> *Id.*

<sup>184</sup> *Id.*

<sup>185</sup> *Id.*, p. 10, citing Ex. TURN-04, Appendix D, Table 3, Row 72 & 83.

<sup>186</sup> *Id.*

now to gain greater cost control over SoCalGas’s TIMP expenditures. The Commission should replace the current two-way TIMPBA with a one-way balancing account with a memorandum account in which SoCalGas can record overspending.<sup>187</sup> Overspending in excess of authorized amounts should be determined on a year-by-year basis so that each year any excess costs would be booked into the memorandum account.<sup>188</sup> The TIMP expenses and capital expenditures recorded in the memorandum account in excess of annual authorized amounts should be subject to an application or a GRC application and a full reasonableness review.<sup>189</sup>

The reform of the TIMPBA that TURN and SCGC recommend is consistent with the Public Utilities Code. Public Utilities Code Section 969 provides that “The Commission shall require the gas corporation to establish and maintain a balancing account for the recovery” of TIMP expenses.<sup>190</sup> However, Section 969 does not prescribe a two-way balancing account. Section 969 gives the Commission discretion to choose between a two-way or one-way TIMPBA. The current two-way balancing account with cost recovery through the advice letter process for amounts that are 35 percent in excess of authorized amounts is clearly not adequately protecting ratepayer interests.<sup>191</sup>

**15.2.5 The Commission Has Been More Successful in Containing SoCalGas’s Pipeline Safety Enhancement Plan Project Costs than It Has Been in Containing TIMP Costs.**

The Commission has enjoyed much better success in containing SoCalGas’s PSEP project costs than the Commission has with TIMP costs. In SoCalGas’s 2019 GRC, A.17-10-

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<sup>187</sup> *Id.*

<sup>188</sup> *Id.*

<sup>189</sup> *Id.*

<sup>190</sup> *Id.*, p. 23, Public Utilities Code § 969.

<sup>191</sup> *Id.*

007/008, PSEP costs were given base rate treatment with a memorandum account plus reasonableness review of any overages.<sup>192</sup> As a result, PSEP projects are forecasted by SoCalGas with much greater precision than TIMP projects.<sup>193</sup> SoCalGas develops its PSEP project forecast at the Class 3 level using the Association for the Advancement of Costs Engineering (“AACE”) standards.<sup>194</sup> An examination of the results for the latest set of projects that were submitted in this proceeding for reasonableness review shows that overall the recorded PSEP costs are 10 percent below the authorized costs.<sup>195</sup> Similarly, SoCalGas has completed its PSEP valve projects with a combined project cost that is 11 percent below the combined forecast project cost.<sup>196</sup>

SoCalGas claims that “it is more challenging to accurately estimate the final costs of a TIMP project than a PSEP project.”<sup>197</sup> SoCalGas claims that “there are fewer high-cost variables in PSEP projects and PSEP projects have more scheduling flexibility to mitigate the impact of planning or execution challenges to a project, such as difficulty assessing a proposed work area.”<sup>198</sup> Nevertheless, the PSEP success demonstrates that requiring a reasonableness review of costs in excess of forecasted costs through the application process enhances cost containment in contrast to out-of-control costs of the current TIMP. SoCalGas is clearly capable of managing its engineering and construction activities efficiently if it is properly incentivized to do so.<sup>199</sup>

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<sup>192</sup> *Id.*, p. 24.

<sup>193</sup> *Id.*

<sup>194</sup> *Id.*

<sup>195</sup> *Id.*

<sup>196</sup> *Id.*

<sup>197</sup> Ex. SCG-209-E, p. TS-AR-14.

<sup>198</sup> *Id.*, p. TS-AR-15.

<sup>199</sup> Ex. TURN-SCGC-04-E, p. 26.

**15.3 The Mileage Covered by the SoCalGas Integrated Safety Enhancement Plan During this GRC Cycle Should Be Significantly Reduced to Reflect Actual Regulatory Requirements.**

SoCalGas proposes to manage the federal regulatory requirements under GTSR Part 1, specifically, the MAOP reconfirmation requirements of 49 CFR § 192.624, and the State requirements under PSEP Phase 2B through an overarching Integrated Safety Enhancement Plan (“ISEP”).<sup>200</sup> However, SoCalGas proposes to address significantly more pipeline mileage than required through its ISEP during this Test Year 2024 GRC cycle. The Commission should direct SoCalGas to reduce the ISEP mileage that would be addressed during this GRC cycle and, accordingly, reduce the capital expenditure that SoCalGas forecasts for the mileage.

**15.3.1 In D.19-09-51, the Commission Directed SoCalGas to Identify by Class All of the SoCalGas Transmission Pipelines Which Were Tested Under the Pre-1970 American Standard Association (“ASA”) Code.**

The Commission directed SoCalGas to make a recommendation in the GRC to identify the PSEP Phase 2B transmission pipelines that should be retested.<sup>201</sup> Subsequently, PHMSA adopted GTSR Part 1 requiring MAOP reconfirmation of pipelines that fail to have records that are, “traceable, verifiable, and complete” and are located in a Class 3 or Class 4 location or in a Class 1 or 2 HCA.<sup>202</sup>

SoCalGas proposes in its new ISEP to combine the federal requirements and the state requirements into a single program. In response to Ordering Paragraph 15 of D.19-09-051 and the federal requirements of 49 CFR § 192.624, SoCalGas developed a flowchart for the identification of pipelines for which SoCalGas would recommend a retest.<sup>203</sup> Following its

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<sup>200</sup> Ex. SCG-08, pp. 13-14, Ex. SCG-09, p. AK-TS-59.

<sup>201</sup> D.19-09-051, pp. 779-780 (September 26, 2019)..

<sup>202</sup> 49 CFR § 192.624(a). 49 CFR § 192.624(c) identifies six methods for reconfirmation.

<sup>203</sup> Ex. SCG-09, Appendix B, p. AK-BS-B-1.

flowchart for the ISEP Scoping Process, in its direct testimony SoCalGas identified 1,108 miles of transmission pipelines to include in the ISEP.<sup>204</sup> SoCalGas presented the 1,108 miles as its “Current ISEP Scope” for retesting.<sup>205</sup> SoCalGas did not provide any explanation for its recommendation to retest 1,108 miles of transmission pipelines even though SoCalGas received a recommendation in an engineer’s report about how only 188 miles “require pressure testing or replacement.”<sup>206</sup>

SoCalGas recommended that 518.5 miles should be “started” during this GRC cycle.<sup>207</sup> SoCalGas forecasted a Test Year 2024 capital expenditure of \$96.132 million for work on the 518.5 miles of pipeline.<sup>208</sup>

SoCalGas recognizes that 49 CFR § 192.624 specifies a maximum deadline of July 2, 2035 to complete MAOP reconfirmations and establishes a midterm July 3, 2028 deadline for at least 50 percent of the pipeline mileage that is subject to 49 CFR § 192.624.<sup>209</sup> Although SoCalGas said in its direct testimony that 1,108 miles of transmission pipeline are within the scope of its ISEP and should be retested, SoCalGas says in its rebuttal testimony that, “approximately 750 miles of DOT-T pipeline segment remain in the scope of the ISEP.”<sup>210</sup> SoCalGas says, further, that 550 of the 750 miles are “subject to 49 CFR § 192.624(b),” so that 50 percent of the pipeline mileage must be retested by July 3, 2028, and the remaining 50 percent must be retested by July 2, 2035.<sup>211</sup>

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<sup>204</sup> Ex. SCG-09, p. AK-TS-60.

<sup>205</sup> *Id.*, Appendix C, AK-TS-C-1, Table KA-App-2.

<sup>206</sup> *Id.*, Appendix D, p. 4.

<sup>207</sup> Ex. SCG-09 CWP, p. 12; Ex. TURN-SCGC-04-E, p. 29.

<sup>208</sup> Ex. TURN-SCGC-04-E, p. 29; Ex. SCG-09-CWP, p. 12; Ex. SCG-09, p. AK-TS-94, Table KS-27.

<sup>209</sup> 49 CFR § 192.624(b).

<sup>210</sup> Ex. SCG-209-E, p. TS-AR-30.

<sup>211</sup> *Id.*

Thus, 225 miles of the 550 miles identified as subject to 49 CFR § 192.624 MAOP reconfirmation must be retested by July 3, 2028, and 225 miles must be retested by July 2, 2035. Nevertheless, SoCalGas continues to insist in its rebuttal testimony that approximately 518.2 miles would need to undergo initial planning during the TY 2024 GRC cycle, at a minimum, to meet the 50 percent and 100 percent compliance deadlines for these 550 miles of pipeline.<sup>212</sup> The 518.5 miles for which SoCalGas projects Test Year 2024 capital expenditures of \$96.132 million would go through “initial planning during the TY 2024 GRC cycle” to meet the 49 CFR § 192.624(b) July 3, 2028 and July 2, 2035 deadlines for reconfirming the full 550 miles.<sup>213</sup> SoCalGas explains the extremely long lead time by saying, “A hydrotest or replacement project can take years to complete due to external and internal factors such as permitting, environmental studies, or operational limitations, and starting the planning process allows SoCalGas the flexibility of quickly responding to execution charges while avoiding inconsistency in productivity.”<sup>214</sup>

**15.3.2 SoCalGas Should Extend the Period of Time for Completing Work on ISEP Mileage to Take Advantage of the Time Allowed Under 49 CFR § 192.624(b) and Under the “As Soon As Practicable” PSEP 2B Requirement.**

SoCalGas should reduce the higher than necessary forecasted Test Year 2024 GRC spending by lengthening the time to complete ISEP activities to take advantage of the full period of time allowed under 49 CFR § 192.624(b) July 3, 2028, and July 2, 2035 deadlines and under the PSEP “as soon as practicable” timeline. Thus, in this GRC cycle, SoCalGas should only reconfirm 50 percent of the 550 miles that, according to SoCalGas, are subject to 49 CFR §

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<sup>212</sup> Ex. SCG-209-E, p. TS-AR-31.

<sup>213</sup> *Id.*

<sup>214</sup> *Id.*

192.624(b).<sup>215</sup> SoCalGas should complete only 225 miles of pipeline MAOP reconfirmations by the end of 2027, which is still ahead of the July 3, 2028 deadline prescribed by 49 CFR § 192.624(b)(1). The other 50 percent of the 550 ISEP miles that are subject to 49 CFR § 192.624(b) should be started during the Test Year 2028 GRC cycle, 2028-2031, with some of the work being left for the Test Year 2032 GRC cycle, 2032-2035, so as to complete work on the full 550 miles subject to 49 CFR § 192.624(b) by the July 2, 2035 deadline set in 49 CFR § 192.624(2).

In its rebuttal testimony, SoCalGas says that 750 miles of “DOT-T” pipeline segments remain in scope for its ISEP, of which 550 miles are subject to 49 CFR § 192.624(b).<sup>216</sup> Thus, 200 miles of the ISEP in-scope mileage is subject to the PSEP, for which the completion requirement is “as soon as practicable.” The remaining 200 miles should be left for later SoCalGas GRC proceedings after the Test Year 2032 GRC.

### **15.3.3 The Forecast for ISEP Mileage and Capital Expenditures Presented in the TURN-SCGC Direct Testimony on the Assumption that 1,108 miles Were in the Scope of the ISEP Should Be Reduced.**

The TURN-SCGC direct testimony was based on SoCalGas’s direct testimony proposal that 1,108 miles of transmission line pipelines would have to be pressure tested to verify the MAOP under the SoCalGas ISEP.<sup>217</sup> Of that mileage, 764 miles were associated with Class 3 and 4 pipelines that were subject to 49 CFR § 192.624, and 14 miles were Class 1 or 2 HCA mileage that were subject to 49 CFR § 192.624, totaling 778 miles. Thus, 330 miles out of the 1,108 miles were subject to the Commission’s PSEP, not 49 CFR § 192.624, and could be left for testing “as soon as practicable.”

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<sup>215</sup> Ex. SCG-209-E, p. TS-AR-30.

<sup>216</sup> *Id.*, pp. 30, 32.

<sup>217</sup> Ex. TURN-SCGC-04-E, p. 28.

The TURN-SCGC direct testimony proposed that SoCalGas should only reconfirm MAOP for 50 percent of 764 miles under the 49 CFR § 192.624 requirements during this GRC cycle, leaving the remaining 50 percent of 764 miles to be addressed during the Test Year 2028 and 2032 GRCs.<sup>218</sup> The direct testimony proposed that the last 330 miles should be pressure tested in two batches, the first 150 miles being tested in the Test Year 2032 GRC cycle and the last 250 miles being tested in the Test Year 2036 cycle.<sup>219</sup> The testimony said, “This approach is reasonable since the PSEP 2B requirement is ‘as soon as practicable,’ which should reflect a consideration of all relevant facts and circumstances, including higher priority gas transmission compliance work and the ratepayer harms from higher than necessary GRC spending.”<sup>220</sup> The TURN-SCGC direct testimony recommended that SoCalGas proposed capital expenditures in this GRC should be reduced so that only half of 764 miles would be covered during this Test Year 2024 GRC cycle.<sup>221</sup>

Insofar as the SoCalGas says in its rebuttal testimony that only 550 miles are subject to 49 CFR § 192.624(b), resulting in only 225 miles being required to be addressed during this Test Year 2024 GRC cycle, the figures presented in the TURN-SCGC direct testimony Table 15 and Table 16 should be reduced. Table 15 below replicates Table 15 from the TURN-SCGC direct testimony, Exhibit TURN-SCGC-04-E. The table shows in the “TURN-SCGC Proposed” line the capital expenditures for the forecast years 2022-2024 and for the post-test years 2025-2027 that SoCalGas would occur if SoCalGas reconfirmed the MAOP only half of the 764 miles of SoCalGas pipelines that were tested under the pre-1970 ASA Code. The table also shows on the

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<sup>218</sup> *Id.*, p. 29.

