

Company: Southern California Gas Company (U 904 G)
Proceeding: 2028 General Rate Case
Application: A.26-06-____
Exhibit: SCG-06

PREPARED DIRECT TESTIMONY OF DEVIN K. ZORNIZER

GAS MAJOR PROJECTS

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



June 2026

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SUMMARY

GAS MAJOR PROJECTS (in 2025\$)			
O&M	2025 Adjusted-Recorded (\$000)	Estimated TY 2028 (\$000)	Change (\$000)
Non-Shared	189,044	209,898	20,854
Shared	2,232	2,487	255
TOTAL O&M	191,276	212,385	21,109

GAS MAJOR PROJECTS (in 2025\$)							
Capital	Esti 2025 Adjusted Recorded (000)	Est 2026 (000)	Est 2027 (000)	Est 2028 (000)	Est 2029 (000)	Est 2030 (000)	Est 2031 (000)
Total CAPITAL	351,237	313,736	382,046	468,425	413,044	416,048	414,595

Summary of Requests

- Southern California Gas Company (SoCalGas or the Company) requests that the California Public Utilities Commission (CPUC or Commission) adopt the Gas Major Projects Test Year 2028 (TY2028) forecast of \$212,385,000 for operations and maintenance (O&M) expenses, which is composed of \$209,898,000 for non-shared service activities and \$2,487,000 for shared services activities. SoCalGas further requests the Commission adopt the forecast for Gas Major Projects capital expenditures in 2026, 2027, and 2028 of \$313,736,000, \$382,046,000, and \$468,425,000, respectively.
- The Gas Major Projects witness area sponsors O&M and capital forecast costs for projects dedicated to the safe, prudent, and cost-effective delivery of complex gas infrastructure programs and projects in compliance with state and federal regulations while driving best practices in major project execution and delivering value to customers.

1. Pipeline Safety Enhancement Plan (PSEP)

- Authorize SoCalGas’s Test Year 2028 PSEP O&M forecast of \$47,188,000 and SoCalGas’s forecast for PSEP capital expenditures in 2026, 2027, and 2028 of \$35,262,000, \$83,968,000, and \$114,178,000, respectively, for pipeline projects scheduled to be completed within the 2028-2031 GRC cycle.
- Find reasonable the costs that form the basis of the requested revenue requirement¹: \$108 million and \$13 million respective capital expenditures and O&M amounts presented for review comprising the execution of 15 PSEP Phase 1A and Phase 1B pipeline projects and one valve enhancement project completed from 2020-2025.

2. Gas Safety Enhancement Programs (GSEP) Execution

- Authorize SoCalGas’s forecast for GSEP Execution capital expenditures in 2026, 2027, and 2028 of \$100,907,000, \$126,849,000, \$134,671,000, respectively, for pipeline and valve projects scheduled to be completed within the 2028-2031 GRC cycle.

3. Transmission Integrity Management Program (TIMP) Execution

- Authorize SoCalGas’s Test Year 2028 TIMP, Non-Shared O&M forecast of \$139,476,000, Shared O&M forecast of 1,538,000, and SoCalGas’s forecast for TIMP capital expenditures in 2026, 2027, and 2028 of \$136,333,000, \$136,284,000, and \$136,248,000, respectively, for TIMP project execution work occurring within the 2028-2031 GRC cycle.

4. High Pressure (HP) Distribution Execution

- Authorize SoCalGas’s Test Year 2028 HP Distribution, O&M forecast of \$15,231,000 and SoCalGas’s forecast for TIMP capital expenditures in 2026, 2027, and 2028 of \$0, \$0, and \$15,680,000, respectively, for HP

¹ SoCalGas seeks recovery of a revenue requirement associated with these expenditures of approximately \$21.8 million in rates, as of December 31, 2025 (*See* Ex. SCG-21). The final revenue requirement will be updated to reflect the actual balance as of December 31, 2027 upon issuance of a final decision.

Distribution project execution work occurring within the 2028-2031 GRC cycle.

5. Compressor Station Compliance and Safety Programs

- Authorize \$31,410,000 for incremental capital costs over the cost cap established by the Commission in D.24-12-074 that are necessary for completion of the Honor Rancho Compressor Modernization (HRCM) project.
- Authorize SoCalGas’s capital forecast of the Regional Clean Air Incentives Market (RECLAIM) project in 2026 of \$10,005,000 for trailing costs associated with work that occurred prior to the forecast period.
- Authorize SoCalGas’s capital forecast of the Blythe Compressor Modernization project in 2026 of \$2,966,000 for trailing costs associated with work that occurred prior to the forecast period.

6. Control Center Modernization Ongoing Programmatic Activities

- Authorize SoCalGas’s capital forecast for the execution of the Control Center Modernization (CCM) Ongoing Programmatic Activities in 2026, 2027, and 2028 of \$18,611,000, \$25,299,000, and \$27,594,000, respectively, for work occurring within the 2028-2031 GRC cycle.

7. Gas Major Projects – Program Management Office

- Authorize SoCalGas’s Test Year 2028 Gas Major Projects – Program Management Office O&M forecast of \$3,502,000.

8. SB 1371 Blowdown Reduction Activities

- Authorize SoCalGas’s Test Year 2028 Blowdown Reduction Activities, Non-Shared O&M forecast of \$4,501,000, Shared O&M forecast of \$311,000 and SoCalGas’s forecast for Blowdown Reduction capital expenditures in 2026, 2027, and 2028 of \$9,652,000, \$9,646,000, and \$9,944,000, respectively, for Blowdown Reduction work occurring within the 2028-2031 GRC cycle

**PREPARED DIRECT TESTIMONY OF DEVIN K. ZORNIZER
GAS MAJOR PROJECTS**

I. INTRODUCTION

A. Summary of Gas Major Projects Compliance and Safety Related Costs and Activities

My name is Devin Zornizer, Vice President of Infrastructure Project Delivery for Southern California Gas Company (SoCalGas). As the executive with oversight of this organization, I am accountable for the planning and execution of complex gas infrastructure projects for both SoCalGas and San Diego Gas & Electric Company (SDG&E), which are managed through a centralized department. This work directly supports the safe, reliable, and resilient operation of SoCalGas’s natural gas transmission, distribution, and storage systems by overseeing project development, coordinating multidiscipline teams, and meeting regulatory, operational, and safety requirements.

The purpose of my testimony is to present and support SoCalGas’s forecasted costs and activities for Gas Major Projects for Test Year (TY) 2028. These activities are essential for maintaining system safety and reliability, complying with state and federal regulations, and enabling operational efficiency and affordability.

Certain forecasted activities and estimated costs were presented previously in SoCalGas and SDG&E's 2025 RAMP Application (A.) 25-05-010/013 (consolidated) filed on May 15, 2025. Those activities and any changes that have occurred since the RAMP filing are detailed below.

**TABLE DZ-1
Gas Major Projects
Test Year 2028 Summary of O&M Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY 2028 Estimated	Change
A. Pipeline Safety Enhancement Plan	31,578	47,188	15,610
B. TIMP Execution	150,882	139,476	(11,406)
C. HP Distribution Assessments Execution	0	15,231	15,231
D. Gas Major Projects – PMO	3,471	3,502	31
E. Blowdown Reduction	3,113	4,501	1,388
Total Non-Shared Services	189,044	209,898	20,854
SVP – Chief Infrastructure Officer	537	639	102

TIMP Execution SDG&E Support	1,619	1,537	-82
Blowdown Reduction – SDG&E	76	311	235
Total Shared Services	2,232	2,487	255
Total O&M	191,276	212,385	21,109

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TABLE DZ-2
Gas Major Projects
Test Year 2028 Summary of Capital Costs

(In 2025 \$) (000s)							
Categories of Management	2025 Adjusted-Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
A. Pipeline Safety Enhancement Plan	28,443	35,262	83,968	114,178	103,609	103,834	102,036
B. Gas Safety Enhancement Programs Execution	78,688	100,907	126,849	134,671	122,566	125,369	125,737
C. TIMP Execution	153,306	136,333	136,284	136,248	136,249	136,238	136,261
D. HP Distribution Assessments Execution	0	0	0	15,680	15,681	15,679	15,682
E. Compressor Station Compliance and Safety Programs	58,122	12,971	0	31,410	0	0	0
F. Control Center Modernization Ongoing Programmatic Activities	28,497	18,611	25,299	27,594	27,595	27,585	27,534
G. Blowdown Reduction	4,181	9,652	9,646	8,644	7,344	7,343	7,345
Total	351,237	313,736	382,046	468,425	413,044	416,048	414,595

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TABLE DZ-3
Pipeline Safety Enhancement Plan (PSEP)
Summary of Reasonableness Review Project Costs

(\$000s)	Capital	O&M
PSEP Reasonableness Review Projects	108,445	13,452

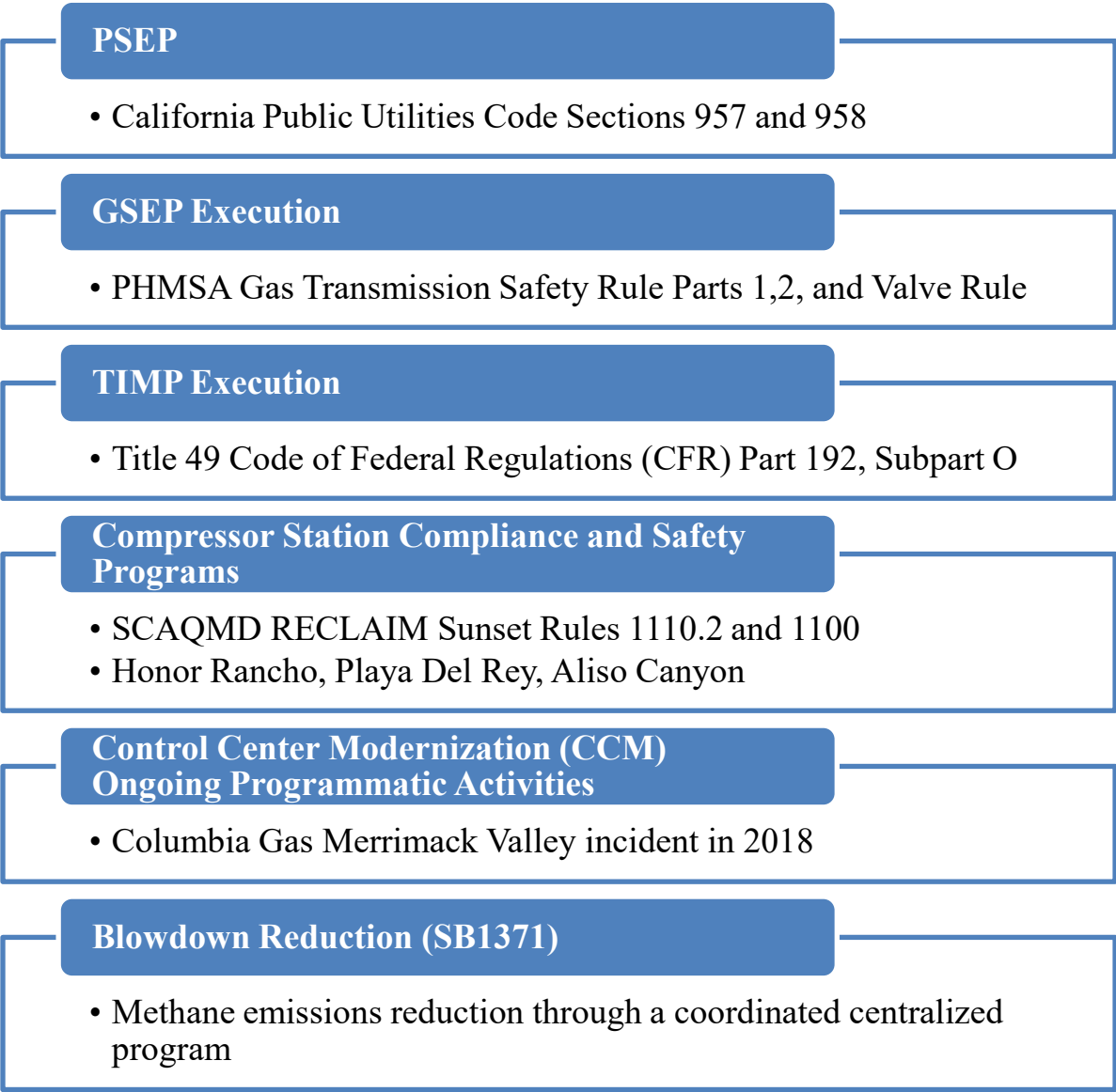
1 **B. Gas Major Projects Executes Predominantly Compliance and Safety Related**
2 **Programs**

3 Gas Major Projects is responsible for the prudent execution of complex gas infrastructure
4 programs and projects, with a primary focus on safety and compliance-driven work aligned with
5 applicable state and federal regulations. These efforts include pipeline safety enhancements and
6 integrity management activities that support system reliability and public safety while satisfying
7 regulatory obligations. Sponsored costs and activities under Gas Major Projects include the Pipeline
8 Safety Enhancement Plan (PSEP), Gas Safety Enhancement Programs (GSEP) Execution, Transmission
9 Integrity Management Program (TIMP) Execution, Compressor Station Compliance and Safety
10 Programs, and Control Center Modernization Ongoing Programmatic Activities. Figure DZ-1 identifies
11 the applicable state and federal regulations and safety programs associated with the programs under Gas
12 Major Projects and the corresponding sponsored costs. The compliance-driven requirements for each
13 program are further discussed below.

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Figure DZ-1
Gas Major Projects
State & Federal Regulations and Safety Programs



1. PSEP

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline ruptured and caught fire in the city of San Bruno, California. In response, the Commission promulgated new regulations in Decision (D.) 11-06-017 (later codified in Cal. Pub. Util. Code §§ 957 and 958), finding that “natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety,” and ordering all California natural gas transmission pipeline operators “to prepare and file a comprehensive Implementation Plan to replace or pressure test all natural gas transmission

1 pipeline in California that has not been tested or for which reliable records are not available.”^{2, 3} The
2 Commission required that the plans provide for testing or replacing all such pipelines “as soon as
3 practicable.” On August 26, 2011, SoCalGas and SDG&E filed their proposed PSEP.

4 The primary objectives of SoCalGas’s PSEP are to: (1) enhance public safety; (2) comply with
5 Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of
6 safety investments. As directed by the Commission, SoCalGas and SDG&E PSEP includes a risk-based
7 prioritization methodology that prioritizes pipelines located in more densely populated areas over those
8 in less populated areas. To implement this approach, PSEP is organized into three distinct phases: Phase
9 1A, 1B, and 2A. The scope of each phase is described in greater detail below.

10 In June 2014, the Commission issued D.14-06-007, approving SoCalGas and SDG&E’s
11 proposed PSEP and “adopt[ed] the concepts embodied in the Decision Tree,” “adopt[ed] the intended
12 scope of work as summarized by the Decision Tree,” and “adopt[ed] the Phase 1 analytical approach for
13 Safety Enhancement [...] as embodied in the Decision Tree [...] and related descriptive testimony.”⁴ In
14 approving the plan, the Commission acknowledged the broad scope of SoCalGas and SDG&E’s PSEP.
15 Subsequently, in A.15-06-013, the assigned Administrative Law Judge directed the parties to meet and
16 confer on a procedural plan to transition PSEP work into the GRC and to address PSEP costs anticipated
17 prior to the next GRC test year. In resolving the application, D.16-08-003 stipulated that all remaining
18 Phase 1A projects, as well as forecasted projects not included in the application, be addressed in the Test
19 Year 2019 GRC and subsequent GRCs.⁵

20 PSEP has made significant progress through its multi-phase implementation framework, with
21 work advancing across Phase 1A, Phase 1B, and Phase 2A projects. As the program has progressed,
22 execution has focused on addressing the highest-priority safety needs (particularly pipelines in higher
23 populated areas), while maintaining operational reliability, and coordinating construction and outage

² D.11-06-017 at 18.

³ Transmission pipelines as defined by the Department of Transportation (DOT) as those with a Maximum Allowable Operating Pressure (MAOP) of 20% or more of Specified Minimum Yield Strength (SMYS).

⁴ D.14-06-007 at 2, 22, 59 (Ordering Paragraph (OP) 1).

⁵ D.16-08-003 at 16 (OP 5).

1 windows to minimize impacts to communities and customers. The following table summarizes the
 2 current status of each phase within the overall PSEP portfolio.

3 **TABLE DZ-4**
 4 **PSEP Scope and Progress**

Pipeline Remediation, YE 2025	Test or Replace Miles		
	Total Miles	Completed Miles	
Phase 1A Pipelines	211	207	98%
Phase 1B Pipelines	187	99	53%
Phase 2A Pipelines	665	310	47%
Total	1,063	616	58%
Valve Automation, YE 2025	Total Valves	Completed Valves	
Base Valves	283	280	99%
Non-Base Valves	147	147	100%
Total	430	427	99%

5 The 2024 GRC Decision (D.24-12-074) requires SoCalGas to demonstrate compliance of its
 6 PSEP hydrotest implementation with Pub. Util. Code § 958 and applicable federal regulations, and to
 7 report the completion status and projected completion dates of forecasted hydrotest and capital pipeline
 8 replacement projects.⁶ This testimony addresses those requirements in Appendix C.

9 **2. GSEP Execution**

10 Following pipeline incidents in San Bruno, California and Marshall, Michigan, Congress enacted
 11 the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act),
 12 which established several mandates to improve pipeline safety. In response, the Pipeline and Hazardous
 13 Materials Safety Administration (PHMSA) issued an Advanced Notice of Proposed Rulemaking
 14 (ANPRM) in 2011 titled “Safety of Gas Transmission and Gathering Pipelines.” Given the breadth and
 15 complexity of issues raised, PHMSA announced in March 2018 that they would split the proposed
 16 regulations into three categories: Part 1, Part 2, and Part 3.

⁶ D.24-12-074 at 228.

1 Section 4 of the 2011 Pipeline Safety Act directed PHMSA to issue regulations, as appropriate,
2 requiring the installation of automatic or remote-controlled shut-off valves (collectively, Rupture
3 Mitigation Valves [RMV]), or equivalent technology, on newly constructed, or replaced natural gas or
4 hazardous liquid pipeline facilities. Beginning in February 2020, PHMSA initiated the Valve
5 Installation and Minimum Rupture Detection Standards rulemaking. The final rule was published in the
6 Federal Register on April 8, 2022, with an effective date of October 5, 2022, and certain provisions
7 became effective on April 10, 2023.

8 Published as the first of three parts of the Gas Transmission and Gathering Rulemaking, the
9 GTSR Part 1 amended sections of Title 49 CFR Parts 191 and 192. On October 1, 2019, PHMSA issued
10 the Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of
11 Assessment Requirements, and Other Related Amendments final rule, GTSR Part 1.⁷ The GTSR Part 1
12 imposes significant new safety and integrity requirements to gas transmission pipelines under PHMSA’s
13 jurisdiction. These changes became effective on July 1, 2020, with certain compliance obligations
14 commencing July 1, 2021 (*See* Section V.B.1.a). PHMSA finalized the Valve Installation and Minimum
15 Rupture Detection Standards rule on March 31, 2022, with final regulatory language published in the
16 Federal Register on April 8, 2022.

17 To meet these requirements and compliance deadlines, SoCalGas has implemented actions
18 including – but not limited to – the following:

- 19 • Implementing procedures to reconfirm MAOP in accordance with 49 CFR § 192.624
20 where Maximum Allowable Operating Pressure (MAOP) reconfirmation is required for
21 pipeline segments outside the scope of the authorized PSEP phases;
- 22 • Conducting assessments on segments outside of HCAs as required in 49 CFR § 192.710,
23 which – consistent with the Transmission Integrity Management Program (TIMP)
24 requirements, are managed under the TIMP framework;
- 25 • Implementing procedures under 49 CFR § 192.607 to opportunistically verify – through
26 nondestructive or destructive testing, examinations, and assessments – the material

⁷ Pipeline Safety: Safety of Hazardous Liquid Pipelines, 84 Fed. Reg. 190,52260 (October 1, 2019), *available*
at: <https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20458.pdf>.

properties and attributes of transmission pipelines and associated components that lack “traceable, verifiable, and complete” records, which are also managed under the TIMP.

TABLE DZ-5
Gas Transmission and Gathering Rulemaking (GTSR)
Scope and Progress

Pipeline Remediation, YE 2025	Test or Replace Miles	
	Total	Completed
GTSR Part 1	332	76 23%

3. TIMP Execution

SoCalGas’s TIMP Execution function serves as the operational implementation core of the TIMP. It is responsible for conducting ongoing in-line inspections and integrity assessments, and for remediating pipeline conditions in accordance with the requirements set forth in 49 CFR § 192, Subpart O – Gas Transmission Pipeline Integrity Management. Although Subpart O originally focused on baseline assessments for transmission pipelines located in HCAs, PHMSA expanded these requirements through 49 CFR § 192.710 to include assessments of transmission pipelines operated in moderate consequence areas (MCAs) and Class 3 and Class 4 locations. Additionally, to further enhance system safety and reliability, SoCalGas evaluates and assesses non-HCA pipeline segments that are contiguous to or in proximity to HCA pipelines on a case-by-case basis.

4. Compressor Station Compliance and Safety Programs

The compressor station compliance and safety programs comprise a multi-year portfolio of projects initiated to meet Air Quality Management District (AQMD) mandates and to enhance the safety and reliability of the SoCalGas System. Key compliance-driven initiatives include the Honor Rancho Compressor Modernization (HRCM) and the Playa Del Rey and Aliso Canyon Regional Clean Air Initiatives Market Projects (PDR/AC RECLAIM Projects). These efforts were undertaken to comply with the South Coast Air Quality Management District’s (SCAQMD) sunset of its Regional Clean Air Initiatives Market (RECLAIM) program.⁸ SCAQMD initiated the RECLAIM sunset program to

⁸ Under RECLAIM program, rather than regulating each individual piece of equipment that emits air pollution, the SCAQMD regulated the total pollution at subject facilities by setting targets for annual facility-wide reductions of NOx emissions. Each facility participating in RECLAIM received RECLAIM trading credits and businesses that beat their reduction targets could trade their credits on the open market.

1 transition equipment at RECLAIM facilities to command-and-control regulations based on Best Available
2 Retrofit Control Technology (BARCT) assessments. The projects within this portfolio, described in
3 Section VI of this testimony, are designed to meet regulatory requirements under SCAQMD Rule
4 1110.2⁹ (“Emissions from Gaseous and Liquid Fueled Engines”) and Rule 1100¹⁰ (“Implementation
5 Schedule for Nox Facilities”). Collectively, these projects will reduce NOx emissions and support ozone
6 attainment goals established by the California Air Resources Board (CARB) and the United States
7 Environmental Protection Agency (EPA).

8 This program has also completed the safety and reliability driven compressor modernization at
9 the Blythe Compressor Station. This work replaced aging equipment that dated back to the 1940s. As
10 the primary compressor station responsible for moving natural gas supplies from the Kinder Morgan
11 interstate pipeline into the SoCalGas Southern System, Blythe compressor station plays a critical role in
12 maintaining reliable service across several counties. With all new assets now in service, these upgrades
13 strengthen operational safety and system reliability, and no additional capital expenditures for Blythe
14 compressor station are planned for this GRC cycle.¹¹

15 **5. Control Center Modernization (CCM) Ongoing Programmatic Activities**

16 The Distribution Regulator Stations (DRS) and High-Consequence Area (HCA) methane sensors
17 constitute the remaining components of the Control Center Modernization (CCM) Ongoing
18 Programmatic Activities.¹² By deploying real-time monitoring and control capabilities at select
19 distribution regulator stations, and improving leak detection along the transmission system through the
20 installation of HCA methane sensors, these activities strengthen system safety by providing Gas Control
21 with a more comprehensive, real-time view of the gas network and enabling faster detection of and
22 response to abnormal operating conditions.

23 **Organization of Testimony**

24 My testimony is organized as follows:

⁹ SCAQMD Rule 1110.2 Emissions from Gaseous- and Liquid-Fueled Engines (Amended November 1, 2019).

¹⁰ SCAQMD Rule 1100 Implementation Schedule for NOx Facilities (Adopted December 7, 2018, and Amended January 10, 2020).

¹¹ Minor post-completion costs (~\$2.7M) in 2026.

¹² Authorized in D.19-09-051 and D.24-12-074

- 1 • **Introduction:** Provides an overview of this testimony and describes the
2 compliance-driven requirements that underpin the Gas Major Projects programs
3 supporting safety, reliability, sustainability, and affordability.
- 4 • **Affordability & Efficiency:** Discusses how Gas Major Projects applies risk-
5 based prioritization, integrated planning, and innovation to deliver energy
6 infrastructure projects and programs that support the execution of a diverse range
7 of construction projects efficiently and affordably.
- 8 • **Non-Shared O&M Costs:** Details forecasted costs and activities for projects and
9 programs such as PSEP, TIMP Execution, HP Distribution Assessment
10 Execution, Gas Major Projects – Program Management Office (PMO), and
11 Blowdown Reduction.
- 12 • **Shared O&M Costs:** Describes the role of the Senior Vice President and Chief
13 Infrastructure Officer overseeing the operation, maintenance, design and
14 execution of all Gas Major Projects executed on the SoCalGas and SDG&E high
15 pressure pipeline operating systems. Also provides detailed information
16 regarding blowdown reduction activities to support SDG&E programs.
- 17 • **Capital Costs:** Outlines planned capital projects for PSEP, GSEP Execution,
18 TIMP Execution, HP Distribution Execution Compressor Station Compliance
19 Programs, Control Center Modernization Ongoing Programmatic Activities, and
20 Blowdown Reduction, explaining how these investments support long-term
21 system safety, reliability and regulatory compliance.
- 22 • **Risk Assessment Mitigation Phase (RAMP) Integration:** Identifies activities
23 that were included in SoCalGas’s RAMP filing and explains how risk mitigation
24 strategies are incorporated into this GRC request.
- 25 • **Reasonableness Review:** Provides justification for the reasonableness of the
26 requested costs associated with PSEP Phase 1A projects in alignment with the
27 Commission directive to execute PSEP projects as soon as practicable.

1 **C. Support To and From Other Witnesses**

2 My testimony references the testimony and workpapers of several other witnesses, either in
3 support of their testimony or as support for mine.

- 4 • Exhibit (Ex.) SCG-02B/SDG&E-02B – RDF Integration
- 5 • Ex. SCG-05 – Gas Transmission & Storage
- 6 • Ex. SCG-03 – Gas Engineering & System Integrity
- 7 • Ex. SCG-13 – Environmental Services
- 8 • Ex. SCG-21 – Regulatory Accounts
- 9 • Ex. SCG-14 – Information Technology
- 10 • Ex. SCG-16/SDGE-20 - Compensation & Benefits
- 11 • Ex. SCG-22/SDGE-27 - Shared Services
- 12 • Ex. SCG-27 – Summary of Earnings

13 **II. AFFORDABILITY & EFFICIENCY**

14 SoCalGas recognizes the Commission’s increasing emphasis on affordability, as reflected
15 throughout the 2024 GRC Decision (D.24-12-074). The forecasts presented in this testimony are
16 consistent with the Commission’s affordability objectives and reinforce SoCalGas’s ongoing
17 commitment to providing safe, reliable, and affordable service to customers. Gas Major Projects is
18 responsible for delivering the Company’s complex pipeline and facility infrastructure projects, applying
19 deep technical expertise and cross-disciplinary coordination to execute on compliance and safety driven
20 programs safely and prudently while meeting regulatory and safety requirements. Advancing pipeline
21 safety and system integrity through innovative, cost-effective engineering and design practices remains a
22 core priority.

23 Gas Major Projects (GMP) is focused on disciplined planning and coordination of large
24 infrastructure programs to realize operational efficiencies and cost savings for customers. Specifically,
25 GMP was established to centralize project and portfolio management expertise and apply a scalable,
26 consistent framework grounded in industry best practices for infrastructure projects across the portfolio.
27 Through a collaborative and agile culture anchored in safety, accountability, and integrity, GMP
28 advances system safety, reliability, and decarbonization objectives through innovative infrastructure

1 delivery. The following discusses key processes implemented by GMP to maximize efficiencies and
 2 customer value. Additionally, Table DZ-6 below briefly describes specific projects that exemplified
 3 these tenets of GMP’s execution approach, providing cost-saving benefits to ratepayers and, in many
 4 cases, bolstering the safety and reliability of SoCalGas’s gas system.

