Proceeding: A.22-05-xxx

Witness: Travis T. Sera

PREPARED TESTIMONY OF

TRAVIS T. SERA

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY AND

SAN DIEGO GAS & ELECTRIC COMPANY

May 4, 2022

(Errata dated October 25, 2022)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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PREPARED TESTIMONY OF TRAVIS T. SERA

I. PURPOSE

Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (together, "Applicants") provide this testimony in support of their Application for Authority to Establish a Gas Rules and Regulations Memorandum Account ("Application").

II. ESTIMATED INCREMENTAL COSTS FOR ACTIVITIES TO BE RECORDED IN MEMORANDUM ACCOUNT

A. GTS Rule Part 1

Over the last several years, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has worked on certain amendments to 49 C.F.R. Parts 191, 192, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines ("GTGS Rulemaking"). On October 1, 2019,[1] PHMSA issued the first final rule of the overall GTGS Rulemaking, the Pipeline Safety: Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure ("MAOP") Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments ("Gas Transmission Safety ("GTS") Rule Part 1" or "Part 1") with an effective date of July 1, 2020.

Compliance with Part 1 is a time-sensitive issue because by July 2028, Applicants are required by the new rule to complete at least 50% of certain integrity enhancements to pipelines. These improvements are substantial and require significant preparation and expense that Applicants already commenced. As part of planning efforts, Applicants have developed the flowchart, attached as Exhibit 1, to support in determining incrementality among Applicants existing pipeline safety and integrity programs.

Expenses associated with the GTS Rule Part 1 will include the implementation of the following activities:

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[1] *See* 84 Fed. Reg. 52180 (Oct. 1, 2019).

- Where MAOP reconfirmation is required for segments not in the scope of the Pipeline Safety Enhancement Plan ("PSEP"), reconfirm MAOP in accordance with 49 C.F.R. § 192.624; current scope analysis has yielded approximately 150 miles of incremental pipeline segments to be initiated by 2023, with an overall incremental scope of approximately 570 miles.

Although the final amounts may vary materially, Applicants estimate that for Part 1 they will incur total incremental costs of approximately $71M through 2023;[2] refer to Tables 1 and 2 below for estimates of costs that will be incurred to implement GTS Rule Part 1. The estimated costs are based on the current assumption that the majority of miles will be reconfirmed through pressure testing, with the remainder being reconfirmed through replacements. Additionally, the estimates were informed by historical pressure test and replacement project actual costs. Currently, Applicants plan to initiate approximately 150 miles of incremental projects in 2022 to progress towards compliance with the 50% milestone established by 49 C.F.R. § 192.624(b)(1). Scope analysis to date has yielded a current total of approximately 570 miles of incremental scope beyond that of existing programs, though this scope is subject to continued analysis and validation. Applicants will continue to evaluate and identify opportunities to improve cost and program efficiency, constructability, and minimize customer impacts as development of projects progress. Applicants have initiated detailed planning for approximately nine (9) miles of incremental projects to begin preparing for the 50% milestone by 2028. These projects will serve as pilots used by Applicants to develop or enhance best practices for scope and cost management between existing and incremental activities.[3]

[2] Operations & maintenance ("O&M") and capital expenses include overhead loaders and escalation. Capital expenses also include capitalized property taxes and allowance for funds used during construction ("AFUDC").~~Capital and operation and maintenance ("O&M") costs include direct and indirect elements including overheads, property tax, allowance for funds used during construction ("AFUDC"), and return on rate base.~~

[3] An additional seven (7) pilot projects incorporating approximately 16 miles have been initiated through the TIMP to inform technical assessment-driven processes that can be leveraged to reconfirm pipeline segments via the Engineering Critical Assessment method (49 C.F.R. § 192.632).