<sup>219</sup> *Id.*

<sup>220</sup> *Id.*

<sup>221</sup> *Id.*, p. 30.

“SoCalGas Proposed” line the SoCalGas forecast of capital expenditures for the 2022-2024 forecast years and for the 2025-2027 post-test years that would occur if it were assumed that SoCalGas’s proposed 518.5 miles would have the MAOP reconfirmed during the Test Year 2024 GRC cycle. As shown in the table, the difference for the 2022-2027 GRC cycle between assuming that one-half of 764 miles, 382 miles, would be reconfirmed and assuming that 518.5 miles would be reconfirmed is \$173.378 million.<sup>222</sup>

	2022	2023	2024	2025	2026	2027	2022-2027
SoCalGas Proposed	6,935	34,601	96,132	159,812	162,467	179,142	639,089
TURN-SCGC Proposed	<u>4,461</u>	<u>19,734</u>	<u>64,810</u>	<u>122,269</u>	<u>123,177</u>	<u>131,261</u>	<u>465,711</u>
Difference	2,474	14,868	31,322	37,543	39,290	47,881	173,378

Insofar as SoCalGas’s rebuttal testimony says that only 550 miles are subject to reconfirmation under to 49 CFR § 192.624, only one-half of the 550 miles, 225 miles, would need to be completed by July 3, 2028, under 49 CFR § 192.624(b)(1). The figures in the line in the table for “TURN-SCGC Proposed” can easily be adjusted downward by multiplying each figure in the line by the fraction 250/382 or the ratio 0.654 to derive TURN-SCGC’s proposal in this proceeding as adjusted to accommodate the SoCalGas rebuttal testimony. Multiplying the 2022-2027 figure of \$465.711 million shown in the table by the ratio 0.654 reduces the TURN-SCGC proposal for the 2022-2027 period from \$465.711 million to \$304.575 million. That reduction significantly increases the difference between the TURN-SCGC proposal in this proceeding and SoCalGas’s proposal to \$334.514.

<sup>222</sup> TURN-SCGC-04-E, p. 30.

**15.3.4 If ISEP Expenditures are Excluded from Post-Test-Year Attrition Adjustments as Requested by SoCalGas, the Commission Should Adopt TURN-SCGC’s Downwardly Adjusted Forecasts for Post-Test-Year ISEP Expenditures.**

In the TURN-SCGC testimony regarding post-test year ratemaking, TURN-SCGC recommend keeping post-test-year amounts for the Gas Safety Enhancement Plan (“GSEP”), which includes the ISEP, within the overall post-test-year mechanism instead of treating the post-test-year amounts as an exclusion. However, if the Commission authorizes a post-test-year ratemaking mechanism that adopts SoCalGas’s proposal to exclude from the post-test-year mechanism TAMP capital additions including the ISEP amounts, the Commission should multiply the TURN-SCGC direct testimony figures for each of the post-test-years 2025-2027 as shown in the table above by 0.654 to derive downwardly adjusted forecasts for the post-test-years.

**15.3.5 Limiting SoCalGas’s ISEP Activities so that SoCalGas Complies With the Deadlines Established in 49 CFR § 192.624(b) and in Public Utilities Code § 958 Without SoCalGas Doing More than is Required to Meet the Deadlines Is Consistent with Commission Policy.**

Approving a forecast for ISEP work that is based upon the assumption that SoCalGas will comply with the deadlines established in 49 CFR § 192.624(b) and the “as soon as practicable” deadline established in Public Utilities Code § 958 without SoCalGas doing more than is required is consistent with Commission policy.

In Resolution G-3595, the Commission considered SoCalGas’s 2022 rate forecasts for the SoCalGas Natural Gas Leak Abatement (“NGLA”) Compliance Plan. The Commission said, “The CPUC closely examines the need for any programs that increase rates.”<sup>223</sup> The

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<sup>223</sup> Resolution G-3595, p. 11 (June 29, 2023).

Commission noted that “since 2016, SoCalGas’s revenue requirement has increased by nearly 55 percent, with a roughly 16 percent increase from 2021-2022.”<sup>224</sup> The Commission cut several of SoCalGas’s NGLA compliance programs because the goal of 20 percent reduction in methane emissions by 2025, in accordance with D.19-08-020, can be exceeded without approving cost recovery for all the proposed programs.”<sup>225</sup> The Commission found, “The statutory goal of a 20 percent reduction in methane emissions by 2025 can be exceeded without the approval of all the proposed programs.”<sup>226</sup>

The Commission should act on the SoCalGas ISEP as it did in Resolution G-3595 regarding the NGLA Plan. SoCalGas should receive funding sufficient to meet statutory or regulatory targets, but SoCalGas should not receive excessive funding to do more than is necessary.

#### **15.4 The Commission Should Deny SoCalGas’s Request for a New GSEP Balancing Account.**

SoCalGas proposes to create a new balancing account, the “Gas Safety Enhancement Programs Balancing Account” (“GSEPBA”), as a two-way, interest-bearing balancing account.<sup>227</sup> SoCalGas proposes to record in the account ISEP costs which would include both the costs of MAOP reconfirmation under GTSR Part 1 and the costs of complying with state PSEP Phase 2B requirements,<sup>228</sup> corrosion control costs incurred under GTSR Part 2,<sup>229</sup> the costs

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<sup>224</sup> *Id* (footnote omitted).

<sup>225</sup> *Id*, p. 12.

<sup>226</sup> *Id*, p. 22, Finding 16.

<sup>227</sup> Ex. SCG-38, p. RMY-19.

<sup>228</sup> Ex. SCG-09, p. AK-TS-90.

<sup>229</sup> *Id*, p. AK-TS-91.

of complying with the Valve Rule,<sup>230</sup> and lastly, the costs of implementing “future gas rules and regulations.”<sup>231</sup>

#### **15.4.1 The Commission Should Deny SoCalGas’s Request to Create a New Permanent GSEP Balancing Account.**

The Commission should deny SoCalGas’s request for a new permanent GSEP balancing account. There is no statutory requirement that the Commission permit creation of a new balancing account. SoCalGas has long experience with activities for which cost will be recorded in the balancing account, negating the need for a balancing account for those activities. Lastly, most of the costs that would be recorded in the account are associated with hydrotesting, which has a very low Risk Spend Efficiency.

##### **15.4.1.1 There Is No Statutory Requirement for the Commission to Establish the GSEPBA.**

Unlike TIMP activities that are undertaken in accordance with Subpart O of the PHMSA regulations, there is no statutory requirement for the Commission to establish a balancing account for the compliance programs that would be covered by the proposed GSPBA. Section 969 of the Public Utilities Code requires the Commission to permit SoCalGas “to establish and maintain a balancing account for the recovery of” expenses incurred “for the gas corporation’s transmission pipeline integrity management program established pursuant to Subpart O (commencing with Section 198.192.901) of Part 192 of Title 49 of the United States Code....”<sup>232</sup>

However, none of the activities for which costs would be recorded in the GSEPBA are subject to Section 969 because the activities are not subject to Subpart O of the PHMSA

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<sup>230</sup> *Id.*, p. AK-TS-92.

<sup>231</sup> *Id.*, p. AK-TS-93.

<sup>232</sup> Public Utilities Code § 969.

regulations.<sup>233</sup> MAOP reconfirmation pursuant to Section 192.624 is in Subpart L of the PHMSA regulations.<sup>234</sup> The Valve Rule addresses Subparts L and M.<sup>235</sup> Corrosion control is subject to Subpart I of the PHMSA regulations.<sup>236</sup>

**15.4.1.2 SoCalGas Has a Long History with the Activities for Which Costs Would Be Recorded in the New GSEPBA, so SoCalGas Does Not Need the GSEPBA.**

SoCalGas has a long history with the types of projects for which costs would be recorded in the GSEPBA. SoCalGas’s ISEP forecast is primarily based on hydrotesting pipeline segments.<sup>237</sup> SoCalGas has completed PSEP hydrotesting projects under the Commission’s regulations for years. More importantly, SoCalGas has completed the PSEP projects at about 10 percent below cost projections, eliminating any need to book any costs into SoCalGas’s Pipeline Safety Enhancement Plan Memorandum Account (“PSEPMA”).<sup>238</sup> SoCalGas should be able to forecast with high accuracy the cost of pressure testing pipelines that are within the scope of the ISEP regardless of whether the pressure testing is on pipelines for which MAOP must be reconfirmed in accordance with 49 CFR § 192.624 or whether the pressure testing is on pipelines that are included in the ISEP because they would have been covered by the PSEP Phase 2B program.<sup>239</sup>

Regarding projects under the Valve Rule, SoCalGas has a long history with valve projects that were a part of the PSEP process.<sup>240</sup> SoCalGas completed its PSEP valve projects

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<sup>233</sup> Ex. TURN-SCGC-04-E.

<sup>234</sup> *Id.*, footnote 88.

<sup>235</sup> *Id.*

<sup>236</sup> *Id.*

<sup>237</sup> Ex. SCG-209-E, p. TS-AR-32.

<sup>238</sup> Ex. TURN-SCGC-04-E, p. 32.

<sup>239</sup> *Id.*

<sup>240</sup> *Id.*

with a combined project cost that is 11 percent less than the combined forecasted project cost.<sup>241</sup> SoCalGas has the full capability to forecast the costs of both ISEP projects and valve projects so as to complete the projects at or below estimated costs.<sup>242</sup> Thus, SoCalGas does not need the proposed GSEPBA.

**15.4.1.3 SoCalGas Should Be Incentivized to Complete Projects At or Below Project Estimates Because, Particularly, Hydrotesting Has a Very Low Risk Spend Efficiency.**

Based on the Risk Spend Efficiency tables presented in Exhibit TURN-4, SoCalGas's Risk Spend Efficiency for PSEP Phase 2A hydrotesting ranks low, 90 out of 117 programs.<sup>243</sup> Providing a two-way balancing account treatment for ISEP hydrotesting for which costs would be covered by the proposed GSEPBA would remove pressure on SoCalGas to contain the costs of the low ranked ISEP pressure testing projects.

ISEP is by far the largest portion of SoCalGas's proposed GSEP costs forecasts.<sup>244</sup> Because of the low-risk Risk Spend Efficiency of hydrotesting, the Commission should emphasize the need for cost containment to the maximum extent possible and deny SoCalGas's request to create the proposed GSEPBA.<sup>245</sup>

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<sup>241</sup> *Id.*, pp. 24-26

<sup>242</sup> *Id.*, p. 32.

<sup>243</sup> Ex. TURN-4, Appendix D, Table 3 Row 90.

<sup>244</sup> Ex. TURN-SCGC-04-E, p. 31.

<sup>245</sup> *Id.*

**15.4.2 If the Commission Determines that SoCalGas Requires Relief for this GRC for the Cost of Hydrotesting ISEP Projects, SoCalGas Should Be Permitted to Establish the GSEP Memorandum Account to Record Overspending Forecasted ISEP Costs for this GRC Cycle Only.**

SoCalGas claims that its estimates for ISEP work are only Class 5 estimates because it has not had time to develop better estimates as it does for PSEP projects. SoCalGas says in its rebuttal testimony, “Though SoCalGas has almost 10 years of experience with the PSEP, the pipeline segments in scope for the ISEP have only been recently identified.”<sup>246</sup> SoCalGas argues further, that its ISEP costs forecasts “are preliminary estimates informed by PSEP historical costs and, because there was no project definition at the time of forecasting beyond the number of miles and AACE’s prescribed level of project definition for Class 5 estimates is 0-2%, these estimates could only be considered Class 5 at best.”<sup>247</sup>

If the Commission is swayed by SoCalGas’s pleas that it needs relief in this GRC because it has not had time to develop ISEP estimates that are beyond “Class 5 estimates at best,” the ISEP forecasted costs should be included in base rates with SoCalGas being permitted to establish a memorandum account in which SoCalGas would record for this GRC cycle only any spending in excess of its forecast for recovery by application in a subsequent proceeding. SoCalGas should not be permitted to establish the GSEPBA as a permanent balancing account on the basis of SoCalGas’s claimed one-time exceptional circumstances in this GRC.

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<sup>246</sup> Ex. SCG-209-E, p. TS-AR-31.

<sup>247</sup> *Id.*

**15.4.3 The Commission Should Unequivocally Deny SoCalGas’s Request to Include Within the Scope of the GSEPBA Implementation of Future Gas Rules and Regulations.**

The Commission should unequivocally deny SoCalGas’s request to extend GSEPBA balancing account coverage to “the implementation of future gas rules and regulations.”<sup>248</sup> The Commission previously denied SoCalGas’s proposal for memorandum account coverage of anticipated but not finalized PHMSA regulations. The Commission explained in D.22-01-011, “The Application does not, and cannot, state with any certainty what are the additional requirements imposed by the new federal regulations because they are not yet in effect. Therefore, it is not possible to know yet whether the new regulations...will impose different or additional compliance obligations that warrant the establishment of a memorandum account.”<sup>249</sup> SoCalGas’s proposal to include future gas rules and regulations in the GSEP balancing account suffers from the same flaws as the proposed memorandum account that the Commission addressed in D.22-02-001 and should similarly be denied.<sup>250</sup>

**15.4.4 If the Commission Permits SoCalGas to Create the GSEPBA for this 2024-2027 GRC Cycle, SoCalGas Should Not Be Permitted to Recover 35 Percent Above Authorized Expenditures Through an Advice Letter Filing.**

SoCalGas proposes not only to create the GSEPBA as a two-way interest-bearing balancing account but also, “to use the same cost recovery mechanism, (i.e., 35 percent of total authorized expenditures threshold) as described above for the total TIMPBA....”<sup>251</sup> If the Commission permits SoCalGas to create the GSEPBA for this 2024-2027 GRC cycle, the Commission should nevertheless deny SoCalGas’s request for permission to recover 35 percent

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<sup>248</sup> Ex. SCG-09, p. AK-TS-93.