5 **Table DZ-6**
 6 **Selected Projects That Achieve Affordability and Efficiency Objectives**

PROJECT	PROCESS	DESCRIPTION
TIMP Supply Line 31-09-C Phase 1-2025 ROBO ILI Assessment	Scope Validation	During the planning phase ¹³ of the project, Pipeline Integrity Execution (PIEx) determined that a portion of the 31-09-C project could be descope due to a recent PSEP hydrotest on the same section of pipe. The hydrotest stabilized the manufacturing threat on the pipeline, eliminating the need to perform a TIMP assessment. During the PSEP hydrotest a small retrofit occurred that removed a pipeline feature that was not piggable, allowing PIEx to remove the direct examination of that location.
PSEP Supply Line 44-675-Lateral P1A Replacement	Program and Project Coordination	Informed by the Target Price Estimate (TPE) process, the contractor's estimate was more than three times the Class 3 estimate. In addition, the construction schedule would have extended into the heating season, necessitating the use of Compressed Natural Gas (CNG)/Liquified Natural Gas (LNG) to maintain customer service. The project team coordinated with the local Distribution Operations district, which offered its high-pressure construction crews to self-perform this work. This approach delivered time and cost savings compared to the original contractor proposal.
PSEP Line 406-Section 13 Hydrotest	Program and Project Coordination	This project incorporated an additional 0.5 miles of GTSR pipeline adjacent to the Section 13 work by installing a stopple and adding one additional test break. This approach eliminated the need to return to the same location to perform a separate hydrotest, resulting in cost savings. In addition, the accelerated remediation of the GTSR scope avoided the need for future outages and supported

¹³ Stage 1 of the Stage Gate Review process.

PROJECT	PROCESS	DESCRIPTION
		earlier progress towards meeting the PHMSA 50% compliance requirement (As described in Section V.B.1.d. below).
GTSR Supply Line 32-55 Hydrotest	Collaboration with Relevant Stakeholders	The GTSR Strategy team submitted a Request for Engineering Review and coordinated with Region Engineering and Operations to confirm that the segment of concern had no active taps and no anticipated future use, supporting its abandonment. This approach eliminated ongoing maintenance expenses, future TIMP assessment costs, planned transmission valve replacements, and the hydrostatic testing costs associated with MAOP reconfirmation under the GTSR program.

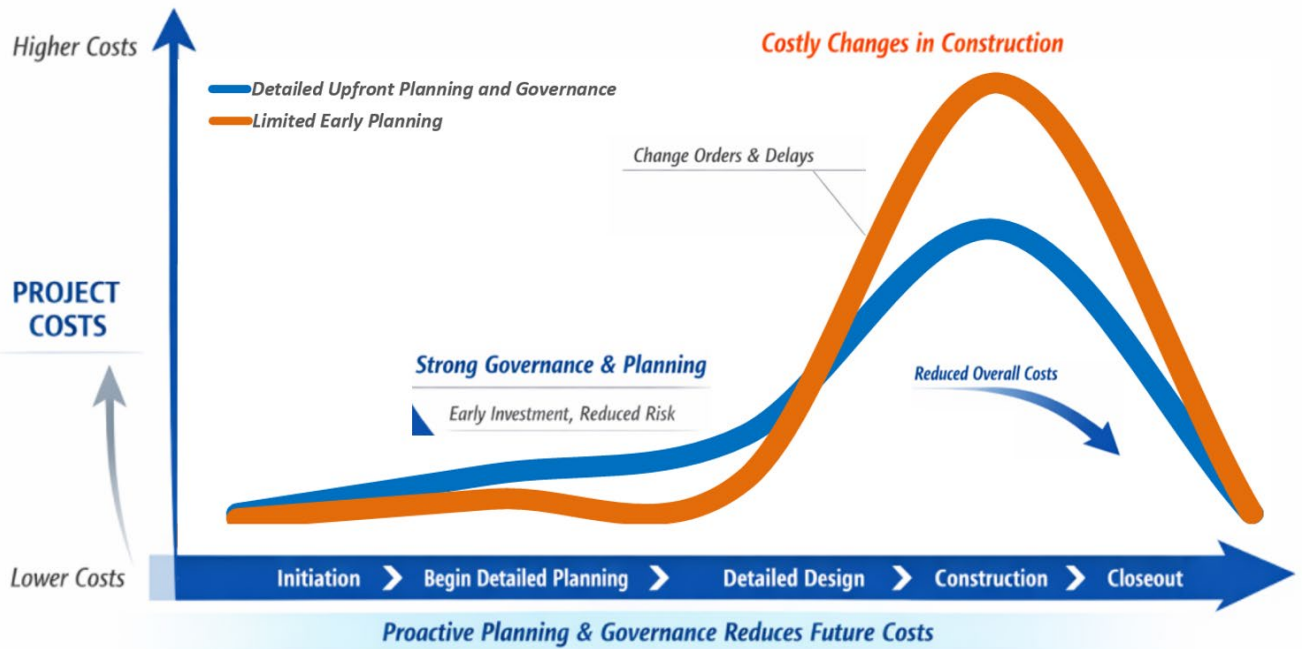
1 **A. Centralized Organizational Governance**

2 To achieve Gas Major Projects’ objectives, the programs are governed through the Gas Major
3 Projects – Program Management Office (PMO), which brings together personnel with specialized
4 technical, project management, and controls expertise. The PMO provides functional guidance on
5 project design and execution to cost effectively meet regulatory requirements, apply industry best
6 practices, and continuously incorporate process improvements. The PMO develops standards and
7 procedures to promote consistency across projects and performs critical functions including
8 organizational-level oversight, policy development, budgeting and portfolio management, and
9 performance reporting to keep management informed of construction progress.

10 The PMO provides structured governance and oversight essential to planning and executing gas
11 infrastructure projects with consistency, predictability, and efficiency. By establishing early-stage
12 decision-making related to scope, design, constructability, and risk mitigation - when decisions have the
13 greatest influence on long term cost outcomes, the PMO reduces costly redesigns and change events
14 during construction. This disciplined approach supports cost control and affordability for customers.
15 Together, GMP’s governance structure, integrated planning approach, and PMO foundation create a
16 disciplined delivery model that advances reliable infrastructure investment while aligning with the
17 Commission’s affordability objectives. Figure DZ-2 illustrates how effective upfront planning and
18 effective governance influence overall project cost outcomes.

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Figure DZ-2
Proactive Planning and Governance Impacts



3 **B. Project Delivery Model**

4 GMP operates according to a Project Delivery Model (PDM), originally developed by SoCalGas
5 and SDG&E for the PSEP program. The PDM provides an integrated framework for planning,
6 managing, and executing a diverse portfolio of complex infrastructure projects. This model centralizes
7 core functions, including scope development, engineering, environmental planning, project controls,
8 procurement, and construction management into a coordinated structure that enhances transparency,
9 consistency, and accountability across all phases of a project. By unifying these key components, the
10 model enables efficient decision making, improves cost and schedule performance, and supports that
11 projects are delivered safely, reliably, and in alignment with regulatory and operational requirements.
12 This approach is particularly effective for an organization responsible for diverse and complex
13 infrastructure portfolios as it supports standardized best practices while allowing flexibility to address
14 project specific needs.

15 **a. The Stage Gate Review Process Promotes Efficient Project Oversight**
16 **and Execution**

17 The PDM is supported by a Stage Gate Review Process that sequences and schedules project
18 workflow deliverables. Through this process, the PMO monitors adherence to standards and procedures,
19 confirms proper authorization and documentation, and promotes consistent project execution. The Stage

Gate Review Process detailed in the table below consists of five stages, each with defined objectives and leadership review at the end of the stage to confirm readiness to proceed.¹⁴

TABLE DZ-7
Stage Gate Descriptions and Objectives

STAGE	DESCRIPTION	OBJECTIVES
Stage 1 Initiation and Business Case	Project Sponsor: <ul style="list-style-type: none"> • develops initial business case and the preliminary cost and schedule based on established requirements, supported by the Project Team. 	<ol style="list-style-type: none"> 1. Initiate Project 2. Complete Feasibility Study 3. Develop Preliminary Cost and Schedule 4. Identify High Level Risk Assessment 5. Refine Scope 6. Develop Revenue Recovery Strategy 7. Conduct Stage Gate
Stage 2 Preliminary Design & Option Selection	Project Team: <ul style="list-style-type: none"> • analyzes proposed options and makes selection based on scope, cost, schedule and risk; • initiates design, long lead procurement and permitting activities are initiated; • baselines scope, cost, and schedule. 	<ol style="list-style-type: none"> 1. Project Site Assessment 2. Option Analysis and Selection 3. Project Execution Plan (PEP) 4. Preliminary Design 5. Baseline Cost and Schedule 6. Long Lead Procurement 7. Conduct Stage Gate
Stage 3 Detailed Design & Procurement	Project Team: <ul style="list-style-type: none"> • obtains funding approval, finalizes design of selected option, secures necessary permits, and completes procurement activities; • submits RFP and awards construction contract; • completes safety requirements. 	<ol style="list-style-type: none"> 1. Obtain Budget Authorization 2. Detailed Design 3. Land Rights and Permit Acquisition 4. Update Risk Assessment 5. Final Design and Material Procurement 6. Update PEP 7. Construction Request for Proposal (RFP) 8. Complete Safety Requirements 9. Re-baseline Cost and Schedule 10. Conduct Stage Gate
Stage 4 Construction	Project Team: <ul style="list-style-type: none"> • manages construction execution, monitoring scope, cost and schedule; 	<ol style="list-style-type: none"> 1. Implement Safety Requirements 2. Mobilize Construction Contractor 3. Monitor Scope, Cost, Schedule and Risk 4. Commissioning and System Start-Up

¹⁴ Evaluations are gate reviews or completion check lists. Certain stages are condensed or combined for valve and small pipeline projects.

1 structure enables consistent oversight, shared planning, and stronger collaboration, resulting in
2 operational and cost efficiencies. When projects occur in the same geographic area, the programs
3 coordinate execution to reduce redundant mobilization, minimize community and customer impacts, and
4 efficiently share field resources. This integrated approach allows PSEP, GTSR, and TIMP scope to be
5 executed under a single project, with clear accounting delineations for cost allocation, reducing outages,
6 and supporting timely, cost-effective integrity remediation. For example, by aligning schedules, scopes,
7 and resource planning across these programs, SoCalGas has the ability to coordinate a hydrostatic test
8 project completion to address integrity needs identified through the TIMP process. This coordination
9 allows TIMP to remediate active threats and other integrity concerns, during the same operational
10 windows used for testing and validation activities. Integrating these efforts reduces the frequency of
11 system outages, minimizes construction impacts on customers and communities, and supports the timely
12 and cost-effective completion of identified integrity actions in support of system safety and risk
13 management.

14 Another advantage to coordination of TIMP activities and hydrotest work are the efficiency
15 benefits enhanced by the likelihood of successful hydrotests for GTSR or PSEP projects. When TIMP
16 assessments identify anomalies or other features that require replacement within the extent of a planned
17 hydrotest, the TIMP scope is completed first, so that the hydrotest can be conducted after known flaws
18 that may have otherwise caused a hydrotest failure (often in the form of leaks or ruptures) have been
19 addressed. In doing so, SoCalGas avoids costs associated with locating and remediating the source of
20 the test failure, and additional costs that are associated with resultant delays in the project schedule.

21 Finally, GMP coordinates across programs through the use of regular enterprise-wide
22 transmission strategy calls involving over 100 participants across functions such as Gas Control, System
23 Planning, Field Operations, and Project Management. These forums promote alignment with outage
24 planning, improve situational awareness, and support informed decision-making. Issues identified often
25 lead to targeted discussions that further enhance collaboration, transparency, and disciplined
26 implementation.

27 **D. Scope Validation**

28 PSEP and GTSR projects, which fall within the scope of state and/or federally-mandated pipeline
29 compliance programs, undergo a rigorous scope validation process prior to execution. Project teams
30 evaluate records and internal data to validate project scope, mileage, and regulatory applicability (*e.g.*,
31 PHMSA and CPUC (or other mandated) regulations). This process considers alternatives to testing or

1 replacing and also may result in scope refinements or reductions, through record reconciliation, MAOP
2 changes, or line abandonment,¹⁵ producing verifiable cost avoidance and direct ratepayer benefits.

3 **E. Prudent Procurement Practices**

4 GMP achieves additional cost savings for the benefit of customers through prudent procurement
5 practices that leverage competitive bidding, market based pricing, and existing agreements. SoCalGas
6 strives to minimize project execution costs through cost-avoidance efforts that focus on efficiencies
7 identified in the engineering and design process through efficient procurement practices, coordination
8 and scheduling effectiveness, and construction execution. The majority of agreements entered into for
9 materials and services have been either competitively bid or set at market-based rates stemming from
10 previous competitive solicitations. In other words, in addition to individual bidding events, as
11 appropriate, SoCalGas executes agreements by leveraging terms and conditions and rates from existing
12 agreements. When acquiring material, material bids are designed to obtain multiple quotes for the best
13 pricing options, promote work with select firms for efficiency of process, and encourage the
14 development of local resources and sourcing.

15 An example of prudent procurement practices that has led to cost savings and efficiencies for
16 GMP is the implementation of the Performance Partnership Program. This program was originally
17 introduced under the PSEP program and allows Construction contractors to enter into competitive
18 bidding for batches of projects as opposed to one at a time. A Performance Partner is a qualified
19 alliance contractor that is willing to partner with SoCalGas by using their unique experience and
20 expertise to seek more efficient ways of executing projects and share in the cost savings. Under the
21 Performance Partnership Program, each project constructed by a Performance Partner is subject to a
22 target price risk/reward mechanism. This mechanism is based on establishing a target price agreed to by
23 SoCalGas and the Performance Partner. The target price provides the Performance Partner with a cost
24 incentive to efficiently perform the project because it stands to share both reduced and excess costs. The
25 Performance Partner is not, however, entitled to any profits when costs exceed 20% of the target price.

¹⁵ Lines are abandoned after a thorough review of the ability of adjoining lines to meet current and future load requirements and to verify there will be no customer impact or system constraints.

1 **F. Test Versus-Replace Review Supports Prudent Selection of an Execution Option**

2 During Stage 1 of the State Gate Review Process, SoCalGas applies the Decision Tree and
3 concepts¹⁶ to review whether a segment should be tested or replaced.¹⁷ In undertaking this review,
4 SoCalGas applies engineering judgment to determine a final execution scope to provide both short- and
5 long-term customer benefits.

6 For pipeline segments longer than 1,000 feet, SoCalGas completes a preliminary review of PSEP
7 and/or GTSR projects to evaluate the feasibility of temporary customer service impacts if the pipeline
8 segment is taken out of service to complete pressure testing. Where mitigation of customer impacts is
9 feasible, SoCalGas compares the costs, constructability, risks, and benefits of pressure testing and
10 replacement to determine the most prudent approach.

11 Project teams assess opportunities to include potential incidental or accelerated mileage to avoid
12 or reduce future costs and operational impacts. Incidental mileage may be incorporated to streamline
13 testing, reduce mobilization, avoid sensitive areas, or minimize customer disruption. For example,
14 including incidental mileage located between required test break locations allows the project team to
15 perform a single hydrotest rather than conducting multiple tests, reducing mobilization, permitting, and
16 construction costs. Test break locations may also be extended to move excavation locations out of
17 environmentally sensitive areas, heavily trafficked roadways, or other locations where excavations and
18 isolations would create significant operational, environmental, or community impacts. These practices
19 reduce overall project costs, minimize customer and community disruption, and avoid future outages by
20 addressing work in one coordinated effort. Accelerated mileage advances future work (*e.g.*, later phase
21 of PSEP under Decision Tree prioritization process) to capture cost and operational efficiencies. As
22 noted above, SoCalGas applies engineering judgment to weigh various factors to reduce overall costs,
23 reduce repeated customer impacts, and support coordinated system-wide risk mitigation while delivering
24 long-term customer benefits of a safe and reliable pipeline system.

25 **III. NON-SHARED O&M COSTS**

26 “Non-Shared Services” are activities performed by a utility solely for its own customers’ benefit.
27 Although Corporate Center provides certain services to SoCalGas and other subsidiaries, for purposes of

¹⁶ Approved in the Safety Enhancement Plan Decision, D.14-06-007.

¹⁷ Similarly, a detailed process is used to determine the scope of work of projects under the Valve Rule.

1 this general rate case, SoCalGas treats the costs for services received from Corporate Center as Non-
 2 Shared Services costs, consistent with the treatment of costs incurred from external vendors. Table DZ-8
 3 summarizes the total forecasted non-shared O&M costs for the listed cost categories.

4 **TABLE DZ-8**
 5 **Gas Major Projects**
 6 **Non-Shared O&M Summary of Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY 2028 Estimated	Change
PSEP	31,578	47,188	15,610
TIMP Execution	150,882	139,476	-11,406
HP Distribution	0	15,231	15,231
Gas Major Projects – PMO	3,471	3,502	31
Blowdown Reduction	3,113	4,501	1,388
Total Non-Shared Services	189,044	209,898	20,854

7 **A. Pipeline Safety Enhancement Plan (PSEP) (NSS 2MP000.000)**

8 **TABLE DZ-9**
 9 **Pipeline Safety Enhancement Plan**
 10 **Non-Shared O&M Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY2028 Estimated	Change
1. Pipeline Safety Enhancement Plan (PSEP)	31,578	47,188	15,610
Total	31,578	47,188	15,610

11 **1. Description of Costs and Underlying Activities**

12 The activities and costs associated with PSEP include labor and non-labor expenses necessary to
 13 execute compliance-driven hydrostatic testing (hydrotests). This work was initiated under CPUC
 14 Decision D.11-06-017 and was later codified in California Public Utilities Code 957 and 958, which
 15 requires utilities to pressure test or replace transmission pipelines that lack records meeting current
 16 standards. These measures establish the basis for validating pipeline safety and determining maximum
 17 allowable operating pressure (MAOP). The PSEP Phase 2A hydrotest projects focus on pipeline

1 segments located in Class 1 and Class 2, non-high consequence (*i.e.* less populated) areas that do not
2 have sufficient documentation of a hydrotest to at least 1.25x MAOP.

3 Detailed project-level information is provided in the supplemental workpapers (Ex. SCG-06-
4 WPS, Volume I) supplemented by a Summary of Standard Planning & Construction for Replacement,
5 Hydrotest, Valve, and Abandonment Projects. The supplemental workpapers identify the portfolio of
6 hydrotest projects that are candidates for completion during the 2028 GRC period. Major hydrostatic
7 testing work scope elements and related cost drivers, include, but are not limited to the following:

8 **2. Planning**

- 9 • Define test objectives and requirements.
- 10 • Perform surveys, base mapping, potholing, and subsurface utility
11 engineering.
- 12 • Develop engineering and design packages, confirm test locations and
13 isolation points.
- 14 • Determine system impact and verify isolation points.
- 15 • Prepare permits, environmental reviews and land access needs.
- 16 • Identify water source and disposal locations.
- 17 • Develop the bill of materials and the hydrotest equipment plan.

18 **3. Pre-construction Preparation**

- 19 • Secure agency permits, right of way, traffic control plans, and third-party
20 agreements.
- 21 • Finalize test locations and establish staging areas and water handling sites.
- 22 • Implement traffic control plans and coordinate with cities, counties,
23 Caltrans, railroads, and utilities.
- 24 • Maintain customer and community notifications to minimize impacts.
- 25 • Mobilize crews, equipment, and materials.

26 **4. Excavation and Test Setup**

- 27 • Excavate at test head locations and any isolation points.
- 28 • Install and inspect temporary test heads, manifolds, gauges, and recorders.
- 29 • Set up filling, pressurizing, depressurizing, and dewatering equipment.

1 **5. Pressure Test**

- 2 • Fill the pipeline with water while monitoring water quality and inspecting
3 for leaks.
- 4 • Increase pressure in stages, stabilize, and reach the target test pressure.
- 5 • Monitor pressure and temperature throughout the segment.
- 6 • Hold for the required duration and verify that results meet acceptance
7 criteria.

8 **6. Tie-ins and Commissioning**

- 9 • Depressurize, dewater, and dry the pipeline.
- 10 • Remove temporary test heads and fittings.
- 11 • Complete any required tie-ins and final welds to restore the permanent
12 configuration.
- 13 • Perform function checks of valves and instrumentation.
- 14 • Confirm records and set documentation to establish the maximum
15 allowable operating pressure are traceable, verifiable, and complete.

16 **7. Depressurization & Dewatering**

- 17 • Restore right of way, pavement, and surfaces.
- 18 • Demobilize and remove temporary water handling facilities.
- 19 • Produce as-builts and integrate hydrotest documentation into records.

20 **8. Description of RAMP Mitigations**

21 This cost category consists entirely of non-shared O&M costs associated with the C186 risk
22 control/mitigation identified in the 2025 RAMP Report (Chapter SCG-Risk-2 High Pressure Gas
23 System).¹⁸ All PSEP hydrotest activities identified above are compliance-driven risk mitigation
24 measures mandated by CPUC and implemented to address pipeline safety risks. Appendix B attached to
25 this testimony provides additional detail regarding the applicable mandates for each control.

¹⁸ A.25-05-004, SoCalGas 2025 RAMP Report (May 15, 2025), available at:
<https://www.socalgas.com/socalgas-2025-ramp-application>.

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TABLE DZ-10
Pipeline Safety Enhancement Plan (2MP000)
RAMP and GRC Risk Control/Mitigation Activities =

ID	Control/Mitigation Name	2025 RAMP 2028 In 2024 \$ (\$000s)	2028 GRC 2028 In 2025 \$ (\$000s)	Change (\$000s)
C186	PSEP Phase 2A	61,144	47,188	(13,956)

a. Description of Selection and Prioritization of RAMP Risk Mitigations

The PSEP began mitigating safety risks on SoCalGas’s natural gas system well before the Commission’s RAMP framework was established.¹⁹ PSEP is a comprehensive, risk-informed program to address transmission pipeline risk through hydrostatic testing, replacement, pressure reduction, and abandonment.

Using the PSEP decision tree (*see* Appendix D), pipeline segments are prioritized based on risk, with segments in more densely populated areas addressed first due to heightened consequence risk, followed by segments in less populated areas as risk drivers are mitigated. This risk-based prioritization continues to guide project selection, sequencing, and execution and is aligned with RAMP objectives. With approximately 98% of Phase 1A pipeline segments remediated (*see* Table DZ-4), PSEP has transitioned to primarily hydrotesting the PSEP Phase 2A pipelines.

PSEP Phase 2A focuses on critical pipelines in the Northern Transmission Zone, an area with elevated risk considerations and potentially heightened operational and customer service impacts in the event of a pipeline failure. These pipelines serve as essential connections between the transmission system and interstate supply sources and are vital to maintaining system capacity and reliability across SoCalGas’s service territory. Prioritizing these assets allows SoCalGas to reduce risk while managing costs responsibly. These hydrotests will advance the objective of confirming that legacy pipelines meet modern safety standards and can be safely operated at their intended pressures.

¹⁹ The first PSEP project was completed in 2013.

1 **9. Forecast Method**

2 The forecast method developed for this cost category is zero-based. Given the size, scope, and
3 complexity of PSEP projects, a project specific cost estimate was developed for each pipeline project,
4 based on preliminary engineering and project planning analyses.

5 SoCalGas requests authorization to execute these activities within a portfolio of pipeline projects
6 over this GRC cycle, aligning with the forecasting approach that was previously reviewed and approved
7 in the 2024 GRC decision²⁰ for the SoCalGas PSEP Program. Accordingly, the O&M forecasts
8 requested in this GRC application recognize that some large-diameter transmission line projects may be
9 delayed or advanced due to system capacity reliability needs driven by varying gas demand, which is
10 outside SoCalGas’s control. As a prudent operator, SoCalGas is committed to maintaining system
11 capacity to support reliability²¹ (a variable factor based on gas demand), where previously planned
12 projects that require shut-ins on these lines may be delayed for later execution, which may occur after
13 detailed design has been completed and a project is ready for the construction phase. These
14 circumstances limit SoCalGas’s ability to execute projects according to previously determined
15 schedules.

16 The request reflects an anticipated level of executable spend from a large portfolio of Phase 2A
17 hydrotest pipeline projects, aligning with the PSEP forecasting methodology that was approved in the
18 2024 General Rate Case. This portfolio-based approach enables SoCalGas to quickly respond to
19 schedule changes by advancing projects in place of those that are delayed. This supports SoCalGas’s
20 ability to timely execute PSEP “as soon as practicable” consistent with the Commission mandate and
21 over-arching objectives of PSEP: (1) enhance public safety; (2) comply with Commission directives;
22 (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.

²⁰ D.24-12-074.

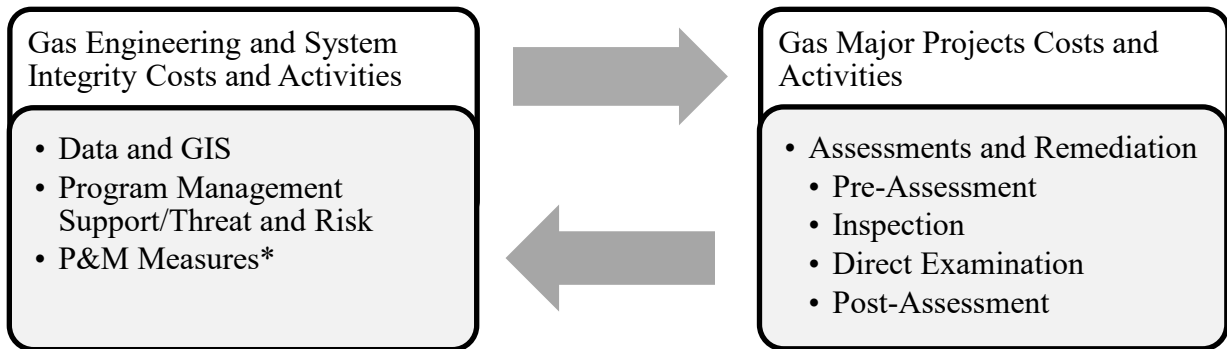
²¹ SoCalGas’s Summer 2026 Technical Assessment provides a forecasted outlook of system reliability during the coming summer season (April 1, 2026 through October 31, 2026), assesses the preparedness of the system for the following winter season, and analyzes the associated risks to energy reliability during these periods. The assessment is available at the following link: <https://www.socalgas.com/regulatory/technical-assessments>.

1 encompasses activities such as threat identification, risk analysis, pipeline assessments, and other actions
2 taken to address integrity concerns and reduce the risk of pipeline failure.

3 GMP, which includes engineers, project managers, technical advisors, project specialists, and
4 other employees with varying levels of responsibility primarily provides oversight of *execution* for
5 TIMP activities. SoCalGas currently organizes TIMP activities and associated costs into four
6 categories: 1) Assessments & Remediation, 2) Preventive & Mitigative (P&M) Measures, 3) Data and
7 GIS, and 4) Program Management Support/Threat & Risk. The forecasted TIMP labor and non-labor
8 costs presented in this testimony and the associated workpapers support the Assessments & Remediation
9 and corrosion-related P&M Measures activities that are necessary for regulatory compliance, system
10 safety, and system reliability. Forecasted TIMP labor and non-labor costs for the remaining categories
11 (e.g., Data and GIS) are presented in the GESI testimony (Ex. SCG-03).

12 SoCalGas executes its TIMP assessment projects primarily through Gas Major Projects to
13 leverage the centralized expertise of its construction and project management professionals. Due to the
14 organization's portfolio and role within the enterprise, its employees are well positioned to effectively
15 plan and execute infrastructure projects across the enterprise. The figures below delineate the forecasted
16 costs and activities across each witness area and provide additional detail regarding the scope of work
17 executed by GMP.