GTS Rule Part 1 currently expands beyond the Commission's approved PSEP Phase 1A, 1B, and 2A. PSEP Phase 1A specifically includes transmission segments in Class 3 and 4 location and Class 1 and 2 locations in high consequence areas ("HCAs") that do not have sufficient documentation of a pressure test to 1.25 MAOP; PSEP Phase 1B includes pipeline segments installed before 1946 and are not piggable; PSEP Phase 2A includes transmission pipelines that do not have sufficient documentation of a pressure test to at least 1.25 MAOP and are located in Class 1, Class 2 and non-HCAs.[4] The GTS Rule Part 1 MAOP Reconfirmation requirements expand scope to include all transmission segments in Class 3, Class 4, and HCAs that do not have traceable, verifiable, and complete test records; this includes pipeline segments that were deferred to PSEP Phase 2B, which has not yet been approved by the Commission.[5]

B. GTS Rule Part 2

PHMSA is anticipated to publish GTS Rule Part 2 ("Part 2") in June 2022 and will impose compliance obligations taking effect as early as 2023.[6] Part 2 will require Applicants to comply with new and updated sections of 49 C.F.R. Part 192.

Proposed requirements under Part 2 for which Applicants would incur implementation costs under the GRRMA include:

- Completing surveys to identify coating damage on transmission lines after construction has been completed, as well as remediation of coating damage found by these surveys (49 C.F.R. §§ 192.319, 192.461);
- Completing additional surveys to identify anomalies in cathodic protection, creating a timeframe for the remediation of these anomalies, and remediation of

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[4] SoCalGas and SDG&E PSEP Reasonableness Review Application (A.18-11-010), Direct Testimony of Rick Phillips (Execution) Amended April 2, 2019, at 7; available at https://www.socalgas.com/regulatory/documents/a-18-11-010/Chapter%203%20-%20Pipeline%20Projects%20and%20Other%20Costs%20(Phillips)%20Amended%204-1-19_clean.pdf. *See also* D.19-09-051 at 197-198.

[5] D.19-09-051 at 198, 221.

[6] According to PHMSA, Part 2's regulations are expected to be finalized on May 25, 2022. *See* PHMSA's PIPES Act Webchart, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-04/4.6.22%20PIPES%20Website%20Chart.pdf (last accessed on April 26, 2022).

cathodic protection deficiencies (49 C.F.R. § 192.465); and

- A periodic interference current survey program and remediation for transmission lines (49 C.F.R. § 192.473).

Based on preliminary analysis of the prospective Part 2 requirements,[7] Applicants estimate they will incur incremental costs approximately $6M in 2023,[8] as indicated in Tables 1 and 2. These estimated costs are driven by assumptions including: (1) an approximation of assets (e.g., footage/mileage) that would likely be in scope for surveying activities based on preliminary draft language provided by PHMSA, (2) estimated average costs to conduct surveys and remediate anomalies, deficiencies, or damages, and (3) an assumed implementation deadline of twelve (12) months from the time of publication. Should the final rule and resulting activities differ from the current assumptions, final costs will vary.

C. The Valve Rule

On February 6, 2020, PHMSA published the Notice of Proposed Rulemaking regarding the Valve Rule, proposing regulations mandating the installation of "remote-control valves ("RCV"), automatic shutoff valves ("ASV"), or equivalent technology, on all newly constructed and fully replaced gas transmission…lines."[9] On April 8, 2022, PHMSA published the final Valve Rule in the Federal Register with an effective date of either October 5, 2022 or April 10,

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[7] *See* 81 Fed. Reg. 20722 (Apr. 8, 2016), available at https://www.govinfo.gov/content/pkg/FR-2016-04-08/pdf/2016-06382.pdf (last accessed on April 26, 2022), and information provided during the Gas Pipeline Advisory Committee ("GPAC") meeting held on March 26-28, 2018, available at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132 (last accessed on April 26, 2022).

[8] O&M and capital expenses include overhead loaders and escalation. Capital expenses also include capitalized property taxes and AFUDC.~~Capital and O&M costs include direct and indirect elements including overheads, property tax, AFUDC, and return on rate base.~~

[9] PHMSA's Notice of Proposed Rulemaking, 85 FR 7162, available at https://www.federalregister.gov/documents/2020/02/06/2020-01459/pipeline-safety-valve-installation-and-minimum-rupture-detection-standards (last accessed on April 26, 2022).