<sup>249</sup> D.22-01-001, p. 7 (February 24, 2022).

<sup>250</sup> Ex. TURN-SCGC-04-E, p. 33.

<sup>251</sup> Ex. SCG-38, p. RMY-19.

above authorized expenditures through filing an advice letter for the reasons addressed above regarding the TAMPBA.

## **16. GAS STORAGE OPERATIONS AND CONSTRUCTION (SOCALGAS ONLY)**

SoCalGas proposes to undertake the Honor Rancho Compressor Modernization (“HRCM”) project. The HRCM project has two components. The first component is the “Principal” component. The Principal component includes replacing the existing compressors at the Honor Rancho storage field, installing a new electrical connection with Southern California Edison Company (“SCE”) facilities, building a new compressor building, and constructing a microgrid designed to serve administrative and auxiliary loads at the Honor Rancho storage field.<sup>252</sup> SoCalGas projects that the Principal component will cost \$537.927 million including the \$23 million cost of the microgrid and will be placed into service in 2027, the last year of this GRC cycle.<sup>253</sup>

SoCalGas says that it is prioritizing the execution of the Principal component to comply with South Coast Air Quality Management District (“AQMD”) rules.<sup>254</sup> However, the AQMD rules do not require the construction of a microgrid as part of the Principal component of the HRCM project. The Commission should direct SoCalGas to exclude the unnecessary \$23 million microgrid from the Principal component of the HRCM project.

The second component of the HRCM project as described by SoCalGas is the “Advanced Renewable Energy” (“ARE”) component.<sup>255</sup> The ARE component includes a facility to produce hydrogen through electrolysis, hydrogen storage and blending equipment, and a hydrogen

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<sup>252</sup> Ex. TURN-SCGC-05, p. 1.

<sup>253</sup> Ex. SCG-10-R, p. LTBSH-21.

<sup>254</sup> *Id.*

<sup>255</sup> Ex. SCG-10-R, p. LTB-SH-21.

fueling station for SoCalGas fleet vehicles.<sup>256</sup> SoCalGas says that the ARE component will be placed into service after the end of Test Year 2024 GRC cycle, 2024-2027. Accordingly, SoCalGas states, “There are no revenue requirements for the ARE component in this General Rate Case.”<sup>257</sup>

Insofar as SoCalGas’s proposal for the ARE component will have no effect on the Test Year 2024 revenue requirement or on rates for this GRC 2024-2027 cycle, the Commission should find that the ARE component is outside the scope of this GRC and decline to address the ARE component.

### **16.1 The Commission Should Reject the Microgrid Portion of the Principal Component of the HRCM Project.**

For the Principal component of the HRCM project, the Commission should direct SoCalGas to complete only the compressor upgrade which includes replacing the compressors, building the compressor building, and installing a new electrical interconnection with SCE to accommodate two electric motor driven compressors.<sup>258</sup> The Commission should not authorize the construction of the \$23 million microgrid.<sup>259</sup>

#### **16.1.1 The Microgrid is Not Necessary for Honor Rancho Storage Field Reliability.**

SoCalGas attempts to justify its proposed microgrid by stating, “A microgrid is a self-sufficient energy system that serves a discrete geographic footprint....and can serve the load when the electric power grid is absent, disrupted, or unavailable.”<sup>260</sup> However, the microgrid

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<sup>256</sup> *Id.* Ex. SCG-10-R, Appendix E, p. LTB-SH-E-i-6.

<sup>257</sup> Ex. SCG-10-R, p. LTB-SH-21.

<sup>258</sup> Ex. TURN-SCGC-05. p. 1

<sup>259</sup> *Id.*, p. 2.

<sup>260</sup> Ex. SCG-10, Appendix E, p. LTB-SH-E-5.

would not be sized to power the two electric driven compressors that would be located at Honor Rancho in addition to four new gas driven compressors.<sup>261</sup> The estimated electrical load breakdown for the HRCM project are 0.1 megawatt (“MW”) for administrative load, 1.1 MW for station auxiliary loads, and 8.5 MW for the electric driven compressors.<sup>262</sup> The microgrid would be sized at 2 MW, so that it could serve administrative load and station auxiliary loads at Honor Rancho but not the 8.5 MW load of the electric compressors.<sup>263</sup>

SoCalGas cannot even show that a microgrid is necessary for reliability to serve administrative and auxiliary loads. SoCalGas admits, “The Honor Rancho station has not experienced any power outages within the last five years that have disrupted operations.”<sup>264</sup> Further, even if there had been power outages at Honor Rancho, SoCalGas has not shown that there would not be far cheaper alternatives including existing equipment to maintain service of 0.1 MW for administrative load and 1.1 MW for station auxiliary loads instead of proposing a \$23 million microgrid.

#### **16.1.2 The Savings in Electricity Costs Would Not Be Sufficient to Justify the \$23 Million Expenditure on the Microgrid.**

SoCalGas has not provided any evidence that a capital expenditure of \$23 million for the proposed microgrid would result in saving electricity costs that could justify the capital expenditure. The microgrid would reduce electricity costs by about \$400,000 per year based on information provided by SoCalGas.<sup>265</sup> Assuming very optimistically that the annual revenue requirement of the microgrid would equate to only ten percent of the total capital expenditure to

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<sup>261</sup> Ex. SCG-10-R, p. LTB-SH-22.

<sup>262</sup> Ex. TURN-SCGC-05, p. 2, Footnote 6.

<sup>263</sup> *Id.*

<sup>264</sup> *Id.*, p. 3.

<sup>265</sup> *Id.*, p. 2

install the microgrid, the microgrid would have to cost no more than \$4 million in order for the investment in the microgrid to be cost effective.<sup>266</sup> Given that the microgrid is projected to cost \$23 million, the microgrid costs six times more than a cost-efficient capital expenditure.<sup>267</sup>

**16.1.3 SoCalGas Fails to Show that the Existing Onsite Electrical Generation at Honor Rancho Would Be Insufficient to Supply Administrative and Auxiliary Load in the Event of an Electrical Outage.**

SoCalGas says, “SoCalGas has historically generated electricity on-site at Honor Rancho due to the critical role of the facility of maintaining reliable gas supply to the customers....<sup>268</sup> SoCalGas fails to make any showing whatsoever about how the existing on-site electrical generation at Honor Rancho would be insufficient to serve on an emergency basis the 0.1 MW for administrative load and 1.1 MW for station auxiliary loads that SoCalGas proposes to supply from its \$23 million microgrid. SoCalGas simply ignores the presence of the existing generation. Absent any showing that the existing electrical generation would be insufficient in the future to serve the limited amount of administrative load and station auxiliary load on an emergency basis at Honor Rancho, the Commission should not authorize the expenditure of \$23 million on a new microgrid.

**16.2 The ARE Component of the HRCM Project is Outside the Scope of this Test Year 2024 GRC.**

The ARE component of the HRCM project is outside the scope of this proceeding and should not be addressed by the Commission. SoCalGas says that it would not complete the ARE component until after the end of the Test Year GRC four-year 2024-2027 cycle, so SoCalGas

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<sup>266</sup> *Id.*

<sup>267</sup> Ex. TURN-SCGC-05, p. 3.

<sup>268</sup> *Id.*

admits, “There are no revenue requirements for the ARE component in this General Rate Case.”<sup>269</sup>

Thus, SoCalGas’s proposals about there ARE component are precisely the same as SoCalGas’s proposals for repairing or replacing SoCalGas Line 235 West. SoCalGas presented no costs representations or revenue requirements for the Line 235 West repair replacement options in the GRC.<sup>270</sup> In a May 1, 2023 Ruling, ALJ Lakhanpal determined that this GRC is not the appropriate forum to consider the Line 235 West for repair options, stating, “The Test Year 2024 GRC proceeding is focused on SoCalGas’s overall revenue requirement, but it is not the appropriate forum to consider a specific project like repairing or replacing Line 235 West where no costs for such a project are at issue in the proceeding.”<sup>271</sup> ALJ Lakhanpal’s Ruling, Paragraph 1, stated that “a review of the longer-term remediation options of repairing or replacing Southern California Gas Company’s Line 235 are not included in the scope of this general rate case proceeding.”<sup>272</sup>

Just like its proposals for repairing or replacing its Line 235 West, SoCalGas’s proposal in this proceeding for the ARE component for the HRCM project is a request for an advisory opinion that would have no bearing on the revenue requirement for this Test Year 2024 GRC. If the Commission were to consider and approve SoCalGas’s ARE component proposals, SoCalGas would certainly leverage the Commission’s advisory opinion to argue for cost

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<sup>269</sup> Ex. SCG-10-R, p. LTB-SH-21.

<sup>270</sup> Administrative Law Judge’s Ruling Granting the Joint Motion Filed by The Utility Reform Network and the Southern California Generation Coalition (“Ruling”) A.22-05-015 and A.22-05-016, p. 3 (May 1, 2023).

<sup>271</sup> Ruling, p. 7.

<sup>272</sup> *Id.*, p. 8.

recovery for the ARE component in the Test Year 2028 GRC.<sup>273</sup> The Commission should decline SoCalGas's request for an advisory opinion about the ARE component.

**16.3 Even if SoCalGas's ARE Component Proposals Were Within the Scope of this Proceeding, the Commission Should Reject the Proposals.**

Even if SoCalGas's ARE component proposals were within the scope of this proceeding, the Commission should reject the proposals.

First, SoCalGas proposes to produce hydrogen, but hydrogen production clearly falls outside the scope of a gas utility's business.<sup>274</sup> Gas utility involvement in hydrogen production raises significant questions about the impact gas utility involvement could have on a competitive hydrogen production market.<sup>275</sup>

Second, SoCalGas proposes to build a new hydrogen fueling station for SoCalGas fleet vehicles at Honor Rancho without demonstrating any gas utility need for the fueling station.<sup>276</sup> SoCalGas estimates that \$2.2 million capital expenditure is associated with the hydrogen fueling station without projecting any associated O&M costs.<sup>277</sup> SoCalGas has not demonstrated that it is necessary or cost effective for SoCalGas to build its own hydrogen fueling stations. There are already over thirty hydrogen fueling stations in the SoCalGas service territory with more than another twenty stations currently under development.<sup>278</sup> Thus, SoCalGas has access to hydrogen for refueling any vehicles it chooses to buy or lease without building its own fueling stations.<sup>279</sup>

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<sup>273</sup> Ruling, p. 4.

<sup>274</sup> Ex. TURN-SCGC-05, p. 4.

<sup>275</sup> *Id.*

<sup>276</sup> Ex. SCG-10-R, Appendix E, p. LTB-SH-E-i-8.

<sup>277</sup> Ex. TURN-SCGC-05, p. 5.

<sup>278</sup> *Id.*

<sup>279</sup> *Id.*

Furthermore, SoCalGas completely ignores the option of buying electric vehicles for the automobile portion of its utility fleet.<sup>280</sup>

Third, SoCalGas has failed to show any ratepayer benefits from the ARE component. The ARE component is effectively nothing more than a hydrogen demonstration project which is outside the scope of gas utility services.<sup>281</sup>

## **17. PROCUREMENT**

## **18. CLEAN ENERGY INNOVATIONS**

SoCalGas forecasts O&M expense of \$47.223 million for Test Year 2024 for what SoCalGas calls “Clean Energy Innovations” (“CEI”). SoCalGas proposes to spend \$20.4 million out of the total \$47.2 million on what SoCalGas calls “Clean Fuels Infrastructure Development.”<sup>282</sup>

Clean Fuels Infrastructure Development includes two “functions” which SoCalGas calls “Business Development” and “Clean Fuels Power Generation.”<sup>283</sup> Additionally, Clean Fuels Infrastructure Development includes three “programs,” the Carbon Capture and Utilization and Sequestration (“CCUS”) Front End Engineering Design (“FEED”) Study Program, the Clean Fuels Operational Readiness Program, and the Clean Fuels Transportation Program.<sup>284</sup>

The Commission should reject SoCalGas’s request for ratepayer funding of \$20.4 million in Test Year 2024 for Clean Fuels Infrastructure Development. Each of the Clean Fuels Infrastructure Development “functions” or “programs” involves SoCalGas providing non-utility

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<sup>280</sup> *Id.*

<sup>281</sup> Ex. TURN-SCGC-05, p. 5.

<sup>282</sup> Ex. SCG-12-R, p. AI-2, Table AI-1.

<sup>283</sup> *Id.*, p. AI-5.

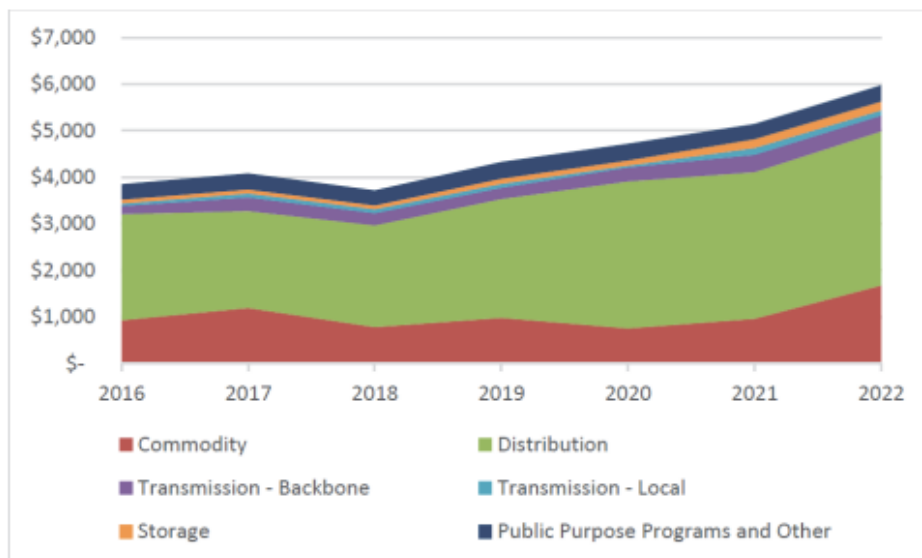
<sup>284</sup> *Id.*, p. AI-5.

services to customers in the guise of promoting “clean fuels.”<sup>285</sup> If SoCalGas desires to pursue the Clean Fuels Infrastructure Development functions or programs, SoCalGas should submit an application for each of the activities to pursue the activities as non-utility products or services with shareholders bearing the expense of offering the services. Alternatively, SoCalGas should pursue the activities through one or more affiliates at shareholder expense.