18 **Figure DZ-3**
19 **Delineation of TIMP Activities**



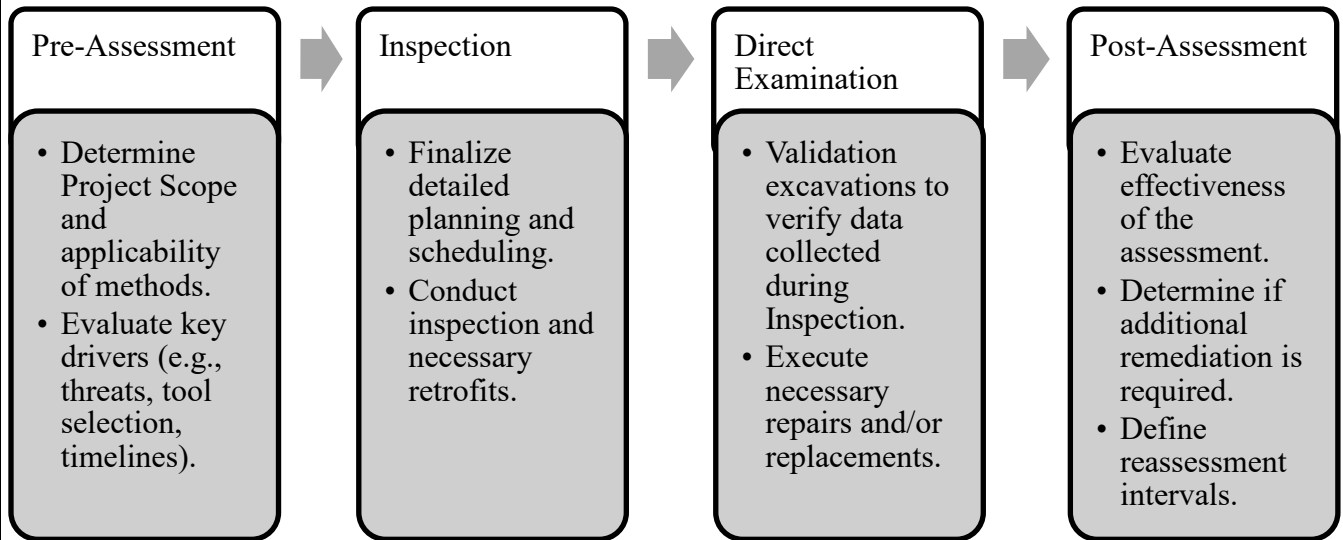
20 *Corrosion Projects identified within P&M Measures are included in Gas Major Projects testimony

1 **Figure DZ-4**

2 **Gas Major Projects Four-Step TIMP Execution Process**

3 The development and handoff of the annual TIMP Assessment Plan described in the GESI
4 testimony (Ex. SCG-03), reflects collaboration between employees within the Integrity Management
5 (IM) Department and Gas Major Projects. TIMP assessments are planned and executed by Gas Major
6 Projects using a four-step Assessment and Remediation process consisting of: (1) Pre-Assessment; (2)
7 Inspection; (3) Direct Examination; and (4) Post-Assessment.

- 8 1. **Pre-Assessment:** The first stage of the four-step Assessment and Remediation process is
9 Pre-Assessment. During this phase, the GMP Project Team reviews operational data,
10 historical records, and prior assessment results to define project scope and determine the
11 federally prescribed assessment method(s) applicable to each pipeline segment. Based on



12 identified threats, SoCalGas may be required to apply one or more assessment methods,
13 including in-line inspection (ILI), various forms of pressure testing, direct examination,
14 Guided Wave Ultrasonic Testing (GWUT), or direct assessments for corrosion and
15 cracking. Assessment methods are typically fixed for the duration of a project unless
16 new information emerges that requires a change in scope. Any such change must still be
17 completed within the applicable regulatory timelines. While selection of assessment
18 method(s) vary on a project-by-project basis, the assessment methods most commonly
19 employed by GMP are described below:

- 20 a. **ILI:** This method utilizes specialized tools, also referred to as “smart pigs”, that
21 travel inside the pipeline to detect pipeline flaws and defects. ILI tools are

1 available in a variety of sizes and technologies, but their use requires that a
2 pipeline be configured to accommodate tool passage. Because many pipeline
3 segments were constructed before ILI technology existed, the use of this
4 assessment method often requires pipeline modifications or retrofits to allow
5 passage of the tool. Retrofits include the replacement of valves, removal of
6 certain bends and any other obstruction for passage, as well as the addition of
7 facilities to insert and remove the tool. Through continued execution of TIMP
8 activities and complying with state mandates,²² the number of miles of pipeline
9 capable of ILI inspection has increased. Currently, approximately 70% of
10 SoCalGas’s transmission system is considered “piggable.” A key benefit of ILI
11 tools is the volume and quality of pipeline data collected across the full length of
12 a pipeline segment, which provides integrity information for both HCA and non-
13 HCA segments and enhances GMP’s ability to conduct risk assessments.
14 Consistent with this approach, the executive summary of the GTSR Part 1 final
15 rule recognizes that “improving ILI methods as an alternative to hydrostatic
16 testing is better for risk evaluation and management of pipeline safety.”²³

17 b. ECDA: The External Corrosion Direct Assessment (ECDA) process integrates
18 operating data and above-ground surveys to identify and address locations where
19 external corrosion activity has occurred, is occurring, or may occur.²⁴ ECDA is
20 labor-intensive and, depending on the location of the excavations, can result in
21 higher costs, particularly if located in environmentally constrained or densely
22 populated areas.

23 c. SCCDA: GMP applies Stress Corrosion Cracking Direct Assessment (SCCDA)
24 when the use of a crack detection ILI tool capable of assessing stress corrosion

²² Pub. Util. Code § 958: “At the completion of the implementation period, all California natural gas intrastate transmission line segments shall meet all of the following: [...] where warranted, be capable of accommodating in-line inspection devices.”

²³ Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 Fed. Reg. 190,52180 (October 1, 2019), *available at*: <https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf>.

²⁴ Described in ANSI/NACE SP0502-2010 as “a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity.”

1 cracking threats is not practicable.¹⁸ SCCDA relies on the results of indirect
2 inspection tools used in ECDA (Close Interval Surveys (CIS), Direct Current
3 Voltage Gradient (DCVG), and Alternating Current Voltage Gradient (ACVG))
4 along with soil resistivity measurements, operational history, and environmental
5 conditions, to identify pipeline locations susceptible to stress corrosion cracking
6 (SCC). Similar to ECDA, SCCDA is labor-intensive and can involve varying
7 excavation costs depending on site conditions.

8 During Pre-Assessment, projects are categorized as baseline assessments (for newly
9 covered segments or segments not previously assessed), first-time assessments (when a
10 new method is applied to a previously assessed segment), or reassessments required
11 under federal regulations. During this step, GMP also identifies key project drivers,
12 including pipeline threats, inspection tool selection, and compliance timelines – and
13 coordinates with internal stakeholders to reduce operational impacts and optimize costs
14 by taking advantage of pipeline outage windows.

- 15 2. **Inspection:** The second step of the Assessment and Remediation process is Inspection.
16 During this phase, GMP executes the selected assessment method(s) (*e.g.*, ILI, ECDA).
17 Activities include finalizing detailed planning and scheduling, overseeing vendors and
18 construction contractors, managing project costs, and documenting inspection activities
19 and results.
- 20 3. **Direct Examination:** The third step in the process is Direct Examination. During Direct
21 Examination, the pipeline is excavated to complete visual and non-destructive
22 examination in order to validate inspection results and to perform necessary repairs
23 and/or replacements. During this step, GMP completes repairs required to address
24 anomalous conditions discovered during assessments, as described below:
- 25 a. Remediation²⁵: Remediation activities conducted during the Direct Examination
26 phase address anomalous conditions in accordance with PHMSA regulations.²⁶
27 Anomalous conditions are analyzed, classified, and prioritized by severity—

²⁵ This activity also consists of capital activities described in workpapers, Ex. SCG-06-CWP Gas Major Projects.

²⁶ 49 CFR §§ 192.933 and 192.714.

1 immediate, scheduled, or monitored—consistent with regulatory requirements.²⁷
2 Immediate repair conditions require prompt action—such as temporary pressure
3 reduction, pipeline shutdown, or urgent repairs—and often necessitate extended
4 work hours by internal departments, city inspectors, contractors, and construction
5 personnel until the threat is mitigated. Scheduled and monitored conditions are
6 addressed in accordance with standard operating procedures and applicable
7 regulations.²⁸ Following validation through surface evaluations, appropriate post-
8 assessment repairs or reconditioning (such as welded steel sleeves, grinding, or
9 pipe replacement) are performed to enhance safety and prevent incidents. In
10 some cases, initial findings may identify the need for further remediation
11 following Post-Assessment.

12 As ordered in D.24-12-074²⁹, an independent study of SoCalGas’s TIMP and
13 DIMP, conducted by Structural Integrity Associates, Inc. (SI Associates)
14 concluded that SoCalGas’s TIMP is effective, in part, due to the identification and
15 repair of³⁰ These conditions require an expedited response given their associated
16 risk, and timely repair is critical to maintaining the safety and reliability of
17 SoCalGas’s pipelines. The study further noted that as a result of new regulations,
18 there has been a notable increase in the conditions in both HCAs and areas outside
19 of HCAs that have required remediation. This is further discussed below.

- 20 4. **Post-Assessment:** The final step of the four step Assessment and Remediation
21 process is Post-Assessment. During this step, GMP reviews data generated
22 during Pre-Assessment, Inspection, and Direct Examination to evaluate the
23 effectiveness of the assessment, determine whether additional remediation is
24 needed, and establish further reassessment intervals. Additional remediation may

²⁷ 49 CFR §§ 192.933 and 192.714, and American Society of Mechanical Engineers (ASME) B31.8s.

²⁸ 49 CFR Part 192, Subpart O and § 192.714.

²⁹ D.24-12-074 at 265: “To facilitate the reallocation of additional activities proposed as FIMP, the Commission directs SoCalGas to have an independent study performed of the efficiency of SoCalGas’s TIMP and DIMP programs and related activities, including their management, to determine how best to improve their effectiveness, efficiency, and cost”.

³⁰ Ex. SCG-03, Appendix F at Section 5.6 Repairs (SI Associates Report: Aligning Safety, Compliance, and Cost-Effectiveness: A Comprehensive Review of SoCalGas’s TIMP and DIMP Programs, January 2026).

1 include expanded pipeline repairs or preventive and mitigative actions, such as
 2 installing permanent monitoring devices, upgrading cathodic protection, or adding
 3 valves. The P&M measures included in this testimony and supporting
 4 workpapers consist primarily of the maintenance or addition of rectifiers and
 5 anodes, monitoring probes, and additional surveys along the pipelines with similar
 6 material coating and environmental characteristics to manage corrosion risks.
 7 Ongoing programmatic improvements to P&M procedures are discussed in the
 8 GESI testimony (Ex. SCG-03).

9 **a. Description of RAMP Mitigations**

10 This cost category consists entirely of non-shared O&M costs associated with the C171 risk
 11 control and mitigation presented in the 2025 RAMP Report and identified in the table below. All TIMP
 12 Execution activities are risk mitigation measures that address safety risks and were identified in the 2025
 13 RAMP Report, Chapter SCG-Risk-2 High Pressure Gas System, as described in the section above.
 14 Activities that are compliance-driven or mandated by the CPUC or other regulatory agencies are shown
 15 in bold. Appendix B to this testimony provides detailed information regarding applicable mandates for
 16 each control.

17 **TABLE DZ-12**
 18 **Transmission Integrity Management Program – TIMP (2MP002.00)**
 19 **RAMP and GRC Risk Control/Mitigation Activities –**
 20 **Non-Shared O&M Costs**

ID	Control/Mitigation Name	2025 RAMP 2028 In 2024 \$ (000s)	2028 GRC 2028 In 2025 \$ (000s)	Change (000s)
C171	Integrity Assessments & Remediation	123,975(31)	139,476	15,501

31 The total RAMP O&M forecast for C171 is \$146.9 million. The cost shown on the table represents the estimated RAMP O&M forecast allocated to this workpaper, proportional to the GRC forecast, representing 84.4% of the total activity. The other portion of costs for C171 can be found in the GESI testimony (Ex. SCG-03).

1 **b. Description of Selection and Prioritization of RAMP Risk Mitigations**

2 As described above, SoCalGas’s TIMP is designed to comply with the requirements of 49 CFR
3 Part 192, Subpart O and 49 CFR § 192.710. Consistent with these regulations, SoCalGas assesses
4 higher-risk transmission pipelines³² for a range of threats, including internal and external corrosion,
5 stress corrosion cracking, manufacturing defects, construction and fabrication issues, weather-related
6 and outside forces, incorrect operations, equipment failure, and third-party damage. Gas Major Projects
7 evaluates pipeline data, operating conditions, and other relevant information to determine the
8 appropriate actions necessary to maintain system integrity and reliability. Regulatory mandates and
9 guidance (*e.g.*, advisory bulletins), current pipeline data, historical activity levels, and system needs are
10 key factors that inform the scope of this control.

11 SoCalGas continues to execute its risk-informed TIMP activities to provide safe and reliable
12 transmission service, support system integrity, and maintain regulatory compliance. In its independent
13 study evaluating the efficiency of SoCalGas’s TIMP and DIMP,³³ SI Associates observed that TIMP
14 efficiency is demonstrated through structured planning and risk-based prioritization, and that SoCalGas
15 employs a rigorous project management process to support consistent execution. SI Associates observed
16 that the annual number of assessments performed, the timely completion of repairs follows those
17 assessments, and year-over-year increases in transmission mileage capable of accommodating ILI reflect
18 effective planning, continuous improvement, risk mitigation, and public safety benefits.³⁴

19 The GESI testimony (Ex. SCG-03) includes a portion of C171 costs and activities for program
20 management of the TIMP. These program management costs are separate and distinct from the project
21 execution management costs and activities sponsored in the Gas Major Projects testimony.

22 **2. Forecast Method**

23 The forecast method used for TIMP Project Execution O&M is a recorded three-year average.
24 As described in the Cost Drivers section below, evolution of TIMP in recent years has impacted TIMP
25 Assessment and Remediation work and associated costs. The level of activity executed in 2023, 2024
26 and 2025 best represents the current organizational structure and the workload required to comply with
27 federal requirements.

³² HCA, Class 3, Class 4, and piggable MCA pipeline segments as scoped by 49 CFR Part 192 Subpart O and 49 CFR § 192.710.

³³ Ex. SCG-03, Appendix F.

³⁴ *Id.* at Section 1.0 (Executive Summary) and 10.0 (Conclusion).

1 The changes in assessment methods (*e.g.*, new ILI tool runs, increase in SCCDA) and related
2 validation and remediation activities in the forecast years, as compared to historical years prior to 2023,
3 are subject to the same enhanced federal requirements that are expected to continue through at least this
4 current assessment cycle. During this cycle, Gas Major Projects will bring pipeline segments under the
5 TIMP into compliance with updated requirements. The level of accuracy of project-specific forecasting
6 decreases particularly as SoCalGas forecasts further into future years. Based on its latest assessment
7 plan, SoCalGas is anticipating a level of activity through 2031 that is similar to that of 2023-2025 and
8 expects that a three-year average will smooth the year-to-year variability that is inherent with TIMP
9 work.

10 SoCalGas made incremental adjustments to each forecast year to account for the increase in the
11 volume of assessments projected for 2026-2031 relative to 2023-2025. To determine these adjustments,
12 SoCalGas evaluated the projected number of assessments in the forecast period and applied average
13 historical cost assumptions, recognizing the variability in scope and cost across individual projects.

14 To determine assessment volumes for the forecast period, SoCalGas applied distinct planning
15 approaches based on the relative level of information available. For 2026–2027, SoCalGas incorporated
16 project quantities based on its most recent Assessment Plan, applicable compliance requirements, and
17 operational considerations. Because the Assessment Plan is updated annually, SoCalGas develops more
18 detailed plans in the near term and recognizes increased uncertainty beyond a two-year horizon.
19 Accordingly, SoCalGas developed the 2028–2031 assessment volumes by reviewing projects completed
20 during 2022–2025. For the assessment volumes that the cost forecast is based on, a six-year historical
21 cycle was used instead of a seven-year cycle, to reflect known execution risks that can affect compliance
22 timing, such as tool availability and permitting constraints, as well as the potential for shortened
23 reassessment intervals or additional assessment requirements identified upon completion of the ILI for
24 pipelines subject to 49 CFR § 192.939(a)(1)–(3). In some cases, ILI results may identify threats that
25 may necessitate an unplanned Direct Assessment. These SCC threats can expand project scope and
26 extend execution timelines, while remaining subject to the same regulatory compliance deadline as the
27 associated ILI, increasing scheduling variability and compliance risk. The 2028–2031 projections were
28 further normalized to account for this variability, recognizing that assessment execution may be
29 advanced or deferred to balance regulatory obligations with system and operational needs.

1 Overall, the TIMP O&M forecast reflects a reasonable and compliant pace of work to maintain the
2 safety and reliability of SoCalGas’s transmission system and is based on information available at the
3 time the forecast was developed.

4 3. Cost Drivers

5 The primary cost drivers for this forecast consist of both labor and non-labor components. Labor
6 costs reflect the employees necessary to direct, oversee, execute, and ultimately manage compliance and
7 program requirements. Non-labor costs include contractor services, materials, permitting, and other
8 non-labor costs directly associated with execution of TIMP requirements.

9 A primary cost driver for TIMP Project Execution O&M is the number and type of assessments
10 required under PHMSA regulations. TIMP project counts and project scopes vary from year to year due
11 to several factors, including prescriptive requirements for assessment methods and reassessment
12 timing,³⁵ system reliability considerations (*e.g.*, seasonal demand and inventory), and opportunities for
13 cost efficiencies (*e.g.*, shifting projects to leverage or integrate with other scopes of work).

14 Regulatory change has also been a significant cost driver in recent years. Beginning with the
15 implementation of GTSR Part 1, effective July 1, 2020 and July 1, 2021, SoCalGas updated its TIMP to
16 comply with new federal requirements and guidance.³⁶ These materially increased TIMP activities and
17 costs, as documented in the independent TIMP and DIMP efficiency study ordered by D.24-12-074.³⁷ In
18 response to enhanced threat evaluation requirements, including those reflected in PHMSA advisory
19 bulletins³⁸ and GTSR Part 1, SoCalGas increased its use of advanced ILI technologies, such as
20 Electromagnetic Acoustic Transducer (EMAT) tools and Circumferential Magnetic Flux Leakage
21 (MFL-C) tools during the TY 2019 GRC period, resulting in higher O&M and capital expenditures.³⁹

³⁵ PHMSA prescribes a maximum seven-year interval (49 CFR § 192.939) and 10-year interval (49 CFR § 192.710) for reassessment of TIMP pipelines and includes provisions for more frequent reassessment depending on evaluations of pipeline data and findings.

³⁶ 49 CFR §§ 191 and 192.

³⁷ Ex. SCG-03, Appendix F.

³⁸ PHMSA issued an advisory bulletin in 2018 declaring the Stress Corrosion Cracking (SCC) threat to be considered “active” by default for all pipeline segments. Since the issuance of the bulletin, the number of pipeline segments considered susceptible to the SCC threat have increased as pipeline operators have discovered SCC on pipeline segments previously considered to be unsusceptible to the SCC threat. Pipeline Safety: Deactivation of Threats, 82 Fed. Reg. 50,14106 (March 16, 2017), *available at*: <https://www.govinfo.gov/content/pkg/FR-2017-03-16/pdf/2017-05262.pdf>.

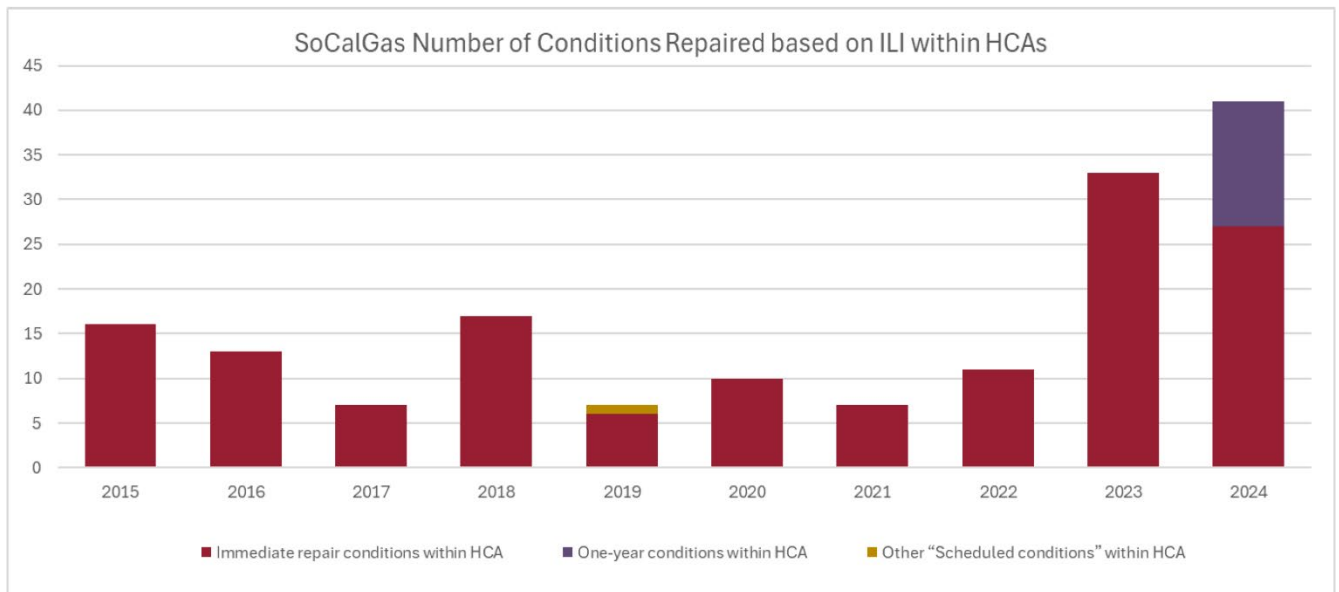
³⁹ A.25-04-020, SoCalGas Application to Recover Costs Recorded in the Transmission Integrity Management Program Balancing Account from January 1, 2019 to December 31, 2023 (April 30, 2025).

1 These advanced technologies has increased the number of Direct Assessments for both tool validation
2 and risk mitigation.

3 GTSR Part 2, which became effective May 24, 2023, expanded remediation requirements for
4 pipeline segments located both within⁴⁰ and outside⁴¹ of HCAs. While certain elements of these
5 requirements were not fully implemented until 2024 due to the enforcement discretion policy issued by
6 PHMSA,⁴² the impacts have been substantial. In its independent study, SI Associates observed that
7 SoCalGas’s pipeline conditions requiring repair had “dramatically” increased as a result of regulatory
8 changes.⁴³

9 **Figure DZ-5**

10 **SoCalGas Total PHMSA-defined ILI Repair Conditions in HCAs⁴⁴**



11 Although 2025 data was not available at the time SI conducted its study, SoCalGas has since
12 reconciled this information and repaired a total of 40 PHMSA-defined ILI conditions within HCAs.

⁴⁰ 49 CFR § 192.933.

⁴¹ 49 CFR § 192.714.

⁴² *Id.*

⁴³ Ex. SCG-03, Appendix F.

⁴⁴ *Id.*

1 Consistent with the SI study, SoCalGas anticipates that this level of activity will continue several
2 years into the future,⁴⁵ though it is possible an increased level of activity could persist through 2034 due
3 to the ten-year maximum assessment/reassessment cycle,⁴⁶ These additional excavations and repairs
4 directly increase the costs GMP incurs to execute the TIMP.

5 In addition to the cost drivers already described, the actual project execution costs are variable
6 due to many factors, including but not limited to the following:

7 **1. Assessment method:**

8 a. ILI Projects

- 9 ○ Tool types – Certain tool types, such as EMAT, continue to be cost
10 drivers. Use of EMAT can increase project costs by up to \$1 million.
11 Other newly utilized tool types (*e.g.* MFL-C) could add a minimum of
12 ~\$300 thousand per project.
- 13 ○ Number of tool runs - ILI projects may require multiple tool runs for a
14 variety of reasons. Pipelines with significant debris often require several
15 cleaning runs and, in some cases, onsite tool recalibration or rebuilds.
16 These circumstances increase costs associated with company labor,
17 contracted workforce, and other services. In addition, ILI tool selection is
18 driven by the potential threats that must be assessed. In many cases,
19 multiple types of ILI tools — each designed to detect particular threats —
20 are required to collect the full range of data necessary to complete an
21 assessment. In some instances, data validation demonstrates that collected
22 data does not meet required quality standards, necessitating tool re-runs
23 and additional analysis, which can further increase project duration and
24 cost. These situations typically arise from tool performance issues.
- 25 ○ Temporary vs. permanent facilities – SoCalGas generally prefers to install
26 permanent facilities for pipelines subject to future reassessments.
27 However, feasibility depends on site-specific factors including available
28 space, easements, rights-of-ways (ROWs), and other factors. Where

⁴⁵ *Id.*

⁴⁶ 49 CFR § 192.710.

1 temporary facilities are required, additional costs associated with
2 excavation, permitting, traffic control, and labor are expected. While costs
3 associated with reassessments may be more predictable, increased
4 variability is expected for baseline or first-time assessments.

5 b. ECDA and SCCDA Projects

- 6 ○ Length of the covered segment – Longer covered segments generally
7 result in higher inspection costs.
- 8 ○ Number of excavations – The number of excavations required to complete
9 an assessment depends on inspection results and can vary by location.
- 10 ○ Location of excavations – Some excavation sites can be difficult to access,
11 and certain locations such as hillsides and water crossings are more
12 susceptible to Stress Corrosion Cracking (SCC). Inspection results may
13 therefore require SoCalGas to perform complex and costly excavations in
14 difficult-to-access locations.

15 Based on the most recent TIMP Assessment Plan and currently identified threats, GMP does not
16 anticipate using pressure testing, spike hydrostatic pressure testing, ICDA, in-situ direct examination,
17 GWUT, or other technologies during the 2026-2031 period. However, assessment methods may change
18 based on pre-assessment analysis conducted for individual projects, and such changes could have
19 significant cost implications.

- 20 **2. Geographical factors:** Urban and suburban location challenges – Projects located in
21 urban or suburban environments often involve restrictive permitting requirements, such
22 as limited work hours or nighttime construction, extensive traffic control measures, and
23 the presence of unknown substructures. These challenges affect project execution
24 timelines and directly drive costs. In dense urban areas, projects may also impact large
25 customers, such as electrical generation plants. To minimize impacts, work may need to
26 be scheduled during nights or weekends, and conditions are subject to change.
- 27 **3. Assessment findings:** The number of ILI tools or assessment method types, which are
28 driven by identified threats that must be evaluated, directly impact both O&M and
29 Capital activities under TIMP. As the quantity and complexity of data collection
30 increases (*e.g.*, more tool types to appropriately assess for threats) the number of required
31 excavations to validate findings also increases. This in turn leads to identification of

1 additional conditions discovered that require remediation. SoCalGas experienced this
2 dynamic following GTSR Part 1, when increased baseline and first-time ILI assessments
3 resulted in a higher volume of excavations and remediations to comply with new
4 regulatory requirements.⁴⁷

5 **4. Impact of evolving regulations:** As described in greater detail in Ex.SCG-03, GESI
6 testimony, PHMSA published new rules updating the edition of ASME B31.8S
7 incorporated into federal regulations. These updates have affected GMP’s threat
8 identification and risk assessment processes, which drive the assessment, excavation, and
9 remediation activities.⁴⁸ In addition, in 2024 PHMSA issued an advisory bulletin
10 emphasizing the “importance of evaluating their pipeline facilities for the existence and
11 potential threat of hard spots in the pipe body.”⁴⁹ The pipeline industry is actively
12 evaluating the ability of ILI and in-the-ditch inspection tools to detect and characterize
13 hard spots, as well as developing criteria to determine when immediate action is
14 warranted. GMP is currently analyzing and integrating these evolving requirements and
15 assessing their impacts on TIMP assessments. To account for enhanced threat
16 identification and risk assessment, the TY 2028 GRC TIMP Project Execution forecasts
17 include one additional excavation dig relative to historical averages.