2023 based on the specific requirements imposed.[10]

Generally, the Valve Rule requires operators to install rupture mitigation valves on certain newly constructed or entirely replaced onshore transmission pipeline segments that have nominal diameters greater than or equal to 6 inches in diameter according to specific spacing intervals from 8 to 20 miles based on class location. In addition, the valves must meet certain performance standards to prevent any public safety consequences due to a pipeline rupture. The Valve Rule also requires updates to existing emergency response procedures to ensure better coordination with emergency response agencies including criteria for identifying potential pipeline ruptures.

The Valve Rule specifies requirements that are beyond what is currently defined for the PSEP Valve Enhancement Plan ("VEP").[11] Applicants currently understand that the Valve Rule differs from the PSEP VEP in three areas. First, the Valve Rule requires ASV/RCV (collectively referred to a Rupture Mitigation Valve "RMV" in the final rule) starting at a smaller diameter transmission line. For instance, the PSEP VEP focuses on adding RMV on replacements that are either 12- or 20-inches, depending on the specified minimum yield strength ("SMYS") value of the line. As part of the PSEP VEP, consideration is given to lines that are either (1) 12 inches or greater that operate in excess of 30% SMYS or (2) 20 inches or greater, operating in excess of 20% SMYS. The Valve Rule, on the other hand, simply considers all on shore transmission lines that are 6 inches or greater. Second, the Valve Rule considers both new construction as well as

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[10] *See* Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards https://www.federalregister.gov/documents/2022/04/08/2022-07133/pipeline-safety-requirement-of-valve-installation-and-minimum-rupture-detection-standards (last visited April 26, 2022).

[11] SoCalGas and SDG&E PSEP Reasonableness Review Application (A.18-11-010), Direct Testimony of Hugo Mejia (Valve Enhancement Plan) dated November 13, 2018, at 1-3; available at https://www.socalgas.com/regulatory/documents/a-18-11-010/Chapter_4_Valves_Mejia.pdf.

entirely replaced transmission pipeline segments. The PSEP VEP primarily adds RMV to replaced lines, whereas the Valve Rule requires the installation of RMV for newly constructed lines and entirely replaced transmission pipeline segments (*see* 49 C.F.R. §§ 192.179, 192.634). While both require the installation of RMV for line replacements, the Valve Rule extends the requirements to newly constructed pipelines and pipeline replacement projects outside of PSEP. Third, the Valve Rule requires updates to business processes that (1) require greater coordination with emergency agencies (2) requires more comprehensive procedures for investigations into failures and incidents, and (3) establishes criteria around identifying pipeline ruptures.

The Valve Rule establishes additional requirements in the following areas:

- 49 C.F.R. § 192.3: Adds three (3) terms to the definition section including "entirely replaced onshore pipeline segments," "notification of potential rupture," and "rupture-mitigation valve (RMV)".
- 49 C.F.R. § 192.9: Establishes the requirements for RMV as applied to gathering lines.
- 49 C.F.R. § 192.18: Establishes the requirements for notifying PHMSA if an operator wishes to install "alternative equivalent technology" to an RMV.
- 49 C.F.R. § 192.179: Establishes spacing requirements on RMV installed on onshore transmission pipelines segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023.
- 49 C.F.R. § 192.610: Provides requirements for installing an RMV in the event that a class location change happens on a transmission line after October 5, 2022 and that results in a pipe replacement.
- 49 C.F.R. § 192.615: Provides requirement for updating emergency plans and coordinating with emergency officials.
- 49 C.F.R. § 192.617: Strengthens incident investigation requirements.
- 49 C.F.R. § 192.634: Requires operators to install RMV on new or entirely replaced onshore transmission pipelines segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023 in HCA, Class 3 or Class 4 locations.
- 49 C.F.R. § 192.635: Establishes the criteria for a "notification of potential rupture."
- 49 C.F.R. § 192.636: Outlines requirements that must be met for RMV installed under the rule in terms of shut off times and monitoring and operating capabilities.
- 49 C.F.R. § 192.745: Establishes the criteria for communications between SCADA system and installed valves, as well as methods to demonstrate compliance with the 30-minute shut off for all RMV installed under the rule.