SoCalGas ratepayers cannot bear the cost of SoCalGas’s extracurricular activities.

SoCalGas gas revenue requirements have increased by 50 percent during the last four years:

**Figure 1: 2016-2022 SoCalGas January 1 Gas Revenue Requirements by Rate Category (\$ millions) (Source: CPUC 2022 SB 695 Report)**



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SoCalGas ratepayers are suffering under historically high natural gas rates.<sup>287</sup> The \$20.4 million that SoCalGas requests for Test Year 2024 would balloon to \$81.6 million over the four-year 2024-2027 cycle before escalation for post-test-year attrition. Ratepayers should not be asked to

<sup>285</sup> Ex. TURN-SCGC-06, p. 2.

<sup>286</sup> Resolution G-3595, p. 12 (June 29, 2023).

<sup>287</sup> Resolution E-5254, p. 18 (April 6, 2023).

bear the cost of the Clean Fuels Infrastructure Development “functions” or “programs” during this period of extremely high natural gas utility rates.

Additionally, SoCalGas requests that ratepayers bear the Test Year expense of \$1.592 million for a CEI “Project Management Office” (“PMO”).<sup>288</sup> The PMO “would be responsible for the establishment and implementation of project management standards and reporting across the entire portfolio of CEI projects,” including the Clean Fuels Infrastructure Development activities.<sup>289</sup> Ratepayers should not bear the cost of establishing and implementing “project management standards” for non-utility activities.<sup>290</sup> Further, as discussed below, the PMO organization as proposed by SoCalGas is wasteful.<sup>291</sup> Yet, SoCalGas asks ratepayers to bear \$6.638 million before escalation for post-test-year attrition for PMO expense over the four-year 2024-2027 GRC cycle. The Commission should deny the request for the PMO.

### **18.1 Clean Fuels Infrastructure Development “Functions.”**

SoCalGas identifies two Clean Fuels Infrastructure Development “functions,” which SoCalGas calls “Business Development” and “Clean Fuels Power Generation.”<sup>292</sup> Ratepayers should not be required to bear expenses of either of the functions.

#### **18.1.1 The Business Development Function.**

SoCalGas forecasts expenses of \$2.33 million in Test Year 2024 above expenses recorded during the 2021 Base Year for the Business Development function. According to SoCalGas, the Base Year 2021 recorded expenses of the five Clean Fuels Infrastructure

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<sup>288</sup> Ex. SCG-12-R, p. AI-2.

<sup>289</sup> Ex. TURN-SCGC-06, Attachment B, SoCalGas response to TURN-SCGC-04-E, Q.4.12.3.

<sup>290</sup> Ex. TURN-SCGC-06, p. 11.

<sup>291</sup> *Id.*

<sup>292</sup> Ex. SCG-12-R, p. AI-5.

Development functions and programs combined totaled \$8.195 million, \$4.0 million in labor expenses and \$4.2 million in non-labor expenses.<sup>293</sup> However, SoCalGas refused to specify the portion of the Base Year 2021 expense that was for the Business Development function.<sup>294</sup> Thus, the SoCalGas Test Year 2024 funding for the Business Development function is unknown.

According to SoCalGas, “The Business Development function supports the development and employment of cost-effective and environmentally sustainable clean energy solutions, including clean fuels and carbon management, to serve SoCalGas’s customers.”<sup>295</sup> However, SoCalGas admits that the clean energy solutions are not part of SoCalGas’s current utility services and that “it is premature and speculative to surmise which specific clean energy solutions may be part of a future utility service.”<sup>296</sup> Nevertheless, SoCalGas asks that its natural gas utility ratepayers pay \$2.33 million more than they paid during the Base Year 2021 for the development and marketing of products and services that are outside of the gas utility business.<sup>297</sup>

SoCalGas cites only two examples of the Business Development providing services, but for each example the Commission has identified a cost recovery mechanism outside of the GRC. SoCalGas says, “For example, the Business Development function supported the development and deployment of four biogas projects related to SB 1383 Dairy Biomethane Pilot Projects.”<sup>298</sup> However, SoCalGas recovers the costs of the SB 1383 Dairy Biomethane Pilot Projects through the Dairy Biomethane Project Balancing Account (“DBPBA”) and the Dairy Biomethane Project

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<sup>293</sup> Ex. SCG-12-R, p. AI-2; Ex. TURN-SCGC-06, p. 4, footnote 9.

<sup>294</sup> Ex. TURN-SCGC-06, p. 5, footnote 13.

<sup>295</sup> Ex. SCG-12-R, p. AI-5.

<sup>296</sup> Ex. TURN-SCGC-06, p. 5.

<sup>297</sup> *Id.*

<sup>298</sup> Ex. SCG-212, p. AI-15.

Memorandum Account (“DBPMA”) pursuant to D.17-12-004.<sup>299</sup> Thus, the costs of the SB 1383 dairy program are separately recovered by SoCalGas.

As a second example, SoCalGas cites the Angeles Link project. However, the cost of Phase 1 of Angeles Link are recorded in the Angeles Link Project Memorandum Account pursuant to D.22-12-055.<sup>300</sup> There is no need for separate GRC funding of the Business Development Function for either the SB 1383 dairy projects or Angeles Link.

The Commission should not require natural gas utility ratepayers to bear the cost of the Business Development activities.<sup>301</sup> Rate recovery mechanisms are in place for the only two Business Development activities that SoCalGas can identify with any specificity, and SoCalGas admits that it is “premature and speculative” to surmise which other Business Development activities might be part of future utility service.

#### **18.1.2 Clean Fuels Power Generation Function.**

SoCalGas proposes to spend \$0.360 million more during Test Year 2024 than during the Base Year 2021 on the Clean Fuels Power Generation function.<sup>302</sup> As with the Business Development function, SoCalGas refuses to specify the amounts spent during Base Year 2021 on the Clean Fuels Power Generation function, so the total amount to be spent in Test Year 2024 on the Clean Fuels Power Generation function is not defined.

SoCalGas explains the “major activities” of the Clean Fuels Power Generation as follows:

The major activities of the clean fuels power generation teams consist of providing policy, technical, and economic feasibility analyses to internal and

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<sup>299</sup> D.17-12-004, pp. 23-24 (December 14, 2017).

<sup>300</sup> D.22-12-055, p. 73, Ordering Paragraph 1 (December 15, 2022).

<sup>301</sup> EX. TURN-SCGC-06, p. 5.

<sup>302</sup> Ex. TURN-SCGC-06, p. 7.

external facility operators advising in areas that pertain to regulatory, tariffs, contracts, air quality, legislation, market transformation, and education and training specific to clean fuel power generation.<sup>303</sup>

The “major activities” pertaining to Clean Fuels Power Generation are outside the scope of the gas utility business. Providing natural gas utility services does not involve “policy, technical, and economic feasibility analyses “for Clean Fuels Power Generation.”

In its rebuttal testimony, SoCalGas gets more specific, claiming, “Decision 22-09-026 modified line extension allowance practices that may impact Distribution Energy Resources (DER) projects. SoCalGas customers may have questions regarding the impact of this decision and need a source to provide them relevant information.”<sup>304</sup>

If SoCalGas customers have questions about D.22-09-026 and line extension allowances, they are more likely to take advantage of the “individualized account management services through highly trained and specialized account representatives” at SoCalGas.<sup>305</sup> SoCalGas fails to show how the services offered through the Clean Fuels Power Generation function are not duplicative of the services provided by account representatives for queries regarding the provision of natural gas service in the absence of line extension allowances.

To the extent to which the Clean Fuels Power Generation teams provide information about electric power generation rather than the provision of natural gas service, they are not providing a gas utility service, and the gas utility ratepayers should not bear the expense of the Clean Fuels Power Generation teams.

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<sup>303</sup> Ex. SCG-12, p. 39.

<sup>304</sup> Ex. SCG-212, p. AI-26.

<sup>305</sup> Ex. SCG-16-2E, p. BCP-35.

## **18.2 Clean Fuels Infrastructure Development Programs.**

In addition to the Clean Fuels Infrastructure Development functions, there are three programs, the Clean Fuels Transportation program, the CCUS FEED Study program, and the Clean Fuels Operational Readiness Program. The Commission should deny funding for the three programs.

### **18.2.1 The Clean Fuels Transportation Program.**

SoCalGas proposes that ratepayers fund the Test Year 2024 costs of \$0.244 million for labor and \$0.133 million for non-labor totaling \$0.357 million more than during the Base Year 2021 for the Clean Fuels Transportation program. As with the Business Development function and the Clean Fuels Power Generation function, SoCalGas's refuses to specify the amount spent during Base Year 2021 for the Clean Fuels Transportation program, so it is unknown what the actual expenditure in Test Year 2024 would be.<sup>306</sup>

SoCalGas explains, "The primary cost driver for an increase in Clean Transportation utility services is based on the increasing demand for hydrogen FCVs and hydrogen refueling stations to support transition into Zero Emissions Vehicles (ZEV)."<sup>307</sup> However, selling hydrogen to vehicle owners is not part of the SoCalGas gas utility business.<sup>308</sup> If SoCalGas wishes to pursue the development of hydrogen fuel and hydrogen fueling stations, SoCalGas should file a separate application proposing that the Commission provide it with the authority to pursue those non-utility products and services at shareholder expense rather than ratepayer expense.

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<sup>306</sup> Ex. TURN-SCGC-06, p. 8, Footnote 22.

<sup>307</sup> Ex. SCG-12-R, p. AI-30.

<sup>308</sup> Ex. TURN-SCGC-06, p. 9.

### 18.2.2 CCUS FEED Study

SoCalGas proposes that ratepayers bear the Test Year 2024 expense of \$6.655 million for a FEED study of a “Carbon dioxide (CO<sub>2</sub>) pipeline route in Southern California to follow to the extent possible existing pipeline corridors....” to connect “the CO<sub>2</sub> source to the CO<sub>2</sub> sink for storage.”<sup>309</sup> Thus, the CCUS FEED study represents 54.5 percent of the \$12.205 million Test Year 2024 increase in the Clean Fuels Infrastructure Development expense over the Base Year 2021 expense of \$8.195.<sup>310</sup> Allowing SoCalGas to recover from natural gas utility ratepayers the \$6.655 million Test Year expense would result in ratepayers contributing \$26.6 million during the four-year 2024-2027 GRC cycle plus post-test-year escalation for the FEED study.

Transporting CO<sub>2</sub> is not a natural gas utility service. Transporting CO<sub>2</sub> would be a completely separate line of business from gas utility services.<sup>311</sup> If SoCalGas desires to enter the CO<sub>2</sub> transportation business, SoCalGas should file a separate application with the Commission in which SoCalGas should explain the Commission’s jurisdiction over the CO<sub>2</sub> pipeline.

Alternatively, SoCalGas should pursue the CO<sub>2</sub> pipeline through an affiliate.<sup>312</sup>

In its rebuttal testimony, SoCalGas argues that approving ratepayer funding of the expense for the CCUS FEED study would “enable SoCalGas to compete for relevant federal funding opportunities under the IIJA.”<sup>313</sup> SoCalGas claims that the Commission’s Resolution E-5254 “expressly permits IOUs to utilize the general rate case application to request cost recovery for proposals seeking funding by the IIJA, IRA, and the CHIPS programs.”<sup>314</sup>

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<sup>309</sup> Ex. SCG-12, p. AI-22.

<sup>310</sup> Ex. SCG-12-R, p. AI-2.

<sup>311</sup> Ex. TURN-SCGC-06, p. 10.

<sup>312</sup> Ex. TURN-SCGC-06, p. 10.

<sup>313</sup> Ex. SCG-212, p. AI-20; Infrastructure Investment and Jobs Act (“IIJA”), Public Law No. 117-58 (November 15, 2021).

<sup>314</sup> *Id.*

SoCalGas misunderstands Resolution E-5254. In Resolution E-5254, the Commission directed both electric and gas utilities including SoCalGas to file advice letters to establish an Infrastructure Investment and Jobs Act (“IIJA”) Memorandum Account for each utility.<sup>315</sup> The Commission said, “The IIJA Memorandum account will track the costs for projects that are awarded federal funding....”<sup>316</sup> Amounts recorded in a utility’s IIJA Memorandum Account would be addressed in the IOUs’ general rate cases or in separate project applications. The Commission said, “While the IIJA Memorandum Account will track any costs associated with match funding, the actual spending requests for projects will be addressed in the IOUs’ General Rate Cases or separate project applications.”<sup>317</sup>

SoCalGas filed an advice letter requesting approval of its Infrastructure Investment and Jobs Act Memorandum Account (“IIJAMA”) on May 2, 2023, and received approval of the advice letter on April 6, 2023.<sup>318</sup>

Now that SoCalGas has in place its IIJAMA, its request for approval of ratepayer funding for the CCUS FEED study in this general rate case is superfluous. If SoCalGas desires to pursue a CCUS FEED study and to seek funding under the IIJA, SoCalGas should record the expenses it incurs in its IIJAMA and seek recovery of the recorded expenses in either the next SoCalGas General Rate Case or in a separate application.