18 **5. Adoption of SI’s Independent Study Recommendations:** Additional factors that may
19 affect TIMP costs, though not currently reflected in Project Execution forecasts, include
20 implementation of recommendations from SI’s independent study⁵⁰ evaluating the
21 efficiency of SoCalGas’s TIMP and DIMP. While some recommendations aim to
22 improve cost efficiencies, the timing, scope, and project-specific applicability of these
23 recommendations remain uncertain. For example, although the study found SoCalGas’s

⁴⁷ See A.25-04-020, Chapter II: Technical – Project Execution and Management, Ex. SCG-02 at 12-13.

⁴⁸ For additional background, refer to the Gas Engineering & System Integrity testimony (Ex. SCG-03).

⁴⁹ Pipeline Safety: Identification and Evaluation of Potential Hard Spots – In-Line Inspection Tools and Analysis, 89 Fed. Reg. 222,90827 (November 18, 2024), available at: <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2024-11/2024-26725.pdf>.

⁵⁰ Ex. SCG-03, Appendix F.

1 SCC evaluation process to be sophisticated⁵¹ and appropriate,⁵² it recommends continued
 2 enhancement of SCC risk assessment data to enable SCCDA as a potential alternative to
 3 EMAT in some circumstances.⁵³ Because assessment scopes are finalized during pre-
 4 assessment, the cost impacts of ongoing SCC process improvements on future
 5 assessments and remediations cannot yet be quantified.

6 In summary, SoCalGas’s TIMP –particularly project execution – is subject to inherent variability
 7 arising from the interaction of prescriptive regulatory requirements, site-specific field conditions, and
 8 continuing enhancements to federal integrity management practices and standards. The Commission has
 9 long recognized this variability and has consistently authorized balancing account mechanisms to
 10 “ensure that SoCalGas has sufficient funds to carry out all the necessary TIMP-related work to ensure
 11 that its gas transmission system remains safe and reliable.”⁵⁴

12 The variability of TIMP Project Execution capital costs, which are incurred to comply with
 13 federal regulations, further necessitates continuation of SoCalGas’s TIMP Balancing Account
 14 (TIMPBA), as discussed in greater detail in Ex. SCG-03 (GESI testimony) and Ex. SCG-21 (Regulatory
 15 Accounts testimony).

16 **C. High Pressure (HP) Distribution Assessments Execution (NSS 2MP002.002)**

17 **TABLE DZ-13**

18 **High Pressure Distribution Assessments Execution**
 19 **Non Shared O&M Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY2028 Estimated	Change
1. High Pressure Distribution	0	15,231	15,231

20 **1. Description of Costs and Underlying Activities**

21 The activities and costs associated with this cost category include O&M labor and non-labor
 22 expenses required to complete integrity assessments on high priority, high-pressure (HP) distribution
 23 pipeline segments (specifically, segments that operate under 20% Specified Minimum Yield Strength

⁵¹ *Id.* at Section 5.8.2 (SCC Threat).

⁵² *Id.*

⁵³ *Id.*

⁵⁴ D.13-05-010 at 387.

1 (SMYS) and pressures exceeding 60 psig). Over time, and in an effort to enhance the safety on certain
2 pipelines, SoCalGas reduced operating pressures on several transmission assets to achieve stress levels
3 below 20% SMYS, where rupture risk is significantly reduced. As a result of these pressure reductions,
4 certain pipelines previously classified as transmission assets are now classified as distribution assets
5 operating at the upper end of the distribution stress spectrum. Although these segments are governed
6 under distribution regulations, they operate at higher stress levels than typical distribution pipelines and,
7 in some cases, may be subject to integrity threats more commonly associated with vintage transmission
8 pipelines. In particular, these HP distribution segments may contain manufacturing-related defects,
9 including pipe body anomalies, longitudinal pipe seam defects, and girth weld issues.

10 Drawing on an established history of in-line inspection (ILI) and defect detection practices under
11 49 CFR Part 192 Subpart O, SoCalGas proposes to apply a TIMP-like approach to the condition
12 assessment of these HP distribution segments. This approach is intended to more comprehensively
13 understand the baseline condition of distribution pipelines that are both more susceptible to certain
14 integrity threats and exposed to higher operating stress. Advanced TIMP methodologies, particularly
15 advanced assessment techniques such as robotic ILI, have proven effective in transmission systems by
16 enabling proactive identification of threats beyond historical leak performance. Applying these
17 techniques to selected HP distribution segments allows SoCalGas to more accurately estimate actual
18 pipeline risk and supports data-driven decision-making for pipeline management and remediation
19 activities.

20 **a. Description of RAMP Mitigations**

21 This cost category consists entirely of non-shared O&M costs associated with the M171 risk
22 control/mitigation. M171 was not included in the 2025 RAMP Report as a mitigation, but rather as an
23 alternative mitigation, and is newly proposed in the TY 2028 GRC. The M171 HP Distribution
24 Assessment Execution activities identified in the section above are safety-driven risk mitigation
25 measures associated with SCG-Risk 2 High Pressure Gas system, identified in the 2025 RAMP Report.
26 Activities that are compliance-driven or mandated by CPUC or other agencies are listed in bold.
27 Appendix B to this testimony provides additional detail regarding applicable mandates for each control.

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TABLE DZ-14
Transmission Integrity Management Program (TIMP)
RAMP and GRC Risk Control/Mitigation Activities - O&M

ID	Control/Mitigation Name	2025 RAMP 2028 In 2024 \$ (000s)	2028 GRC 2028 In 2025 \$ (000s)	Change (000s)
M171	High Pressure Distribution Assessments	17,435	15,231	(2,204)

b. Description of Selection and Prioritization of RAMP Risk Mitigations

SoCalGas selected this mitigation as a targeted assessment activity focused on high pressure distribution pipeline segments. In prioritizing this mitigation, SoCalGas considered factors such as pipeline age, material, stress level, and diameter. As described above, the proposed scope is limited to a small number of pipelines that share characteristics with pipelines subject to TIMP. The objective of this mitigation is to generate more comprehensive baseline condition data for selected high pressure distribution segments exposed to higher stress levels. This mitigation measure would enable SoCalGas to improve threat identification and risk assessment methodologies, such as those described in the GESI testimony (Ex. SCG-03), that will enhance risk mitigation activities and decision-making.

2. Forecast Method

Using existing DIMP pipeline analysis, SoCalGas identified seven candidate HP distribution segments for robotic ILI assessment. This cost category is forecast using a zero-based method, with project specific cost estimates developed for each segment. The estimates are informed by historical cost data and execution experience from comparable ILI projects.

The Full Time Equivalent (FTE) forecast is based on an average FTE per dollar ratio derived from historical average TIMP execution data (2MP002.000). Depending on company-wide resource availability during this GRC cycle, the work may be performed using internal labor, outside contractors, overtime, or a combination. The FTE forecast reflects average labor hours required to complete the planned activities.

3. Cost Drivers

The cost drivers for HP distribution assessments include both labor and non-labor components. Labor costs consist of the employees required to direct, oversee, and execute the assessments on the HP

distribution segments. Non-labor costs consist of contractors, materials, permitting, and other expenses necessary to complete the assessments. The primary cost driver is the number of assessments, along with segment-specific factors, such as pipeline configuration and assessment complexity.

D. Gas Major Projects – Program Management Office (PMO) (NSS 2MP003.000)

TABLE DZ-15

**Gas Major Projects – Program Management Office (PMO)
Non Shared O&M Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY2028 Estimated	Change
1. Program Management Office (PMO)	3,471	3,502	31

1. Description of Costs and Underlying Activities

The Gas Major Projects – Program Management Office (PMO) includes labor and non-labor expenses required to provide governance, oversight, and program management for Gas Major Projects. These activities are necessary to cost-effectively execute projects that enhance the safety and reliability of the SoCalGas system, and in compliance with applicable regulatory requirements and include establishing proper controls and management across functional areas to verify that each component of a project, including design, material procurement, construction, and closeout is performed correctly and consistently.

The PMO establishes standardized delivery frameworks (for consistent execution of PSEP, GSEP, TIMP, CCM ongoing program activities, and other complex projects), lifecycle processes, and stage gate controls; manages portfolio planning, cost control, scheduling, and risk mitigation; and supports quality assurance aligned with regulatory standards. The function also supports integrated reporting, performance analytics, contractor oversight, and workforce readiness through training and documented procedures. These functions enable traceable decision-making, regulatory compliance, and predictable project outcomes while optimizing resources and maintaining safety and reliability across all project types.

The importance of centralized project governance was recognized by the Safety and Enforcement Division (SED) (formerly known as the Consumer Protection and Safety Division) in its 2012 Technical Report on SoCalGas and SDG&E’s PSEP, which concluded that a PMO is critical to proper execution of large safety programs: “CPSD believes the Companies are approaching the need to manage the PSEP

1 in a reasonable manner and that the PMO will be critical to the proper execution of PSEP.”⁵⁵ This
2 assessment remains valid, as the PMO continues to serve as the central governance body for Gas Major
3 Projects.

4 Notably, the Gas Major Projects PMO maintains standards and procedures, facilitates the stage
5 gate process, and promotes each project’s ability to (1) collaborate, coordinate, and provide functional
6 guidance on project design and construction to cost effectively meet or exceed compliance requirements,
7 (2) follow, as appropriate, industry best practices, and (3) identify and incorporate process
8 improvements.

9 The PMO develops reports and Key Performance Indicators (KPIs) at various levels (which may
10 include financial metrics, project’s progress, safety metrics, environmental compliance, material
11 availability, and headcount). The PMO reviews the KPIs with management on a monthly basis to
12 monitor the various programs.

13 **2. Forecast Method**

14 The PMO forecast is based on base-year recorded costs, as the most recent year of historical
15 actuals best reflects current portfolio scale, project delivery timelines, and resource capacity and
16 requirements. The base year recorded costs provides projections that are aligned with the GMP’s actual
17 operating and delivery conditions.

18 **3. Cost Drivers**

19 PMO costs are driven primarily by Labor and Non-Labor needs associated with the scale and
20 complexity of the GMP portfolio. Additional cost drivers include project or program timelines, scope
21 changes, and cross program dependencies that increase oversight, coordination, and reporting
22 requirements.

⁵⁵ Rulemaking (R.) 11-02-019, Technical Report of the Consumer Protection and Safety Division Regarding the Southern California Gas Company and San Diego Gas and Electric Company Pipeline Safety Enhancement Plan (January 17, 2012) at 22, available at: <https://www.socalgas.com/regulatory/documents/r-11-02-019/CPSD%20Technical%20Report%20on%20SoCalGas%20and%20SDGE%20Implementation%20Plan%201-17-12.pdf>.

1 readiness. Blowdown equipment is often deployed for weeks and requires ongoing maintenance to
2 sustain efficiency and meet safety and regulatory requirements.

3 Beyond field operations, the CNG/LNG/GC Support Services Team also performs back office
4 support necessary to sustain safe, compliant, and effective blowdown reduction operations. These
5 functions include process improvements, engineering analysis, documentation, cost control, and
6 performance tracking. These operations include analyzing and documenting gas volumes being
7 captured instead of vented into atmosphere to support regulatory reporting, demonstrate compliance
8 with CPUC methane reduction requirements. In addition, tracking systems are used to monitor
9 equipment deployment, operating hours, inspections, and maintenance activities so compressors, trailers,
10 hoses, and associated assets remain in a safe and operable condition throughout extended field
11 deployments. The documentation and oversight are essential for maintaining equipment reliability,
12 meeting safety and regulatory requirements, supporting audits and internal controls, and continuous
13 improvement of methane reduction practices across the pipeline system.

14 These collective efforts are essential to reducing methane emissions across SoCalGas's high-
15 pressure pipeline network, supporting compliance with 2025 emission mandates and the target of 40%
16 emission reductions by 2030. Continued investment in personnel, equipment maintenance, and process
17 improvements is essential to maintaining compliance with regulatory directives in support of
18 California's climate goals.

19 **2. Forecast Method**

20 The forecast for this cost category is Base Year Recorded, reflecting a mature and stable
21 program. The Base Year best reflects the current scale and is a reliable indicator of expected costs. The
22 forecast includes incremental adjustments to incorporate annual maintenance and recertification costs of
23 company owned equipment following expiration of vendor maintenance agreements that are not
24 included in the Base Year costs.

25 **3. Cost Drivers**

26 Cost drivers include labor and non-labor costs necessary to comply with the CPUC's mandated
27 methane reduction requirements⁵⁸, including staffing, equipment rentals for large volume projects,
28 maintenance of compression and capture equipment, and implementation of internal safety procedures.

⁵⁸ D.17-06-015 and D.19-08-020.

1 These cost drivers reflect the technical and logistical demands of minimizing vented emissions
 2 during pipeline operations while maintaining compliance with CPUC directives and internal
 3 performance standards. Notably, the equipment maintenance agreement was built into the Capital
 4 purchase agreement at the time of procurement, thus eliminating annual O&M maintenance costs. The
 5 maintenance agreement will end in 2027, and annual costs for maintenance and inspections will begin in
 6 2028.

7 **IV. SHARED O&M COSTS**

8 As described in Ex. SCG-22/SDGE-27, Shared Services testimony are activities performed by a
 9 utility shared services department (*i.e.*, functional area) for the benefit of one or more of the following
 10 entities: (i) SDG&E or SoCalGas, (ii) Sempra Energy Corporate Center, and/or (iii) any affiliate
 11 subsidiaries. The utility providing Shared Services allocates and bills incurred costs to the entity or
 12 entities receiving those services.

13 Table DZ-17 summarizes the total shared O&M forecasts for the listed cost categories.

14 **TABLE DZ-17**
 15 **Gas Major Projects**
 16 **Shared O&M Summary of Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY 2028 Estimated	Change
SVP – Chief Infrastructure Officer	537	639	102
TIMP Execution SDG&E Support	1,619	1,537	-82
Blowdown Reduction – SDG&E	76	311	235
Total Shared Services	2,232	2,487	255

17 The forecasts for Shared Services are based on a total incurred basis, and are allocated using
 18 shared service allocation percentages. These allocation percentages, together with a description of the
 19 allocation methodology, are presented in the shared services workpapers. *See* Ex. SCG-22/SDG&E-27-
 20 WP. The dollar amounts allocated to affiliates are identified and presented in the Shared Services
 21 testimony, Ex. SCG-22/SDG&E-27.

A. Senior Vice President Chief Infrastructure Officer (US\$ 2594.000)

TABLE DZ-18

**Senior Vice President Chief Infrastructure Officer Costs
Shared O&M Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY2028 Estimated.	Change
1. SVP - Chief Infrastructure Officer	537	639	102

1. Description of Costs and Underlying Activities

This category includes the costs and activities associated with the Senior Vice President/Chief Infrastructure Officer (SVP). In this role, the SVP is responsible for the safe planning, operation, and modernization of critical energy infrastructure to deliver reliable service to customers. The role emphasizes protection of the public and workforce through rigorous safety standards, proactive risk management, and compliance with all applicable federal, state, and local regulatory requirements. In addition, the SVP is responsible for strengthening system resilience and integrity while driving disciplined capital investment and operational efficiency to maintain affordability for customers. By balancing long-term infrastructure stewardship with day-to-day operational reliability, the SVP facilitates the gas system to meet current demand and adapt to future energy needs. Leadership responsibilities include oversight of gas distribution and transmission operations, engineering and construction, asset management, system integrity, maintenance activities, operational compliance, and long-term infrastructure planning.

2. Forecast Method

The forecast method used for the SVP cost category is Base Year Recorded. The most recent recorded expenses represent the most accurate estimate of costs for the forecast years. Accordingly, base year recorded costs were used to forecast future labor and non-labor expenses associated with this cost category.

3. Cost Drivers

The primary cost drivers for this forecast are the labor and non-labor costs associated with the SVP, who provides executive leadership and strategic direction across all major gas operational functions. These costs reflect the SVP’s responsibilities for establishing safety priorities, aligning organizational objectives with regulatory expectations, and fostering consistent implementation of policies, standards, and practices across the enterprise. This cost category also includes the costs of an Executive Administrative Assistant, who supports the SVP by managing schedules, coordinating

1 documentation, and facilitating communication across departments. This support enables efficient and
2 effective executive oversight of critical operational, safety, and compliance activities.

3 **B. TIMP Execution SDG&E Support (US\$ 2299.001)**

4 **TABLE DZ-19**

5 **TIMP Execution SDG&E Support**
6 **Shared O&M Costs**

In 2025\$ (000s)	2025 Adjusted-Recorded	TY2028 Estimated	Change
TIMP Execution SDG&E Support	1,619	1,537	-82

7 **1. Description of Costs and Underlying Activities**

8 The TIMP Execution SDG&E Support cost category includes shared labor and non-labor
9 expenses associated with assessment and remediation support activities that SoCalGas performs in
10 support of SDG&E's TIMP described above. SDG&E leverages SoCalGas resources for certain TIMP-
11 related activities, such as engineering oversight and technical analysis. This coordination enhances
12 operational efficiency and consistent program implementation across both utilities. As discussed above,
13 these activities are compliance requirements pursuant to 49 CFR § 192, Subpart O – Gas Transmission
14 Pipeline Integrity Management and 49 CFR § 192.710.

15 **a. Description of RAMP Mitigations**

16 This cost category includes shared O&M costs associated with risk controls and mitigations
17 presented in the 2025 RAMP Report, as listed in table DZ-20 below. All TIMP activities are risk
18 mitigation measures addressing gas safety risks and were identified in the 2025 RAMP Report, Chapter
19 SCG-Risk-2 High Pressure Gas System. Activities that are compliance-driven or mandated by the
20 CPUC or other regulatory agencies are identified in bold. Appendix B to this testimony provides
21 additional detail regarding the regulatory mandates applicable to each control.

1 **TABLE DZ-20**

2 **RAMP and GRC Risk Control/Mitigation Activities - O&M Costs (000s)**
 3 **Transmission Integrity Management Program TIMP (2MP002.00)**

ID	Control/Mitigation Name	2025 RAMP 2028 In 2024 \$	2028 GRC 2028 In 2025 \$	Change
C171	Integrity Assessments & Remediation	1,366(59)	1,537	171

4 **B. Description of Selection and Prioritization of RAMP Risk Mitigations**

5 RAMP risk mitigation efforts are associated with specific actions, such as programs, projects,
 6 processes, and utilization of technology, and are designed to address a specific safety and/or reliability
 7 risk. In selecting and prioritizing these mitigation activities, the Company considered multiple factors to
 8 determine whether the investments are prudent and effective. The Enterprise Risk Management (ERM)
 9 process for identifying and assessing system risk is described in the RDF Integration testimony
 10 (Ex. SCG-02B/SDGE-02B). As required by CFR Part 192, Subpart O and § 192.710, SoCalGas
 11 assesses higher risk transmission pipelines for threats, including but not limited to internal and external
 12 corrosion, stress corrosion cracking, manufacturing defects, construction and fabrication issues, weather-
 13 related and outside forces, incorrect operations, equipment failure, and third-party damage. Pipeline
 14 data, operating conditions, and other relevant information are evaluated to determine appropriate actions
 15 needed to maintain system integrity and reliability. Regulatory mandates and guidance (*e.g.*, advisory
 16 bulletins), current pipeline data, historical activity levels, and overall system needs inform the scope of
 17 this control. The GESI testimony (Ex. SCG-03) also sponsors a portion of C171 costs related to TIMP
 18 program management. These costs are separate and distinct from the TIMP execution management
 19 sponsored in Gas Major Projects testimony.⁶⁰

⁵⁹ The total RAMP O&M forecast for C171 is \$146.9 million. The cost shown on the table represents the estimated RAMP O&M forecast allocated to this workpaper, proportional to the GRC O&M forecast, representing- 0.9% of the total activity. The other portion of costs for C171 can be found in the GESI testimony (Ex. SCG-03).

⁶⁰ Section III.B.1.b. provides additional detail regarding SoCalGas’s risk-informed TIMP, including its regulatory framework, threat assessment methodology, data-driven decision-making, and ongoing activities to maintain system integrity, reliability, and compliance.

1 **2. Forecast Method**

2 The forecast method for this cost category is based on a historical three-year average from 2023
3 through 2025. This methodology best reflects the current level of activity required to comply with
4 evolving federal pipeline safety regulations that have become more stringent in the last three years.

5 **3. Cost drivers**

6 Costs in this category are driven by the level of engineering oversight and technical analysis
7 activities needed to support the execution of SDG&E’s TIMP Assessment & Remediation projects, as
8 described in SDG&E’s Gas Major Projects testimony (Ex. SDGE-06).

9 **C. Blowdown Reduction (US\$ 0610.002)**

10 **TABLE DZ-21**

11 **Blowdown Reduction**
12 **Shared O&M Costs**

In 2025\$ (000s)	2025 Adjusted Recorded	TY2028 Estimated	Change
Blowdown Reduction	76	311	235

13 **1. Description of Costs and Underlying Activities**

14 The Blowdown Reduction cost category includes shared labor and non-labor expenses associated
15 with the implementation and maintenance of SoCalGas’s and SDG&E’s blowdown operations. These
16 activities are compliance-related requirements pursuant to D.17-06-015 and D.19-08-020 (the Natural
17 Gas Leak Abatement Decisions). The Blowdown Reduction Program is a long-term O&M activity also
18 integrated into SDG&E’s gas operations to reduce methane emissions.

19 Since 2018, the Blowdown Reduction Program has significantly reduced methane emissions
20 from transmission construction and maintenance activities, achieving an average annual reduction of
21 7,214 Mscf during 2023 and 2024. By using the EPA Greenhouse Gas Equivalencies Calculator⁶¹, the
22 annual savings are equivalent to greenhouse gas emissions from 92 gasoline power passenger vehicles
23 driven for one year or CO2 emissions from 44,496 gallons of gasoline consumed. These reductions
24 support California’s climate goals and improve air quality.

⁶¹ EPA, *Greenhouse Gas Equivalencies Calculator*, available at: <https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator>.

1 As discussed previously, the Blowdown Reduction Program is supported by a dedicated
2 CNG/LNG/GC Support Services Team that coordinates with field, construction, and Transmission
3 operations to minimize methane emissions during pipeline work requiring gas venting across SoCalGas
4 and SDG&E regions.

5 **2. Forecast Method**

6 The forecast method for this cost category is based on a three-year historical average from 2023
7 through 2025, with incremental adjustments for equipment maintenance and recertification costs
8 beginning in 2028 following expiration of existing maintenance agreements. CPUC Resolution G-3606
9 approved partial cost recovery for the program..

10 **3. Cost Drivers**

11 The primary cost drivers for the Blowdown Reduction Program are the operational requirements
12 established by the CPUC,⁶² which mandate the implementation of best practices to reduce methane
13 emissions. To comply, SoCalGas and SDG&E maintain a comprehensive blowdown reduction program
14 that includes labor and non-labor costs for the CNG/LNG/GC Support Services team and transmission
15 operations personnel, equipment rentals for large-volume projects, maintenance of blowdown reduction
16 equipment, and labor and equipment costs to meet internal safety requirements.

17 Ongoing emissions reduction efforts require continued equipment maintenance, inspection, and
18 periodic recertification. Equipment maintenance was included in the original capital purchase
19 contract, avoiding separate O&M costs during the initial term. The maintenance agreement expires
20 in 2027, and recurring O&M costs for equipment maintenance and inspection recertification will
21 increase beginning in 2028. These cost drivers reflect the operational, technical and regulatory
22 requirements necessary to minimize vented emissions during pipeline operations while maintaining
23 compliance with CPUC directives and internal performance standards.

24 **V. CAPITAL**

25 Capital costs for Gas Major Projects include expenditures for Pipeline Safety Enhancement Plan
26 (PSEP), Gas Safety Enhancement Programs (GSEP) Execution, Transmission Integrity Management
27 Program (TIMP) Execution, Compressor Station Compliance Programs, and the Control Center
28 Modernization (CCM) Ongoing Programmatic Activities. These investments are necessary to meet
29 regulatory requirements and support safety, reliability, and operational objectives. Table DZ-22

⁶² D.17-06-015 and D.19-08-020.

1 summarizes capital forecasts for 2026 through 2031. Project-specific in-service dates are provided in
 2 workpapers. Appendix C identifies capital expenditures expected to be placed in-service between 2026
 3 and Test Year 2028, and therefore are included in the Test Year 2028 revenue requirement (refer to
 4 Summary of Earnings testimony (Ex. SCG-27)). Capital expenditures with post-test year in-service
 5 dates (*i.e.*, 2029-2031) are also shown in Appendix C and are supported by the capital post-test year
 6 mechanism presented in the Post-Test Year Ratemaking testimony (Ex. SCG-28).

7 **TABLE DZ-22**
 8 **Gas Major Projects**
 9 **Capital Expenditures Summary of Costs**

In 2025 \$ (000s)							
Categories of Management	2025 Adjusted-Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
A. Pipeline Safety Enhancement Plan	28,443	35,262	83,968	114,178	103,609	103,834	102,036
B. Gas Safety Enhancement Plan Execution	78,688	100,907	126,849	134,671	122,566	125,369	125,737
C. TIMP Execution	153,306	136,333	136,284	136,248	136,249	136,238	136,261
D. HP Distribution Execution	0	0	0	15,680	15,681	15,679	15,682
E. Compressor Station Compliance Programs	58,122	12,971	0	31,410	0	0	0
F. Control Center Modernization	28,497	18,611	25,299	27,594	27,595	27,585	27,534
G. Blowdown Reduction	4,181	9,652	9,646	8,644	7,344	7,343	7,345
Total	351,237	313,736	382,046	468,425	413,044	416,048	414,595

A. Pipeline Safety Enhancement Plan (PSEP) (005580, 005630, 005120)

TABLE DZ-23

Pipeline Safety Enhancement Plan (PSEP)

Capital Costs

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
Pipeline Safety Enhancement Plan	28,443	35,262	83,968	114,178	103,609	103,834	102,036

1. Description and Background

PSEP is a compliance-driven program established in response to the 2010 San Bruno incident and the Commission’s directives in the Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans (D.11-06-017), later codified in the Pub. Util. Code §§ 957–958. The program enhances public safety through risk-based replacement and hydrotesting of transmission pipelines, prioritizing higher-risk segments in more populated areas before progressing to lower-consequence locations. PSEP is organized into Phases 1A, 1B, and 2A.

This capital request supports Phase 1B and Phase 2A pipeline replacements, as well as the Phase 2A capital component of hydrotesting. While the total PSEP capital portfolio exceeds the revenue requirement request, only projects anticipated to be executable during this GRC period are reflected in the revenue requirement forecast. Approximately 88 miles of Phase 1B mileage remain to be addressed for SoCalGas.

Phase 1B scope focuses on replacing pre-1946, non-piggable pipelines⁶³ that cannot accommodate in-line inspection tools and were constructed using outdated methods.⁶⁴ The Commission

⁶³ “Non-piggable” pipelines cannot accommodate in-line inspection tools that assess pipeline integrity. Pre-1946 pipelines were built using non-state-of-the-art construction methods and materials (*i.e.*, pipe manufacturers used various non-state-of-the-art manufacturing processes), were not designed to accommodate a post-construction hydro test and have an increased risk of developing leaks on girth welds.

⁶⁴ The scope of Phase 1B in the SoCalGas and SDG&E Amended PSEP Application (A.11-11-002) also included those pipeline segments that otherwise would be addressed in Phase 1A but cannot be addressed in the near term due to the need to construct new infrastructure to maintain service during hydrotesting. Phase 2 of the Pipeline Safety and Reliability Project, also known as Line 1600 (A.15-09-013), addresses this aspect of Phase 1B, as defined in the Amended PSEP Application.

1 ordered California pipeline operators to “address retrofitting pipeline to allow for in-line inspection
2 tools” in D.11-06-017.⁶⁵

3 Phase 2A scope addresses remaining transmission pipelines lacking verified hydrotest
4 documentation to at least 1.25 MAOP, primarily located in Class 1 and 2 non-high consequence areas.
5 Approximately 355 miles of Phase 2A mileage remain to be addressed for SoCalGas, primarily
6 consisting of large hydrotest projects located in the desert regions.