- 49 C.F.R. § 192.935: Requires risk analysis and assessments completed to mitigate risks against ruptures in HCA to be reviewed and certified by a senior executive by the company.

Applicants anticipate expenses to implement the following activities:

- Development and updating of procedures emergency response (49 C.F.R. § 192.615), investigation of failures and incidents (49 C.F.R. § 192.617), notification of potential ruptures (49 C.F.R. § 192.635), and reviews of risk analysis for ruptures in HCAs (49 C.F.R. § 192.935); and
- Installation of RMV on newly installed, or entirely replaced onshore transmission pipeline segments that are 6 inches or greater diameter in Class 3 and 4 locations or HCAs (49 C.F.R. §§ 192.179, 192.610, 192.634, 192.636, 192.745).

As the requirements in the Valve Rule have very recently been finalized, Applicants will continue to review the final rule language and plan work accordingly. Currently, Applicants estimate that they will incur approximately $14M in incremental costs in 2023,[12] as indicated in Tables 1 and 2, subject to potential variation in the final sum.

D. Estimated Compliance Costs

Applicants' costs are not speculative and will be substantial. Tables 1 and 2 below provides Applicants' estimates of costs for the years 2021, 2022, and 2023 to implement GTS Rule Parts 1 and 2 and the Valve Rule.

Table 1
SoCalGas Estimated Costs (in $Millions)[13]

	2021 (Actuals)	2022 (Estimate)	2023 (Estimate)
GTSR Part 1			
CAPITAL	$0.15	$8.0	$57.0
O&M	$0.00	$0.3	$1.0
TOTAL	**$0.15**	**$8.3**	**$58.0**
GTSR Part 2			
CAPITAL	-	-	$5.2
O&M	-	-	$0.2
TOTAL	**-**	**-**	**$5.4**
Valve Rule			
CAPITAL	-	-	$12.1
O&M	-	-	$0.5
TOTAL	**-**	**-**	**$12.6**

[12] O&M and capital expenses include overhead loaders and escalation. Capital expenses also include capitalized property taxes and AFUDC.~~Capital and O&M costs include direct and indirect elements including overheads, property tax, AFUDC, and return on rate base.~~

[13] *Id.*

Table 2
SDG&E Estimated Costs (in $Millions)[14]

	2021 (Actuals)	2022 (Estimate)	2023 (Estimate)
GTSR Part 1			
CAPITAL	-	-	$4.5
O&M	-	-	$0.1
TOTAL	**-**	**-**	**$4.6**
GTSR Part 2			
CAPITAL	-	-	$0.5
O&M	-	-	$0.0
TOTAL	**-**	**-**	**$0.5**
Valve Rule			
CAPITAL	-	-	$1.1
O&M	-	-	$0.0
TOTAL	**-**	**-**	**$1.1**

III. CONCLUSION

This concludes my prepared testimony.

[14] *Id.*

IV. QUALIFICATIONS

Travis T. Sera

My name is Travis T. Sera. I am employed by SoCalGas as the current Director of Integrity Management. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011.

I joined SoCalGas in 1995 and have held various positions of increasing responsibility within the Gas Engineering and System Integrity department. I left SoCalGas briefly, from 2003 to 2005, and during this time held the title of Senior Consulting Engineer for Structural Integrity Associates, an engineering consulting firm to the nuclear, petro-chemical, and pipeline industries.

I have been in my current position at SoCalGas since 2019. My responsibilities include oversight of the Transmission Integrity Management Program and the Distribution Integrity Management Program, in addition to the broad application of Integrity Management principles across various departments within SoCalGas and SDGE. I have a Bachelor of Science degree in Materials Engineering from California Polytechnic State University - San Luis Obispo. I am a registered Professional Metallurgical Engineer in the State of California, and I hold a CP4 - Cathodic Protection Specialist certification from the National Association of Corrosion Engineers ("NACE").

I have previously testified before the Commission.

EXHIBIT 1

Exhibit 1 – GTSR Planning Flow Chart