### **18.2.3 Clean Fuels Operational Readiness Program.**

SoCalGas requests “an incremental increase of \$2.500 million”<sup>319</sup> for its Clean Fuels Operational Readiness Program above Base Year 2021 costs. Once again, SoCalGas does not

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<sup>315</sup> Resolution E-5254, p. 6 (April 6, 2023).

<sup>316</sup> *Id.*

<sup>317</sup> *Id.*

<sup>318</sup> SoCalGas Advice No. 6137 (May 2, 2023).

<sup>319</sup> Ex.SCG-12-R. p. AI-27.

specify the amounts of Base Year 2021 expense associated with the Clean Fuels Operational Readiness program. However, the request for ratepayer funding of \$2.5 million expense in Test Year 2024 represents \$10.0 million over the four-year 2024-2027 GRC cycle.

The Commission’s Rulemaking (“R.”) 13-02-008 has been underway in several phases for a decade to address issues regarding open access to the SoCalGas system for renewable natural gas (“RNG”) producers and to ensure that RNG that is injected into the natural gas transportation system will be pipeline quality gas.<sup>320</sup> Additionally, it is the responsibility of RNG producers, not the SoCalGas ratepayers, to bring their RNG to pipeline quality.<sup>321</sup> The Commission should not allow any increase in GRC expense levels to support a new evaluation of RNG effects on the SoCalGas system.<sup>322</sup>

Regarding hydrogen, SoCalGas jointly with San Diego Gas and Electric Company (“SDG&E”) and Southwest Gas Corporation submitted A.22-09-006 to support a study of hydrogen blending.<sup>323</sup> Any expense of studying hydrogen blending should be the subject of A.22-09-006, not this GRC.<sup>324</sup>

In its rebuttal testimony SoCalGas claims, “None of the previous or current SoCalGas activities or programs have addressed the operational readiness of the existing natural gas infrastructure system to support a diverse portfolio of clean fuels across all aspects of the value chain.”<sup>325</sup> However, beyond RNG and hydrogen, the only other “clean fuel” identified by SoCalGas is synthetic natural gas (“SNG”).<sup>326</sup> SNG is like RNG in that it is the responsibility of

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<sup>320</sup> Ex. TURN-SCGC-06, p. 6.

<sup>321</sup> *Id.*

<sup>322</sup> *Id.*

<sup>323</sup> A.22-09-006 (September 8, 2022).

<sup>324</sup> Ex. TURN-SCGC-06, p. 7.

<sup>325</sup> Ex. SCG-212, p. AI-23.

<sup>326</sup> *Id.*, p. AI-22.

the producer, not the SoCalGas ratepayers, to assure that any SNG injected into the SoCalGas transportation system is pipeline quality gas.

Ratepayers should not be required to bear the expense of the Clean Fuels Operational Readiness Program because the SoCalGas system is ready to transport pipeline quality RNG and SNG. The ongoing proceeding in A.22-09-006 will determine the standards for injecting blended hydrogen. Beyond SNG, RNG and hydrogen, SoCalGas fails to identify any other “clean fuels” which would necessitate the Clean Fuels Operational Readiness program. The requested funding for the program should be denied.

### **18.3 Clean Energy Innovations Project Management Office.**

SoCalGas forecasts an expense of \$1.592 million for Test Year 2024 for what it calls a “Project Management Office” (“PMO”).<sup>327</sup> The expense that SoCalGas requests ratepayers to bear for the four years 2024-2026 of the GRC cycle would be \$6.368 million before any escalation for post-test-year attrition. SoCalGas’s request should be denied.

SoCalGas says that the PMO would focus on two areas:

The CEI-PMO is comprised mainly of two focus areas: (1) the PMO Portfolio Management Group that is responsible for the establishment and implementation of project management standards and reporting across the entire portfolio of CEI projects, and (2) the PMO Special Initiatives Group that is responsible for project management of specific initiatives and established based on the initiatives’ changing needs.<sup>328</sup>

The first focus area on “project management standards and reporting” for the entire portfolio of CEI projects will shrink dramatically with the Commission’s denial of SoCalGas’s \$20.4 million request for funding of the five Clean Fuels Infrastructure Development functions

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<sup>327</sup> Ex. SCG-12-R, p. AI-41.

<sup>328</sup> *Id.*, p. AI-42.

and programs discussed above. Out of the remaining \$26.823 million that SoCalGas requests as Test Year 2024 expense for Clean Energy Innovations, \$23.249 million is for Research Development and Demonstration (“RD&D”).<sup>329</sup> SoCalGas has managed its RD&D program for years without the incremental expense of a PMO.

The only other category of Clean Energy Innovations expense to be subject to the PMO would be “Sustainability” with a Test Year 2024 expense of 1.982 million for Test Year 2024,<sup>330</sup> only a little above the forecast \$1.592 million for the PMO itself. There is no need for a \$1.592 million PMO to manage a \$1.982 million “sustainability” program.

Furthermore, as proposed by SoCalGas, the PMO organizational structure is exceedingly wasteful.<sup>331</sup> SoCalGas proposes a twelve-person office with six managers and six analysts. Four of the six managers would have only a single analyst to manage, and a fifth manager would have only two specialists to manage, which is an extremely top-heavy organizational structure.<sup>332</sup> Ratepayers should not have to fund personnel being paid as managers if the managers are not going to have any duties beyond managing one or two others.<sup>333</sup> The proposed PMO expense for Test Year 2024 should be denied as both unnecessary and wasteful.

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<sup>329</sup> Ex. SCG-12-R, p. AI-2.

<sup>330</sup> *Id.*

<sup>331</sup> Ex. TURN-SCGC-06, p. 11.

<sup>332</sup> *Id.*

<sup>333</sup> *Id.*

19. **ELECTRIC GENERATION (SDG&E ONLY)**
20. **ELECTRIC DISTRIBUTION (SDG&E ONLY)**
21. **CUSTOMER SERVICES**
22. **SUPPLY MANAGEMENT, LOGISTICS AND SUPPLIER DIVERSITY**
23. **CLEAN TRANSPORTATION (SDG&E ONLY)**
24. **FLEET SERVICES**
25. **REAL ESTATE, LAND SERVICES, AND FACILITY OPERATIONS**
26. **ENVIRONMENTAL SERVICES**
27. **INFORMATION TECHNOLOGY**
28. **CYBERSECURITY**
29. **CORPORATE CENTER – GENERAL ADMINISTRATION**
30. **INSURANCE**
31. **COMPENSATION AND BENEFITS**
32. **PENSION AND POST-RETIREMENT BENEFITS OTHER THAN PENSIONS**
33. **PEOPLE AND CULTURE DEPARTMENT**
34. **ADMINISTRATIVE AND GENERAL**
35. **SHARED SERVICES BILLING, SHARED ASSETS BILLING, SEGMENTATION & CAPITAL REASSIGNMENTS**
36. **RATE BASE**
37. **DEPRECIATION**
38. **TAX**
39. **WORKING CASH**
40. **CUSTOMER FORECAST**
41. **COST ESCALATION**
42. **MISCELLANEOUS REVENUES**

**43. REGULATORY ACCOUNTS**

**44. SUMMARY OF EARNINGS/RESULTS OF OPERATIONS**

**45. POST TEST YEAR RATEMAKING**

SoCalGas and TURN-SCGC both propose a two-part post-test year ratemaking (or “attrition”) mechanism with separate annual revenue requirement adjustments for expense and capital during the 2025-2027 post-test years. The disputes between TURN-SCGC and SoCalGas boil down to three issues: (1) the index to use for escalating authorized test year O&M expense; (2) the years included in the historical average of capital additions to use for capital attrition; and (3) whether to exclude any cost categories from the general capital attrition mechanism and instead to authorize post-test year budgets for those activities. SoCalGas proposes to escalate O&M expense using Global Insight’s proprietary utility-specific indices, with medical expense separately escalated based on the actuarial forecast by Willis Towers Watson for Southern California. TURN-SCGC would escalate all O&M expense based on general inflation using CPI-U. SoCalGas would use a 5-year average of 2020-2021 recorded and 2022-2024 forecast capital additions for capital attrition, while TURN-SCGC would use a 7-year 2015-2021 recorded average. And SoCalGas would add budgets for certain capital cost categories, while TURN-SCGC propose no exceptions to the general capital attrition mechanism.<sup>334</sup>

For the reasons explained below, the Commission should find that TURN-SCGC’s two-part attrition mechanism meets the objectives of attrition and more reasonably balances the interests of ratepayers and shareholders during the post-test year period.

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<sup>334</sup> See, e.g., Ex. SCG-240, p. KN-2.

#### **45.1 Attrition Is Intended to Provide Some Reasonable Relief to Shareholders Between General Rate Cases, Not Guarantee Company Earnings.**

Attrition is a mechanism that the Commission has used to offset the financial risk experienced by the utilities between general rate cases.<sup>335</sup> The Commission adopted the original attrition mechanism in 1980 during a period of very high inflation.<sup>336</sup> By 1996, the Commission still characterized attrition mechanisms as an exception to the general strategy of examining one test year out of every three years and providing the utility an incentive to improve its productivity; the Commission only allowed attrition adjustments in years when inflation was high.<sup>337</sup> Since that time, the Commission has continued to affirm its discretion to grant or deny attrition requests, and has maintained that the utilities are not automatically entitled to an attrition mechanism between rate cases.<sup>338</sup>

Moreover, the Commission has made it quite clear over the years that attrition does not provide a guarantee of earnings but rather a reasonable offset to increasing costs:

Attrition is the year-to-year decline in a utility's earnings caused by increased costs that are not offset by increased rates or sales. In order to protect utility-shareholders from the effects of attrition to some extent, the Commission has-adopted a ratemaking mechanism called the Attrition Rate Adjustment (ARA). The ARA mechanism was designed to 'provide utilities with the reasonable opportunity of achieving their authorized rates of return during years in which they are not permitted under the Commission's rate case plan procedures to file for general rate relief but in which they still face volatile economic conditions.<sup>339</sup>

Similarly, attrition allowances "are not intended to insulate utilities from economic pressures that all businesses experience."<sup>340</sup> Unlike a test year cost of service analysis, an attrition mechanism

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<sup>335</sup> D.92497, Cal. PUC LEXIS 1024; 4 CPUC2d 725 (December 5, 1980) at \*101.

<sup>336</sup> TURN-SCGC-07, p.4..

<sup>337</sup> D.00-02-046, p. 428 (discussing Re Pacific Gas and Electric Company (1996) 69 CPUC2d 691, 695).

<sup>338</sup> See, e.g., D.21-08-036, p. 546.

<sup>339</sup> D.04-05-055, p. 26 (citing D.85-12-076, Finding of Fact 1, 9 CPUC 2d 453,476).

<sup>340</sup> D.04-07-022, p. 270.

serves “merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity.”<sup>341</sup>

In a number of cases the Commission has specifically found that a utility’s attrition proposal placed too great a burden on ratepayers and significantly reduced the authorized attrition amount.<sup>342</sup> While TURN-SCGC are not proposing that the Commission deny attrition relief to SoCalGas in the pending case, nonetheless the utility’s need for increased funds to offset rising costs should be balanced against the burden that higher rates place on ratepayers.

#### **45.2 O&M Attrition Should Be Based on General Inflation (CPI-U).**

As noted above, SoCalGas proposes to escalate authorized Test Year O&M expense, other than medical expense, in each year of the post-test year period on a highly tailored basis using Global Insight’s proprietary utility-specific indices.<sup>343</sup> SoCalGas further proposes to escalate medical expenses on an even more specific Willis Towers Watson actuarial forecast for Southern California.<sup>344</sup> These are the same approaches to forecasting escalation that SoCalGas proposes for establishing test year expense levels.

While these indices may be appropriate for projecting test-year expenses, which the Commission now establishes every four years, the complex and utility-specific indices are not the best choice for the attrition period. These complex indices simply pass along the costs of business-as-usual activities during the attrition period, providing little incentive for SoCalGas to

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<sup>341</sup> D.14-08-032, pp. 652-653. *See also* D.20-01-002, p. 41 (affirming this language and accordingly rejecting SCE’s request for assurance that under the new four-year rate case plan adopted in that decision, utilities would receive an attrition mechanism that “fully compensates the utility for its costs of service in the attrition years”).

<sup>342</sup> *See*, for example, D.09-03-025, pp. 305-306 and D.13-05-010, pp. 1009-1010.

<sup>343</sup> Ex. SCG-40-2R, pp. KN-4 – 5.

<sup>344</sup> Ex. SCG-40-2R, p. KN-6.

keep its costs down. As the Commission most recently recounted in D.20-01-002, an attrition mechanism

is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [the utility’s] rate of return [during the attrition years],” but “is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity.”<sup>345</sup>

Indeed, as the Commission explained in D.14-08-032, “[W]e seek to promote [the utility’s] incentive to stretch to achieve productivity between test years.”<sup>346</sup> Thus, SoCalGas’s proposal to incorporate each of the complex and proprietary indices used to establish test year expense levels is not the best choice to increase expense levels for the attrition period.

For the reasons provided below, the Commission should reject the utility’s request and instead incorporate broad indices for all O&M escalation in the attrition years to provide the proper incentives to utility management to manage costs.

#### **45.2.1 Using a Broad Index for O&M Escalation Reasonably Addresses Inflation-Related Cost Pressures While Providing the Utility an Incentive to Manage its Operations as Efficiently as Possible.**

The Commission’s traditional attrition mechanism was a two-part mechanism, combining escalation of labor and non-labor O&M expenses with broad indices and a determination of capital-related revenue requirement based on seven years of recorded capital additions.<sup>347</sup> In this GRC, TURN-SCGC likewise recommend that the Commission apply the traditional attrition mechanism and base O&M escalation on a broad inflation index.<sup>348</sup> TURN-SCGC specifically propose to escalate SoCalGas’s authorized TY 2024 O&M expenses by CPI-U to determine the

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<sup>345</sup> D.20-01-002, p. 41 (quoting TURN’s comments which quoted and cited D.14-08-032, pp. 652-653).