7 Additional information regarding each project is provided in supplemental workpapers (Ex.
8 SCG-06-WP-S, Volume I) along with a Summary of Standard Planning & Construction for
9 Replacement, Hydrotest, Valve, and Abandonment Projects (SCG-06-WP-S). The supplemental
10 workpapers represent the full suite of potential replacement and hydrotest projects within the GRC
11 period. Section III.A.1 currently outlines the major hydrostatic test scope elements and related cost
12 drivers. The summary below describes the principal pipeline replacement scope elements and associated
13 cost drivers:

14 **1. Planning**

- 15 • Define replacement objectives.
- 16 • Perform surveys, base mapping, potholing, and subsurface utility
17 engineering.
- 18 • Select alignment and complete constructability reviews.
- 19 • Determine system impacts, verify isolation points, and draft the outage
20 and tie-in plan.
- 21 • Prepare design packages, permits, environmental reviews, and identify
22 land access needs.
- 23 • Develop the bill of materials, identify long-lead items, and set the
24 procurement plan.

25 **2. Pre-construction Preparation**

- 26 • Secure agency permits, right-of-way, traffic control plans, and third-party
27 agreements.
- 28 • Stake alignment, establish yards and staging areas, complete safety plans.

⁶⁵ D.11-06-017 at 21, 30 (Finding of Fact (FOF) 9).

- Implement traffic control plans and coordinate with cities, counties, Caltrans, railroads, and utilities.
- Maintain customer and community notifications to minimize impacts.
- Mobilize crews, equipment, and materials.

3. Excavation and Installation

- Excavate and trench, or complete trenchless crossings such as horizontal directional drilling or bores where required.
- Locate utilities and set any temporary supports or shoring.
- String, fit, and weld pipe; perform nondestructive examination.
- Apply coating and perform required testing; install cathodic protection components.
- Install valves, fittings, and any inline inspection appurtenances.

4. Pressure Test of New Pipe

- Hydrotest the new segment to required test pressure and duration.
- Monitor pressure and temperature, verify acceptance criteria, and document results.
- Dewater and dry the new pipe.
- Manage water handling and disposal consistent with permits.

5. Tie-ins and Commissioning

- Execute isolation, complete tie-in welds, and perform post-weld inspections.
- Purge, gas-in, pipeline seasoning, and function test valves and instrumentation.
- Confirm records and set documentation to establish the maximum allowable operating pressure are traceable, verifiable, and complete.

6. Restoration and Closeout

- Backfill, compact, restore surfaces, pavement, and landscaping.

- Complete habitat restoration and demobilize.
- Produce as-builts and integrate documentation into records.

a. Description of RAMP Mitigations

PSEP remains a primary mitigation for SCG-Risk-2 (High Pressure Gas System) and includes capital risk controls identified in the 2025 RAMP Report, specifically, PSEP Phase 1B (C185) and Phase 2A (C186).⁶⁶ The program continues to align with RAMP principles through its decision-tree framework, approved in D.14-06-007, which prioritizes projects based on consequence risk and constructability.

Activities that are compliance-related or mandated by the CPUC or other regulatory agencies are listed in bold. Appendix B provides the details regarding the applicable mandates for each control.

TABLE DZ-24

**Pipeline Safety Enhancement Plan (PSEP)
RAMP and GRC Risk Control/Mitigation Activities
Capital Costs (\$000s)**

ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$	2028 GRC 2028-2031 In 2025 \$	Change
C185	PSEP Phase 1B	340,758	282,693	(58,065)
C186	PSEP Phase 2A	173,740	140,964	(32,776)
TOTAL GRC Based		514,498	423,657	(90,841)

b. Description of Selection and Prioritization of RAMP Risk Mitigations

PSEP began mitigating safety risk on SoCalGas’s natural gas system before the advent of the Commission’s RAMP process⁶⁷. PSEP was established as a comprehensive, risk-informed program focused on addressing transmission pipeline risk through hydrostatic testing, replacement, pressure reduction, and abandonment.

By employing the PSEP decision tree⁶⁸ (Appendix D) pipeline segments are prioritized to address pipelines located in more densely populated areas first, reflecting heightened consequence risk,

⁶⁶ Refer to the RDF Integration testimony (Ex. SCG-02B) for more details regarding the SoCalGas 2025 RAMP Report.

⁶⁷ The first PSEP project was completed in 2013.

⁶⁸ Approved in D.14-06-007.

1 before progressing to segments in less populated areas as risk drivers were mitigated. This risk-based
2 prioritization continues to guide project selection, sequencing, and execution today and is aligned with
3 the objectives of the RAMP framework. The project prioritization within each PSEP phase is based on
4 the ease of constructability, which considers necessary steps (engineering/design, permitting, land rights,
5 etc.) to proceed with construction in a timely and cost-effective manner. Therefore, the relative risk
6 between individual projects within each phase is indistinguishable.

7 **2. Forecast Method**

8 The PSEP forecast is developed using a zero-based, project-specific approach, supported by
9 preliminary engineering and construction planning. This method is most appropriate given the size,
10 scope, and complexity of PSEP projects. The request reflects an anticipated level of executable spend
11 from a large portfolio of Phase 1B and 2A pipeline projects, aligning with the PSEP forecasting
12 methodology that was approved in the 2024 General Rate Case. As such, the forecast and resulting
13 revenue requirement requested in this GRC application will be less than the total costs of the overall
14 portfolio of projects shown in supplemental workpapers. The forecast also includes an allowance for
15 hydrotest failures based on expected test mileage and historical test failure rates, recognizing the
16 inherent constraints associated with system reliability and operational scheduling.

17 This approach allows SoCalGas to quickly respond to project execution schedule changes by
18 advancing projects from the overall project portfolio into construction in place of those that may be
19 delayed. This maximizes SoCalGas's ability to execute PSEP "as soon as practicable" in accordance
20 with the Commission mandate laid out in D.11-06-017. Further, this approach is consistent with the four
21 over-arching objectives of PSEP: (1) enhance public safety; (2) comply with Commission directives; (3)
22 minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.

23 **3. Cost Drivers**

24 Primary cost drivers include both labor and non-labor components associated with Phase 1B and
25 Phase 2A engineering and design, route validation, materials procurement (*e.g.*, long lead materials like
26 pipe, fittings, valves), permitting, construction activities (*e.g.*, excavation, welding, testing, traffic
27 control, and site restoration), hydrotesting preparation and execution, and project closeout (*see* section
28 V.A.1. for a more detailed list). For Phase 2A capital component of hydrotests, removing and replacing
29 pipeline segments (and associated fittings) to establish test head locations, isolate the segment, and
30 complete the pressure test in compliance with current standards, and also includes the related
31 engineering, planning, and permitting activities necessary for those locations (*see* project specific

1 workpapers (Ex. SCG-06-WP-S)). Costs are influenced by project size, pipeline diameter, geographic
2 location, constructability constraints, and system reliability considerations. Several large-scale
3 transmission replacement and hydrotest projects contribute significantly to capital needs during the GRC
4 period, as detailed in the supplemental workpapers and are highlighted below:

- 5 • **Line 85 Project:** This project will replace approximately 13.0 miles of pipe installed in
6 1931 between Elk Hills Road and Lake Station. The segment is the sole source of
7 supply for several core and large non-core customers and provides critical support to the
8 transmission and distribution systems serving the San Joaquin Valley and Central Coast.
9 The new alignment prioritizes installation within public roadways, reducing reliance on
10 private property, improving constructability, and mitigating third-party damage risk,
11 thereby enhancing long term safety, reliability, and operational efficiency. *See*
12 supplemental workpaper Ex. SCG-06-WP-S.
- 13 • **Supply Line 44-306/44-307:** This project includes installation of in-line inspection tools,
14 replacement of non-piggable pipeline segments, valves, and fittings; hydrotesting and/or
15 selective replacement, customer service extensions, and cathodic protection upgrades.
16 SoCalGas acquired Line 306 from PG&E to serve regional demand while avoiding the
17 higher cost and environmental impacts associated with replacing Supply Line (SL) 44-
18 1008, which will be derated and abandoned as part of this scope. *See* supplemental
19 workpaper Ex. SCG-06-WP-S.
- 20 • **Supply Line 38-539 Phase 2A:** This project will replace approximately 12.57 miles of
21 pipeline and includes a combination of open trench installation, horizontal directional
22 drilling (HDD) and other bore methods, hydrotesting, traffic control, dense utility
23 crossings, rail, waterway, and agency permitting, as required. The project is designed to
24 enable future integrity assessments (*see* supplemental workpaper, Ex. SCG-06-WP-S).
- 25 • **North Desert Transmission Hydrotests:** As discussed in Section III.A.3, hydrotesting
26 activities in north desert regions involve remote access challenges and heat-related
27 construction constraints. These conditions increase execution complexity and costs
28 relative to projects in more accessible or temperate areas and are explicitly reflected in
29 the workpapers

B. Gas Safety Enhancement Programs (GSEP) Execution (003670, 003690)

**TABLE DZ-25
Gas Safety Enhancement Program (GSEP) Execution
Capital Costs**

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
Gas Safety Enhancement Program (GSEP) Execution	78,688	100,907	126,849	134,671	122,566	125,369	125,737

1. Description and Background

These forecasted capital expenditures for GSEP support compliance with PHMSA’s GTSR Part 1 and the Valve Installation and Minimum Rupture Detection Standards (Valve Rule).

Following the San Bruno and Marshall incidents, Congress enacted the 2011 Pipeline Safety Act, prompting PHMSA to adopt strengthened federal gas transmission and gathering requirements. GTSR Part 1, issued October 1, 2019, amended 49 CFR Parts 191 and 192, establishing new mandates for MAOP reconfirmation, expanded non-HCA assessments, and material verification, with compliance beginning July 1, 2021.⁶⁹ The Valve Rule, published April 8, 2022, added new rupture-mitigation valve and rupture detection requirements for applicable transmission pipelines.

SoCalGas complies with these requirements by performing MAOP reconfirmation under §192.624, non-HCA assessments under §192.710 through TIMP, and material verification under §192.607 as applicable for assets lacking traceable, verifiable, and complete records.

The new and impending gas rules and regulations include the PHMSA GTSR Part 1 and the Valve Rule. While the impacts of the GTSR Part 1 have been assessed and are continually managed and validated by the Integrity Management department and supporting groups, there are requirements stemming from the Valve Rule that will also result in incremental scope impacting this GRC period, which are further discussed below.

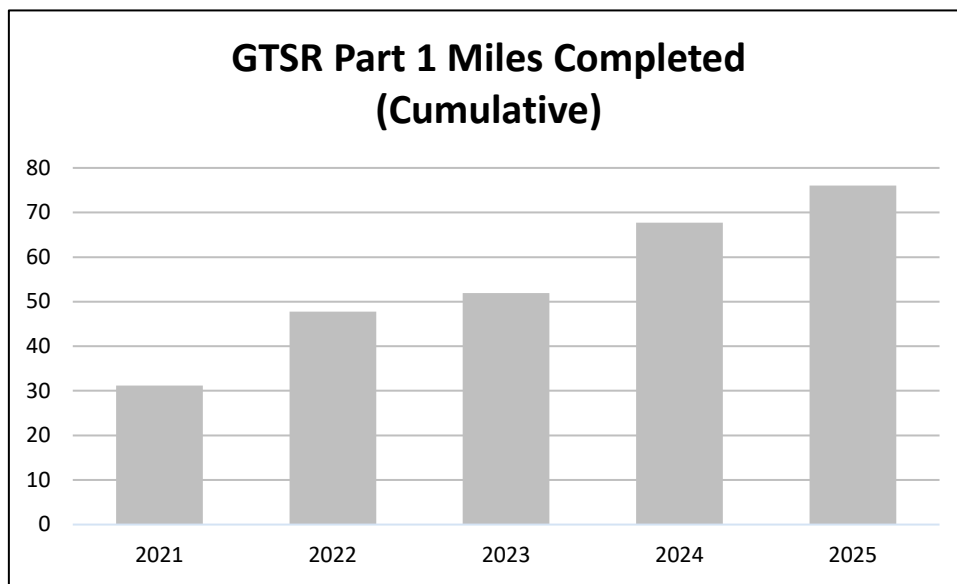
⁶⁹ Some requirements were effective July 1, 2020; *see* FAQ 1 of Frequently Asked Questions (FAQ) for the Final Rule titled “Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,” published on October 1, 2019, *available at* <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-06/Batch-1-FAQs-PHMSA-2019-0225-9-15-20.pdf>.

1 **a. GTSR Part 1 Replacements and Hydrotests**

2 GTSR Part 1 requires reconfirmation of MAOP for applicable transmission pipelines, with 50
3 percent completion by July 3, 2028⁷⁰, and 100 percent by July 2, 2035, or as otherwise required.⁷¹ Based
4 on applicable federal requirements, SoCalGas reviewed its transmission pipeline segments to determine
5 whether they are in the scope of the GTSR Part 1. These deadlines require careful coordination to
6 balance compliance milestones with system reliability and capacity constraints. GTSR Part 1 Mileage
7 Progress up to 2025 is shown in the figure below:

8 **Figure DZ-6**

9 **GTSR Part 1 Miles Completed Progress**



10 Consistent with FERC accounting guidance issued June 23, 2020,⁷² costs incurred for first-time
11 pressure testing to meet new federal safety standards are capitalized.⁷³ The forecast is based on an
12 assumption that pipeline segments will generally be tested or replaced; however, 49 CFR § 192.624
13 permits operators to use any of six reconfirmation methods: pressure testing, pressure reduction,

⁷⁰ Refer to 49 CFR § 192.624(a).

⁷¹ 100% of in-scope segments must be reconfirmed by July 2, 2035 or “as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) [...] whichever is later.” 49 CFR §192.624(b).

⁷² FERC Accounting Guidance, Docket: AI20-3-000, *Accounting for Pipeline Testing Costs Incurred to Comply with New Federal Safety Standards* (June 23, 2020), available at: <https://www.ferc.gov/sites/default/files/2020-06/AI20-3-000.pdf>.

⁷³ *Id.* at 2.

1 engineering critical assessment (ECA), pipe replacement, pressure reduction for pipeline segments with
2 small potential impact radius (PIR), and alternative technology. Final reconfirmation methods for
3 pipeline segments may change subject to a segment- or project-specific evaluation of factors including,
4 but not limited to, safety; constructability; customer, community, and environmental impacts; system
5 reliability; costs, etc.

6 Detailed project information is provided in the supplemental workpapers (Ex. SCG-06-WPS,
7 Volume I) accompanied by a Summary of Standard Planning & Construction for Replacement,
8 Hydrotest, Valve, and Abandonment Projects.

9 **b. Valve Rule**

10 The Valve Rule requires installation of rupture mitigation valves (RMV) on onshore gas
11 transmission pipelines that have nominal diameters greater than or equal to six inches in diameter that
12 are either newly constructed or entirely replaced transmission pipeline segments.⁷⁴ PHMSA also revised
13 regulations regarding identification of potential ruptures, notifications to public safety agencies, among
14 other requirements. The final requirements address congressional mandates, incorporate
15 recommendations from the National Transportation Safety Board, and are necessary to reduce the
16 consequences of large-volume, uncontrolled releases of natural gas and hazardous liquid pipeline
17 ruptures. The final rule was published in the Federal Register on April 8, 2022.⁷⁵

18 The Valve Rule expands the scope beyond SoCalGas's existing PSEP Valve Enhancement Plan
19 (VEP) and requires additional capital investment during this GRC period. While both aim to accomplish
20 the objective of identifying and isolating pipelines in the event of a rupture, the VEP preceded the Valve
21 Rule by approximately 10 years and is narrower in scope. The requirements of the Valve Rule in
22 comparison to the VEP are summarized in Table DZ-256 below.

⁷⁴ Defined to be where more than two miles, in the aggregate, or pipeline is replaced within any five contiguous miles within any 24-month period. Also specifies spacing intervals from eight to twenty miles based on class location per 87 Fed. Reg. 68,20983 (April 8, 2022).

⁷⁵ Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards, 87 Fed. Reg. 68,20940 (April 8, 2022), available at: <https://www.govinfo.gov/content/pkg/FR-2022-04-08/pdf/2022-07133.pdf>.

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TABLE DZ-26
Valve Rule and PSEP VEP Comparison

	Valve Rule	PSEP VEP
Type of Project	New or Replacement	Replacement
OD Threshold	≥6 inches	≥12 inches
SMYS Threshold	20%	30% or ≥200 psig
Class Location	Class 3 or 4 OR HCA	Class 3 or 4 OR HCA
Interval	20, 15, 8 Miles, Depending on Class Location	8 Miles

c. Description of RAMP Mitigations

This cost category includes capital costs for risk controls and mitigations identified in the 2025 RAMP Report, as summarized in Table DZ-27 below. GSEP is a safety-driven program that serves as key mitigations for one of SoCalGas’s highest priority safety risks, SCG-Risk-2 High Pressure Gas System. All forecasted GSEP capital costs presented above are compliance-driven risk mitigation measures mandated by PHMSA and implemented to address pipeline safety risks, as further described in SoCalGas and SDG&E’s 2025 RAMP Report.⁷⁶ Activities that are compliance-driven or mandated by the CPUC or other regulatory agencies are listed in bold. Appendix B provides the applicable mandates for each control.

TABLE DZ-27
RAMP and GRC Risk Control/Mitigation Activities – Capital

Gas Safety Enhancement Programs (GSEP) (\$000s)				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 <i>In 2024\$</i>	2028 GRC 2028-2031 <i>In 2025\$</i>	Change
C01 3	Gas Transmission Safety Rule – MAOP Reconfirmation	328,890	306,528	-22,362
C11 8	Rupture Mitigation Valve Installation – Valve Rule	162,048	201,815	39,767

⁷⁶ Refer to the RDF Integration testimony (Ex. SCG- 02B/SDG&E-02B) for more details regarding the SoCalGas’s 2025 RAMP Report.

TOTAL	490,938	508,343	17,405
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d. Description of Selection and Prioritization of RAMP Risk Mitigations

GSEP activities are driven by new federal gas transmission safety requirements. PHMSA’s GTSR Part 1 requires operators to reconfirm the MAOP for transmission pipeline segments under 49 CFR § 192.624, with milestone deadlines in 2028 and 2035.

The relative risk of GTSR Part 1 Replacements and Hydrotests is indistinguishable. Therefore, prioritization is based primarily on constructability, including engineering and design, system constraints, permitting status, land rights and access, and other factors to enable execution within available construction windows while minimizing system impacts and maintaining compliance while progressing to meet the 50% PHMSA compliance target. Similar to PSEP, prioritization also places an emphasis on addressing pipelines located in more populated areas.

GSEP execution is also driven by PHMSA’s Valve Rule, which requires additional rupture mitigation valve installations and related construction activities. Valve Rule activities are prioritized based on annual risk analysis to identify areas where RMV installations are appropriate.⁷⁷ The initial estimate is based on an initial implementation strategy that leverages established processes and resources from the PSEP VEP to promote efficient compliance.

2. Forecast Method

a. GTSR Part 1 Replacements and Hydrotests

The forecast for GTSR Part 1 activities is developed using a zero-based, project-specific methodology. This method reflects the size, scope, and complexity of executing GTSR projects. Class 3 project-specific cost estimates were developed for projects over \$10M, using preliminary engineering and project planning analyses. For projects that did not reach this threshold, Class 4 project-specific cost estimates were developed.⁷⁸ The forecast also includes a hydrotest failure allowance derived from forecasted pipeline test mileage and historical test failure rates. Project-level cost information and assumptions are provided in the supplemental workpapers (Ex. SCG-06-WP-S). SoCalGas forecasted costs based on an anticipated level of executable spending from the portfolio of projects compiled with

⁷⁷ 49 CFR § 192.935(a)(1).

⁷⁸ Per AACE International Recommended Practice No. 97R-18, a Class 3 estimate are based on 10-40% project definition and typically result in final project costs that are within +30% to -20% of the estimated amount. In contrast, a Class 4 estimate is based on 1-15% project definition and typically results in final costs that are within +50% to -30% of the estimated amount.

1 the goal to manage reconfirmation projects to an annual forecast that meets the 50% and 100%
2 compliance milestone targets established by PHMSA while balancing SoCalGas's obligation to maintain
3 gas system capacity planning to support system reliability. Given system reliability requirements,
4 certain projects requiring pipeline shut-ins may be delayed despite engineering readiness. This approach
5 allows Gas Major Projects to advance alternate projects from the overall GTSR portfolio to maintain
6 progress toward PHMSA's milestone deadlines while remaining within GRC-authorized spending
7 levels.

8 **b. Valve Rule**

9 The HRCM project is a compliance-driven effort required to address the sunset of South Coast
10 AQMD RECLAIM program, and to comply with Rule 1110.2 and Rule 1100.

11 **3. Cost Drivers**

12 **a. GTSR Part 1 Replacements and Hydrotests**

13 Primary cost drivers include both labor and non-labor components for compliance with
14 PHMSA's GTSR Part 1 MAOP reconfirmation requirements, particularly for certain gas transmission
15 segments located in more populated areas, such as Class 3 or Class 4 locations and HCAs. Performing
16 hydrotests and replacements in these more densely populated areas introduces construction challenges
17 that drive incremental cost due to constrained access, limited work windows, complex traffic control,
18 enhanced safety requirements, and extensive coordination with local and state agencies.

19 Specifically, hydrotests in dense population areas face elevated construction complexity that may
20 include sites such as schools and hospitals, which tighten work windows and restrict access.
21 Establishing and isolating test sections in congested rights-of-way often requires significant traffic
22 control, additional excavations at valves and pipeline connections, temporary bypass and jumper
23 configurations, and more complex shut-in system analysis to limit customer impacts. Urban permitting
24 and traffic control may include work-hour restrictions, encroachment permits, lane closures, detours, and
25 intensive coordination with cities, counties, state transportation agencies, and other entities. Water
26 handling in built-up areas (sourcing, staging, containment/treatment, and permitted discharge) may
27 require additional equipment, haul routes, and staging constraints on tight sites. Finally, work in high
28 trafficked areas typically requires enhanced safety measures, extensive notifications, and potentially
29 off-hour construction that may increase staffing and duration.

30 Similar to hydrotesting activities, additional cost drivers include non-contiguous pipeline
31 replacements that may be located at discrete, geographically separated sites, requiring repeated

1 mobilization and demobilization of crews, equipment, and traffic control. Construction activities
 2 frequently occur within congested rights-of-way and may necessitate localized excavations, temporary
 3 pipeline shutdowns or bypass configurations, and detailed system isolation analysis to minimize
 4 customer impacts. Urban permitting requirements can include work-hour restrictions, encroachment
 5 permits, lane closures, and coordination with multiple local and state agencies, which may extend
 6 project duration and increase costs. In addition, work in highly trafficked or sensitive areas typically
 7 requires enhanced safety measures, stakeholder notifications, and off-hour construction, further
 8 contributing to increased labor, traffic management, and overall execution costs relative to contiguous
 9 pipeline replacements.

10 **b. Valve Rule**

11 Valve Rule costs are driven by the number and scope of remote-controlled and automatic shutoff
 12 valve installations required to comply with PHMSA’s Valve Rule. Costs include both labor and
 13 non-labor components necessary to support program execution and regulatory compliance. Labor costs
 14 reflect the personnel required to plan, oversee, execute, and manage valve installations, including project
 15 management, engineering, and construction management functions. Non-labor costs include contractor
 16 services, materials and equipment, permitting, traffic control, and other supporting costs incurred to
 17 implement these requirements.

18 **C. Transmission Integrity Management Program (TIMP) Execution (P3120, 002760)**

19 **TABLE DZ-28**

20 **Transmission Integrity Management Program (TIMP) Execution**
 21 **Capital Expenditures Summary of Costs**

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
TIMP Execution	153,306	136,333	136,284	136,248	136,249	136,238	136,261

22 **1. Description and Background**

23 The cost category for TIMP execution captures all capital costs associated with integrity
 24 assessments, retrofits, repairs, and replacements for pipelines classified as transmission under DOT
 25 regulations. The TIMP continually evaluates the transmission pipeline system and takes action through
 26 inspections, replacements, and other remediation activities to improve the safety and reliability of the
 27 system. Actual TIMP capital costs will be balanced and recorded in the TIMPBA.

1 Consistent with 49 CFR Part 192, Subpart O and 49 CFR § 192.710, SoCalGas TIMP is a risk-
2 based program designed to identify pipeline threats, assess pipeline condition, and implement
3 remediation actions to reduce the likelihood of pipeline incidents and maintain system reliability. As of
4 year-end 2025, approximately 87% of SoCalGas’s transmission pipelines in HCAs, and approximately
5 70% of the overall transmission system are capable of in-line inspections. SoCalGas continues to
6 evaluate its system for ILI expansion where necessary.

7 ILI pipeline assessments are primarily O&M activities, and are performed using specialized
8 devices that internally traverse the pipeline to collect information that is used to assess the pipeline
9 condition. However, some pipelines are not designed to accommodate these inspection tools, requiring
10 retrofitting along the pipeline route (a predominantly capital activity). –A typical retrofit may include
11 replacing valves with less-restrictive valves that allow inspection devices to traverse internally, insertion
12 of tees with bars, and the change-out of bends and other fittings that may impede the progress of the
13 inspection tool. Costs to retrofit pipeline segments are in addition to the installation of the tool launcher
14 and receiver typically installed near the time of inspection. Once the retrofit is completed, the
15 inspection tool is run, followed by direct examinations to both validate the inspection findings and
16 determine necessary repairs, if needed. In certain cases, pipeline replacement is selected when it is more
17 economically feasible and allows for future ILI assessments. ILI provides detailed condition data,
18 particularly for time-dependent threats, and supports informed remediation decisions.

19 Following assessments, SoCalGas implements appropriate remediation measures in compliance
20 with 49 CFR Part 192, Subpart O and § 192.714. Remediation may include, but is not limited to,
21 different combinations of cylindrical replacement of targeted pipe segments, recoating of pipe segments
22 identified as having ineffective cathodic protection, installing new cathodic protection infrastructure
23 such as rectifiers, and reducing the Maximum Operating Pressure (MOP).

24 **a. Description of RAMP Mitigations**

25 TIMP capital costs include risk control(s)/mitigation(s) measures addressing safety risks that
26 were identified in the 2025 RAMP Report addressing SCG-Risk 2 High Pressure Gas System. TIMP
27 activities constitute required safety mitigations and are compliance driven, as such costs are reviewed at
28 the workpaper level to support timely completion as planned. Activities that are compliance-driven or
29 mandated by the CPUC or other regulatory agencies are listed in bold. Appendix B provides details
30 regarding applicable mandates for each control.

1 **TABLE DZ-29**

2 **Transmission Integrity Management Program-TIMP (\$000s)**
3 **RAMP and GRC Risk Control/Mitigation Activities – Capital**

ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$	2028 GRC 2028-2031 In 2025 \$	Change
C171	Integrity Assessments & Remediation	543,048(79)	544,996	1,948

4 **b. Description of Selection and Prioritization of RAMP Risk Mitigations**

5 TIMP prioritization is guided by regulatory requirements,⁸⁰ system risk, pipeline condition data,
6 and operational considerations. SoCalGas assesses higher-risk transmission pipelines for threats
7 including corrosion, cracking, manufacturing and construction defects, outside force damage, equipment
8 failure, and operational corrections. SoCalGas evaluates pipeline data, operating conditions, and other
9 necessary data to determine the appropriate actions needed to maintain system integrity and reliability.
10 Remediating identified threats through replacement, repair, or other corrective actions reduces the risk
11 of pipeline failures and improves the overall safety, reliability, and integrity of the system. Factors such
12 as regulatory mandates and guidance (*e.g.*, advisory bulletins), current pipeline data, historical activity
13 levels, and system needs inform the scope of this control.

14 SoCalGas continues its risk-informed TIMP activities to maintain compliance, support system
15 integrity, and provide safe and reliable transmission service. An independent efficiency review by SI
16 Associates observed that SoCalGas’s TIMP reflects effective risk-based prioritization, structured
17 planning, and disciplined project execution, resulting in timely repairs, increasing ILI, and measurable
18 public safety benefits.

19 Program management costs associated with C171 (Integrity Assessment and Remediation) are
20 addressed separately in the GESI testimony (Ex. SCG-03).

⁷⁹ The 2028-2031 total RAMP capital forecast for C171 is \$595.2 million. The cost shown on the table represents only 91.2% the estimated RAMP capital forecast associated with HP Gas System Integrity Assessments & Remediation activities included in this testimony, proportional to the GRC capital forecast. The other portion of costs for C171 can be found in the GESI testimony (Ex. SCG-03).

⁸⁰ Refer to the GESI testimony, Ex. SCG-03.

1 **2. Forecast Method**

2 The TIMP capital forecast is based on a recorded three-year average (2023-2025). This period
3 best reflects the impact of enhanced federal requirements, including GTSR-related changes. Given the
4 inherent variability of TIMP activities, driven by inspection findings and evolving conditions, this
5 approach provides a reasonable estimate of expected costs while acknowledging forecasting limitations
6 and supporting continued use of the TIMPBA.

7 **3. Cost Drivers**

8 Primary cost drivers for TIMP Execution include both labor and non-labor components
9 estimating the number and type of required integrity assessments, capital retrofits needed to enable ILI,
10 and repairs and pipeline replacements resulting from assessment findings. Labor consists of the
11 employees required to direct, oversee, execute, and ultimately manage compliance and program
12 requirements. Non-labor consists of contractors, materials, permitting, and other non-labor costs that are
13 necessarily incurred in relation to those requirements.

14 Consistent with evolving federal regulations, SoCalGas continues to evaluate and implement
15 enhanced TIMP processes and tools to maintain the integrity of the gas transmission pipeline system.
16 As previously described, federal compliance requirements have introduced changes to SoCalGas’s
17 TIMP processes and activities and highlight the impacts that retrofitting, repair, and replacement
18 activities have on SoCalGas’s overall TIMP capital costs.

19 When determined necessary through SoCalGas’s four-step assessment process, employing new
20 ILI tools such as those capable of assessing cracks and crack-like features (*e.g.*, EMAT) may result in
21 additional retrofitting when pipeline segments that were not previously ILI-capable, or were ILI-capable
22 but not compatible with crack detection tools, are considered potential candidates for cracking risks.
23 The increase in first-time ILI tool runs driven by enhanced federal requirements is expected to continue
24 through at least this current assessment cycle, during which SoCalGas will bring pipeline segments
25 under the TIMP into compliance with updated requirements. As previously described, assessment
26 method and tool selection is determined during the Pre-Assessment phase of O&M activities.

27 Capital repairs and replacements are also driven by the O&M activities and findings, and the
28 type and amount of work is dependent upon pipeline/project specific factors. When deploying new
29 assessment methods (*e.g.*, SCCDA) and assessment tools (*e.g.*, MFL-C, EMAT), the increase in pipeline
30 data for a pipeline project requires additional analysis which also leads to an increase in validation

excavations to confirm the data on pipeline conditions.⁸¹ Due to the overall increase in pipeline data and findings, SoCalGas has seen an increase in conditions requiring repair, previously described above (Non-shared O&M Costs). As a result of the increase in assessment findings combined with the enhanced GTSR Part 2 repair requirements for areas outside of HCAs, the increase in remediation is expected to continue at least through this current assessment cycle, which the independent study on SoCalGas’s TIMP and DIMP efficiency projected to 2030 based on a seven year reassessment cycle⁸², though SoCalGas anticipates that an increased level of activity through 2034 is plausible due to the ten-years maximum assessment/reassessment cycle of 49 CFR § 192.710.

Due to the variability and regulatory nature of SoCalGas’s TIMP Project Execution capital costs, SoCalGas requests continuation of the TIMPBA, but modified to revert back to a two-way balancing account with 50 percent interim rate recovery for capital-related costs and O&M costs, as further discussed in the GESI testimony (Ex. SCG-03).

D. High Pressure (HP) Distribution Assessments Execution (A02760)

TABLE DZ-30

**High Pressure Distribution Assessments Execution
Capital Expenditures Costs
(In 2025 \$)**

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
1. High Pressure Distribution Assessments Execution	0	0	0	15,680	15,681	15,679	15,682

1. Description and Background

The forecast for high pressure (HP) distribution assessment execution includes capital related costs necessary to complete integrity assessments on selected high priority, HP distribution pipeline segments. As part of prior safety initiatives, SoCalGas reduced operating pressures on certain transmission pipelines to below 20% SMYS, significantly lowering rupture risk. As a result, some pipelines formerly classified as transmission assets are now regulated as distribution assets but continue

⁸¹ See A.25-04-020, Chapter II: Technical – Project Execution and Management, Ex. SCG-02 at 12-14.

⁸² Ex. SCG-03, Appendix F (Section 5.6 Repairs).

1 to operate at higher pressures than typical distribution pipelines. Due to their operating history, age, and
2 construction characteristics, these HP distribution segments may be exposed to threats more commonly
3 associated with vintage transmission pipelines, including manufacturing-related defects in the pipe body,
4 pipe seams, or girth welds. To proactively identify and evaluate these potential threats, SoCalGas
5 proposes targeted integrity assessments such as robotic ILI technology where practicable. Conducting
6 TIMP-like assessments on these segments provides more detailed and actionable condition data than
7 traditional distribution-only inspection methods, enhancing threat identification, risk modeling, and
8 prioritization of mitigation activities.

9 ILI pipeline assessments are primarily O&M activities performed using specialized devices that
10 travel internally through the pipeline to collect data used to assess pipeline condition. However, capital
11 investments are required where pipeline retrofits are necessary to accommodate inspection tools. These
12 retrofits may include installation of pressure control fittings to provide entry and exit points for robotic
13 tools, valve replacements, or fitting modifications for adequate internal clearance. Once the retrofit is
14 completed, the inspection tool is run, followed by direct examinations to both validate the inspection
15 findings and determine necessary repairs, if needed.

16 **a. Description of RAMP Mitigations**

17 This cost category consists entirely of capital costs associated with the M171 risk
18 control/mitigation, M171 was not included in the 2025 RAMP Report as a mitigation, but rather as an
19 alternative mitigation, and is newly proposed in the 2028 GRC. The M171 HP Distribution Assessment
20 Execution activities identified in the section above are safety-driven risk mitigation measures associated
21 with SCG-Risk 2: High Pressure Gas system, identified in the 2025 RAMP Report. Activities that are
22 compliance-driven or mandated by the CPUC or other regulatory agencies are listed in bold. Appendix
23 B provides details regarding applicable mandates for each control.

1 **TABLE DZ-31**

2 **RAMP and GRC Risk Control/Mitigation Activities – Capital**

Transmission Integrity Management Program – TIMP (\$000s)				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 <i>In 2024 \$</i>	2028 GRC 2028-2031 <i>In 2025 \$</i>	Change
M171	High Pressure Distribution Assessments	24,192	62,722	38,530
TOTAL		24,192	62,722	38,530

3 **b. Description of Selection and Prioritization of RAMP Risk Mitigations**

4 SoCalGas selected this mitigation as a targeted assessment activity focused on high pressure
 5 distribution pipeline segments. In prioritizing this mitigation, SoCalGas considered factors such as
 6 pipeline age, stress level, and diameter. As described above, the proposed scope is limited to a small
 7 number of pipelines that share characteristics with pipelines subject to TIMP. The objective of this
 8 mitigation is to generate more comprehensive baseline condition data for selected high pressure
 9 distribution segments exposed to higher stress levels. This mitigation measure would enable SoCalGas
 10 to improve threat identification and risk assessment methodologies, such as those described in the GESI
 11 direct testimony (Ex. SCG-03), that will enhance risk mitigation activities and decision-making.

12 **2. Forecast Method**

13 The cost category uses a zero-based forecast informed by historical cost data and execution
 14 experience from comparable ILI projects. Construction cost estimates reflect previous work of similar
 15 scope in similar settings. HP distribution assessment costs are driven by variable conditions (*e.g.*,
 16 pipeline data, findings, and conditions) that are typically not known until the Pre-Assessment phase.

17 The FTE forecast is based on average FTE per dollar from TIMP historical data (P3120,
 18 002760). Staffing may include internal labor, contractors, overtime, or a combination thereof. The FTE
 19 estimate represents the average company labor required to complete this activity.

20 **3. Cost Drivers**

21 Primary capital cost drivers include the number of assessments and associated retrofits, repairs,
 22 and replacements. Labor costs reflect personnel required to direct, oversee, and execute assessments.
 23 Non-labor costs include contractors, materials, permitting, and other related expenses.

E. Compressor Station Compliance and Safety Programs (A03350, A04190, A0411A)

TABLE DZ-32

**Compressor Station Compliance and Safety Programs
Capital Expenditures Costs**

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
Compressor Station Compliance and Safety Programs	58,122	12,971	0	31,410	0	0	0

1. Description and Background

Capital forecasts for Compressor Station Compliance and Safety Programs are primarily driven by compliance with South Coast AQMD (SCAQMD) requirements. SoCalGas plans to place all remaining program elements in service by the Test Year.

These projects collectively support SoCalGas’s long-term strategy to modernize compressor assets, comply with air quality regulations, and enhance the safety and reliability of the gas transmission system. Major efforts include the Honor Rancho Compressor Modernization (HRCM) project and previously completed compliance work at Playa Del Rey (PDR), Aliso Canyon (AC), and Blythe Compressor Station.

a. Honor Rancho Compressor Modernization Project

The HRCM project is a compliance-driven effort required to address the sunset of South Coast AQMD RECLAIM program, and to comply with Rule 1110.2 and Rule 1100. In the TY 2024 GRC Decision, the Commission authorized costs up to \$525.2 million in direct 2021 dollars for the HRCM project, which SoCalGas was permitted to seek recovery for in a Tier 2 Advice letter once the project is completed and placed in service.⁸³ Within this GRC, SoCalGas is not requesting a modification to the authorized amount but instead is requesting an additional \$31.4 million . After adjusting the originally authorized costs based on direct 2021 dollars to nominal dollars, the requested amount equates to a 4.2% increase on an inflation-adjusted basis.

The original forecast at the time of submission for the 2024 GRC was a Class 3 estimate, consistent with AACE International Recommended Practice No. 18R-97, which denotes an estimated

⁸³ D.24-12-074 at 287-289

1 final project cost between -20% or +30% from the current project cost. Since the approval of the 2024
2 GRC, the project design has matured to 90% completion, revealing a clearer understanding of the
3 engineering scope, construction requirements and vendor pricing. Some of the changes include
4 additional staffing, extended schedule durations, and expanded project design requirements to improve
5 constructability, safety, and operability. Specifically, cost estimates increased due to commercial terms
6 with the Engineering, Procurement, and Construction (EPC) contractor. These combined factors, along
7 with the incremental design refinements, have contributed to the updated project forecast and the
8 resulting funding request. The requested increase remains well within the Class 3 estimate range.
9 Additional details are provided in supplemental workpaper (Ex. SCG-06-WP-S).

10 **b. Blythe Compressor Station Modernization Project**

11 In the SoCalGas TY 2019 and TY 2024 GRC Decisions, the Commission authorized capital
12 investments for the Blythe Compressor Modernization Project.⁸⁴ Blythe Station’s function is to receive
13 natural gas from the Kinder Morgan interstate pipeline and compress it westward into the Southern
14 System. The transmission pipelines that comprise the Southern System provide the natural gas supply to
15 Imperial County, Riverside County, San Diego County, parts of Orange County and parts of San
16 Bernardino County. SoCalGas noted completion of the construction, installation, and commissioning of
17 Plant 4 in the 2024 GRC. Retrofits to Units 11, 12, 14, and 15 have been completed and commissioned
18 in accordance with the facilities’ operating permit. In authorizing the Blythe Compressor Station
19 Modernization project, the Commission recognized the importance of compressor modernization
20 projects to maintain operational reliability and the safety of the gas transmission system.⁸⁵

21 Because the Blythe Compressor Station Modernization Project is fully complete and operational,
22 no additional capital funding is requested in this 2028 GRC cycle.

23 **c. Playa Del Rey and Aliso Canyon Regional Clean Air Incentives**
24 **Market Projects (PDR/AC RECLAIM Projects)**

25 Following the South Coast AQMD’s transition away from the NOx RECLAIM program,
26 SoCalGas completed required compliance projects (*e.g.*, retrofits and permitting updates) at PDR and
27 AC underground storage fields to meet Best Available Retrofit Control Technology (BARCT) standards
28 and update New Source Review (NSR) requirements. Specifically, the PDR/AC RECLAIM projects

⁸⁴ D.19-09-051 at 116-117; D.24-12-074 at 194-195, 1041-1042 (OP 38).

⁸⁵ D.19-09-051 at 116-117.

1 included engineering and installation of emissions-control retrofits (such as combustion modifications
 2 and selective catalytic reduction), permitting adjustments, and enhancements to monitoring systems to
 3 support compliance under the new command-and-control framework. All construction and testing work
 4 required to bring the emissions equipment at Playa Del Rey and Aliso Canyon underground storage
 5 fields into compliance is complete, and affected facilities now operate under BARCT and NSR
 6 protocols. Accordingly, no incremental capital costs are forecasted for this GRC cycle.

7 **2. Forecast Method**

8 A zero-based forecast is used for HRCM, relying on detailed project-specific estimates, vendor
 9 pricing, and execution experience. This approach is appropriate for costs exceeding the cost cap that
 10 cannot be supported by historical trends.

11 **3. Cost Drivers**

12 Primary cost drivers are non-labor and include costs associated with design refinements to the
 13 project to enhance operational safety and third-party project support needed from the extended schedule
 14 of the project. Labor costs reflect project execution, coordination, compliance, and closeout activities
 15 that are associated with the extended schedule of the project.

16 **F. Control Center Modernization (CCM) Ongoing Programmatic Activities (002500,**
 17 **004050)**

18 **TABLE DZ-32**
 19 **Control Center Modernization (CCM) Ongoing Programmatic Activities Capital**
 20 **Expenditures Costs**
 21 **(In 2025 \$s)**

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
Control Center Modernization Ongoing Programmatic Activities	28,497	18,611	25,299	27,594	27,595	27,585	27,534

22 **1. Description and Background**

23 The forecast for CCM Ongoing Programmatic Activities includes High-Consequence Area
 24 (HCA) Methane Sensor installations and Distribution Regulator Stations (DRS) enhancements. There
 25 are no incremental building-related costs requested in this General Rate Case. During this GRC cycle,

1 SoCalGas will continue deploying DRS enhancements and installing HCA Methane Sensors as part of
2 the Control Center Modernization (CCM) initiative originally authorized in D.19-09-051⁸⁶ and D.24-12-
3 074.⁸⁷

4 These activities enhance system safety and reliability by expanding visibility and control
5 capabilities across the gas network. Collectively, these investments strengthen operational resiliency
6 and situational awareness, through the ability to monitor and respond to abnormal operating conditions
7 in near-real time and support SoCalGas’s objectives to enhance public and employee safety, system
8 reliability, and operational effectiveness.

9 **a. CCM Distribution**

10 The DRS component of the program introduces real-time monitoring and remote-control
11 functionality at targeted regulator stations along high to medium pipelines, which provides Gas Control
12 with enhanced visibility into the dynamic pressures and flows across the gas distribution system. By
13 enabling Gas Control to remotely operate and control DRS sites, this represents a shift from a monitor-
14 and-respond approach to a monitor, operate, and control approach, allowing for faster response times
15 and reducing reliance on manual field intervention. This change in approach places increased emphasis
16 on safety, system reliability, data analytics, remote operations, and proactive maintenance. Overall,
17 these enhancements reduce both the likelihood and potential consequences of overpressure or under-
18 pressure events.

19 **b. CCM Transmission**

20 The CCM Transmission component includes the installation of HCA Methane Sensors, which
21 enables 24/7 control room monitoring personnel to accelerate the identification of, response to, and
22 remediation of potential leaks in high-risk locations along high-pressure pipelines using advanced
23 sensing technology. These sensors will help increase system reliability, support sustainability efforts,
24 and enhance the overall safety of our system.

25 During this GRC cycle, SoCalGas will transition the HCA Methane Sensor component to
26 Version 2 (V2) methane sensors, which will provide enhanced monitoring capabilities at a significantly
27 lower capital and O&M cost than the Version 1 sensors. The V2 sensors reduce installation complexity
28 and lifecycle costs, enabling SoCalGas to improve safety while increasing cost-effectiveness and

⁸⁶ D.19-09-051 at 127-132.

⁸⁷ D.24-12-074 at 112-115, 192-194.

1 affordability for ratepayers. Although this transition to the V2 sensor extends the end date of
 2 deployment to 2031, the cost of the overall project has decreased. Additional details on scope and cost
 3 estimates are provided in a supporting workpaper (Ex. SCG-06-CWP-S, Volume IV).

4 **c. Description of RAMP Mitigations**

5 All CCM Ongoing Programmatic Activities in this cost category are designated as RAMP
 6 mitigations. The DRS work aligns with mitigation C124 (Regulator Station Installation, Replacement &
 7 Enhancement), and the HCA Methane Sensor work aligns with mitigation C010 (Pipeline Monitoring
 8 Technologies). These mitigations were prioritized based on safety, reliability, and cost-effectiveness
 9 considerations, as reflected in the Benefit-Cost Ratio (BCR) analysis. While certain BCR values are
 10 below one, these activities provide substantial public safety benefits by reducing the likelihood and
 11 severity of incidents that could impact customers and communities.

12 **TABLE DZ-33**

13 **Control Center Modernization Ongoing Programmatic Activities – CCM (\$000s)**
 14 **RAMP and GRC Risk Control/Mitigation Activities – Capital**

ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$	2028 GRC 2028-2031 In 2025 \$	Change
C010	Pipeline Monitoring Technologies	14,770	18,537	3,767
C124	Regulator Station, Installation Replacement & Enhancement	118,302	91,771	(26,531)
TOTAL		133,072	110,308	(22,764)

15 **d. Description of Selection and Prioritization of RAMP Risk Mitigations**

16 RAMP risk mitigation activities consist of targeted programs, projects, processes, and
 17 technologies designed to address identified safety and/or reliability risks. Selection and prioritization
 18 considers many factors, including the Enterprise Risk Management (ERM) framework for identifying
 19 and assessing system risk, as described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B),
 20 safety impact, reliability benefits, technological maturity, and cost-effectiveness. Further details on the
 21 original site selection for DRS’s can be found in the 2024 GRC second revised Gas Transmission
 22 Operations and Construction testimony (Ex. SCG-06, Appendix E - Control Center Modernization –
 23 Enhanced Distribution Regulator Station Site Selection and Prioritization Approach) while details

1 regarding site selection of HCA Methane sensors can be found in the supplemental workpapers at
2 Ex. SCG-06-CWP-S, Volume IV.

3 **2. Forecast Method**

4 **a. CCM Distribution**

5 For the CCM Distribution, DRS enhancement component, a three-year historical average
6 forecast was applied to smooth out early project volatility associated with project execution and
7 subsequent close-out activities. This approach reflects the actual experience learned from project
8 execution and provides a normalized basis for projecting ongoing requirements beyond the
9 implementation phase.

10 **b. CCM Transmission**

11 For the CCM Transmission, HCA Methane Sensor component, a zero-based forecast was applied
12 as SoCalGas will deploy a new generation of methane sensors with materially different technology and
13 cost profiles than those reflected in the 2024 GRC. The zero-based estimates are based on vendor
14 quotes, engineering analysis, and anticipated deployment volumes rather than historical averages.

15 **3. Cost Drivers**

16 **a. CCM Distribution**

17 The underlying cost drivers are for project management, planning, designing, engineering,
18 permitting, construction and close out activities related to the enhancement of DRSs. Non-labor costs
19 include third-party engineering design, materials and equipment, permitting, project execution and
20 inspection support. Labor costs reflect the planning, permitting, project and construction management,
21 commissioning, and project documentation closeout activities that company employees perform.

22 **b. CCM Transmission**

23 The primary cost drivers for the HCA methane sensor project are driven by the technical
24 complexity of integrating new field detection capabilities into an existing control center environment,
25 rather than by relying on routine operations or regulatory compliance activities. Labor costs reflect the
26 project management, construction management, and business readiness activities that company
27 employees perform. Non-labor costs reflect contractor services for site design, installation, and
28 commissioning; procurement of advanced control and sensing equipment; and permitting and
29 environmental compliance for field installations. Supporting documentation is provided in the
30 accompanying workpaper (Ex. SCG-06-CWP-S, Volume IV).

G. Blowdown Reduction (A05960, A05900)

TABLE DZ-34

**Blowdown Reduction
Capital Expenditures Costs**

In 2025 \$ (000s)	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. Blowdown Reduction	4,181	9,652	9,646	8,644	7,344	7,343	7,345

1. Description of Costs and Activities

The cost forecast for Blowdown Reduction includes labor and non-labor expenses to implement and maintain SoCalGas’s blowdown operations, which supports compliance with the Natural Gas Leak Abatement Decisions.⁸⁸ The forecast also includes non-recurring procurement costs of Blowdown Reduction Equipment for 2028, including four medium trailers. These trailers replace aging equipment that are necessary to maintain the reliability and effectiveness of blowdown mitigation operations required under the Leak Abatement Decisions. The Blowdown Reduction Program is a cornerstone of SoCalGas’s emission reduction strategy and is a long-term operational and maintenance activity necessary to sustain performance. This program played a key role in achieving the 20% methane emissions reduction required by 2025 and remains critical to helping reach the state’s 40% reduction target by 2030 under SB 1371 and SB 1383.

Pursuant to D.17-06-015,⁸⁹ SoCalGas integrated blowdown-reduction best practices into its operational gas standards and procedures. Since inception, hundreds of projects have reduced emissions by minimizing gas releases during pipeline and valve replacements through coordinated planning with the CNG/LNG/Gas Capture (GC) Support Services Team.

Without continued investment in this program, SoCalGas would be unable to sustain mandated emissions reduction levels. All high-pressure pipeline blowdowns are managed through this program, and ongoing staffing and equipment support are essential to maintaining compliance with regulatory directives.

⁸⁸ D.17-06-015 and D.19-08-020.

⁸⁹ See D.17-06-015 at Appendix B (foundational Best Practices, Nos. 3, 4, 5, 6, 7, 23).

1 **2. Forecast Method**

2 The forecast for the Blowdown Reduction program is based on a four-year average (2022
3 through 2025). This approach mitigates the effect of atypically low 2025 activity caused by capital
4 project deferrals pending CPUC approval of Resolution G-3605, resulting in a more representative
5 forecast.

6 A zero-based forecast was developed for replacement of Blowdown Reduction equipment based
7 on procurement experience and historical pricing for medium capacity, trailer mounted CNG equipment,
8 as this method provides the most accurate representation of future costs.

9 **3. Cost Drivers**

10 Primary cost drivers include regulatory requirements, labor and contractor services (*e.g.*,
11 CNG/LNG/GC Support Services Team and Transmission operations staff), specialized equipment
12 rentals for large-volume projects, equipment procurement, and labor and equipment needed to
13 implement internal safety procedures. These costs reflect the technical and logistical demands of
14 minimizing vented emissions while maintaining operational safety and compliance.

15 These cost drivers reflect the technical and logistical demands of minimizing vented emissions
16 during pipeline operations while maintaining compliance with CPUC directives and internal
17 performance standards.

18 **VI. RISK ASSESSMENT MITIGATION PHASE (RAMP) INTEGRATION**

19 **A. Risk Controls/Mitigations and Benefit Cost Ratios**

20 As previously discussed, certain costs supported in this testimony are for Control/Mitigation
21 activities described in SoCalGas’s 2025 RAMP Report⁹⁰ for activities designed to reduce risk.
22 Specifically, the controls and mitigations in this testimony were included in: Chapter SCG-Risk-2 High-
23 Pressure Gas System and Chapter SCG-Risk-3 Medium-Pressure Gas System. As further reference, a
24 roadmap matching controls and mitigations to both the 2025 RAMP and the TY 2028 GRC testimony is
25 appended to the RDF Integration testimony, Ex. SCG-02B/SDGE-02B. Table DZ-36 below summarizes
26 the Control/Mitigation costs forecasted⁹¹ in this testimony and estimated in the 2025 RAMP with the
27 associated BCRs. Controls/Mitigations that are mandated by CPUC or other agencies are listed in bold

⁹⁰ A.25-05-010/013 (consolidated).

⁹¹ Post-test year forecasts can be found in the detailed workpapers Ex. SCG-28-WP and Ex. SCG-28-CWP.

in the table below and are listed in Appendix B, attached to this testimony, providing the details regarding the respective mandates for each Control/Mitigation.

TABLE DZ-36
Gas Major Projects
BCRs by Discount Rate

ID	Control/ Mitigation Name	2025 RAMP Direct, in 2024 \$ 2028-2031			2028 GRC Direct, in 2025 \$ 2028-2031		
		BCR Societal	BCR Hybrid	BCR WACC	BCR Societal	BCR Hybrid	BCR WACC
		C010	Pipeline Monitoring Technologies	1.46	1.10	0.93	7.27
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	0.35	0.25	0.22	0.89	0.34	0.27
C118	Rupture Mitigation Valve Installation – Valve Rule	0.28	0.08	0.08	0.47	0.13	0.13
C124	Regulator Station Installation Replacement & Enhancement	0.10	0.04	0.04	0.08	0.03	0.03
C171	Integrity Assessments & Remediation	3.97	3.82	3.43	4.17	3.89	3.54
C185	PSEP Phase 1B	0.51	0.12	0.08	0.44	0.11	0.08
C186	PSEP Phase 2A	0.23	0.05	0.04	0.13	0.11	0.10
M171	High Pressure Distribution Assessments	0.13	0.12	0.11	0.11	0.10	0.10

Note: Controls/Mitigations shown in bold font are those that are mandated by state or federal regulations.

1. Justification For Proposed Mitigations with BCRs <1

The RDF prescribes a methodology for calculating Benefit Cost Ratios under three discount rates, as detailed in the table above. While certain mitigations have BCRs below one under RDF methodology, SoCalGas justifies their inclusion based on operational and regulatory compliance considerations. Detailed justifications are provided in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B) and summarized in Table DZ-37, with supporting compliance drivers/mandates identified in Appendix B.

Table DZ-37

BCR <1 Justification

ID	Control/Mitigation Name	Justification
C185	PSEP Phase 1B	Compliance with Pub. Util. Code §§ 957–958. Replacing Pre-1946 transmission pipelines that cannot be assessed and were constructed using outdated methods.
C186	PSEP Phase 2A	Compliance with Pub. Util. Code §§ 957–958. Verifying records on transmission pipelines and validating integrity of the pipeline.
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	This mitigation is required for compliance with the PHMSA-issued GTSR Part 1. Operators must reconfirm the MAOP of high-pressure pipelines in populated areas in accordance with 49 CFR § 192.624(a).
C118	Rupture Mitigation Valve Installation – Valve Rule	This mitigation is required for compliance with the PHMSA-issued Valve Rule. Operators are required to perform a risk analysis of HCAs and determine where RMVs must be installed in accordance with 49 CFR § 192.935(c).
M171	High Pressure Distribution Assessments	This mitigation is a targeted assessment activity for high-pressure distribution pipeline segments based on factors such as pipeline age, stress level, diameter, and similarities to pipelines subject to TIMP. The mitigation is intended to generate baseline condition data for selected higher-stress segments and support improved integrity management decision-making. The BCR does not fully account for the foundational safety and reliability benefits that will result from integrating the collected data into integrity management planning, including improved understanding of these segments, enhanced risk modeling, and more targeted risk-informed investments.
C124	Regulator Station Installation Replacement & Enhancement	Continuation of activities authorized in the 2019 and 2024 GRCs to enhance the safety and reliability of the Gas Distribution system. This work aims to expand Gas Control’s ability to continuously monitor the system to enable faster identification of leaks and abnormal operating conditions (<i>e.g.</i> , high pressure gas moving into a medium pressure system resulting in a pipeline over-pressurization) so corrective actions can be taken as soon as practicable.