<sup>346</sup> D.14-08-032, p 652.

<sup>347</sup> Ex. TURN-SCGC-07, p. 4.

<sup>348</sup> Ex. TURN-SCGC-07, pp. 7-8.

appropriate amount for O&M expenses in Attrition Year (AY) 2025; SoCalGas's AY 2025 O&M expense levels would similarly be escalated by CPI-U to determine AY 2026 O&M levels, with the same approach used to escalate AY 2026 O&M levels for AY 2027.<sup>349</sup> As an alternative, the Commission could escalate O&M using CPI-U increased by 50 basis points.<sup>350</sup>

In this proceeding the Commission must consider whether SoCalGas's proposed PTY mechanism with its myriad of account specific escalators best serves the Commission's purpose of promoting SoCalGas to "stretch to achieve productivity" in AY 2025 through AY 2027. TURN-SCGC submit that the PTY escalation index that SoCalGas requests using, Global Insight's various utility cost forecasts, is simply too protective of SoCalGas to properly incent it to manage operations productively before its next GRC. Use of a broad index like CPI as a measure of inflation during the PTYs, rather than an index that more precisely tracks the escalation in utility costs (like Global Insight), is a reasonable method of achieving the Commission's purpose in providing attrition adjustments.

TURN-SCGC understand that the Commission has, on some occasions, relied on forecasts of escalation that are specific to utility sector costs for purposes of attrition instead of the CPI-U, while expressing its concern that CPI-U "does not specifically cover the prices of the typical goods [the utility] purchases."<sup>351</sup> The Commission reached this conclusion in the last SoCalGas and SDG&E GRC.<sup>352</sup> However, such an approach is not required to fulfill the purpose of attrition. As noted above, an attrition mechanism "is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [the utility's] rate of return

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<sup>349</sup> Ex. TURN-SCGC-07, p. 7.

<sup>350</sup> Ex. TURN-SCGC-07, pp. 7-8.

<sup>351</sup> *See, e.g.*, D.04-07-022, p. 278.

<sup>352</sup> D.19-09-051, p. 708.

[during the attrition years],” but “is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity.”<sup>353</sup>

The Commission should not shy away from recognizing the utility’s own responsibility to manage costs and improve efficiencies during the rate case cycle. Adopting an attrition approach that mimics test year cost of service ratemaking undermines the utility’s incentive to do so. The Commission made this clear in its decision in the Sempra Utilities’ Test Year 2012 GRC, D.13-05-010:

Having reviewed all of the testimony and arguments of the parties concerning the PTY proposals, we hesitate to adopt the proposal of SDG&E and SoCalGas to adopt their PTY ratemaking mechanisms. Their proposed mechanisms seek to include the use of two formulas which lean in their favor. These are the use of Global Insight’s utility-specific cost index, and a California-specific health care cost index. Although these utility-specific indexes may be a better reflection of the PTY costs in a “business as usual” setting, such indexes, if adopted, will not provide the Applicants with an incentive to manage and reduce their costs during the PTY period.<sup>354</sup>

The Commission further clarified that use of Global Insight’s utility specific cost index in setting the test year revenue requirement “does not mean we should automatically use those same indexes for the PTY period.”<sup>355</sup> The Commission accordingly chose to replace the utility specific indices proposed by SoCalGas and SDG&E with an index based on CPI-U plus 75 basis points.<sup>356</sup>

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<sup>353</sup> D.14-08-032, pp. 652-653. *See also* D.20-01-002, p. 41 (affirming this language and accordingly rejecting SCE’s request for assurance that under the new four-year rate case plan adopted in that decision, utilities would receive an attrition mechanism that “fully compensates the utility for its costs of service in the attrition years”).

<sup>354</sup> D.13-05-010, p. 1008.

<sup>355</sup> D.13-05-010, p. 1009.

<sup>356</sup> D.13-05-010, p. 1010.

Here, too, the Commission should weigh the importance of proper incentives for the utility during the PTY period more highly than the need to compensate the company exactly for any change in its expenses between test years. TURN-SCGC's proposal to use CPI-U as a measure of inflation during the attrition period achieves a reasonable balance between the interests of shareholders and ratepayers.

Alternatively, if the Commission prefers to follow the approach taken for the Sempra Utilities in D.13-05-010, TURN-SCGC recommend that the Commission use an adjusted CPI-U plus 50 basis points. This alternative is not "arbitrary," as SoCalGas suggests.<sup>357</sup> It is based on the attrition mechanism the Commission adopted for SoCalGas and SDG&E in D.13-05-010, CPI-U plus 75 basis points.<sup>358</sup> As TURN-SCGC witness Yap explained, a smaller adjustment is appropriate here because TURN-SCGC are recommending a separate attrition adjustment mechanism for capital, whereas the attrition mechanism adopted in D.13-05-010 covered O&M expense and capital revenue requirements.<sup>359</sup>

#### **45.2.2 The Commission Should Reject SoCalGas's Request for Separate Medical Expense Escalation.**

SoCalGas proposes to escalate medical costs based on Willis Towers Watson's (WTW's) actuarial forecast, which is the same proposal SoCalGas and SDG&E presented in at least the previous two GRCs.<sup>360</sup> SoCalGas proposes this separate escalation schedule for medical costs because "SoCalGas's medical costs are expected to increase above general utility cost inflation."<sup>361</sup> SoCalGas asserts that WTW's actuarial forecast "is more reflective of the cost

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<sup>357</sup> Ex. SCG-240, p. KN-7.

<sup>358</sup> Ex. TURN-SCGC-07, pp. 7-8; D.13-05-010, p. 1010.

<sup>359</sup> Ex. TURN-SCGC-07, pp. 7-8.

<sup>360</sup> Ex. SCG-40-2R, p. KN-6; D.19-09-051, p. 705 (TY 2019 GRC); D.16-06-054, pp. 224-225 (TY 2016 GRC).

<sup>361</sup> Ex. SCG-40-2R, p. KN-6.

trends in Southern California” because “it takes into account demographic factors specific to SoCalGas,” including location, workforce demographics, and medical plan design.<sup>362</sup> Finally, SoCalGas suggests that the proposed approach is “similar to the post-test year medical expense escalation rate mechanism that was adopted in Southern California Edison Company’s (SCE’s) TY 2018 and TY 2021 GRCs.”<sup>363</sup>

The Commission should reject SoCalGas’s proposal to separately escalate medical costs based on WTW’s actuarial forecast for three reasons. As explained below, SoCalGas fails to address the Commission’s reasoning for denying the same request in the TY 2019 GRC. Also, WTW has consistently overforecast medical cost escalation (and medical costs) from 2014-2019. Finally, comparisons to the Commission’s treatment of SCE’s medical cost escalation during the attrition years is inapposite because SCE’s medical costs are subject to a two-way balancing account, unlike the Sempra Utilities’.

In the last SoCalGas and SDG&E GRC, the Commission rejected the utilities’ similar request to separately escalate medical costs based on WTW’s actuarial forecast.<sup>364</sup> The Commission explained:

While we do not necessarily disagree with Applicants that medical costs are expected to increase faster than general utility cost inflation or broad-based inflation in the general economy, the forecast for O&M costs is a forecast of the average increase in costs. Thus, there should be categories of costs that are higher than the average as well as costs that fall below the average. Applications focused their testimony and arguments in support of their proposed escalation rates for medical costs to be applied for the attrition years and did not fully justify why medical costs should be treated differently from other O&M costs. We therefore find it reasonable to apply the PTY mechanism deemed appropriate for O&M costs to medical costs as well.<sup>365</sup>

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<sup>362</sup> Ex. SCG-40-2R, p. KN-6; Ex. SCG-240, p. KN-6.

<sup>363</sup> Ex. SCG-40-2R, p. KN-6; Ex. SCG-240, p. KN-6.

<sup>364</sup> D.19-09-051, p. 707.

<sup>365</sup> D.19-09-051, p. 707.

SoCalGas's showing in this GRC suffers from the same deficiency; it focuses exclusively on the basis for the proposed medical cost escalation rates and does not address why medical costs are so unique.<sup>366</sup> The Commission should accordingly reach the same conclusion here.

Second, SoCalGas used WTW's medical cost trend forecast in at least the past two GRCs to forecast medical costs, and those forecasts have proven too high every year from 2014-2019. The following table compares SoCalGas's medical cost forecasts for 2014, 2015, and 2016 presented in the TY 2016 GRC to the recorded medical costs for 2014, 2015, and 2016 presented in the TY 2019 GRC.<sup>367</sup> Because SoCalGas presented TY 2016 GRC forecasts in 2013\$ and TY 2019 GRC recorded costs in 2016\$, TURN-SCGC converted both to 2021\$ using escalation factors provided by SoCalGas.<sup>368</sup> The table also compares SoCalGas's medical cost forecasts for 2017, 2018, and 2019 presented in the TY 2019 GRC to the recorded medical costs for 2017, 2018, and 2019 presented in this GRC.<sup>369</sup> Because SoCalGas presented TY 2019 GRC forecasts in 2016\$ and TY 2024 GRC recorded costs in 2021\$, TURN-SCGC converted TY 2019 GRC forecasts to 2021\$ using escalation factors provided by SoCalGas.<sup>370</sup>

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<sup>366</sup> See Ex. SCG-40-2R, p. KN-6, lines 8-21; SCG-40-WP-2R, p. 3; Ex. SCG-240, p. KN-6.

<sup>367</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.1.3 Attachment (SCG-30-WP from TY 2019 GRC); Q. 34.1.4 Attachment (SCG-21-WP from TY 2016 GRC).

<sup>368</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.1.3 and 34.1.4.

<sup>369</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.1.3 Attachment (SCG-30-WP from TY 2019 GRC); Ex. SCG-25-WP, p. 15.

<sup>370</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.1.3 and 34.1.4.

	Forecast	Forecast	Recorded	Recorded	Forecast > Recorded
	2016 GRC (2013\$)	(2021\$)	2019 GRC (2016\$)	(2021\$)	(2021\$)
2014	\$ 75,962	\$ 88,908	\$ 75,044	\$ 86,225	\$ 2,683
2015	\$ 80,335	\$ 94,026	\$ 75,948	\$ 87,263	\$ 6,763
2016	\$ 89,763	\$ 105,061	\$ 78,922	\$ 90,681	\$ 14,381
	2013\$ to 2021\$	1.17043			
	2016\$ to 2021\$	1.14899			
	Forecast	Forecast	Recorded	Recorded	Forecast > Recorded
	2019 GRC (2016\$)	(2021\$)	2024 GRC (2021\$)	(2021\$)	(2021\$)
2017	\$ 76,043	\$ 87,373	\$ 83,018	\$ 83,018	\$ 4,355
2018	\$ 84,678	\$ 97,294	\$ 87,793	\$ 87,793	\$ 9,501
2019	\$ 96,023	\$ 110,329	\$ 82,095	\$ 82,095	\$ 28,234

The Commission should not rely on WTW’s forecast of medical cost escalation to set attrition year rates in this GRC because of this track record.

Finally, SoCalGas points to the Commission’s treatment of medical cost escalation in setting attrition year adjustments for SCE. SoCalGas overlooks a fundamental difference between medical cost ratemaking for SCE and itself. SCE has a two-way balancing account that tracks the difference between authorized and recorded medical, dental, and vision expenses authorized in the GRC, the Medical Programs Balancing Account.<sup>371</sup> The Commission adopted this two-way balancing account in D.09-03-025, issued in SCE’s TY 2009 GRC, “to protect ratepayers from any overestimating of” medical costs.<sup>372</sup> SoCalGas’s ratepayers enjoy no such protection when they overpay for medical costs.

<sup>371</sup> See D.21-08-036, p. 468; D.19-05-020, pp. 268-269; SCE Preliminary Statement VV - Medical Programs Balancing Account.

<sup>372</sup> D.09-03-025, p. 143.

### **45.3 Capital Attrition Should Be Based on Seven Years of Recorded Rate Base Additions Without Exceptions.**

SoCalGas proposes to calculate PTY capital-related revenue requirements using a five-year average of capital additions (2020-2021 actual, 2022-2024 forecast), escalated using Global Insight's utility cost escalation factors. In addition to this general capital attrition mechanism, SoCalGas seeks attrition year budget forecasts for three "exceptions," including the Honor Rancho Compressor Modernization project, the Customer Information System (CIS) Replacement project, and the Gas Integrity Management Programs. The Gas Integrity Management Programs include the Transmission Integrity Management Program (TIMP), the Distribution Integrity Management Program (DIMP), the Storage Integrity Management Program (SIMP), the Facilities Integrity Management Program (FIMP), and the Gas Safety Enhancement Program (GSEP).<sup>373</sup>

TURN-SCGC recommend a different approach, a trended seven-year average of recorded capital additions (2015-2021), without any exceptions.<sup>374</sup> TURN-SCGC use CPI-U to escalate the 7-year average for the attrition years. TURN-SCGC's proposal is consistent with the Commission's traditional approach to capital attrition.<sup>375</sup> The TURN-SCGC proposal is a more robust and balanced approach and should be adopted by the Commission.

#### **45.3.1 Seven Years of Recorded Data Is a Very Robust Basis for Trending Capital.**

The general capital attrition mechanisms proposed by SoCalGas and TURN-SCGC differ in three primary ways: (1) the number of years included in the historical average; (2) the number of years of recorded data included in the historical average; and (3) the index used to escalate the

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<sup>373</sup> Ex. SCG-240, p. KN-3.

<sup>374</sup> Ex. TURN-SCGC-07, p. 2.

<sup>375</sup> Ex. TURN-SCGC-07, p. 4.

average to the attrition years. The TURN-SCGC approach should be adopted for the following reasons.