1 **2. Changes From 2025 RAMP Report**

2 Since the filing of the 2025 RAMP Report in May 2025, certain circumstances have changed that
3 affect the control/mitigation scope – including units, costs, and other factors underlying the forecasts
4 presented in this GRC. In addition, updates to assumptions used to calculate the BCRs are described in
5 the RDF Integration testimony (Ex. SCG-02B/SDGE-02B). The key changes are summarized below:

- 6 • C185 PSEP Phase 1B: Compared to the 2025 RAMP report, the TY 2028 GRC forecast
7 reflects higher unit counts and lower overall costs. This change is primarily driven by
8 incorporating the abandonment scope for Line 44-1008 once Supply Lines 44-306 and
9 44-307 are put in-service, and other forecast refinements.
- 10 • C186 PSEP Phase 2A: The TY 2028 GRC forecast reflects lower units and costs
11 compared to the 2025 RAMP Report, primarily due to differences in reporting
12 conventions between the two filings. Specifically, the reduction in reported units is
13 driven by the PSEP Line 235 West Hydrotest, which is a refundable project included in
14 the RAMP Report but not forecasted in this General Rate Case.
- 15 • C013 Gas Transmission Safety Rule - MAOP Reconfirmation: Relative to the 2025
16 RAMP report, the TY 2028 GRC forecast reflects lower units and costs due to updated
17 scope validation and refinement of MAOP reconfirmation activities.
- 18 • C118 Rupture Mitigation Valve Installation - Valve Rule: The TY2028 GRC forecast
19 includes fewer valve installations but higher overall costs compared to the 2025 RAMP
20 report. This reflects refinement of the forecasted Valve Rule compliance scope informed
21 by actual historical unit costs from the Valve Enhancement Program (VEP). In contrast,
22 the initial RAMP estimates were preliminary and based on higher-level assumptions.
- 23 • C171 Integrity Assessments & Remediation: TIMP forecast updates are informed by the
24 latest assessment plan information, evolving compliance requirements, and updated
25 assumptions regarding planned integrity assessment and remediation activity. The
26 number of forecasted projects and associated costs have been updated to reflect the latest
27 projections.
- 28 • M171 High Pressure In Line Inspection: M171 is a new mitigation since the 2025 RAMP
29 report. It is a targeted subset of A171 with a narrower scope limited to select pipeline
30 segments. The cost reflects updated estimates based on more detailed engineering
31 evaluation and technology selection.

- 1 • C124 Regulator Station Installation Replacement & Enhancement: The TY2028 GRC
2 forecast reflects lower units and costs than the 2025 RAMP report due to updates to the
3 annual project execution pace. The 2025 RAMP projections were based on planning-
4 level assumptions that anticipated higher steady-state activity, whereas the TY2028 GRC
5 forecast reflects a revised installation schedule informed by recent project execution and
6 updated assumptions.
- 7 • C010 Pipeline Monitoring Technologies: The TY2028 GRC forecast reflects schedule
8 and cost changes relative to the 2025 RAMP report driven by the transition from V1 to
9 V2 sensors. The 2025 RAMP report assumed installation of V1 sensors through 2029;
10 however, following the transition to V2 sensors, installations continue through 2031 and
11 reflect lower overall costs. As a result, the TY2028 GRC forecast shows a longer
12 installation timeline with more refined cost assumptions compared to the initial RAMP
13 estimates.

14 3. Feedback from Safety Policy Division and Parties

15 The Commission’s Safety Policy Division (SPD) issued its assessment of the Companies’ 2025
16 RAMP Reports on October 10, 2025. Parties submitted opening and reply comments on November 17,
17 2025 and December 1, 2025, respectively. Appendix B of the RDF Integration testimony (Ex. SCG-
18 02B/SDG&E-02B) summarizes the feedback received and the Companies’ responses.

19 VII. CLIMATE ADAPTATION VULNERABILITY ASSESSMENT (CAVA) INTEGRATION

20 Pursuant to Commission direction in the Climate Adaptation OIR (R.18-04-019),⁹² SoCalGas
21 prepared and filed in 2025 its CAVA evaluating system vulnerabilities in the 2030, 2050, and 2070
22 timeframes. The assessment identified asset and operational vulnerabilities to climate hazards such as
23 extreme heat, wildfire, inland and coastal flooding, coastal erosion, and landslides. Climate change is
24 recognized as a factor that can drive, trigger, or exacerbate multiple RAMP risks. Integrating climate
25 vulnerability considerations into RAMP controls and mitigations can enhance system infrastructure
26 longevity and reduce the severity of long-term negative climate impacts. The controls and mitigations
27 described in this chapter support SoCalGas’s objective of enhancing physical and operational resilience as
28 climate hazards increase in frequency and severity. Additional information is provided in Table DZ-38.

29 Table DZ-38

⁹² D.19-10-054; D.20-08-046.

**Gas Major Projects - Controls and Mitigations
that Align with Increasing Resilience to Climate Hazards**

Potential Climate Hazard(s)	Relevant ID	Relevant Control / Mitigation	Risk Chapter
Inland Flooding and Landslides	C010	Pipeline Monitoring Technologies	High-Pressure Gas System
Inland Flooding and Landslides	C013	Gas Transmission Safety Rule - MAOP Reconfirmation	
Inland Flooding and Landslides	C171	Integrity Assessments & Remediation	
Inland Flooding and Landslides	C185	PSEP Phase 1B	
Inland Flooding and Landslides	C186	PSEP Phase 2A	
Inland Flooding, Landslides, and Wildfires	C124	Regulator Station Installation Replacement & Enhancement	Medium-Pressure Gas System

VIII. PSEP PHASE 1 REASONABLENESS REVIEW

A. Introduction

The purpose of this section of testimony is to present for reasonableness review the activities associated with 13 Phase 1A and two Phase 1B PSEP pipeline projects, and one PSEP valve project completed primarily between January 2020 and December 2025, representing approximately six miles of transmission pipeline. This section describes how SoCalGas prudently executed 16 pipeline and valve projects in compliance with D.11-06-017, subsequent Commission decisions, and Cal. Public Util. Code § 957 and 958.

This testimony describes how:

- the PSEP organizational framework supported effective program and project oversight;
- prudent execution of PSEP projects mitigated implementation challenges, maximized efficiencies, and advanced construction to completion safely, and as soon as practicable; and
- SoCalGas’s actions enhanced safety, satisfied Commission and statutory directives, minimized impacts to customers and communities, and avoided and/or reduced costs.

1 Consistent with one of the core PSEP objectives adopted in D.14-06-007, PSEP maximized the
2 cost-effectiveness of safety investments through its commitment to affordability through scope
3 validation, thoughtful project sequencing, disciplined procurement, and the Performance Partnership
4 Program to improve contractor cost performance. SoCalGas acted as a reasonable manager by making
5 decisions based on the information available at the time, exercising professional judgment, and
6 balancing safety, cost, constructability, and community impacts. Accordingly, SoCalGas seeks
7 reasonableness of the activities and associated costs to allow full recovery of mandated PSEP projects
8 executed during this period. As discussed in the Regulatory Accounts testimony (Ex. SCG-21), the
9 remaining revenue requirement amount that would be incorporated in rates reflects 50% interim rate
10 recovery subject to refund pending reasonableness pursuant to D.16-08-003.

11 This testimony also fulfills the additional requirements set forth in D.24-12-074, including the
12 provision of providing more information regarding cost variance explanations.

13 **B. Reasonableness Review Projects Summary of Costs**

14 This testimony presents the reasonableness of approximately \$108 million in capital
15 expenditures and \$13 million in O&M expenditures incurred in executing 13 Phase 1A and 2 Phase 1B
16 PSEP pipeline projects and one PSEP valve project. As discussed in the Regulatory Accounts testimony
17 (Ex. SCG-21), SoCalGas seeks recovery of an estimated revenue requirement associated with these
18 expenditures of approximately \$25.5 million in rates, as of December 31, 2027.⁹³ This revenue
19 requirement has been calculated as net of the amounts already being recovered in rates via the 50%
20 interim rate recovery mechanism the Commission adopted in D.16-08-003. While SoCalGas requests
21 findings that the underlying capital and O&M expenditures are just and reasonable, the recovery sought
22 in rates during this GRC reflects the remaining unrecovered balances for these projects.

23 As authorized by D.14-06-007, this testimony describes the PSEP cost components, application
24 of the Commission-approved Decision Tree, calculation of disallowed costs, and reconciliation of the
25 “as filed” forecasted mileage versus the actual project mileage. The costs discussed herein support
26 balances recorded in the Safety Enhancement Capital Cost Balancing Account (SECCBA) and Safety
27 Enhancement Expense Balancing Account (SEEBA). Detailed project-level information is provided in
28 the supporting project workpapers.

⁹³ The final revenue requirement will be updated to reflect the actual balance as of December 31, 2027, upon issuance of a final decision.

1 **1. Project Cost Components**

2 The PSEP costs presented were incurred through December 31, 2025. The associated revenue
3 requirement treatment is addressed in Ex. SCG-21, Regulatory Accounts testimony. The project costs
4 include direct project costs (e.g., hydrotest, replacement, or valve projects), programmatic support
5 costs⁹⁴, and indirect costs.⁹⁵ Depending on project scope, costs may be capital or O&M. For example,
6 hydrotesting activities are predominantly O&M, however certain activities are capitalized consistent
7 with SoCalGas’s accounting policy (e.g., pipe replacement for test head installation or anomaly
8 remediation). As part of the normal hydrotesting process, a section of the existing pipeline is removed
9 to accommodate temporary test heads that are used to conduct the hydrotest. After the line is tested and
10 the temporary test heads are removed, a new section of pipe is installed to “tie-in” the just-tested
11 segment to the pipeline on either end of the segment. The tie-in pipe is new pipe and is capitalized.
12 Other capital costs typically associated with hydrotests may be due to short replacements necessary to
13 address anomalies or to allow for future inline assessment through the use of smart pigs.

14 The project costs included for review are fully loaded. They include direct and indirect costs
15 charged and/or allocated to projects. Direct cost categories include:

- 16 • Company Labor: Labor costs for SoCalGas employees charging directly to the project,
17 such as project managers, engineers, land services personnel, environmental services personnel,
18 communication and outreach managers, construction managers, and field support personnel.
- 19 • Materials: Costs for materials that SoCalGas purchased to complete the project, such as
20 piping, valves, fittings, and other miscellaneous materials. Materials planned to be purchased by the
21 construction contractor may be included in the construction contractor costs.
- 22 • Construction Contractor: Costs for Construction Contractor activity and materials or
23 equipment acquired by the contractor. The actual Construction Contractor costs include authorized
24 change order costs and risk-reward payments minus construction credits, when applicable.
- 25 • Construction Management and Support: Costs for construction inspection, contamination
26 mitigation, environmental monitoring, hydrotesting services, and other miscellaneous activities that
27 occur in the field.

⁹⁴ PSEP organizational costs not attributable to a specific project (i.e., PSEP General Management and Administration costs) are allocated to hydrotest, replacement, abandonment, and valve projects.

⁹⁵ Certain company overhead costs are deemed incremental to PSEP and subject to recovery as they are associated with incremental PSEP activities. The applicable incremental overheads are included in the costs presented for review in this Application.

1 • Environmental: Costs for environmental assessments, monitoring, asbestos abatement,
 2 water and waste management, and miscellaneous environmental permits and fees not reflected in other
 3 cost categories.

4 • Engineering and Design: Costs for planning and design services, engineering,
 5 environmental services, land use and permitting fees not included in other categories, and project
 6 support, such as survey, mapping, and miscellaneous expenses.

7 • Project Management Services: Contracted costs for project management services and
 8 general PSEP program support.

9 • General Administration Costs (GMA): Programmatic PSEP costs.

10 The supplemental PSEP workpapers also include indirect costs. Indirect costs are incremental
 11 overheads applied to PSEP projects. Indirect costs include payroll taxes, pension and benefits,
 12 allowance for funds used during construction (AFUDC), and property tax on construction work in
 13 progress (CWIP). Additional information, which is applicable to PSEP, is provided in the Rate Base
 14 testimony (Ex. SCG-23) and the Tax testimony (Ex. SCG-25/SDGE-30).

15 **2. Summary of Project Costs**

16 **a. Replacement Projects**

17 **Table DZ-39**

18 **Replacement Projects**

19 **Summary of Capital and O&M Costs (in Fully Loaded \$000's)**

Project	Capital	O&M	Total
Supply Line 31-25 Replacement Project	7,140	-	7,140
Supply Line 44-675 Lateral Replacement Project	1,921	-	1,921
Line 38-1102 PSEP Project	2,770	-	2,770
Line 31-6349 Phase 1A Replacement	106	55	161
Supply Line 36-9-09 North Section 5B-01	5,436	-	5,436
Line 2001 West Santa Ana River Project	40,360	-	40,360
Supply Line 31-08 Replacement Project	1,340	343	1,683
Supply Line 33-750 Haskell Station	18,055	-	18,055

Project	Capital	O&M	Total
Project			
Alhambra Station Piping	2,463	-	2,463
Supply Line 35-20 PSEP Project	3,778	-	3,778
Supply Line 32-09 PSEP Project	2,370	-	2,370
Total	85,739	398	86,137

b. Hydrotest Projects

Table DZ-40

Hydrotest Projects

Summary of Capital and O&M Costs (in Fully Loaded \$000's)

Project	Capital	O&M	Total
Supply Line 31-09-C Hydrotest Project	812	2,946	3,758
Line 1004 Section 1 and 3 Hydrotest Project	527	4,712	5,239
Supply Line 33-750 Hydrotest Project	1,674	4,258	5,932
Line 128 PSEP Project	18,619	1,138	19,757
Total	21,632	13,054	34,686

c. Valve Project

Table DZ-41

Valve Project

Summary of Capital and O&M Costs (in Fully Loaded \$000's)

Project	Capital	O&M	Total
Wilmington Lecouvreur Ave & F St Enhancement Valve Project	1,072	-	1,072
Total	1,072	-	1,072

3. Miscellaneous Costs

a. Post Completion Construction

Post-completion cost adjustments totaling \$76,954 are included for projects previously reviewed in A.16-09-005. Post-completion adjustments arise from contractor invoices, accrual true-ups, labor charges, and journal entries processed after the application filing for reasonableness review.

1 **4. Disallowed Costs**

2 Consistent with D.14-06-007 (as modified by D.15-12-020), SoCalGas has excluded from
 3 recovery specified disallowed costs totaling approximately \$1.5 million, including post-1955 pipe costs
 4 and executive incentive compensation. Table DZ-42 summarizes the relevant disallowed costs for
 5 review.

6 **Table DZ-42**
 7 **Disallowed Costs**
 8 **Summary of Costs (in \$000's)**

Disallowance Type	Total
Post-1955 PSEP Costs	1,548
Undepreciated Book Balances	-
Executive Incentive Compensation	1
Records Search	-
Total	1,549

9 **5. PSEP Mileage Reconciliation**

10 In compliance with D.14-06-007, Table DZ-43 reconciles “as filed” forecasted mileage with the
 11 actual mileage that was hydrotested, replaced or abandoned for the projects included in this filing.⁹⁶

12 **Table DZ-43**
 13 **Pipeline Projects**
 14 **Mileage Summary**

Line	As Filed (Miles)	Included in this Filing	
		(Miles)	(Feet)
Supply Line 31-25 Replacement Project	N/A	0.157	828
Supply Line 44-675 Lateral Replacement Project	0.011	0.024	127
Line 38-1102 PSEP Project	N/A	0.035	185
Supply Line 36-9-09 North Section 5B-01	16.016	0.143	756
Line 2001 West Santa Ana River	64.100	0.559	2,951

⁹⁶ The “as filed” mileage is consistent with the workpapers included with the SoCalGas and SDG&E Amended PSEP Application (A.11-11-002) filed in December of 2011.

Project			
Supply Line 31-08 Replacement Project	N/A	0.008	42
Supply Line 33-750 Haskell Station Project	N/A	0.117	615
Alhambra Station Piping	N/A	0.006	34
Supply Line 35-20 PSEP Project	N/A	0.082	432
Supply Line 32-09 PSEP Project	N/A	0.005	29
Supply Line 31-09-C Hydrotest Project	N/A	1.347	7,111
Line 1004 Section 1 and 3 Hydrotest Project	12.718	2.504	13,222
Supply Line 33-750 Hydrotest Project	N/A	0.926	4,888
Line 128 PSEP Project	N/A	0.466	2,460
Line 31-6349 Replacement Project	N/A	0.001	3
Total	92.845	6.316	33,356

1 **C. Reasonableness of PSEP Costs**

2 SoCalGas implemented PSEP with prudent management, informed decision making, and
3 disciplined execution. PSEP has followed the effective program governance, cost controls, and project
4 management principles discussed above in Section II – Affordability & Efficiency. These practices,
5 refined over the program’s lifecycle, have been central to PSEP’s success. This section describes the
6 Reasonable Manager Standard, which serves as a foundational basis for the actions taken by SoCalGas
7 and the PSEP organization in its implementation of the program. Also included in this section is
8 additional information that demonstrates the reasonableness of SoCalGas’ actions implementing the
9 PSEP program.

10 **1. Reasonable Manager Standard**

11 Consistent with D.24-12-074, SoCalGas demonstrates reasonableness under the “reasonable
12 manager standard” articulated in D.90-09-088 and reaffirmed in D.05-01-054. This standard evaluates
13 actions based on what a reasonable manager would have done given the information available at the
14 time, not on hindsight or perfection: “The act of the utility should comport with what a reasonable
15 manager of sufficient education, training, experience and skills using the tools and knowledge at his
16 disposal would do when faced with a need to make a decision and act. The action taken should logically

1 be expected, at the time the decision is made, to accomplish the desired result at the lowest reasonable
2 cost consistent with good utility practices.”⁹⁷ Similarly, in D.05-01-054, the Commission recognized
3 that “[t]here’s a range of outcomes that defines reasonableness, and it’s based on what the manager
4 knew or should have known at the time that the decision was made.”⁹⁸

5 The Commission has repeatedly recognized SoCalGas’s adherence to this standard, finding over
6 99% of prior PSEP costs reasonable. Nonetheless, SoCalGas continues to seek efficiencies and cost
7 effectiveness in support of the Commission’s affordability objectives.

8 In D.14-06-007, which originally adopted the proposed PSEP analytical approach/decision tree
9 and established balancing accounts to record costs for Phase 1 projects, the Commission further
10 commented on the standard of review that would be undertaken consistent with its earlier rulings on the
11 reasonable manager standard: “When SDG&E and SoCalGas file applications to demonstrate the
12 reasonableness of Safety Enhancement they will bear the burden of proof that the companies used
13 industry best practices and that their actions were prudent. This is not a ‘perfection’ standard: it is a
14 standard of care that demonstrates all actions were well planned, properly supervised and all necessary
15 records are retained.”⁹⁹ D.14-06-007 builds upon a similar statement in D.90-09-088 where the
16 Commission found that “the reasonable and prudent act is not limited to the optimum act, but includes a
17 spectrum of possible acts consistent with the utility system need, the interest of the ratepayers, and the
18 requirements of governmental agencies of competent jurisdiction.”¹⁰⁰ The Commission’s use of the
19 terms “perfection standard” and “optimum act” is important to consider in light of the uniqueness and
20 complexity of the PSEP projects presented herein, which were subject to various outcomes during their
21 respective project life cycles that influenced costs. In each situation, SoCalGas properly exercised its
22 engineering and execution experience to achieve the most reasonable, cost-effective outcomes for
23 ratepayers.

⁹⁷ D.90-09-088 at 171 (FOF 14).

⁹⁸ D.05-01-054 at 14.

⁹⁹ D.14-06-007 at 36.

¹⁰⁰ D.90-09-088 at 171 (FOF 14).

1 **2. Full-Time Equivalents (FTEs) Calculation**

2 FTEs were calculated based on actual labor charged to projects over their active periods,
3 adjusted for standard work hours and Vacation & Sick consistent with PSEP Track 3 of the 2024 GRC:

- 4 • The total hours charged to a project by company employees were calculated for the years
5 a project was active;
- 6 • The total workable hours were calculated for the same time period using the standard
7 assumption of 8-hour working days, 5 days per week, and proportionally adjusted for the
8 first year and last year in which the project was active;
- 9 • The total charged hours were divided by the total workable hours to derive the
10 “Unadjusted FTE;”
- 11 • Vacation and Sick (V&S) factors for SoCalGas are consistent with those presented in
12 2024 GRC Track 1;
- 13 • The maximum V&S value was isolated for the time period in which the project was
14 active;
- 15 • The Unadjusted FTE was multiplied by the maximum V&S factor to derive the average
16 number of FTEs directly charging to a project throughout its lifecycle.¹⁰¹

17 **3. Cost Variances**

18 SoCalGas’s supplemental workpapers submitted herewith (provided as Ex. SCG-06-WP-S,
19 Volume V) explain project-specific variances between estimated and actual costs. The estimates are
20 derived from a Total Installed Cost (TIC) estimate.¹⁰² Consistent with industry-standard estimating
21 practices established by the Advancement of Advance of Cost Engineering International (ACEi¹⁰³),
22 the TIC is classified within the Class 3 level, which is characterized by a maturity level of 10-40%
23 (more typically 30%) and an estimate accuracy range of -20% on the low end to +30% on the high
24 end.¹⁰⁴ According to ACEi, the Class 3 level end use is appropriate to form the basis for budget
25 authorization, appropriation, and/or funding and “to support full project funding requests and become

¹⁰¹ The FTE calculation excludes General Management and Administration (GMA) costs, which are non-project specific charges that are incurred to support the implementation of the PSEP program.

¹⁰² TIC estimate is synonymous with “Estimate at Completion”, which is defined as: “an estimate of the total cost an activity or group of activities will accumulate upon final completion.” ACEi Recommended Practice No. 10S-90, Cost Engineering Terminology, available at: <https://library.aacei.org/terminology/welcome.shtml#E>.

¹⁰³ ACEi is an industry-leading association of cost estimating professionals.

¹⁰⁴ ACEi, Recommended Practice No. 97R-18 Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Pipeline Transportation Infrastructure Industries (ACEi RP 97R-18) (August 7, 2020) at 4, 10.

1 the first of the project phase control estimates against which all actual costs and resources will be
2 monitored for variations to the budget.”¹⁰⁵ ACEi also states: “[Class 3 estimates] are used as the
3 project control budget until replaced by more detailed estimates. In many owner organizations, a Class
4 3 estimate is often the last estimate required and could very well form the only basis for cost/schedule
5 control.”¹⁰⁶ Once the TIC is finalized, SoCalGas moves forward with budget authorization through the
6 Work Order Authorization (WOA) process. The TIC, which includes direct costs only, is supplemented
7 with indirect costs. Together the direct and indirect costs are combined into the Phase 2 WOA. The
8 approval of the Phase 2 WOA by GMP leadership is required to proceed with the execution of a
9 project.¹⁰⁷

10 In aggregate, the portfolio of the 16 SoCalGas pipeline and valve projects presented for review
11 was approximately \$23 million or 23 percent above the estimated costs (\$122 million actual versus \$99
12 million estimated). While the aggregated actual costs are within ACEi Class 3 estimate accuracy
13 ranges, individual pipeline and valve project actuals may vary above or below estimated amounts. As
14 directed by the Commission in D.24-12-074, the revised workpapers provide explanations for variances
15 on an individual project basis.

16 As mentioned above, the accepted accuracy range for a TIC/Class 3 estimate is -20% to +30%.
17 This range reflects that TIC estimates are generated when the project has yet to advance through detailed
18 design. Notwithstanding the level of rigor inherent to this process, each PSEP project is unique, and
19 foreseeable and unforeseeable conditions may be encountered during construction, resulting in actual
20 expenditures varying from estimates. Furthermore, between completing the detailed project cost
21 estimates and the start of construction, construction, contractor, and material costs may change, new
22 environmental regulations may be enacted, and other external forces.

23 Variances reflect normal construction uncertainties, including subsurface conditions, permitting
24 challenges, scheduling changes, cost inflation, and external factors (e.g., COVID-19). Longer
25 construction durations increase associated labor, contractor, and overhead costs. For example, the

¹⁰⁵ *Id.*

¹⁰⁶ *Id.* at 10.

¹⁰⁷ Any significant project activities and costs subsequently added to the project scope after execution of the TIC—such as during detailed design or construction—would not be reflected in the estimated costs presented in the supplemental workpaper. These additional costs and activities are authorized and documented through the scope change process. If these additional costs exceed a certain threshold, a reviewed Work Order Authorization must be obtained.

1 COVID-19 global pandemic exemplifies how costs can be driven upward by added health and safety
2 protocols. Other examples may include prolonged construction durations that arise from challenges
3 experienced in the field that were not reasonably anticipated at the time of the initial estimate. These
4 challenges may include unanticipated conditions when conducting potholing and geologic investigations
5 to ascertain the subsurface conditions of a project site, which could result in deviations from planned
6 trenching or boring methods under existing roads, railways, water crossings or other physical
7 impediments to pipeline installation. In some cases, these challenges may even cause the need to
8 demobilize from the project site to redesign certain project elements. Detailed explanations for each
9 project are provided in the supplemental workpapers.

10 **IX. CONCLUSION**

11 In summary, GMP is responsible for the prudent execution of complex gas infrastructure and
12 pipeline safety programs that are predominantly driven by state and federal safety and compliance
13 requirements. These programs, including PSEP, GSEP Execution, TIMP Execution, and Compressor
14 Station Compliance and Safety Programs, and Control Center Modernization Ongoing Programmatic
15 activities, are designed to reduce risk, enhance public and workforce safety, and improve system
16 integrity and reliability. Many of these investments are direct responses to regulatory mandates issued
17 following major pipeline incidents and reflect Commission and PHMSA directives to bring legacy
18 pipeline facilities into compliance with modern safety standards.

19 While compliance and safety are the primary drivers of these programs, GMP executes this work
20 with a strong focus on affordability and operational efficiency. GMP applies risk-based prioritization,
21 integrated planning, and disciplined project governance to sequence and coordinate work in a manner
22 that minimizes customer and community impacts while optimizing costs. Centralized program
23 management, standardized delivery processes, cross program coordination, and prudent procurement
24 practices enable GMP to reduce redundant mobilization, minimize outages, and capture efficiencies
25 across programs. Through these approaches, GMP advances regulatory compliance and system safety
26 objectives while exercising careful stewardship of customer dollars consistent with the Commission's
27 emphasis on affordability and prudent infrastructure investment.

28 This concludes my prepared direct testimony.

1 **X. WITNESS QUALIFICATIONS**

2 My name is Devin K. Zornizer. I work in Los Angeles, California. I am employed by SoCalGas
3 as Vice President of Infrastructure Project Delivery with responsibility for SoCalGas and SDG&E's Gas
4 Major Projects execution where I am responsible for executive leadership and oversight of infrastructure
5 programs, major project delivery, and operational support functions. My career experience includes
6 work in engineering design, field operations, and project execution, providing a comprehensive
7 understanding of infrastructure assets across their full life cycle. I have over 25 years of professional
8 experience in engineering, project management, and operations. Throughout my career, I have held
9 positions of increasing responsibility involving the planning, design, construction, and operation of
10 critical energy and infrastructure systems. My experience includes direct oversight of pipeline and
11 compressor station operations, 24-hour control room operations, engineering, safety, and operational
12 functions to support safe, reliable system performance. I hold a Bachelor of Science degree in Civil
13 Engineering from California State Polytechnic University, Pomona. I am a Registered Professional
14 Engineer in the State of California (RCE 67723). My education, professional licensure, and extensive
15 industry experience have provided me with substantial technical, operational, and leadership
16 qualifications relevant to the matters addressed in this proceeding. I have previously testified before the
17 Commission.