First, the TURN-SCGC method uses a broader (and deeper) data set, 7 years instead of 5, and without SoCalGas's proposed exclusions.<sup>376</sup> Using a broader range of data can provide a more accurate representation of historical and long-term trends. Second, TURN-SCGC's proposal uses 7 years of recorded data, whereas SoCalGas uses only two years of recorded data plus three years of forecast data. Greater reliance on recorded data reduces the risk to ratepayers that the utility's forecasts will prove too high.

The Commission has previously recognized the importance of tying the trending of capital related costs to recorded costs and preferred a 7-year average to a 5-year average. In the Sempra Utilities' TY 2019 GRC, the Commission rejected SoCalGas's and SDG&E's proposals to trend capital additions based on two years of recorded data (2015-2016) and three forecast years (2017-2019). The Commission instead adopted an attrition mechanism based on a 7-year average of capital additions, with four years of recorded data. The Commission reasoned:

While we agree with Applicants' forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives, it is not certain at this point in time at what level these activities will continue to increase and whether or not and at what point additional spending efficiently matches the amount of risk reduction and increased safety. Thus, we find that it is also important to incorporate historical adjustments. A seven-year average provides a more effective normalization of capital additions.<sup>377</sup>

In Pacific Gas and Electric Company's (PG&E's) Test Year 2014 GRC, the Commission likewise adopted a capital attrition mechanism based on a 7-year average that combined four

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<sup>376</sup> Ex. TURN-SCGC-07, p. 12. TURN-SCGC data is based on Form 2 without exclusions; hence, the data includes all of the gas safety capital additions.

<sup>377</sup> D.19-09-051, p. 709.

years of recorded data with three years of forecast data, concluding, “Use of an historical average is consistent with the approach applied in the past, and normalizes actual utility spending variations over time.”<sup>378</sup>

Although the Commission adopted a 7-year average in D.19-09-051 and D.14-08-032 that incorporated a blend of recorded and forecast capital additions, TURN-SCGC recommends a 7-year average in this case based entirely on recorded data. Incorporating three years of forecast data, as SoCalGas proposes (2022-2024), runs the risk of the forecast significantly deviating from actual additions. This is what happened following the Commission’s adoption of PG&E’s capital attrition mechanism in D.14-08-032, which incorporated the forecast for capital additions in Test Year 2014. The actual expenditures were nearly \$400 million below the authorized test year level.<sup>379</sup>

Finally, TURN-SCGC’s approach to escalating the historical average to the attrition years using CPI (instead of Global Insight’s indices) is a reasonable means of promoting the Commission’s interest in utility productivity during the attrition years. TURN-SCGC discuss the reasonableness of using CPI to escalate Test Year 2024 dollars to the attrition years in the context of TURN-SCGC’s O&M attrition proposal above. The same reasoning applies here as well.

#### **45.3.2 SoCalGas’s Critiques of TURN-SCGC’s Capital Attrition Mechanism Should Be Dismissed.**

SoCalGas offers three criticisms of TURN-SCGC’s approach, none of which is compelling. First, SoCalGas suggests that TURN-SCGC’s approach is “haphazard and

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<sup>378</sup> D.14-08-032, pp. 656-657.

<sup>379</sup> Ex. TURN-SCGC-07, p. 10.

fundamentally flawed” because of how TURN-SCGC escalate costs within our capital attrition methodology.<sup>380</sup> Second, SoCalGas suggests that its 5-year average mechanism is superior because it “best captures the utility investment profile,” with its evolving focus on “utility safety, reliability, and sustainability.”<sup>381</sup> Third, SoCalGas asserts that TURN-SCGC’s 7-year methodology will “significantly underestimate SoCalGas’s post-test year capital needs.”<sup>382</sup> Contrary to SoCalGas’s suggestions, TURN-SCGC’s approach reasonably captures fluctuations in utility capital additions across the utility’s operations over time and avoids the “cherry-picking” approach of SoCalGas’s proposed exceptions, which are discussed in Section 45.3.3 below.

#### **45.3.2.1 The TURN-SCGC Model is Logically Sound.**

SoCalGas argues that the TURN-SCGC approach is “fundamentally flawed” because it uses Global Insight indices to escalate 2015-2021 recorded costs to 2024 test year dollars to compute the seven-year average, while using CPI to escalate the 7-year average in the attrition years.<sup>383</sup> In fact, TURN-SCGC’s approach is logical, not a flaw in the model.

The choice of how to estimate inflationary effects for purposes of utility ratemaking is a policy matter. TURN-SCGC’s position is that use of Global Insight’s indices is not objectionable for setting test year cost of service revenue requirements. For this reason, TURN-SCGC used Global Insight’s indices to escalate historical capital additions to 2024 dollars. On the other hand, attrition year adjustments are not updates to cost of service; such updates occur with the next GRC. TURN-SCGC used CPI-U to escalate the historical average from 2024

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<sup>380</sup> Ex. SCG-240, p. KN-7.

<sup>381</sup> Ex. SCG-240, p. KN-8.

<sup>382</sup> Ex. SCG-240, pp. KN-8 – 9.

<sup>383</sup> Ex. SCG-240, p. KN-7.

dollars to attrition year dollars, instead of Global Insight’s indices, for the same reason we used CPI-U to escalate O&M in the attrition years.

The Commission has the discretion to use any measure of inflation that it finds reasonably suited to advancing the Commission’s goals for attrition rate adjustments. TURN-SCGC’s proposal to escalate test year dollars to the attrition years using CPI-U is a reasonable approach to balancing the interests of ratepayers and shareholders.

#### **45.3.2.2 The TURN-SCGC Approach Reasonably Captures the Current Utility Spending Focus.**

SoCalGas argues that its 5-year average mechanism should be adopted instead of TURN-SCGC’s recorded 7-year average to “best capture[] the utility investment profile and operating initiatives of the current utility environment, which has evolved in the past few years with the risk-informed GRC framework and ‘SoCalGas’s strong commitment to the State’s climate policy goals.’”<sup>384</sup> SoCalGas suggests that its “capital program is continuing to evolve with a greater focus on increasing investment in utility safety, reliability, and sustainability, which directly support California’s clean energy and environmental initiatives.”<sup>385</sup> There are four flaws in SoCalGas’s reasoning.

First, SoCalGas does not track plant in service additions for “safety,” “reliability,” or “sustainability”.<sup>386</sup> For this reason, SoCalGas cannot identify the safety, reliability, and sustainability programs or the level of capital additions reflected in its 5-year average.<sup>387</sup> Nor can SoCalGas identify whether it has excluded any “safety,” “reliability,” or “sustainability”

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<sup>384</sup> Ex. SCG-240, p. KN-8.

<sup>385</sup> Ex. SCG-240, p. KN-8.

<sup>386</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.2.

<sup>387</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.2.

recorded or forecast capital additions or plant in service retirements from its 5-year average.<sup>388</sup>

Because SoCalGas does not know the level of investment in safety, reliability, and sustainability reflected in its own 5-year average, it cannot compare those levels of investment to what's captured by TURN-SCGC's 7-year average.

Second, SoCalGas excluded all Gas Integrity Management Programs spending from its 5-year average calculation.<sup>389</sup> The Gas Integrity Management Programs, according to SoCalGas, maintain and enhance safety and reliability.<sup>390</sup> On the other hand, TURN-SCGC's 7-year average is based on the FERC Form 2 values for each year<sup>391</sup> and, thus, includes all Gas Integrity Management Programs recorded capital additions, as well as PSEP recorded capital additions, from 2015 through 2021.<sup>392</sup>

Third, SoCalGas and SDG&E presented a similar rationale in support of their proposed 5-year average for capital attrition in the TY 2019 GRC, which included recorded years 2015-2016 and forecast years 2017-2019.<sup>393</sup> As the Commission recounted in D.19-09-051, they pointed to "the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy."<sup>394</sup> This is the same evolution SoCalGas cites in this GRC in support of its proposed 5-year average. TURN-SCGC's 7-year average includes recorded capital additions

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<sup>388</sup> Ex. TURN-401, TURN-SCGC-034, Q. 34.2.

<sup>389</sup> Ex. SCG-40-WP-2R, pp. 4-5; Ex. TURN-401, TURN-SCGC-034, Q.43.2.3 and Supplemental Response to 43.2.3.

<sup>390</sup> Ex. SCG-09, p. AK-TS-1.

<sup>391</sup> Ex. TURN-SCGC-07, Attachment B, see, p. 53 vs. 81-83; p. 55 vs. 77.

<sup>392</sup> Ex. TURN-SCGC-07, p. 11, Figure 1, p. 12.

<sup>393</sup> In that proceeding, the Public Advocates Office (then called the Office of Ratepayer Advocates) recommended a 7-year average if the Commission declined to adopt a uniform adjustment for O&M and capital. *See* D.19-09-051, p. 705.

<sup>394</sup> D.19-09-051, pp. 708-709.

from the first three years of the TY 2019 GRC cycle, 2019-2021, thus capturing the evolution in capital spending focus anticipated in that case (to the extent it took place).<sup>395</sup>

Fourth, the majority of the “sustainability” and “clean energy” proposals presented by SoCalGas involve non-tariffed products and services that should be excluded from the utility revenue requirement borne by ratepayers.<sup>396</sup> TURN-SCGC elsewhere address certain “clean energy” proposals of SoCalGas, demonstrating that these proposals should not be included in SoCalGas’s revenue requirement. Consequently, these investments should not be covered by SoCalGas’s attrition proposal.<sup>397</sup>

Furthermore, SoCalGas misleadingly compares the average escalated capital additions in 2015 and 2016 to the average in 2020 and 2021 to imply that TURN-SCGC’s 2015-2021 average is out of line with the utility’s operational needs.<sup>398</sup> TURN-SCGC witness Yap provides a chart illustrating recorded capital additions from 2015-2021, with the distribution portion of capital additions adjusted to account for the difference in meter counts, consistent with the Commission’s traditional capital attrition methodology.<sup>399</sup> That chart shows that recorded capital additions have fluctuated from 2015-2021.<sup>400</sup> While SoCalGas is correct that capital additions were lower in 2015 and 2016 than in 2020 and 2021, capital additions were even lower in 2017

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<sup>395</sup> D.19-09-051, p. 709 (acknowledging that the Sempra Utilities’ plans for future capital spending are just plans, making it uncertain how actual spending will evolve “and whether or not and at what point additional spending efficiently matches the amount of risk reduction and increased safety”).

<sup>396</sup> *See, e.g.*, Ex. TURN-SCGC-06 (opposing SoCalGas’s proposed spending on Clean Fuels Infrastructure Development and a new Clean Energy Innovations Project Management Organization in Ex. SCG-12 because they focus on providing non-utility services to customers under the guise of promoting “clean fuels”); Ex. TURN-SCGC-05, pp. 3-6 (opposing SoCalGas’s proposal in Ex. SCG-10 to build a hydrogen fueling station as part of the Honor Rancho Compressor Modernization project).

<sup>397</sup> Ex. TURN-SCGC-07, p. 4.

<sup>398</sup> Ex. SCG-240, pp. KN-8 – 9.

<sup>399</sup> Ex. TURN-SCGC-07, pp. 11-12.

<sup>400</sup> Underlying data is presented in Ex. TURN-SCGC-07 Attachments, pp. 47, 49.

and 2019 than in 2015 and 2016, and higher in 2018 than in 2020 and 2021.<sup>401</sup> TURN-SCGC's 7-year average appropriately captures this fluctuation in recorded additions.

### **45.3.2.3 The TURN-SCGC Approach Reasonably Addresses Attrition Year Capital Costs.**

SoCalGas argues that TURN-SCGC's 7-year methodology "ignores present day trends and challenges and will significantly underestimate SoCalGas's post-test year capital needs."<sup>402</sup>

To demonstrate the insufficiency of TURN-SCGC's methodology, SoCalGas provides a table, Table KN-3, showing that TURN-SCGC's "Capital Related Cost Attrition" adjustments are lower than those from SoCalGas's methodology in each attrition year.<sup>403</sup> The Commission should not find this argument persuasive.

As an initial matter, Table KN-3 compares TURN-SCGC's capital related attrition adjustment to SoCalGas's requested capital attrition adjustment. The table does not present SoCalGas's "post-test year *capital needs*."

In fact, SoCalGas's post-test year capital needs have not been vetted in this proceeding. On the other hand, SoCalGas's test year capital needs have been vetted, and intervenors have recommended adjustments to many of the utility's capital proposals.<sup>404</sup> TURN cannot recall a litigated GRC decision in which the Commission authorized the utility to proceed with 100% of its proposed capital investments over the rate case period. The Commission should not presume that the utility's post-test year capital investment plans are reasonable for the purpose of evaluating attrition mechanism proposals.

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<sup>401</sup> Ex. TURN-SCGC-07, p. 11, Figure 1.

<sup>402</sup> Ex. SCG-240, p. KN-9.

<sup>403</sup> Ex. SCG-240, p. KN-9, Table KN-3.

<sup>404</sup> See, generally, SoCalGas and SDG&E Joint Comparison Exhibits, Attachment A (SoCalGas Joint Comparison Exhibit).

Moreover, the Commission has made clear that a capital attrition adjustment mechanism need not cover all attrition year capital expenditures – either projected by the utility or actual. In PG&E’s Test Year 2014 GRC, PG&E argued that capital attrition based on a 7-year average would be inadequate because PG&E’s projected attrition year capital investment levels would be “much higher than a seven-year historic average.”<sup>405</sup> The Commission dismissed PG&E’s concern, noting that PG&E’s criticisms mistakenly presupposed that its attrition year spending forecasts were reasonable, when those spending plans had not received close scrutiny (unlike test year spending).<sup>406</sup> The Commission further acknowledged that a 7-year average would “not necessarily cover all attrition year capital expenditures that PG&E may ultimately find prudent.”<sup>407</sup> Even so, the Commission noted, “the Commission historically has not closely covered projected revenue requirement through an attrition mechanism,” yet rate base has grown.<sup>408</sup> The Commission also explained that a 7-year average would provide PG&E “a stronger incentive to find ways to curb the rate of spending growth.”<sup>409</sup> The Commission ultimately concluded that “use of a seven year average better balances the interests of both ratepayers as well as shareholders than does PG&E’s methodology.”<sup>410</sup>

### **45.3.3 SoCalGas Fails to Demonstrate the Reasonableness of Its Three “Exceptions” to a Trend-Based Capital Attrition Mechanism.**

The final area of dispute between TURN-SCGC and SoCalGas concerns the cost categories that should be excluded from the general capital attrition mechanism and based

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<sup>405</sup> D.14-08-032, p. 657. In that case, PG&E proposed to escalate authorized test year capital additions. (D.14-08-032, p. 656).