APPENDIX A
GLOSSARY OF TERMS

APPENDIX A

Glossary of Terms

ACRONYM	DEFINITION
AACEi	Advancement of Advance of Cost Engineering International
AC	Aliso Canyon
ACVG	Alternating Current Voltage Gradient
AFUDC	Allowance for Funds Used During Construction
ANPRM	Advanced Notice of Proposed Rulemaking
ANSI	American National Standards Institute
AQMD	Air Quality Management District
ASME	American Society of Mechanical Engineers
BARCT	Best Available Retrofit Control Technology
BCR	Benefit-Cost Ratio
CARB	California Air Resources Board
CAVA	Climate Adaptation Vulnerability Assessment
CCM	Control Center Modernization
CFR	Code of Federal Regulations
CIS	Close Interval Surveys
CNG	Compressed Natural Gas
CPUC	California Public Utilities Commission
CWIP	Construction Work in Progress
D	Decision
DCVG	Direct Current Voltage Gradient
DOO	Date of Operation
DOT	Department of Transportation
DRS	Distribution Regulator Stations
ECA	Engineering Critical Assessment
ECDA	External Corrosion Direct Assessment
EMAT	Electromagnetic Acoustic Transducer
EPA	Environmental Protection Agency

ACRONYM	DEFINITION
EPC	Engineering, Procurement, and Construction
ERM	Enterprise Risk Management
FERC	Federal Energy Regulatory Commission
FOF	Finding of Fact
FTE	Full Time Equivalent
GC	Gas Capture
GESI	Gas Engineering and System Integrity
GIS	Geographic Information System
GMA	General Administration Costs
GMP	Gas Major Projects
GRC	General Rate Case
GSEP	Gas Safety Enhancement Programs
GTP	Gas Transmission Planning
GTSR	Gas Transmission and Gathering Rulemaking
GWUT	Guided Wave Ultrasonic Testing
HCA	High Consequence Area
HDD	Horizontal Directional Drilling
HP	High Pressure
HRCM	Honor Rancho Compressor Modernization
Hydrotests	hydrostatic testing
ILI	In Line Inspection
KPI	Key Performance Indicators
LNG	Liquified Natural Gas
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
MFL-C	Circumferential Magnetic Flux Leakage
MOP	Maximum Operating Pressure
MSCF	Million Standard Cubic Feet
NACE	National Association of Corrosion Engineers
NOP	Notice of Operation

ACRONYM	DEFINITION
NSR	New Source Review
O&M	Operations and Maintenance
P&M	Preventive & Mitigative
PDM	Project Delivery Model
PDR	Playa Del Rey
PEP	Project Execution Plan
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIEx	Pipeline Integrity Execution
PIR	Potential Impact Radius
PMO	Project (or) Program Management Office
PSEP	Pipeline Safety Enhancement Plan
RAMP	Risk Assessment Mitigation Phase
RDF	Risk-Based Decision-Making Framework
RECLAIM	Regional Clean Air Incentives Market
RFP	Request for Proposal
RMV	Rupture Mitigation Valves
ROW	Right-of-Way
SCAQMD	South Coast Air Quality Management District
SCC	Stress Corrosion Cracking
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SCG	Southern California Gas Company
SDGE	San Diego Gas and Electric
SECCBA	Safety Enhancement Capital Cost Balancing Account
SED	Safety and Enforcement Division
SEEBA	Safety Enhancement Expense Balancing Account
SI Associates	Structural Integrity Associates, Inc.
SL	Supply Line
SMYS	Specified Minimum Yield Strength

ACRONYM	DEFINITION
SPD	Safety Policy Division
SVP	Senior Vice President
SVP	Senior Vice President/Chief Infrastructure Officer
TIC	Total Installed Cost
TIMP	Transmission Integrity Management Program
TIMPBA	TIMP Balancing Account
TY	Test Year
V2	Version 2
Valve Rule	Valve Installation and Minimum Rupture Detection Standards
VEP	PSEP Valve Enhancement Plan
WOA	Work Order Authorization
YE	Year End

APPENDIX B
GAS MAJOR PROJECTS
CONTROLS AND MITIGATIONS COMPLIANCE DRIVER ROADMAP

APPENDIX B

GAS MAJOR PROJECTS

CONTROLS AND MITIGATIONS COMPLIANCE DRIVER ROADMAP

The table below indicates the compliance drivers that underpin activity identified in testimony.

RAMP Control/ Mitigation ID	Activity / Control/Mitigation Name	Compliance Driver
C010	Pipeline Monitoring Technologies	N/A
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	49 CFR § 192.624
C118	Rupture Mitigation Valve Installation – Valve Rule	PHMSA “Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards” final rule (49 CFR Parts 192 and 195)
C124	Regulator Station Installation Replacement & Enhancement	N/A
C171	Integrity Assessments & Remediation	49 CFR Part 192, Subpart O 49 CFR § 192.710
C185	PSEP Phase 1B	California Public Utilities Code Sections 957 and 958
C186	PSEP Phase 2A	California Public Utilities Code Sections 957 and 958
M171	High Pressure Distribution Assessments	N/A

APPENDIX C

PSEP STATUS AND COMPLIANCE WITH D.24-12-074

APPENDIX C

PSEP STATUS AND COMPLIANCE WITH D.24-12-074

In its treatment of the PSEP forecast in D.24-12-074, the Commission required SoCalGas to describe how its PSEP hydrotest implementation plan complies with Public Utilities Code (PUC) Section 958 and pertinent federal regulations¹ and report the dates when each of the hydrotest and capital pipeline replacement projects included in its forecast were completed, as well as the anticipated completion dates of remaining projects.² The following section describes the requirements of PUC 958, how SoCalGas's PSEP program is executed in alignment with this important regulation, the status of the forecasted projects, and how other pertinent federal regulations are being addressed by SoCalGas.

A. PUC 958

Public Utilities Code 958, which became effective on January 1, 2012, codified the requirements promulgated by the Commission in D.11-06-017, which initially established the fundamental elements for each California gas utility's pressure testing implementation plan in the wake of the San Bruno incident.

B. SoCalGas's Compliance with PUC 958 and Status of PSEP

SoCalGas has complied with PUC Section 958 since the inception of its PSEP program. SoCalGas's PSEP was filed in August 2011 according to the mandates set forth in D.11-06-017, and was approved by the Commission in D.14-06-007, which adopted the Decision Tree framework governing whether pipelines would be hydrotested, replaced, or abandoned.³ SoCalGas's PSEP included an ambitious schedule reflecting a timeline consistent with PUC 958's requirement to test or replace all [in-scope] intrastate transmission lines "as soon as practicable." SoCalGas also complied with PUC 958 through the implementation of interim

¹ The "pertinent federal regulations" cited include 49 C.F.R. Part 192, §§ 192.607, 192.624, 192.634, and 192.636. These regulations are separate and distinct from Public Utilities Code Section 958.

² D.24-12-074 at 228-229.

³ D.14-06-007 at 2, 22, 59 (Ordering Paragraph 1).

safety measures which included increased frequency of ground patrols and leakage surveys and, where feasible, implementation of pressure reductions.

SoCalGas has worked diligently in the course of its 14 year implementation of the program to execute hundreds of projects beginning with those that comprise the highest priority projects. Throughout this time, SoCalGas’s implementation of PSEP has followed the criteria laid out in its original implementation plan that was approved by the Commission in D.14-06-007. To support its successful execution, SoCalGas has put in place a robust framework of program governance, cost and schedule controls, and leadership oversight. Additionally, PSEP complies with SoCalGas and SDG&E’s Gas Standards, applicable laws and regulations, and involves the oversight of the Commission’s Safety Policy Division to prudently and lawfully manage the safety enhancement work. To date (excluding this 2028 GRC), SoCalGas and SDG&E have submitted six applications and one Tier II advice letter covering approximately 200 pipeline projects (SoCalGas only). Approximately 80% of these projects have completed construction.

Table DZ-44 presents the status of PSEP projects forecasted in the 2024 GRC, all of which comply with PUC 958. As noted in prior 2024 GRC testimony,⁴ forecasted costs reflect a portfolio of projects exceeding executable work levels during the GRC period, recognizing that not all projects would be completed within the forecast window.

TABLE DZ-44 - 2024 GRC Forecasted PSEP Project Status

Project⁵	Mileage	In-service Date
38-100 Replacement	0.01	7/11/23
38-539 Replacement	12.9	9/25/27
44-707 Replacement	0.01	5/29/24
44-729 Replacement	0.01	10/25/2028
85 North Lake Station to Grapevine Road Replacement	30.0	11/10/2033
159 Replacement	0.13	11/28/2028
225 North Coles Levee Replacement	0.09	8/1/2028
235 East Kelso Station Replacement	0.05	6/3/24
1004 Section 2 Replacement	2.57	4/17/2029
Indio Laterals Replacement	0.02	11/21/24

⁴ 2024 GRC Testimony of Bill Kostelnik (Ex. SCG-08) at 19, 26.

⁵ Project names were derived from 2024 GRC testimony; however, certain projects are being planned/executed in phases or separate sections to promote constructability, work within system constraints, or facilitate timely permitting approvals.

Project⁵	Mileage	In-service Date
Mesa Cathodic Station Replacement	0.01	8/30/24
Brea Canyon Road Replacement	0.05	10/31/2028
44-306/44-307 Retrofit	52.6	10/4/28 (307) 10/5/29 (306) 10/4/30 (44-1008 Abandon)
41-6000-1 Abandonment	7.96	12/6/23
38-101 Section 3 Derate	10.6	6/12/34
38-2101 Derate	15.4	11/2/23
133 Derate	3.11	10/20/23
38-143 Replacement/Derate	8.08	6/16/34
38-362 Hydrotest	7.31	3/6/30
38-504 Hydrotest	1.90	6/13/25
225 South Hydrotest	10.6	6/12/32
235 East Section 1 Hydrotest	58.1	10/17/28
235 East Section 2 Hydrotest	56.3	10/9/29
Line 257 Hydrotest	0.02	2/24/26
404 Section 12 Hydrotest	6.09	9/15/27
406 Hydrotest	15.4	2/3/28
1004 Hydrotest	0.44	7/20/2026
1005 Hydrotest	15.3	7/18/25
3000 East Hydrotest	116.9	9/5/25 – 8/29/31
4000 Hydrotest	44.02	10/25/24 – 08/18/30
36-9-09 North Hydrotest/Replacement	1.45	9/1/28
38-952 Hydrotest/Replacement	9.23	7/27/31

C. Compliance with Pertinent Federal Regulations as Cited in D.24-12-074

The “pertinent federal regulations” referenced in D.24-12-074 include 49 C.F.R. Part 192, Sections 192.607, 192.624, 192.634, and 192.636. These provisions are separate and distinct from PUC 958 as they govern verification of pipeline material properties and attributes; reconfirmation of MAOP; and installation of rupture mitigation valves, respectively. Compliance with these requirements is overseen by SoCalGas’s Integrity Management department. The regulations were substantially expanded through PHMSA’s Gas Transmission Safety Rule Parts 1 and 2 (including the Valve Rule), promulgated in 2020 and 2022, respectively.

As described in the 2024 GRC Gas Integrity Management testimony (Ex.SCG-09), SoCalGas is implementing these requirements as follows:

- i) **Material Verification (Section 192.607):** SoCalGas is implementing procedures to opportunistically verify through nondestructive and destructive testing, examinations, and assessments, the material properties and attributes of transmission pipelines and components lacking traceable, verifiable, and complete (TVC) records. These activities are managed under TIMP.⁶ 49 CFR Section 192.607 establishes stringent sampling and testing requirements, which increase the volume of testing conducted under TIMP.⁷
- ii) **MAOP Reconfirmation (Section 192.624):** SoCalGas is required to reconfirm, by July 2035, the MAOP of transmission pipelines that meet specified criteria, including: 1) pipelines without TVC pressure test records that are located in HCAs or Class 3 or 4 locations, or 2) pipelines with MAOP established under 49 CFR § 192.619(c) that exceed 30% SMYS and are located in HCAs, Class 3 or 4 locations, or certain segments with small potential impact radius (PIR), or moderate consequence areas where ILI is feasible.⁸ While SoCalGas’s forecast generally assumes pipelines will be pressure tested or replaced, § 192.624 permits the use of six reconfirmation methods, including pressure testing, pressure reduction, engineering critical assessment (ECA), or pipe replacement. The specific reconfirmation method for a given segment may change based on segment or project specific evaluations, including safety; constructability; customer, community, and environmental impacts; system reliability; costs, etc.⁹
- iii) **Rupture Mitigating Valves – Valve Rule (Sections 192.634 and 192.636):** The Valve Rule requires installation of RMVs on onshore gas transmission pipelines with nominal diameters of six inches or greater that are either newly constructed, or entirely replaced segments.¹⁰ The Valve Rule also specifies spacing intervals from eight to twenty miles based on class location. PHMSA has also revised regulations related to identification of potential ruptures, notifications to public safety agencies, among other requirements. These requirements implement congressional mandates and National Transportation Safety Board recommendations to reduce the consequences of large-

⁶ 2024 GRC Gas Integrity Management (Ex. SCG-09) at 7-8.

⁷ Id. at 28.

⁸ Id. at 13.

⁹ Id. at 61.

¹⁰ Includes projects where more than two miles of pipeline are replaced within any five contiguous miles over a 24-month period.

volume, uncontrolled gas releases. SoCalGas has conducted a preliminary analysis of the final rule language, and the costs reflected in workpapers represent the minimum incremental cost required for compliance. The Valve Rule will result in additional RMV installations beyond those implemented under the PSEP Valve Enhancement Plan (VEP)¹¹, where pipeline projects meet applicable criteria.

¹¹ Id. at 64-65.

APPENDIX D
CAPITAL EXPENDITURES

Southern California Gas Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Major Projects	2026	2027	2028	2029	2030	2031
Total Capital	313,736	382,046	468,425	413,044	416,048	414,595
2026 - 2028 Capital Request	307,222	375,811	413,134	-	-	-
Post-Test Year Capital Forecast	6,514	6,235	55,291	413,044	416,048	414,595

Southern California Gas Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Major Projects						
2026 - 2028 Capital Request						
Category	Workpaper Sub	Workpaper Description	In-Service Date	2026	2027	2028
Pipeline Safety Enhancement Plan	005120.001	PSEP Phase 2A Replacements	Routine	484	918	14,270
	005120.002	PSEP Phase 2A Replacements	9/30/2027	989	30,166	-
	005120.003	PSEP Phase 2A Replacements	9/30/2027	569	22,115	-
	005580.001	PSEP Phase 1B Replacements	Routine	5,062	2,003	4,611
	005580.003	PSEP Phase 1B Replacements	9/30/2028	206	306	1,870
	005580.004	PSEP Phase 1B Replacements	10/31/2028	1,294	1,691	39,757
	005630.001	PSEP Phase 2A Capital Component of Hydrotests	Routine	6,175	13,722	3,158
	005630.002	PSEP Phase 2A Capital Component of Hydrotests	10/31/2028	-	-	16,961
	005630.006	PSEP Phase 2A Capital Component of Hydrotests	6/30/2027	192	6,845	271
	005630.008	PSEP Phase 2A Capital Component of Hydrotests	7/31/2026	13,777	105	-
Pipeline Safety Enhancement Plan Total				28,748	77,871	80,898
Gas Safety Enhancement Plan Execution	003670.001	GTSR Part 1 Replacements and Hydrotests	Routine	67,372	35,594	14,232
	003670.002	GTSR Part 1 Replacements and Hydrotests	9/30/2027	642	17,648	-
	003670.003	GTSR Part 1 Replacements and Hydrotests	2/29/2028	533	11,228	2,864
	003670.004	GTSR Part 1 Replacements and Hydrotests	8/31/2028	147	77	8,139
	003670.009	GTSR Part 1 Replacements and Hydrotests	3/31/2028	352	11,693	36,972
	003690.001	Valve Rule	Routine	31,861	50,471	50,453
Gas Safety Enhancement Plan Execution Total				100,907	126,711	112,660
TIMP Execution	002760.001	TIMP Distribution Execution	Routine	21,253	21,246	21,242
	P03120.001	TIMP Transmission Execution	Routine	115,080	115,038	115,006
TIMP Execution Total				136,333	136,284	136,248
HP Distribution Execution	A02760.001	HP Distribution Assessments Execution	Routine	-	-	15,680
HP Distribution Execution Total				-	-	15,680
Compressor Station Compliance Programs	A03350.001	Blythe Compressor Modernization	5/31/2026	2,966	-	-
	A0411A.001	A0411A - Honor Rancho Compressor Modernization	10/31/2028	-	-	31,410
	A04190.001	Reclaim Projects	6/30/2026	10,005	-	-
Compressor Station Compliance Programs Total				12,971	-	31,410
Control Center Modernization	002500.001	CCM Distribution	Routine	16,767	22,967	22,942
	004050.001	CCM Transmission	Routine	1,844	2,332	4,652
Control Center Modernization Total				18,611	25,299	27,594
Blowdown Reduction	A05900.001	Blowdown Reduction - Equipment	6/30/2028	-	-	1,300
	A05960.001	Blowdown Reduction	Routine	9,652	9,646	7,344
Blowdown Reduction Total				9,652	9,646	8,644
Grand Total				307,222	375,811	413,134

Southern California Gas Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Major Projects									
Post-Test Year Capital Forecast									
Category	Workpaper Sub	Workpaper Description	In-Service Date	2026	2027	2028	2029	2030	2031
Pipeline Safety Enhancement Plan	005120.001	PSEP Phase 2A Replacements	Routine	-	-	-	852	8,801	766
	005120.004	PSEP Phase 2A Replacements	7/31/2031	-	-	-	1,319	1,287	20,607
	005580.001	PSEP Phase 1B Replacements	Routine	-	-	-	3,940	12,330	6,570
	005580.002	PSEP Phase 1B Replacements	5/31/2031	4,104	4,104	4,530	5,872	41,894	52,156
	005580.003	PSEP Phase 1B Replacements	9/30/2028	-	-	-	113	-	-
	005580.004	PSEP Phase 1B Replacements	10/31/2028	-	-	-	3,486	-	-
	005580.005	PSEP Phase 1B Replacements	10/31/2029	1,349	1,752	4,542	45,170	3,062	-
	005580.006	PSEP Phase 1B Replacements	4/30/2029	1,060	241	23,793	21,460	12	-
	005580.007	PSEP Phase 1B Replacements	10/31/2030	-	-	-	1,076	6,449	-
	005630.001	PSEP Phase 2A Capital Component of Hydrotests	Routine	-	-	-	1,282	1,763	632
	005630.002	PSEP Phase 2A Capital Component of Hydrotests	10/31/2028	-	-	-	535	39	-
	005630.003	PSEP Phase 2A Capital Component of Hydrotests	10/31/2029	-	-	-	18,089	234	-
	005630.004	PSEP Phase 2A Capital Component of Hydrotests	8/31/2030	-	-	269	269	17,244	-
	005630.005	PSEP Phase 2A Capital Component of Hydrotests	8/31/2030	-	-	146	146	10,719	-
	005630.007	PSEP Phase 2A Capital Component of Hydrotests	8/31/2031	1	-	-	-	-	10,871
	005630.009	PSEP Phase 2A Capital Component of Hydrotests	8/31/2031	-	-	-	-	-	10,434
Pipeline Safety Enhancement Plan Total				6,514	6,097	33,280	103,609	103,834	102,036
Gas Safety Enhancement Plan Execution	003670.001	GTSR Part 1 Replacements and Hydrotests	Routine	-	-	-	36,783	48,734	38,799
	003670.005	GTSR Part 1 Replacements and Hydrotests	11/30/2029	-	87	20,776	17,990	-	-
	003670.006	GTSR Part 1 Replacements and Hydrotests	1/31/2030	-	51	1,199	15,598	3,461	-
	003670.007	GTSR Part 1 Replacements and Hydrotests	2/28/2031	-	-	-	167	3,133	12,806
	003670.008	GTSR Part 1 Replacements and Hydrotests	6/30/2031	-	-	-	415	6,161	23,672
	003670.010	GTSR Part 1 Replacements and Hydrotests	12/31/2030	-	-	36	1,159	13,432	-
	003690.001	Valve Rule	Routine	-	-	-	50,454	50,448	50,460
Gas Safety Enhancement Plan Execution Total				-	138	22,011	122,566	125,369	125,737
TIMP Execution	002760.001	TIMP Distribution Execution	Routine	-	-	-	21,242	21,240	21,243
	P03120.001	TIMP Transmission Execution	Routine	-	-	-	115,007	114,998	115,018
TIMP Execution Total				-	-	-	136,249	136,238	136,261
HP Distribution Execution	A02760.001	HP Distribution Assessments Execution	Routine	-	-	-	15,681	15,679	15,682
HP Distribution Execution Total				-	-	-	15,681	15,679	15,682
Compressor Station Compliance Programs	A03350.001	Blythe Compressor Modernization	5/31/2026	-	-	-	-	-	-
	A0411A.001	A0411A - Honor Rancho Compressor Modernization	10/31/2028	-	-	-	-	-	-
	A04190.001	Reclaim Projects	6/30/2026	-	-	-	-	-	-
Compressor Station Compliance Programs Total				-	-	-	-	-	-
Control Center Modernization	002500.001	CCM Distribution	Routine	-	-	-	22,943	22,935	22,951
	004050.001	CCM Transmission	Routine	-	-	-	4,652	4,650	4,583
Control Center Modernization Total				-	-	-	27,595	27,585	27,534
Blowdown Reduction	A05960.001	Blowdown Reduction	Routine	-	-	-	7,344	7,343	7,345
Blowdown Reduction Total				-	-	-	7,344	7,343	7,345
Grand Total				6,514	6,235	55,291	413,044	416,048	414,595

APPENDIX E
GRC-RAMP INTEGRATION

Area: GAS MAJOR PROJECTS

Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
002500.001	CCM Distribution	2CR03 C124	SCG-Risk-3 Medium Pressure Gas System Regulator Station Installation Replacement & Enhancement	SCADA Enhanced Sites	23,709	16,767	22,967	22,942	22,943	22,935	22,951	8	13	13	13	13	13	13
002760.001	TIMP Distrubution Execution	2CR02 C171	SCG-Risk-2 High Pressure Gas System Integrity Assessments & Remediation	No feasible units	19,429	21,253	21,246	21,242	21,242	21,240	21,243	0	0	0	0	0	0	0
003670.001	GTSR Part 1 Replacements and Hydrotests	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	0	67,372	35,594	14,232	36,783	48,734	38,799	0	40	18	3	8	5	1
003670.002	GTSR-L1018 -TEST-SANT AANA	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	0	642	17,648	0	0	0	0	0	0	12	0	0	0	0

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GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS							
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031	
003670.003	GTSR-L407-TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	533	11,228	2,864	0	0	0	0	0	0	0	0	0	0	0
003670.004	GTSR-L2000-MORENO VALLEY-TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	147	77	8,139	0	0	0	0	0	0	0	0	0	0	0
003670.005	GTSR-L404-TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	0	87	20,776	17,990	0	0	0	0	0	0	0	11	0	0
003670.006	GTSR-L406-TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	0	51	1,199	15,598	3,461	0	0	0	0	0	0	0	8	0

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GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
003670.007	GTSR-L3000 -WEST-TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	0	0	0	167	3,133	12,806	0	0	0	0	0	0	3
003670.008	GTSR-L235- WEST-TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	0	0	0	415	6,161	23,672	0	0	0	0	0	0	9
003670.009	GTSR-L1017 -TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	352	11,693	36,972	0	0	0	0	0	0	6	0	0	0
003670.010	GTSR-L1004 -TEST	2CR02 C013	SCG-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	0	0	36	1,159	13,432	0	0	0	0	0	3	0	

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Area: GAS MAJOR PROJECTS

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GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
003690.001	Valve Rule	2CR02 C118	SCG-Risk-2 High Pressure Gas System Rupture Mitigation Valve Installation - Valve Rule	Valves	62,494	31,861	50,471	50,453	50,454	50,448	50,460	8	6	13	13	13	13	13
004050.001	CCM Transmission	2CR02 C010	SCG-Risk-2 High Pressure Gas System Pipeline Monitoring Technologies	Installations	0	1,844	2,332	4,652	4,652	4,650	4,583	0	50	75	260	260	260	252
005120.001	PSEP Phase 2A Replacements	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	484	918	14,270	852	8,801	766	0	0	0	2	0	1	0
005120.002	PSEP-SL38- 539-P2A	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	989	30,166	0	0	0	0	0	0	7	0	0	0	0
005120.003	PSEP-SL38- 539-P2-01-N ORTH	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	569	22,115	0	0	0	0	0	0	6	0	0	0	0
005120.004	PSEP-SL38- 952-P2A	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	0	0	0	1,319	1,287	20,607	0	0	0	0	0	0	2

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Area: GAS MAJOR PROJECTS

Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
005580.001	PSEP Phase 1B Replacements	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	5,062	2,003	4,611	3,940	12,330	6,570	0	0	0	0	0	0	0
005580.002	Line 85 Elk Hills to Lake Station	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	4,104	4,104	4,530	5,872	41,894	52,156	0	0	0	0	0	0	23
005580.003	PSEP-SL36-1032-P1B-14-Z	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	206	306	1,870	113	0	0	0	0	0	1	0	0	0
005580.004	PSEP-SL44-307-P1B-P1	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	1,294	1,691	39,757	3,486	0	0	0	0	0	1	0	0	0
005580.005	PSEP-SL44-307-P1B-P2	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	1,349	1,752	4,542	45,170	3,062	0	0	0	0	0	1	0	0
005580.006	PSEP-L1004-P1B-Sec 2 Repl	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	1,060	241	23,793	21,460	12	0	0	0	0	0	2	0	0

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GRC - RAMP Integration

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					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
005580.007	PSEP-44-307 -P1B-P3	2CR02 C185	SCG-Risk-2 High Pressure Gas System PSEP Phase 1B	Miles of Pipe	0	0	0	0	1,076	6,449	0	0	0	0	0	0	52	0
005630.001	PSEP Phase 2A Capital Component of Hydrotests	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	6,175	13,722	3,158	1,282	1,763	632	0	360	791	244	15	60	15
005630.002	PSEP-L235E- P2-01 Test	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	0	0	16,961	535	39	0	0	0	0	100	0	0	0
005630.003	PSEP-L235E- P2-02 Test	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	0	0	0	18,089	234	0	0	0	0	0	275	0	0
005630.004	PSEP-L4000- P2A-LUCER NE VLY TO ORD MTN	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	0	0	269	269	17,244	0	0	0	0	0	0	2,166	0
005630.005	PSEP-L4000- P2A-ORD MTN TO NEWBERRY STN	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	0	0	146	146	10,719	0	0	0	0	0	0	1,188	0

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					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031	
005630.006	PSEP-L4000-P2A-APPLE VLY TO LUCERNE VLY	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	192	6,845	271	0	0	0	0	0	0	512	0	0	0	0
005630.007	PSEP-L3000 E-P2A-ESSEX TO KELBAKER	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	1	0	0	0	0	10,871	0	0	0	0	0	0	0	1,095
005630.008	PSEP-L3000 E-P2A-KELBAKER TO LUDLOW	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	13,777	105	0	0	0	0	0	742	0	0	0	0	0	
005630.009	PSEP-L3000 E-P2A-NEEDLES TO ESSEX	2CR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	0	0	0	0	0	0	10,434	0	0	0	0	0	0	0	1,068
A02760.001	HP Distribution Assessments Execution	2CR02 M171	SCG-Risk-2 High Pressure Gas System DIMP - High Pressure Pipeline In-Line Inspections	No feasible units	0	0	0	15,680	15,681	15,679	15,682	0	0	0	0	0	0	0	0

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					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
P03120.001	TIMP Transmission Execution	2CR02 C171	SCG-Risk-2 High Pressure Gas System Integrity Assessments & Remediation	No feasible units	**133	**115	**115	**115	**115	**114	**115	0	0	0	0	0	0	0

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					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
2200-2299.001	TIMP Execution SDG&E Support	2OR02 C171	SCG-Risk-2 High Pressure Gas System Integrity Assessments & Remediation	Miles	1,619	1,538	1,538	1,537	1,537	1,537	1,536	0	0	0	0	0	0	0
2MP000.000	Pipeline Safety Enhancement Plan (PSEP)	2OR02 C186	SCG-Risk-2 High Pressure Gas System PSEP Phase 2A	Miles of Pipe	31,578	31,299	39,776	47,188	39,801	44,901	44,694	44	34	18	63	63	39	62
2MP002.000	TIMP Execution	2OR02 C171	SCG-Risk-2 High Pressure Gas System Integrity Assessments & Remediation	Miles	**150	**153	**159	**139	**139	**139	**139	614	449	517	410	410	410	410
2MP002.002	HP Distributions Assessments Execution	2OR02 M171	SCG-Risk-2 High Pressure Gas System DIMP - High Pressure Pipelin In-Line Inspections	Miles of Pipe	0	0	0	15,231	15,231	15,231	15,229	0	0	0	4	4	4	4

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