<sup>406</sup> D.14-08-032, pp. 657-658.

<sup>407</sup> D.14-08-032, pp. 658-659.

<sup>408</sup> D.14-08-032, pp. 658-659.

<sup>409</sup> D.14-08-032, p. 657.

<sup>410</sup> D.14-08-032, p. 657.

instead on post-test year budgets. SoCalGas requests budget-based attrition for its Gas Integrity Management Programs, the Honor Rancho Compressor Modernization project, and the Customer Information System (CIS) Replacement Program. TURN-SCGC recommend no exceptions to the general attrition mechanism.<sup>411</sup>

The Commission has historically frowned upon budget-based attrition. It rejected SCE's request for budget-based capital attrition in every GRC from the 2006 GRC through the 2018 GRC and permitted only narrow exceptions in the 2021 GRC.<sup>412</sup> The Commission has adopted budget-based attrition in limited circumstances where the costs at issue are extraordinary.<sup>413</sup>

SoCalGas relies on the Commission's treatment of Pipeline Safety Enhancement Plan (PSEP) capital-related costs in D.19-09-051 and SCE SmartConnect costs in D.12-11-051 to support its proposed exceptions. But those examples are readily distinguishable from SoCalGas's proposals here.

The Commission authorized capital budget-based attrition for PSEP in D.19-09-051 "because PSEP is being incorporated into the GRC for the first time and timing and completion of the proposed projects should not be delayed."<sup>414</sup> In D.16-08-003, the Commission had authorized SoCalGas and SDG&E to include in their TY 2019 GRC all PSEP costs not subject to prior applications, making that GRC the first to include any PSEP costs.<sup>415</sup> In contrast, none of the capital attrition "exceptions" proposed by SoCalGas here represent entirely new GRC activities.

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<sup>411</sup> Ex. SCG-240, pp. KN-2 - 3.

<sup>412</sup> D.19-05-020, pp. 283-285; D.21-08-036, pp. 548-549.

<sup>413</sup> D.21-08-036, pp. 547-550.

<sup>414</sup> D.19-09-051, pp. 215-216.

<sup>415</sup> D.19-09-051, p. 197.

In D.12-11-051, the Commission addressed SCE's TY 2012 GRC. Under highly unusual circumstances, the Commission adopted an attrition year budget for SCE's advanced metering infrastructure program, called Edison SmartConnect (or SmartConnect), reflecting both costs and projected benefits. As the Commission explained in D.12-11-051:

A one-time wrinkle in forecasting for 2013 arises due to the deployment of SCE's advanced metering infrastructure program (SmartConnect, AMI or smart meters) to residential and small commercial customers by the end of 2012. Edison's SmartConnect deployment consists of metering and communications infrastructure as well as the related computerized systems and software. Pursuant to D.08-09-039, costs through 2012 related to the deployment of SmartConnect are to be recovered through the ESCBA [Edison SmartConnect Balancing Account], and moved into general rates in 2013.<sup>416</sup>

The Commission noted the complications created by the timing of SmartConnect deployment (2008-2012) relative to the TY 2012 GRC period (2012-2014) "require[ing] the development of GRC forecasts that delineate between SmartConnect and GRC funded costs to avoid double recovery."<sup>417</sup> Accordingly, SCE prepared a 2012 GRC forecast assuming no SmartConnect meter deployments, plus a separate 2013 O&M forecast assuming full SmartConnect deployment that included SmartConnect benefits of \$58.2 million and costs of \$23.0 million.<sup>418</sup> Citing the Commission's expectation that post-deployment costs and benefits would be integrated into the 2012 GRC, the Commission found it reasonable and appropriate to adopt a separate SmartConnect-related forecast for attrition year 2013, with SCE's estimated benefits providing an offset to authorized 2013 costs.<sup>419</sup> The SmartConnect 2013 revenue requirement was then subject to the standard attrition mechanism for 2014.<sup>420</sup>

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<sup>416</sup> D.12-11-051, pp. 302-303.

<sup>417</sup> D.12-11-051, p. 307.

<sup>418</sup> D.12-11-051, p. 307.

<sup>419</sup> D.12-11-051, pp. 308-309.

<sup>420</sup> D.12-11-051, p. 609.

SoCalGas has failed to demonstrate that the costs for which it seeks budget-based attrition are truly extraordinary and warrant special treatment. As explained below, they are encompassed by the ebb and flow of ongoing operations and should be subject to the general attrition mechanism, specifically, TURN-SCGC's 7-year average methodology.

#### **45.3.3.1 Gas Integrity Management Programs**

SoCalGas argues that the Gas Integrity Management Programs “will be underfunded if escalated using” TURN-SCGC's methodology.<sup>421</sup> To support this claim, SoCalGas isolates one area of post-test year spending, the Gas Integrity Management Programs, and compares the purported “capital related cost attrition” provided under TURN-SCGC's methodology to SoCalGas's budget-based attrition.<sup>422</sup> This comparison is inapt for two reasons. First, it does not make sense to attempt to isolate the impact of TURN-SCGC's methodology on a single program area. TURN-SCGC's methodology would provide an additional level of revenue requirement for all post test year capital spending without constraining the utility's spending in any one program area. SoCalGas will spend more than historical levels in some program areas and less in others; TURN's approach encompasses this variation. Moreover, the appropriate level of funding for the Gas Integrity Management Programs is a contested issue in this GRC.<sup>423</sup> SoCalGas's comparison relies on SoCalGas's forecasts, not the Commission's determination of reasonable spending levels.

SoCalGas next argues, “It is also not appropriate to use the historical average to determine the future costs of the Integrity Management Programs since they are approved and

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<sup>421</sup> Ex. SCG-240, p. KN-9.

<sup>422</sup> Ex. SCG-240, p. KN-10, Table KN-4.

<sup>423</sup> *See, e.g.*, Ex. SCG-209, p. TS-AR-1 (summarizing difference among parties for SoCalGas's Gas Integrity Management Programs).

balanced for each GRC cycle only.”<sup>424</sup> Once again, SoCalGas misconstrues TURN-SCGC’s attrition proposal, which does not limit SoCalGas to a historical level of capital investment in the Gas Integrity Management Programs. TURN-SCGC’s mechanism would provide additional revenue requirement in the attrition years for capital-related costs across the utility’s operations. On the other hand, some of the integrity management work may continue to be, or become, subject to balancing account and/or memorandum account treatment, allowing SoCalGas an opportunity to request specific recovery of capital expenditures in excess of authorized revenues.<sup>425</sup>

Additionally, TURN-SCGC’s approach is consistent with the attrition approach adopted by the Commission in the TY 2019 GRC. In that case, SoCalGas did not request or receive budget-based attrition for the gas integrity management programs.<sup>426</sup> These programs are included in the 7-year average trending approach adopted in D.19-09-051.

At this point, SoCalGas has been pursuing its gas integrity programs and pipeline safety enhancement programs for much longer than seven years, and these programs resulted in substantial levels of capital additions being recorded to rate base.<sup>427</sup> A 7-year average of recorded capital additions is appropriate to support SoCalGas’s ongoing safety efforts.

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<sup>424</sup> Ex. SCG-240, p. KN-9.

<sup>425</sup> See, e.g., Ex. TURN-15, pp. 17-18 (discussing and reacting to SoCalGas’s proposals to continue the existing two-way TIMP, DIMP, and SIMP balancing accounts); pp. 22-24 (discussing and opposing SoCalGas’s proposals to create new two-way FIMP and GSEP balancing accounts).

Transmission Integrity Management Program (TIMP) Balancing Account and Memorandum Account (in dispute, per TURN OB Section 3.14.2); In-Line Inspection (ILI) Balancing Account and Memorandum Account (in dispute, per TURN OB Section 3.14.3.1).

<sup>426</sup> D.19-09-051, p. 705 (SoCalGas and SDG&E proposals); pp. 708-710 (authorized capital attrition mechanism). The only exception to general capital attrition requested by SoCalGas was for the Pipeline Safety Enhancement Plan (PSEP). (D.19-09-051, p. 705).

<sup>427</sup> Ex. TURN-SCGC-07, p. 10.

### 45.3.3.2 Honor Rancho Compressor Modernization and CIS Replacement

SoCalGas argues that a separate capital adder is needed for the Honor Rancho Compressor Modernization and CIS Replacement projects because they will not go into service in the test year and because of the magnitude of the revenue requirement associated with these projects.<sup>428</sup> Guaranteeing a forecasted capital addition amount for these projects is unreasonable.

As an initial matter, the “Principal component” of the Honor Rancho compressor project is not forecasted to come online before 2027, the final year of the GRC cycle.<sup>429</sup> The CIS project is not expected to be operational until 2026.<sup>430</sup> If these timelines slip, which is reasonable to contemplate for any long-term capital project, the projects may not be used and useful during the GRC cycle.<sup>431</sup>

Moreover, these project do not represent truly exceptional circumstances, even if they are large projects. Yet SoCalGas did not exclude any recorded or forecast gas storage operations and construction capital additions from the 5-year average it proposes for its general attrition mechanism.<sup>432</sup> Nor did it exclude any recorded or forecast IT capital additions.<sup>433</sup> Historic capital investments for these operational areas are reflected in SoCalGas’s general attrition mechanism. Likewise, TURN-SCGC’s 7-year average includes historical capital additions in these areas.

Furthermore, the historical averages also include capital spending in other areas that will not recur during the attrition years, either at all or at comparable levels. For instance, both

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<sup>428</sup> Ex. SCG-240, p. KN-10.

<sup>429</sup> Ex. SCG-210, p. LB-SH-7. SoCalGas projects that the “Advanced Renewable Energy component” will not come online until January 2028. *Id.*

<sup>430</sup> Ex. SCG-13, p. EDG-20.

<sup>431</sup> Ex. TURN-SCGC-07, pp. 10-11.

<sup>432</sup> Ex. TURN-401, TURN-SCGC-034, Q.34.3.1.

<sup>433</sup> Ex. TURN-401, TURN-SCGC-034, Q.34.3.2.

SoCalGas’s and TURN-SCGC’s historical averages include capital additions for new business construction. Given the Commission’s elimination of line extension allowances for new business connections in D.22-09-026 (with certain potential exceptions), the future will not look like the past.<sup>434</sup> A much larger percentage of new business construction costs will be borne by the individual customers or third parties requesting the extension, rather than ratepayers, and customer-funded capital projects do not become plant in service.<sup>435</sup> Nonetheless, if the Commission uses a historical average to determine capital attrition adjustments, SoCalGas will receive additional capital-related revenue requirement as if D.22-09-026 had not been adopted. The following table shows the significant level of new business construction capital additions (and retirements) included in TURN-SCGC’s 7-year average (2015-2021) and SoCalGas’s 5-year average (2020-2024).<sup>436</sup>

<b>New Business Construction Capital (Nominal\$) - 2015-2021 Recorded, 2022-2024 Forecast</b>					
	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>
Additions	\$ 61,988,304	\$ 76,562,984	\$ 91,379,135	\$106,987,956	\$105,028,419
Retirements	\$ (61,223)	\$ (41,003)	\$ (44,417)	\$ (99,265)	\$ (199,312)
Net Additions	\$ 61,927,081	\$ 76,521,981	\$ 91,334,718	\$106,888,691	\$104,829,107
	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>
Additions	\$115,230,870	\$127,327,543	\$ 92,067,458	\$105,062,715	\$108,343,560
Retirements	\$ (375,017)	\$ (307,844)	N/A	N/A	N/A
Net Additions	\$114,855,853	\$127,019,699			

<sup>434</sup> See D.22-09-026, Ordering Paragraphs 1-2. The appropriate forecast for new business construction activity during this rate case cycle is in dispute, but parties do not dispute that D.22-09-026 will reduce the level of capital spending funded by ratepayers. See, e.g., Ex. TURN-14 (disputing SoCalGas’s new meter forecast); Ex. TURN-05, pp. 25-26 (referencing Ex. TURN-14 in disputing SoCalGas’s new business construction capital forecast); Ex. CEJA-01, pp. 1, 16-17; Ex. SCG-204, p. CCQ/SQW-31 (reducing the “non-collectible” capital new business forecast in light of D.22-09-026, meaning the costs that ratepayers will pay for this work).

<sup>435</sup> Ex. SCG-402/SDG&E-402, pp. 2-3 (pending admission into the record).

<sup>436</sup> Ex. TURN-401, TURN-SCGC-034, Q.34.4.

The fact that new construction capital additions will in fact be much lower in the attrition years does not mean that the historical average will “overcompensate” SoCalGas. Rather, a historical average will inevitably capture capital spending that is higher in some areas and lower in others compared to the attrition years. Cherry-picking a few spending areas with particularly large planned capital projects for budget-based attrition undermines the balance embedded in the historical average.

In sum, SoCalGas has not demonstrated that basing capital attrition on a historical trend with exceptions is reasonable. The Commission should deny the utility’s request for capital exceptions.

**46. REVENUES AND RATES**

**47. AFFORDABILITY METRICS**

**48. OTHER ISSUES**

**49. CONCLUSION**

For the reasons set forth above, TURN and SCGC respectfully request that the Commission adopt the recommendations presented herein.

Respectfully submitted,

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